

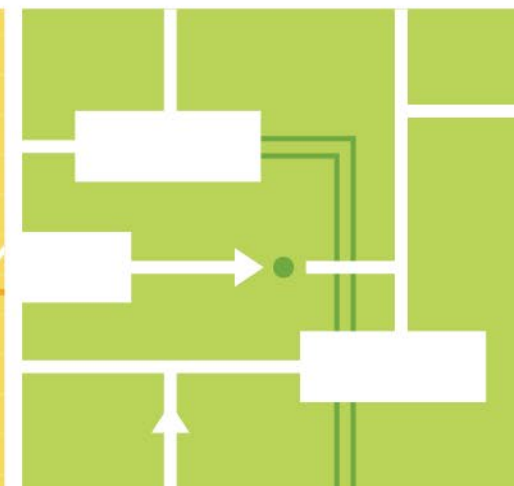
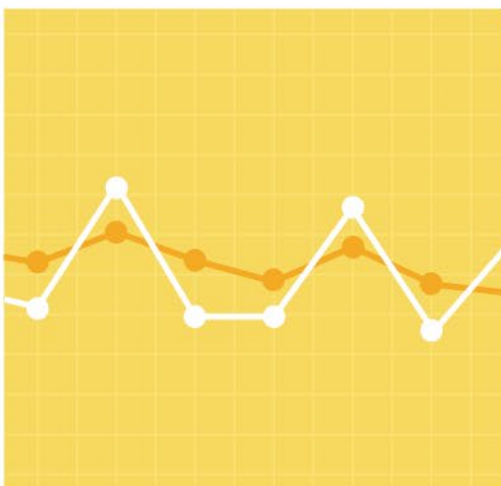


2019 ISO New England Electric Generator Air Emissions Report

© ISO New England Inc.
System Planning

MARCH 2021

ISO-NE PUBLIC



Contents

Summary of Changes to the 2019 Emissions Report	1
Executive Summary.....	2
Section 2 Background	6
2.1 History of Marginal Emissions Methodologies.....	7
2.2 History of Heat Rate Methodologies.....	8
Section 3 Data Sources and Methodologies.....	9
3.1 Data Sources.....	9
3.2 Total System Emission Rate Calculation	9
3.3 Marginal Emission Rate Calculation	10
3.4 Marginal Heat Rate Calculation	11
3.5 Time Periods Analyzed	12
Section 4 Data and Assumptions.....	13
4.1 2019 New England Weather.....	13
4.2 Emissions Data.....	13
4.3 ISO New England System Installed Capacity.....	14
4.4 ISO New England System Energy Production	16
4.5 Locational Marginal Unit Scenarios.....	18
4.5.1 All LMUs.....	18
4.5.1.1 Time-Weighted Approach – All LMUs.....	18
4.5.1.2 Load-Weighted Approach – All LMUs.....	20
4.5.1.3 Comparison of Time-Weighted and Load-Weighted Results – All LMUs.....	21
4.5.2 Emitting LMUs	22
4.5.2.1 Time-Weighted Approach – Emitting LMUs	22
4.5.2.2 Load-Weighted Approach – Emitting LMUs	23
4.5.2.3 Comparison of Time-Weighted vs. Load-Weighted Results - Emitting-LMUs	24
4.6 High Electric Demand Days.....	25
Section 5 Results and Observations	26
5.1 2019 ISO New England System Emissions	26
5.1.1 Results.....	26
5.1.2 Additional Observations	29
5.2 2019 ISO New England Marginal Heat Rate	30
5.3 2019 ISO New England Marginal Emission Rates	31
5.3.1 Marginal Emission Rates Using the Time-Weighted Approach	31
5.3.1.1 All-LMU Scenario	31
5.3.1.2 Emitting-LMU Scenario.....	33
5.3.1.3 2010 to 2019 Time-Weighted LMU Marginal Emission Rates	34
5.3.2 Marginal Emission Rates Using the Load-Weighted Approach.....	35
5.3.2.1 All-LMU Scenario	35
5.3.2.2 Emitting-LMU Scenario.....	36
5.3.3 Comparison of Marginal Emission Rates Using the Time- and Load-Weighted Approaches.....	36
5.3.4 Additional Observations	39
5.4 Marginal Emission Rates for High Electric Demand Days.....	40
5.5 Observations.....	40
Section 6 Appendix	42

Figures

Figure 1-1: Percentage energy generation by fuel type, 2010 compared with 2019.....	3
Figure 1-2: Comparison of 2019 ISO New England system and marginal emission rates (lbs/MWh).....	5
Figure 4-1: 2019 ISO New England generator summer capacity by state (MW).	14
Figure 4-2 : ISO New England generator additions, 2010 to 2019 (MW).	15
Figure 4-3: Major retirements in ISO New England, 2010 to 2019 (MW).	16
Figure 4-4: 2019 ISO New England monthly generation by fuel type, including imports (% GWh, GWh).....	17
Figure 4-5: ISO New England annual native generation by fuel type, 2015 to 2019 (million MWh).....	18
Figure 4-6: 2019 percentage of time various resource types were marginal —all LMUs.....	19
Figure 4-7: Annual percentage of time various resource types were marginal —all LMUs, 2015 to 2019.	20
Figure 4-8: 2019 percentage of load for which various resource types were marginal —all LMUs.....	20
Figure 4-9: Annual percentage of load for which various resource types were marginal – all LMUs, 2018 and 2019.	21
Figure 4-10: Comparison of 2019 annual marginality for various resource types using the time-weighted vs. load-weighted approach —all LMUs.....	22
Figure 4-11: 2019 percentage of time various resource types were marginal —emitting LMUs.....	23
Figure 4-12: Annual percentage of time various resource types were marginal – emitting LMUs, 2015 to 2019.....	23
Figure 4-13: 2019 percentage of load for which various resource types were marginal —emitting LMUs.....	24
Figure 4-14: Annual percentage of load for which various resource types were marginal – emitting LMUs, 2018 and 2019.	24
Figure 4-15: Comparison of 2019 annual marginality for various resource types using the time-weighted vs. load-weighted approach —emitting LMUs.....	25
Figure 5-1: 2019 ISO New England system annual emissions of NO _x , SO ₂ , and CO ₂ (ktons).	27
Figure 5-2: ISO New England system annual generator emissions, 2010 to 2019 (ktons).	27
Figure 5-3: 2019 ISO New England system monthly average generator emission rates (lbs/MWh).....	28
Figure 5-4: ISO New England system annual average generator emission rates, 2010 to 2019 (lbs/MWh).....	29
Figure 5-5: 2019 time- and load-weighted LMU monthly marginal heat rate (MMBtu/MWh).....	30
Figure 5-6: LMU annual marginal heat rate, 2010-2019 (MMBtu/MWh).	31
Figure 5-7: 2019 time-weighted monthly LMU marginal emission rates—all LMUs (lbs/MWh).	32
Figure 5-8: 2019 time-weighted monthly LMU marginal emission rates—emitting LMUs (lbs/MWh).....	33
Figure 5-9: Time-weighted LMU marginal emission rates, 2010 to 2019—all LMUs (lbs/MWh).....	34
Figure 5-10: Time-weighted LMU marginal emission rates, 2010 to 2019—emitting LMUs (lbs/MWh).....	34
Figure 5-11: 2019 load-weighted monthly LMU marginal emission rates—all LMUs (lbs/MWh).....	35
Figure 5-12: 2019 load-weighted monthly LMU marginal emission rates—emitting LMUs (lbs/MWh).....	36
Figure 5-13: 2019 time- and load-weighted monthly LMU marginal SO ₂ emission rates.	38
Figure 5-14: 2019 time- and load-weighted monthly LMU marginal NO _x emission rates.....	38
Figure 5-15: 2019 time- and load-weighted monthly LMU marginal CO ₂ emission rates.	39

Tables

Table 1-1 2018 and 2019 ISO New England System Emissions (ktons) and Emission Rates (lbs/MWh)	3
Table 1-2 2018 and 2019 Annual Time-Weighted and Load-Weighted LMU Marginal Emission Rates (lbs/MWh)	4
Table 5-1 2019 ISO New England System Annual Average Generator Emission Rates (lbs/MWh)	28
Table 5-2 2018 and 2019 ISO New England System Emissions (ktons) and Emission Rates (lbs/MWh)	29
Table 5-3 2019 Time-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MWh) ^(a, b)	32
Table 5-4 2019 Time-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MWh)	33
Table 5-5 2019 Load-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MWh).....	35
Table 5-6 2019 Load-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MWh)	36
Table 5-7 2019 Time-Weighted and Load-Weighted LMU Marginal Emission Rates (lbs/MWh).....	37
Table 5-8 2018 and 2019 Annual Time-Weighted and Load-Weighted LMU Marginal Emission Rates (lbs/MWh)	39
Table 5-9 High Electric Demand Day LMU Marginal Emission Rates (lbs/MWh)	40
Appendix Table 1 ISO New England Total Cooling and Heating Degree Days, 2000 to 2019	42
Appendix Table 2 2019 ISO New England Summer Generating Capacity (MW, %) ^(a, b)	42
Appendix Table 3 2019 ISO New England Winter Generating Capacity (MW, %) ^(a, b)	43
Appendix Table 4 ISO New England System Annual Generator Emissions, 2001 to 2019 (kilotons) ^(a)	43
Appendix Table 5 2019 ISO New England System Average Monthly Generator Emission Rates (lbs/MWh).....	44
Appendix Table 6 ISO New England System Annual Average Generator Emission Rates, 1999 to 2019 (lbs/MWh)....	44
Appendix Table 7 LMU Marginal Heat Rate, 2010 to 2019 (MMBtu/MWh)	45
Appendix Table 8 2019 Time-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MMBtu)	45
Appendix Table 9 2019 Monthly Time-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MWh).....	45
Appendix Table 10 2019 Time-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MMBtu).....	46
Appendix Table 11 2019 Monthly Time-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MWh).....	46
Appendix Table 12 NO _x Time-Weighted LMU Marginal Emission Rates, 2010 to 2019 —All LMUs (lbs/MWh).....	46
Appendix Table 13 NO _x Time-Weighted LMU Marginal Emission Rates, 2010 to 2019—Emitting LMUs (lbs/MWh)....	47
Appendix Table 14 SO ₂ Time-Weighted LMU Marginal Emission Rates, 2010 to 2019—All LMUs (lbs/MWh).....	47
Appendix Table 15 SO ₂ Time-Weighted LMU Marginal Emission Rates, 2010 to 2019—Emitting LMUs (lbs/MWh)	48
Appendix Table 16 CO ₂ Time-Weighted LMU Marginal Emission Rates, 2010 to 2019—All LMUs (lbs/MWh)	48
Appendix Table 17 CO ₂ Time-Weighted LMU Marginal Emission Rates, 2010 to 2019—Emitting LMUs (lbs/MWh)....	49
Appendix Table 18 2019 Load-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MMBtu)	49
Appendix Table 19 2019 Monthly Load-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MWh)	49
Appendix Table 20 2019 Load-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MMBtu).....	50
Appendix Table 21 2019 Monthly Load-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MWh).....	50

Summary of Changes to the 2019 Emissions Report

The following is a summary of changes implemented in the *2019 Emissions Report*:

- Net imports, which amounted to 19% of total ISO New England energy in 2019, were added to the total annual and monthly energy generation by fuel type in Figure 1-1 and Figure 4-4.
 - In this version of the *2019 Emissions Report*, imports are reported as having zero emissions.
 - Following the completion of the *2018 Emissions Report*, the 2018 annual CO₂ emission rates for imports from New York, New Brunswick and Quebec were calculated and presented to the EAG in June 2020.¹ The ISO is in the process of updating the CO₂ rates for 2019, and will also develop 2019 import emission rates for NO_x and SO₂.
 - When emission rates for imports become available, all of the system emissions and marginal emission rates will be recalculated and included as an appendix to the report.
- Section 4.5 Locational Marginal Unit Scenarios was rearranged so that the results from both the time-weighted and load-weighted approaches were included together under the all-LMU and emitting-LMU scenarios. This was done for ease of comparison between the two approaches.

Questions regarding the *2019 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/static-assets/documents/2020/06/estimating_envtl_attributes_imports_2020625.pdf

Section 1

Executive Summary

This 2019 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 [SO₂], and carbon dioxide [CO₂]) and a review of relevant system conditions. The main factors analyzed are as follows:

- System² 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 New England region's aggregate NO_x, SO₂, and CO₂ 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 resources within the New England region.

During the ten-year period from 2010 through 2019, total system emissions (ktons) have decreased overall: NO_x by 55%, SO₂ by 97%, and CO₂ by 41%. The decline in emissions during this period reflects shifts in the regional generation mix, with imports and wind generation offsetting decreases in coal-fired generation (see Figure 1-1).

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.

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

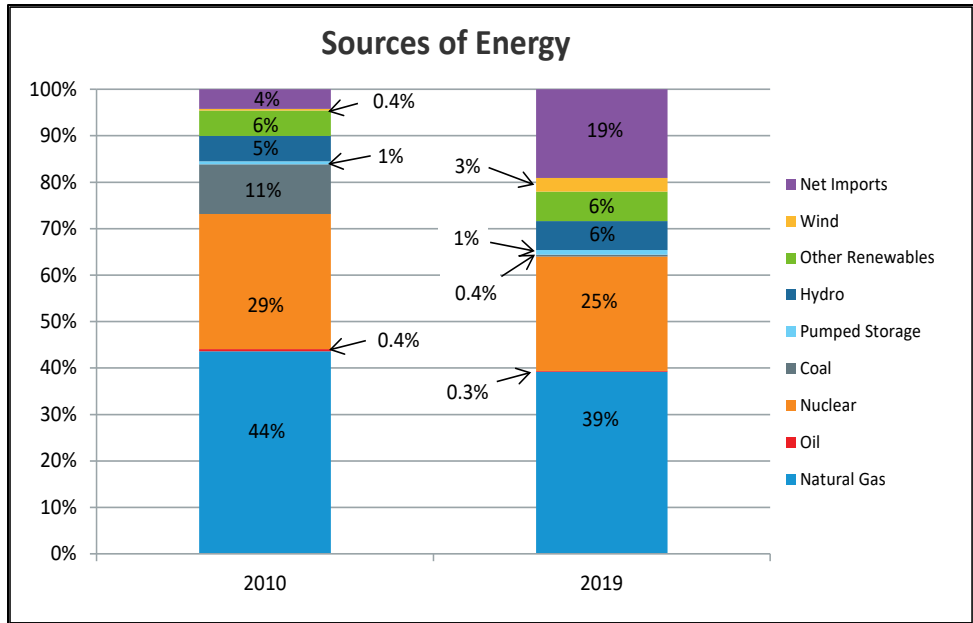


Figure 1-1: Percentage energy generation by fuel type, 2010 compared with 2019.

Compared with the 20-year average for heating and cooling days (i.e., an indicator of weather), 2019 had both an average summer and winter. From 2018 to 2019, the net energy for load⁴ and generation⁵ by native ISO New England resources decreased by 3.4% and 5.6%, respectively. The net energy that ISO New England received from neighboring systems in 2019 was approximately 7% higher than the previous year. Generation by hydro, wind, and solar resources increased by about 14%, while nuclear generation declined by 5%. Generation by all fossil-fueled resources declined as well from 2018 to 2019: coal- and oil-fired generation decreased by 60% and 87%, respectively, and natural gas-fired generation decreased by 6%.

Table 1-1 shows the total 2018 and 2019 ISO New England system emissions (ktons) and average system emission rates (lbs/MWh) of NO_x, SO₂ and CO₂. In 2019, both the system emissions and the emission rates decreased for all emission types.

Table 1-1
2018 and 2019 ISO New England System Emissions (ktons)
and Emission Rates (lbs/MWh)

Annual System ^(a) Emissions						
	2018 Emissions (ktons)	2019 Emissions (ktons)	Change in Emissions (%)	2018 Emission Rate (lbs/MWh)	2019 Emission Rate (lbs/MWh)	Change in Emission Rate (%)
NO _x	15.61	12.87	-17.6	0.30	0.26	-13.3
SO ₂	4.96	2.34	-52.8	0.10	0.05	-50.0
CO ₂	34,096	30,997	-9.1	658	633	-3.8

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

⁴ 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 fill/refill pumped storage plants.

⁵ In this report, “generation” refers to energy production and not capacity.

The 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.

The ISO calculated 2019 marginal emission metrics 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, the load-weighted LMUs 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.

The time-weighted LMU annual marginal rates for SO₂, NO_x, and CO₂ have exhibited an overall decrease during the past ten years. Compared with 2010, the 2019 LMU SO₂ annual marginal rates have declined by over 97% for both the all-LMU and emitting-LMU scenarios.

Since the load-weighted LMU annual marginal rates have only been calculated since the 2018 Emissions Report, a long-term history of those rates is not available. However, as shown in Table 1-2, the reductions in the annual average marginal emission rates from 2018 to 2019 using the load-weighted approach are similar to those of the time-weighted approach. Both approaches resulted in reductions ranging from 41% to 46% for NO_x, 75% to 82% for SO₂, and 1% to 4% for CO₂.

**Table 1-2
2018 and 2019 Annual Time-Weighted and Load-Weighted LMU Marginal Emission Rates (lbs/MWh)**

	LMU Marginal Emission Rates					
	Time-Weighted			Load-Weighted		
	2018 Annual Rate	2019 Annual Rate	Percent Change 2018 to 2019	2018 Annual Rate	2019 Annual Rate	Percent Change 2018 to 2019
	(lbs/MWh)	(lbs/MWh)	(%)	(lbs/MWh)	(lbs/MWh)	(%)
All LMUs						
NO _x	0.17	0.10	-41.2	0.20	0.11	-45.0
SO ₂	0.11	0.02	-81.8	0.13	0.03	-76.9
CO ₂	655	648	-1.1	745	719	-3.5
Emitting LMUs						
NO _x	0.28	0.15	-46.4	0.27	0.15	-44.4
SO ₂	0.17	0.04	-76.5	0.16	0.04	-75.0
CO ₂	1,005	970	-3.5	971	943	-2.9

As can be observed above, the load-weighted marginal emission rates for the all-LMU scenario are 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 only 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.

Figure 1-2 summarizes the 2019 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 simple-cycle natural gas-fired units on the margin was higher than on average during the year.

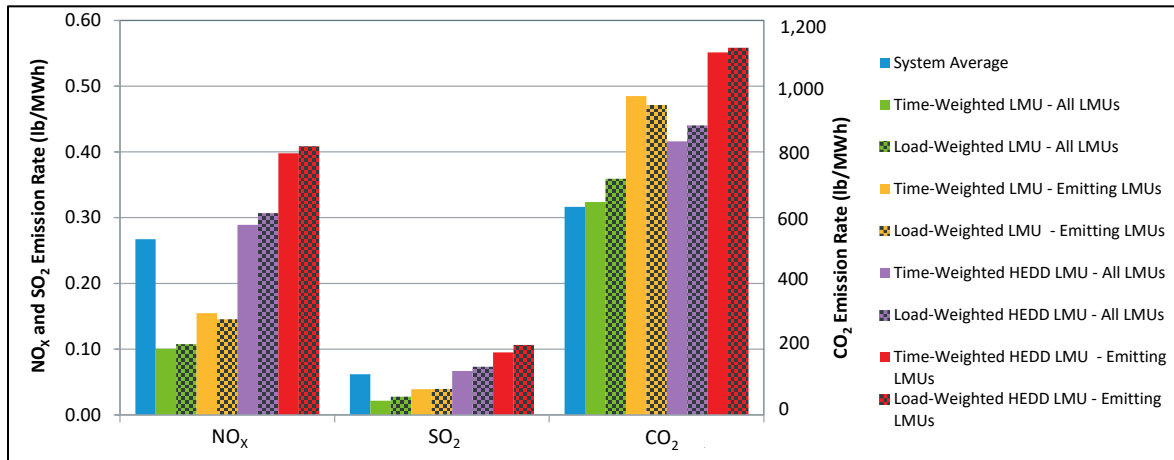


Figure 1-2: Comparison of 2019 ISO New England system and marginal emission rates (lbs/MWh).

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 2019 calculated all-LMU marginal heat rate of 5.223 MMBtu/MWh was 1.4% higher than the 2018 value of 5.153 MMBtu/MWh. When considering the emitting units only, the LMU marginal heat rate decreased 0.5%, from 7.855 MMBtu/MWh in 2018 to 7.815 MMBtu/MWh in 2019.

The heat rates were also calculated using the load-weighted approach, which resulted in 2019 marginal heat rates of 5.918 MMBtu/MWh and 7.716 MMBtu/MWh for the all-LMU and emitting-LMU scenarios, respectively. In both cases, those values represented decreases of less than 1% from the 2018 load-weighted marginal heat rates.

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 (SO₂), and carbon dioxide (CO₂) 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 air emissions from the entire ISO New England electric generation system.

The *Emissions Report* includes a marginal emission rate 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.

In 2018, in response to a request by the EAG, the ISO added to the *Emissions Report* a new, load-weighted LMU 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, SO₂, and CO₂ power plant air emissions. The *2019 Emissions Report* focuses on analysis and

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 Power Supply Planning Committee (PSPC); <http://www.iso-ne.com/eag>.

observations over the past decade (2010 to 2019). The Appendix includes data for years before 2010, 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) because actual hourly generation, fuel type and emissions data were not readily available electronically. 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 dynamics of the energy dispatch, out-of-merit and reliability-based dispatches, unit-specific short-term 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 only 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, must-run, or were non-dispatchable and not typically dispatched to balance supply with demand on the system. Other non-emitting resources, such as hydro-electric, 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 method for calculating the marginal emission rate, as described above, was 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 added a new method for calculating marginal emission rates, which is based on the percentage of system load a marginal unit can serve. This new method, which was first included in the *2018 Emissions Report*, is referred to as the load-weighted LMU approach. It 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 type⁹. The marginal emission rates calculated with the load-weighted LMU approach are included in this *2019 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.

Starting 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 heat-rate data provided to the ISO by the generators. 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 original 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.

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 wind resources, which became frequently marginal with the implementation of the Do Not Exceed (DNE) dispatch rules on May 25, 2016. DNE incorporates wind and hydro intermittent units into economic 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, SO₂, and CO₂ was the US EPA Clean Air Markets Division (CAMD) database.¹¹ The database contains measured 2019 air emissions (tons) reported by generators under EPA’s monitoring and recordkeeping requirements for the Acid Rain Program, 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 eGRID2018 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 energy production (generation), from the ISO’s database used for energy market settlement purposes, to calculate tons of emissions.

All electric generators and demand response resources dispatched by ISO New England are included in the emissions calculations. Emissions from “behind-the-meter” resources 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 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 CO₂ emissions to EPA. Additional details for the monitoring, recordkeeping, and reporting requirements of SO₂, NO_x, and CO₂ emissions, volumetric flow, and opacity data from affected units under 40 CFR Part 75 are available at <https://www.epa.gov/airmarkets/emissions-monitoring-and-reporting>.

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 eGRID2018 database (2021) is available at <http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html>.

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 a specific 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 (transmission) 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 process
- **Emitting LMUs**—excludes all non-emitting units with no associated air emissions, such as pumped storage, hydro-electric, and nuclear generation, as well as 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 generator¹⁴. 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:

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

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 2019 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 SO₂ and CO₂ 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/genrntion_resrcs/reports/emission/peak_nox_analysis.pdf

Section 4

Data and Assumptions

This section highlights the key parameters and assumptions modeled in the *2019 Emissions Report*, including weather, emissions data, installed capacity, and system generation.

4.1 2019 New England Weather

Because the weather significantly affects the demand for energy and peak loads, comparing 2019 temperatures, total energy use and both cooling and heating degree days to previous years can provide some perspective.

New England monthly temperatures in 2019 were generally close to their averages. The January 2019 weather was milder than the previous year: there were 1,190 heating degree days, which was 2% lower than January 2018. The average temperature of 27°F in January was the same as the 20-year average. In summer 2019, slightly cooler and less humid weather in New England led to a 5% decrease in average loads, compared to the prior summer. In 2019, the Temperature-Humidity Index (THI) was 69°F compared to 70°F in summer 2018, and summer 2019 had fewer Cooling Degree Days (672 CDD vs. 714 CDD) than summer 2018. Compared to the 20-year average, July was approximately 4°F hotter, or about 5% higher than average, and August was about the same as the average.

The 2019 summer peak electricity demand of 24,361 MW was 6.2% lower than the 2018 summer peak of 25,980 MW. There were 325 cooling degree days in 2019, which is 1.3% lower than the 20-year average.¹⁶ The net energy for load was 3.4% lower in 2019 than 2018. With respect to the winter months, there were 6,046 heating degree days, which is 0.5% higher than the 20-year average.

New England's historical cooling and heating degree days for 2000 through 2019 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 25% of the total NO_x emissions, 34% of the SO₂ emissions and 71% of the CO₂ emissions were based on EPA's Clean Air Markets data. When emissions data obtained from NEPOOL GIS are also included, those percentages increase to approximately 93% of total NO_x, SO₂, and CO₂ emissions.

The emission rates were multiplied by the 2019 energy generation reported to the ISO to obtain the emissions (tons) by each generator.

¹⁶ Over the 20-year span from 2000 to 2019, the average number of cooling degree days was 329, and the average number of heating degree days was 6,018.

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 prices and emission allowance costs
- Imports from and exports to neighboring regions
- System peak load and energy consumption
- Water availability to hydro-electric facilities and for thermal power plant cooling
- A variety of other factors

Figure 4-1 shows the total 2019 summer capacity for ISO New England generation as obtained from *ISO New England's 2020–2029 Forecast Report of Capacity, Energy, Loads and Transmission (CELT)*.¹⁷ Appendix Table 2 and Appendix Table 3 summarize the total summer and winter capacity, respectively for ISO New England generation by state and fuel type.¹⁸

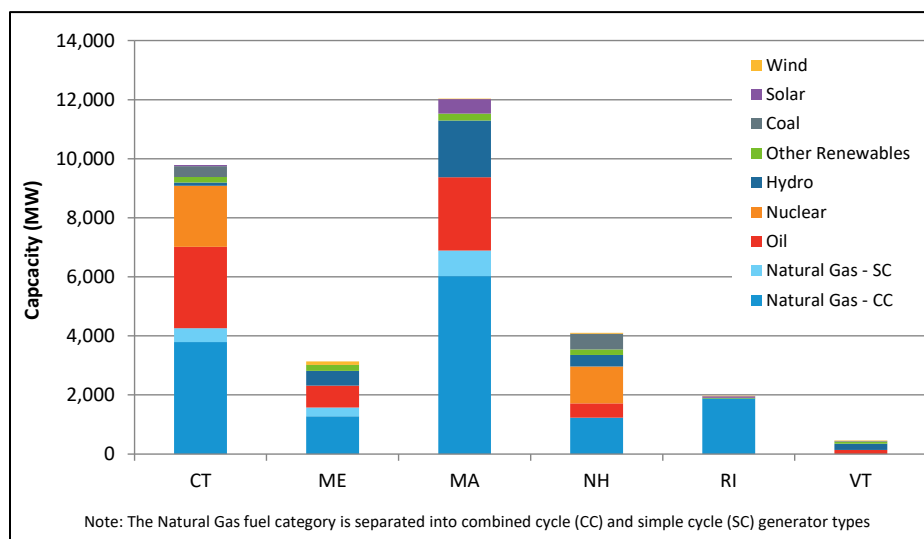


Figure 4-1: 2019 ISO New England generator summer capacity by state (MW).

Figure 4-2 illustrates the new generating capacity added to the ISO New England system from 2010 through 2019. A total of 5,113 MW was added, with combustion turbines and combined-cycle plants capable of burning natural gas or distillate oil making up about 79% of this new capacity. Notably, 75% of the total natural gas capacity additions during this period occurred in 2018 and

¹⁷ The ISO New England *CELT Report* is typically issued in May of each year. The *2020 CELT Report* (using the seasonal claimed capabilities (SCC) as of January 1, 2020) was used to completely capture all the new capacity additions that occurred during the prior calendar year, 2019. The capacity may also include generators that retired in 2019. The CELT reports are available at iso-ne.com/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.

2019, with approximately 2,600 MW of new gas-fired capacity. The remaining additions over the prior ten years consist primarily of renewable generation, including 15% of total capacity from wind and solar resources.

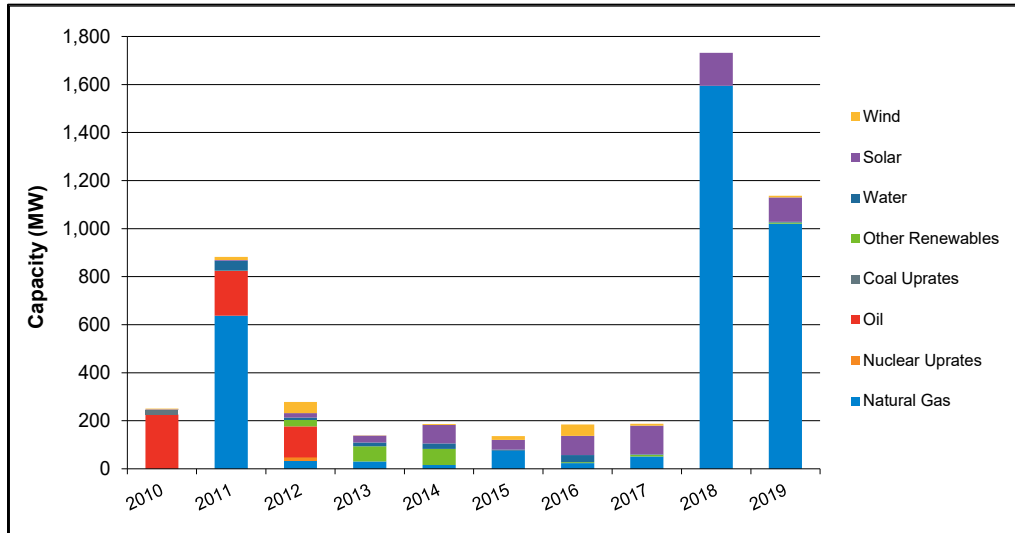


Figure 4-2 : ISO New England generator additions, 2010 to 2019 (MW).

Note: The generator additions and uprate values are based on the summer Seasonal Claimed Capabilities, as reported in the 2020 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 1,281 MW of nuclear generation since late 2011.

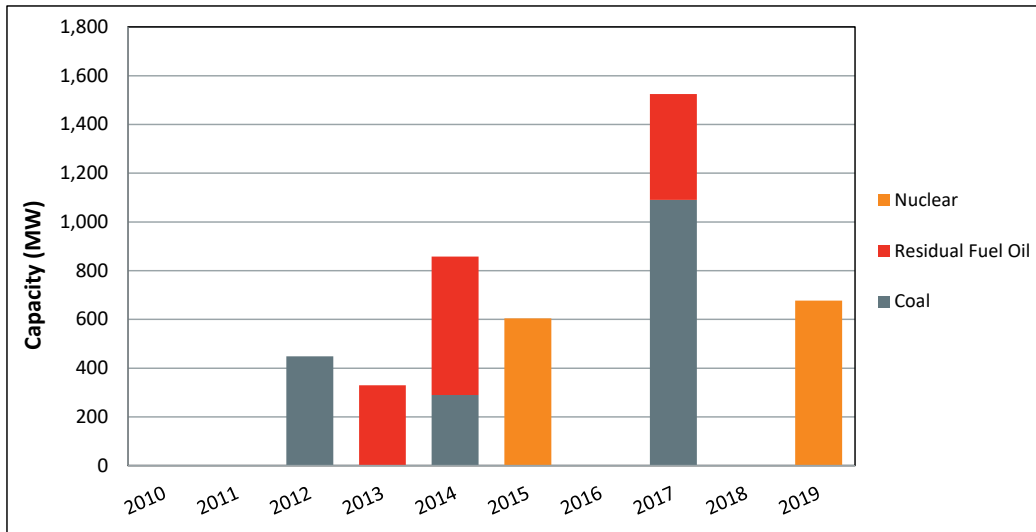


Figure 4-3: Major retirements in ISO New England,¹⁹ 2010 to 2019 (MW)²⁰.

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 2019 monthly sources of energy by fuel type, which includes both native generation and net imports. The overlaid black line represents the total energy in each month and corresponds with the right axis. Natural-gas-fired generation accounted for 41% to 60% of the total native generation in each month,²¹ or an annual average of 39% of total system energy when taking net imports into account. 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. 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.²² Almost all gas-fired generating units lack both firm supply and transportation contracts.

Although oil- and coal-fired generation were each less than 0.4% of the annual system total in 2019, the contribution of coal to total generation in the month of January was somewhat higher than the average (1.6%) and the contribution of oil to total generation was higher during the months of July and August (1.5% and 0.7%, respectively), due to the higher demand in those months. The

¹⁹ See <https://www.iso-ne.com/about/what-we-do/in-depth/power-plant-retirements> for a discussion of New England resource retirements, and https://www.iso-ne.com/static-assets/documents/2016/08/retirement_tracker_external.xlsx for a listing of retirements.

²⁰ 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.

²¹ The share of annual native energy production for natural gas-fired generation was 48% in 2019, compared to 49% in 2018.

²² Firm customers of regional gas LDCs include residential, commercial, and industrial (RCI) customers.

percentage of natural-gas-fired generation also increased in the summer months to meet the higher demand, and was lowest in the winter and spring months.

Combined hydro-electric, solar, and wind generation accounted for 8% to 21% of the total 2019 native generation, or an annual average of 12% in terms of total system energy. These fuel types exhibit seasonal differences in their generation due to fuel availability; typically hydro-electric 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 April and September.

The percentage of net imports ranged from 15% to 22% of total energy.

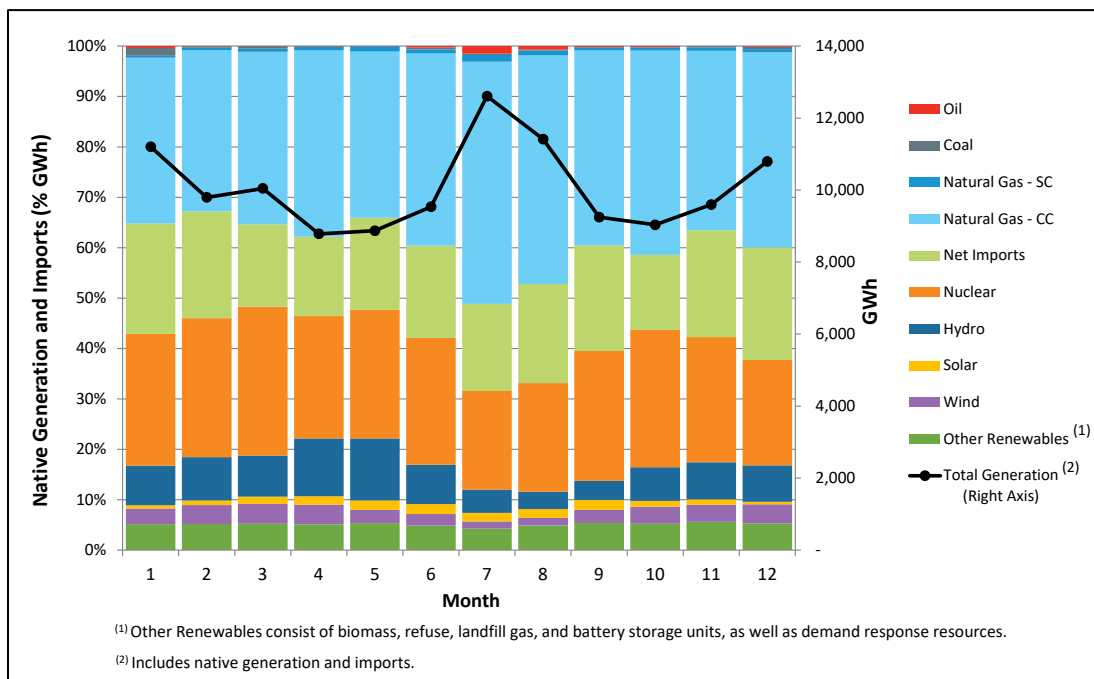


Figure 4-4: 2019 ISO New England monthly generation by fuel type, including imports (% GWh, GWh).

Figure 4-5 shows the native generation (MWh) by fuel type from 2015 to 2019 based on the resource’s primary fuel type listed in the *2020 CELT Report*. In 2019, there was a decrease in generation in all fuel categories except for hydro, wind and solar. Coal-fired generation continued its decline, and was about 700 GWh lower than in 2018. Oil-fired generation, which has been declining throughout this five-year period, decreased by 1,100 GWh in 2019. Natural-gas-fired generation in 2019 was about 2,900 GWh lower than in 2018, decreasing by about 6%. Nuclear generation decreased by about 1,600 GWh, or 5%. Generation by non-emitting renewable resources increased in 2019: hydro-electric generation was 1% higher, and solar and wind together increased by nearly 600 GWh, or 13% over 2018. The overall native generation of 97,864 GWh²³ in 2019 was 6% lower than in 2018.

²³ This total does not include the 26 GWh of demand-response resources, i.e., Price Responsive Demand (PRD), that is included as supply in the New England energy totals (see Net Energy and Peak Load by Source Report <https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/net-ener-peak-load>).

Net imports, which are not included in the figure, were 7.1% higher in 2019 than in 2018, increasing from 21,536 GWh to 23,063 GWh. They were comprised of 24,808 MW of imports and 1,745 MW of exports.

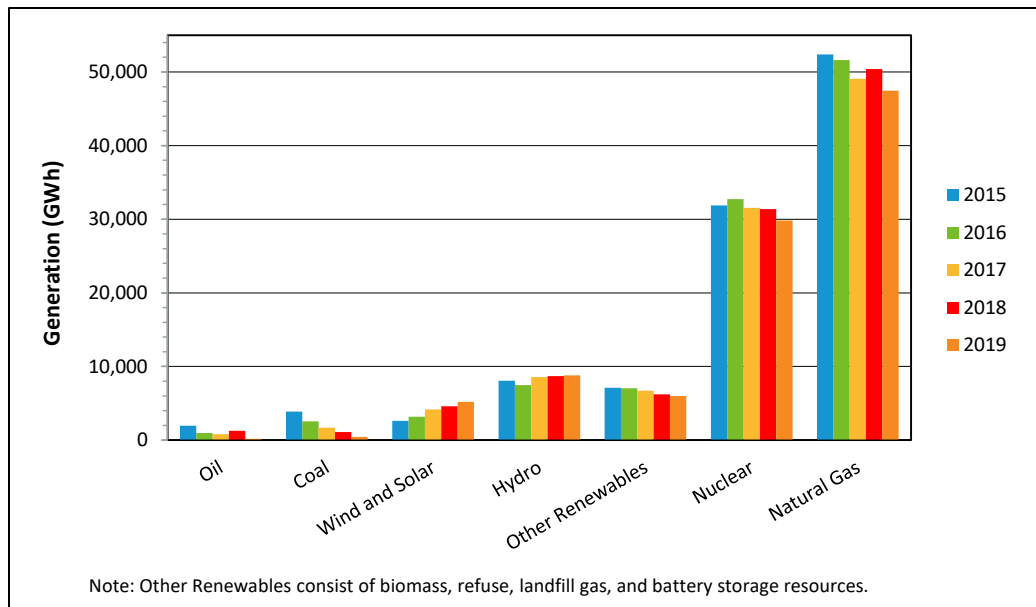


Figure 4-5: ISO New England annual native generation by fuel type, 2015 to 2019 (GWh).

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 help explain changes in electricity prices and emissions.

4.5.1 All LMUs

4.5.1.1 Time-Weighted Approach – 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 for the time-weighted approach. Natural gas was marginal 54% to 77% of the time. The months when natural gas units were marginal in the higher end of that range were July through September. Oil-fired generation was on the margin an average of less than 0.1% during the year, and was marginal a maximum of 0.5% of the time in December when temperatures were slightly colder than normal. During the month of January, coal-fired generation was on the margin more than other months, about 3% of the time. Other Renewables, which consist of biomass, refuse, and landfill gas units, as well as demand response resources, were marginal an average of 2% of the time, with a peak of 6% in October. 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 2019, the time that wind was marginal ranged from 3% in August to a maximum of 22% in February. Note that Figure 4-6 includes a

breakdown of the pumped storage category into pumped storage generation and pumped storage demand²⁴, which were marginal an average of 10% and 6% of the time, respectively.

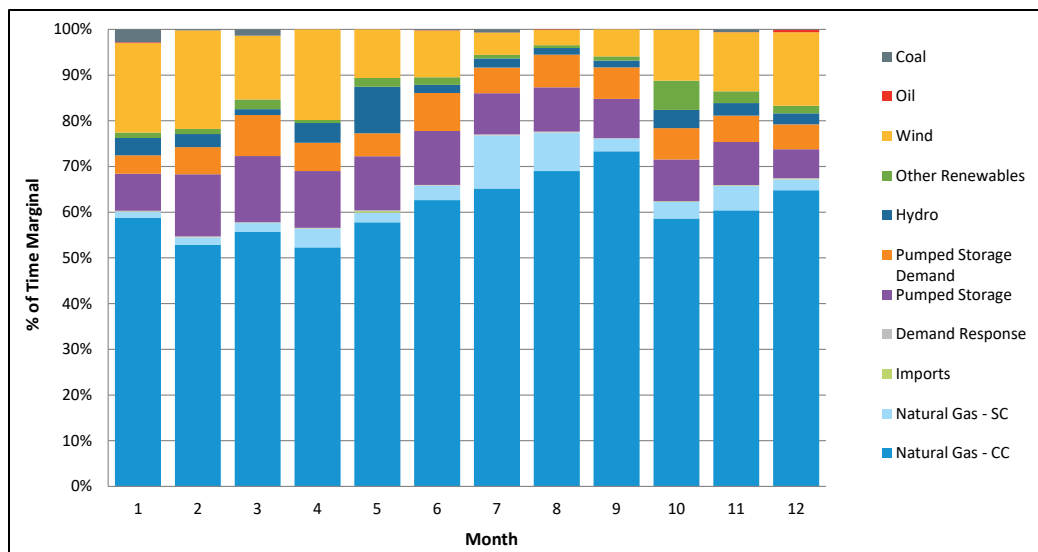


Figure 4-6: 2019 percentage of time various resource types were marginal —all LMUs.

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 2018 to 2019, the percentage of time that natural gas was marginal increased by 3%. The amount of time that oil was the marginal fuel dropped to nearly zero (0.08%) in 2019, and coal remained at 1%. The percentage of time that the Other Renewables category was marginal decreased by 4%. In 2019, as in 2018, wind often displaced gas as the price-setting fuel. Though wind was marginal 12% of the time in 2019, 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,²⁵ as shown in the next section.

²⁴ Pumped storage demand refers to the electric energy used to pump water into a pumped-storage unit's storage pond.

²⁵ 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/>.

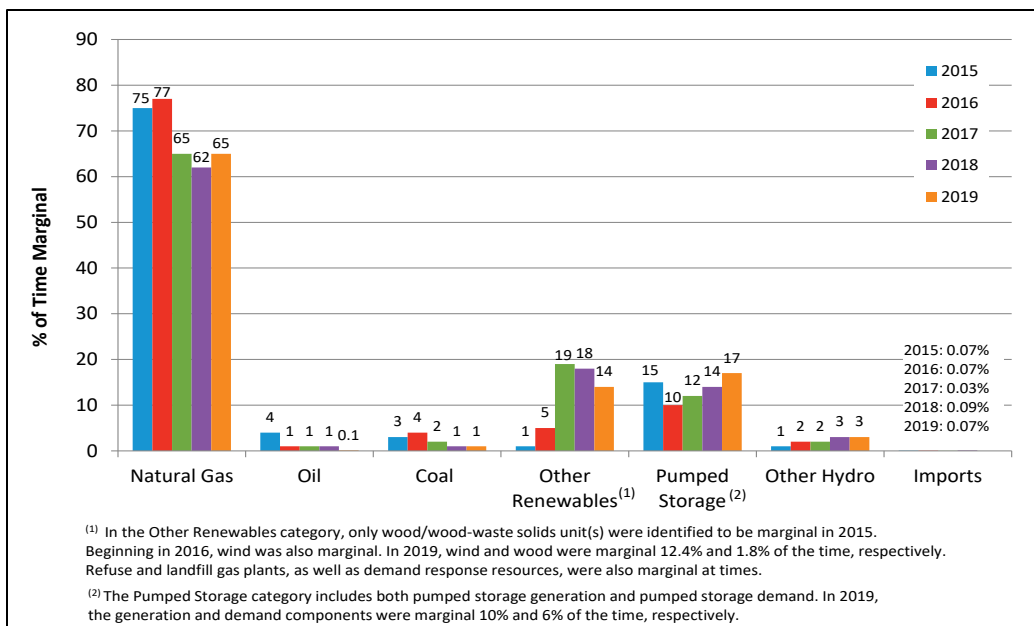


Figure 4-7: Annual percentage of time various resource types were marginal —all LMUs, 2015 to 2019.

4.5.1.2 Load-Weighted Approach – All LMUs

Figure 4-8 shows the percentage of time that the resource types were marginal during each month, using the load-weighted approach. The primary difference from the time-weighted analysis is the much lower percentage of wind on the margin, which ranged from 0.05% in July to a maximum of 2.2% in January. In turn, the load-weighted approach resulted in higher percentages of other generation on the margin. The greatest increases using this approach were in natural gas-fired generation, which was marginal for 67% to 81% of the system load, and pumped storage generation, which was marginal for 11 to 19% of the load.

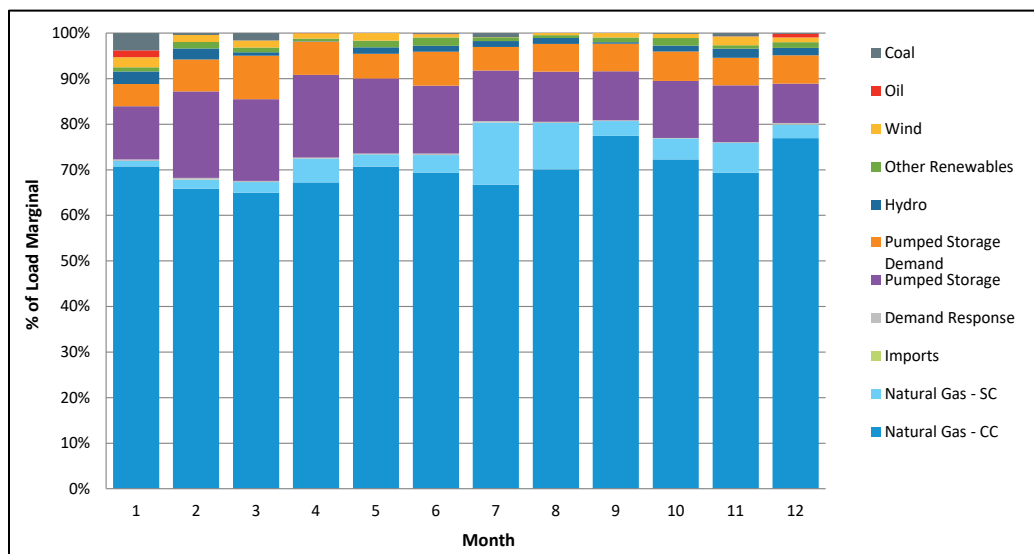


Figure 4-8: 2019 percentage of load for which various resource types were marginal —all LMUs.

Figure 4-9 shows the average percentage of load for which the resource types were marginal in 2018 and 2019, the two years for which the load-weighted analysis has been performed. The percentage of natural gas on the margin increased by 3% in 2019; oil, coal and other hydro marginality decreased slightly; and both the Other Renewables category and pumped storage increased by 1%. The percentage of imports on the margin was nearly zero in both years.

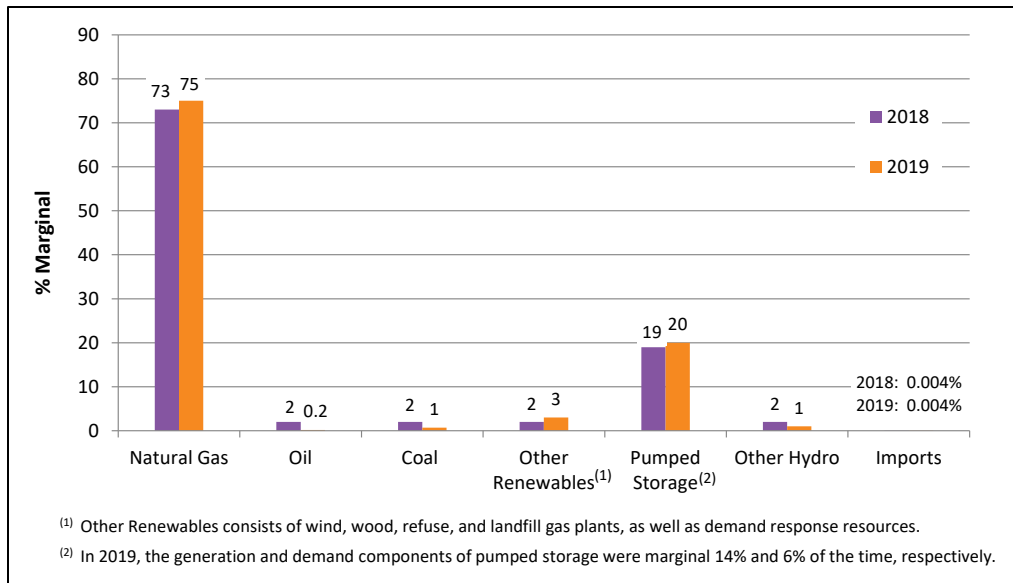


Figure 4-9: Annual percentage of load for which various resource types were marginal – all LMUs, 2018 and 2019.

4.5.1.3 Comparison of Time-Weighted and Load-Weighted Results – All LMUs

The impact of using the load-weighted rather than the time-weighted approach for determining the LMU can be seen in Figure 4-10. As previously mentioned, many wind resources are located behind transmission constraints and are unable to fully contribute to meeting the system load. The resulting impacts on the load-weighted percentages are most apparent in the reduced percentage of marginal wind resources and the higher percentage of natural gas and pumped storage resources on the margin. Since some wood-burning units and hydro-electric resources are also constrained, their marginality using the load-weighted approach is lower than with the simple time-weighted analysis.

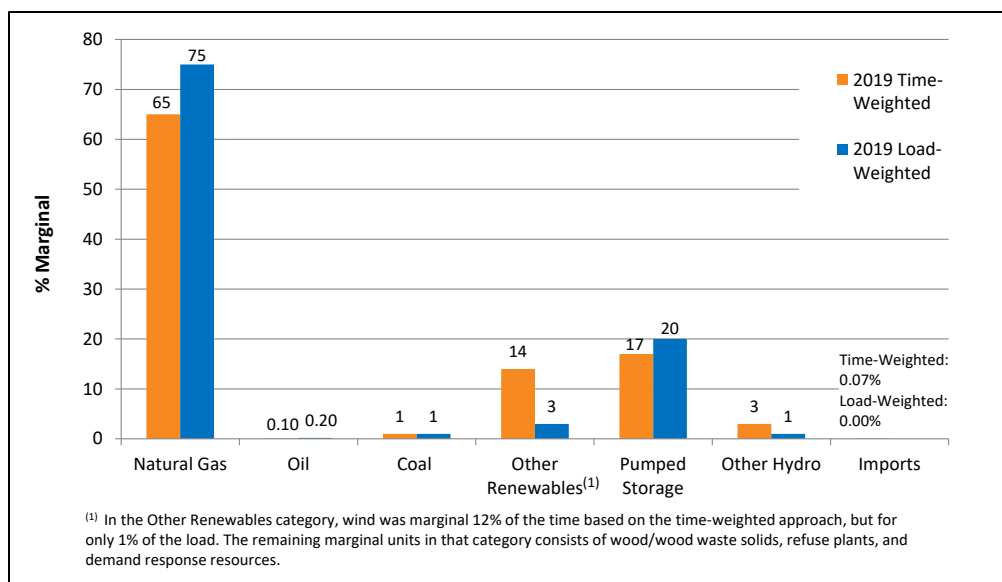


Figure 4-10: Comparison of 2019 annual marginality for various resource types using the time-weighted vs. load-weighted approach —all LMUs.

4.5.2 Emitting LMUs

Marginal generating resources with no air emissions were excluded in this scenario. Therefore, hydro-electric, pumped storage, external transactions, and other renewables with no air emissions were not taken into account, while all other LMUs were. Imports are included as emitting LMUs for the first time in this *Emissions Report*; however, their emissions are assumed to be zero.

4.5.2.1 Time-Weighted Approach – Emitting LMUs

As shown in the monthly percentages in Figure 4-11, when using the time-weighted approach for emitting LMUs only, natural gas-fired combined cycle units were marginal 82% to 93% of the time. The simple-cycle natural gas peaking units were marginal an average of 7% of the time during the year, but during the peak summer months of July and August the percentages increased to 16% and 12%.

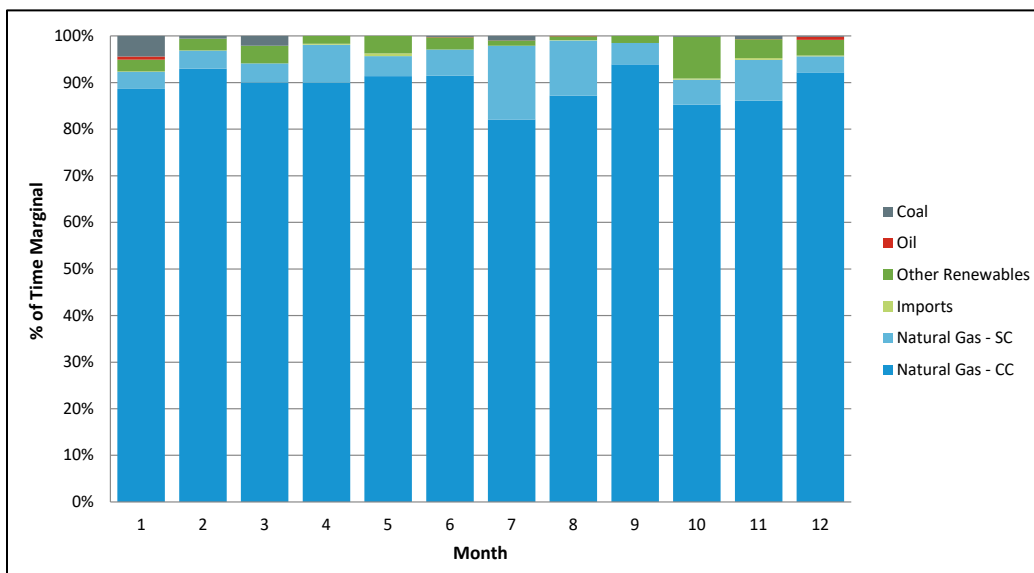


Figure 4-11: 2019 percentage of time various resource types were marginal —emitting LMUs.

Figure 4-12 shows that during the past five years, the percentage of time that natural gas-fired units have been on the margin has been increasing, while the amount of marginal oil- and coal-fired generation has been falling.

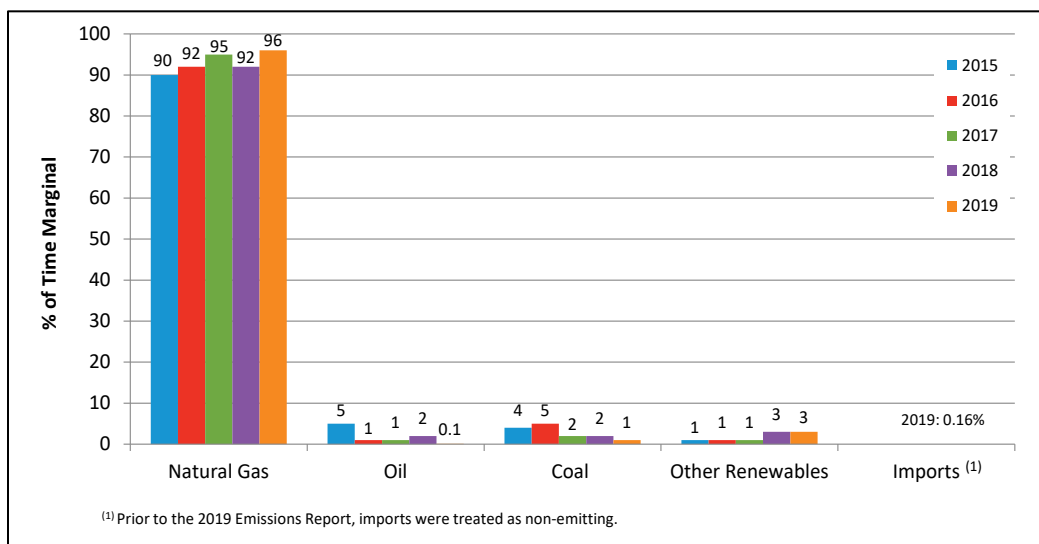


Figure 4-12: Annual percentage of time various resource types were marginal – emitting LMUs, 2015 to 2019.

4.5.2.2 Load-Weighted Approach – Emitting LMUs

Figure 4-13 shows the monthly and annual percentage of load for which the emitting resources were marginal. The monthly load-weighted marginal percentages for the emitting LMUs scenario are not significantly different from those of the time-weighted approach. The primary difference is in the lower amount of Other Renewables generation, which averaged only 1.4% of the annual total,

and a corresponding higher percentage of natural gas-fired generation on the margin. Figure 4-14 shows the annual marginal percentages, which increased for natural gas and decreased for oil and coal in 2019.

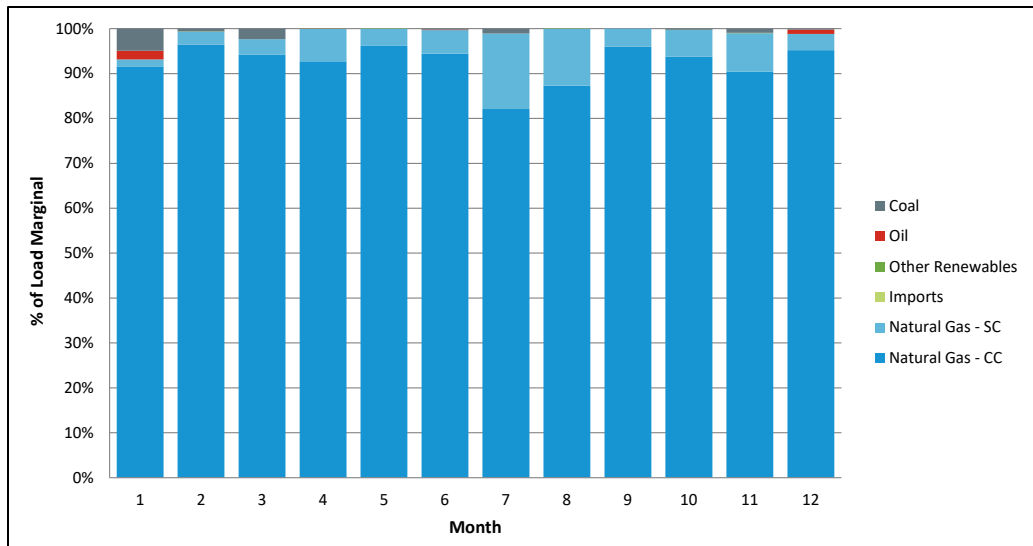


Figure 4-13: 2019 percentage of load for which various resource types were marginal —emitting LMUs.

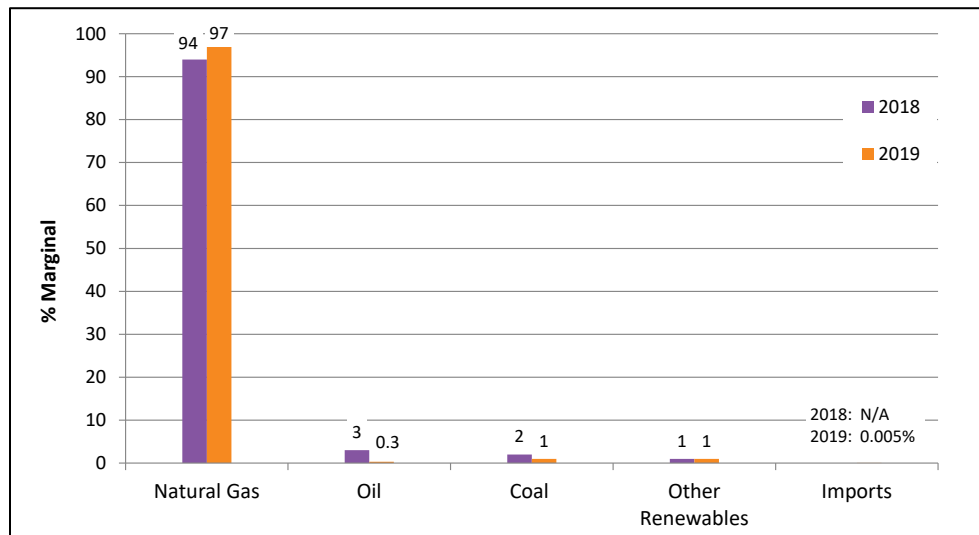


Figure 4-14: Annual percentage of load for which various resource types were marginal – emitting LMUs, 2018 and 2019.

4.5.2.3 Comparison of Time-Weighted vs. Load-Weighted Results - Emitting-LMUs

Figure 4-15 is a comparison of the 2019 time-weighted and load-weighted results for emitting LMUs. The impact of constrained wood-burning units on the marginal percentage is apparent in the

lower marginality of Other Renewables when using the load-weighted approach. This resulted in a higher percentage of natural gas-fired units on the margin.

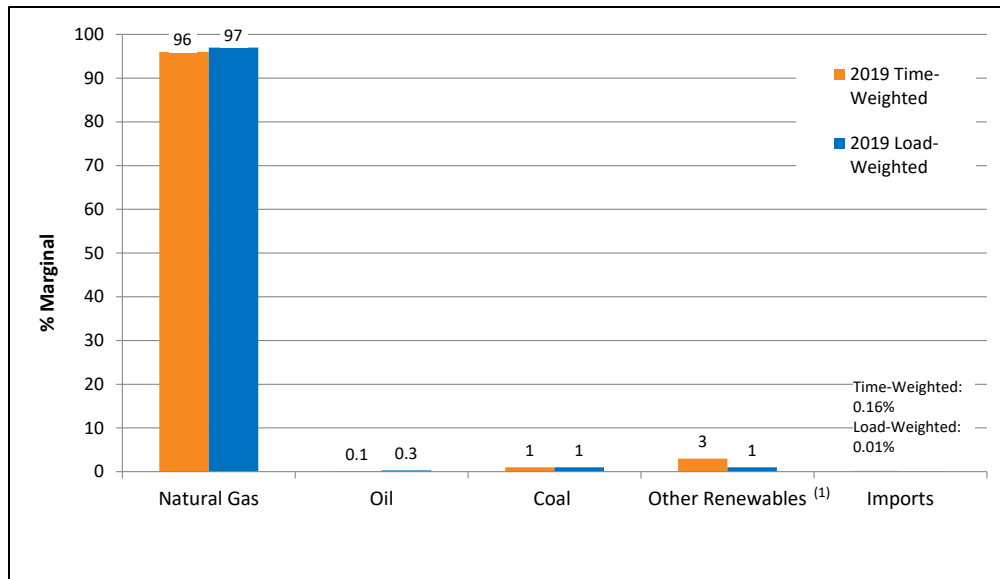


Figure 4-15: Comparison of 2019 annual marginality for various resource types using the time-weighted vs. load-weighted approach —emitting LMUs.

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 5.3.2) 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 2019 native generation emissions representing all generators but not emissions from imports. 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 2019 ISO New England System Emissions

Results are presented for the following metrics:

- Aggregate NO_x, SO₂, and CO₂ emissions for each state for 2019
- A comparison of aggregate NO_x, SO₂, and CO₂ emissions for 2010 to 2019
- 2019 annual average NO_x, SO₂, and CO₂ emission rates, by state and for the ISO New England system as a whole
- Monthly variations in the emission rates for 2019
- A comparison of annual average NO_x, SO₂, and CO₂ emission rates for 2010 to 2019

5.1.1 Results

Figure 5-1 shows the 2019 annual aggregate NO_x, SO₂, and CO₂ air emissions for each state. The ISO New England total emissions from native generation for NO_x, SO₂, and CO₂ were 12.87 ktons, 2.34 ktons, and 30,997 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.²⁶ 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.

²⁶ 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: 2019 ISO New England system annual emissions of NO_x, SO₂, and CO₂ (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, SO₂, and CO₂ air emissions for 2010 through 2019. Since 2010, NO_x emissions have declined by 55% and SO₂ by 97%, while CO₂ has decreased by about 41%. Refer to Appendix Table 4 for the values behind this graph.

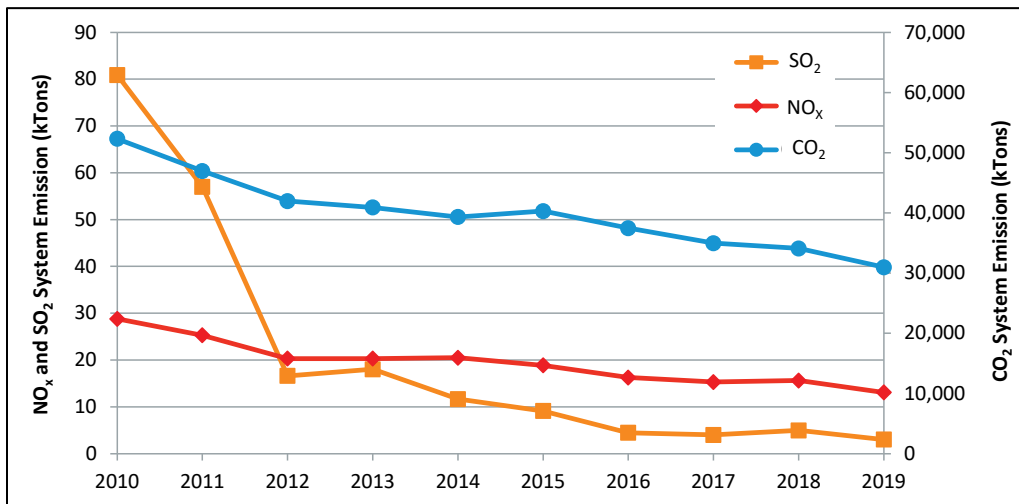


Figure 5-2: ISO New England system annual generator emissions, 2010 to 2019 (ktons).

Table 5-1 shows the 2019 annual average NO_x, SO₂, and CO₂ 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
2019 ISO New England System
Annual Average Generator Emission Rates (lbs/MWh)

State	NO _x	SO ₂	CO ₂
Connecticut	0.18	0.02	560
Maine	0.31	0.09	495
Massachusetts	0.50	0.09	877
New Hampshire	0.18	0.06	443
Rhode Island	0.14	0.01	898
Vermont	0.27	0.02	533
New England	0.26	0.05	633

Monthly variations in the emission rates shown in Figure 5-3 reflect the generation by different fuel types shown in Figure 4-4. In 2019, the highest CO₂ emission rates occurred in July and August. During those summer months, a larger amount of gas-fired generation as well as oil-fired peaking units were needed to meet peak demand. Slightly higher levels of coal- and oil-fired generation resulted in a rise in emission rates in January and December as well.

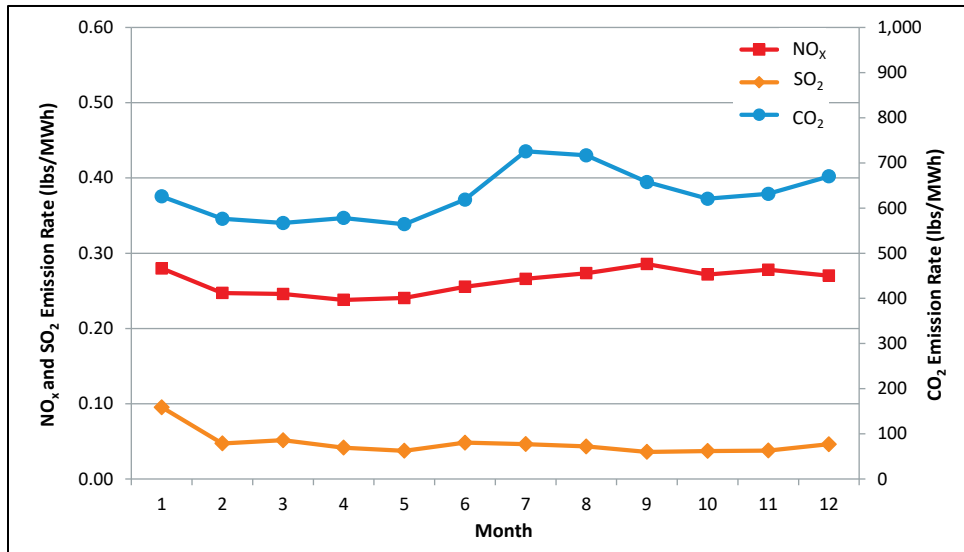


Figure 5-3: 2019 ISO New England system monthly average generator emission rates (lbs/MWh).

Figure 5-4 illustrates the annual average NO_x, SO₂, and CO₂ air emission rates (lbs/MWh) for 2010 to 2019 using the calculation method presented in Section 3.2. Since 2010, the annual average NO_x emission rate has decreased by 43%, SO₂ by 96%, and CO₂ by 23%. Appendix Table 6 shows historical emission rates since 1999.

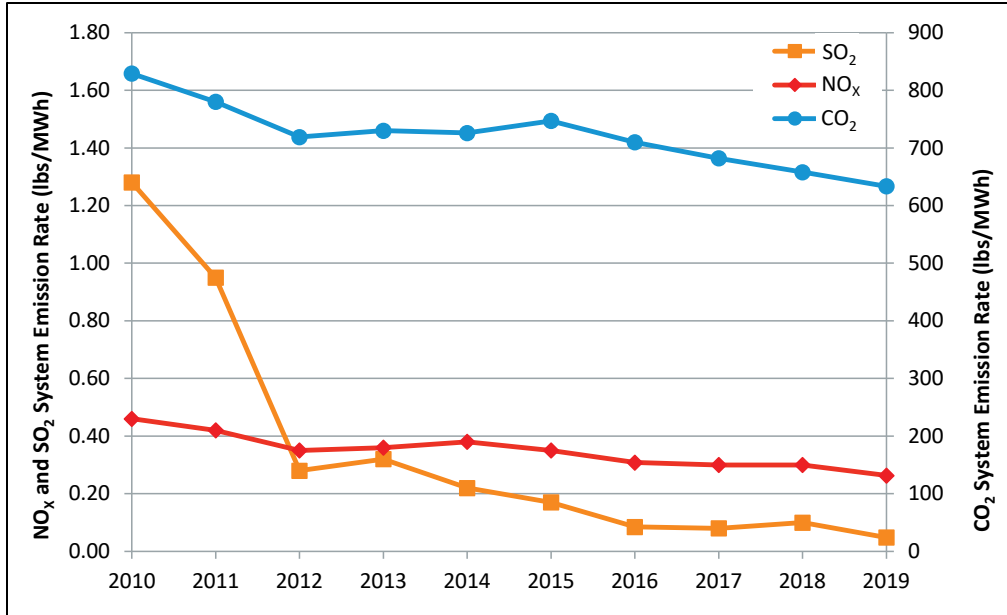


Figure 5-4: ISO New England system annual average generator emission rates, 2010 to 2019 (lbs/MWh).

5.1.2 Additional Observations

Total native generation decreased by 5.6% in 2019 from 2018. Generation in all of the emitting fuel categories fell, and there was also a decrease in non-emitting nuclear generation. The amount of energy from coal-fired generation continued its decline in 2019, decreasing by 60% to 0.5% of total generation. After an uptick in energy from oil-fired generators in 2018 due to an extended cold snap at the beginning of the year, oil-fired generation decreased in 2019 by about 69%, to 0.4% of total generation. Natural gas-fired generation fell by 6% from 2018 but maintained its 48% share of total generation, and nuclear generation decreased by 5% to 30% of the total. In contrast, energy produced by wind and solar resources increased by 13%, reaching 5% of total generation. The impacts on system emissions resulting from these changes in the generation mix can be seen in Table 5-2. System emissions and emission rates decreased for all three pollutants from 2018 to 2019: NO_x total emissions dropped by 17.6% while the rate decreased by 12.3%; the SO₂ emissions and emission rate both decreased by about 52%; and the CO₂ emissions and emission rate decreased by 9.1% and 3.7%, respectively.

Table 5-2
2018 and 2019 ISO New England System Emissions (ktons)
and Emission Rates (lbs/MWh)

Annual System Emissions						
	2018 Emissions (ktons)	2019 Emissions (ktons)	Change in Emissions (%)	2018 Emission Rate (lbs/MWh)	2019 Emission Rate (lbs/MWh)	Change in Emission Rate (%)
NO_x	15.61	12.87	-17.6	0.30	0.26	-13.3
SO₂	4.96	2.34	-52.8	0.10	0.05	-50.0
CO₂	34,096	30,997	-9.1	658	633	-3.8

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
- Mandated use of lower-sulfur fuels
- Retirement of oil- and coal-fired generation, and retrofits of NO_x and SO₂ emission controls on some of the remaining oil- and coal-fired generators
- Increasing amounts of wind and solar generation

5.2 2019 ISO New England Marginal Heat Rate

The calculated annual marginal heat rate reflects the average annual efficiency of all the marginal emitting units dispatched throughout 2019. The 2019 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 2019 are presented in Figure 5-6. The values behind Figure 5-6 are provided in Appendix Table 7.

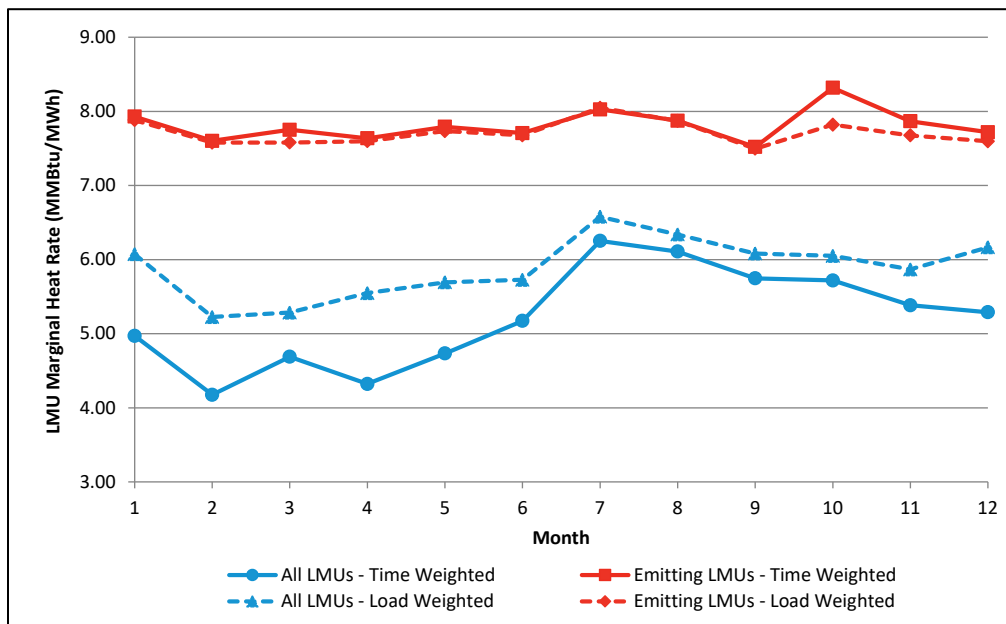


Figure 5-5: 2019 time- and load-weighted LMU monthly marginal heat rate (MMBtu/MWh).

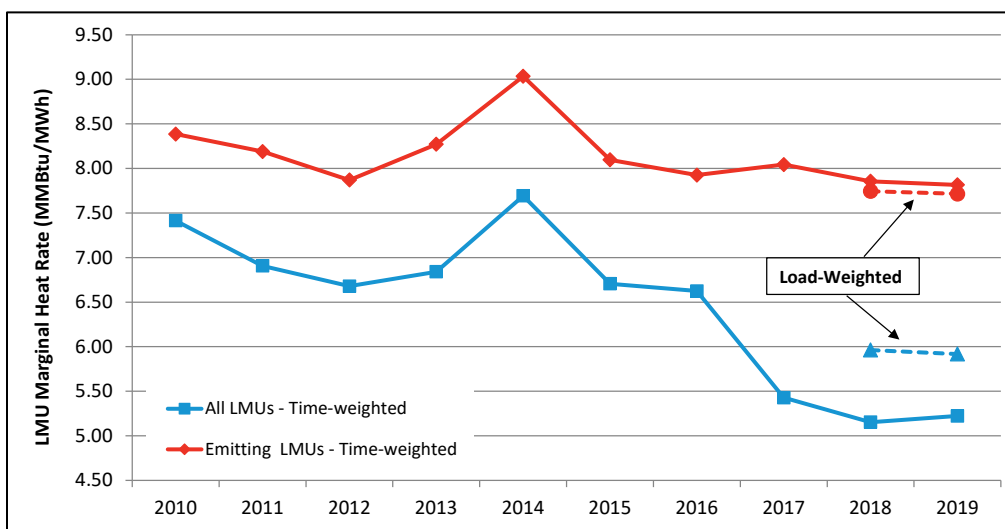


Figure 5-6: LMU annual marginal heat rate, 2010-2019 (MMBtu/MWh).

There has been an overall trend of declining heat rates from 2010 through 2019, with the exception of a spike in 2014. In 2017, there was 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 and 2019 LMU marginal heat rates that were calculated using the load-weighted approach. In 2019, the value for the all-LMU scenario was 13% 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 1% 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 2019 ISO New England Marginal Emission Rates

This section presents the 2019 calculated LMU-based marginal emission rates for the all-LMU and emitting-LMU scenarios, as defined in Section 4.5. The 2019 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 SO₂ and CO₂, 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 5.223 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 2019 percentage of time various fuel types were marginal for all LMUs) and Figure 5-3 (showing the 2019 ISO New England system monthly average NO_x, SO₂, and CO₂ emission rates). Appendix Table 9 lists the values behind Figure 5-7.

Table 5-3
2019 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	0.11	0.10	0.09	0.10	0.10
Annual Emissions (SO ₂ and CO ₂)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO ₂		0.03	0.02		0.02
CO ₂		678	626		648

- (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.

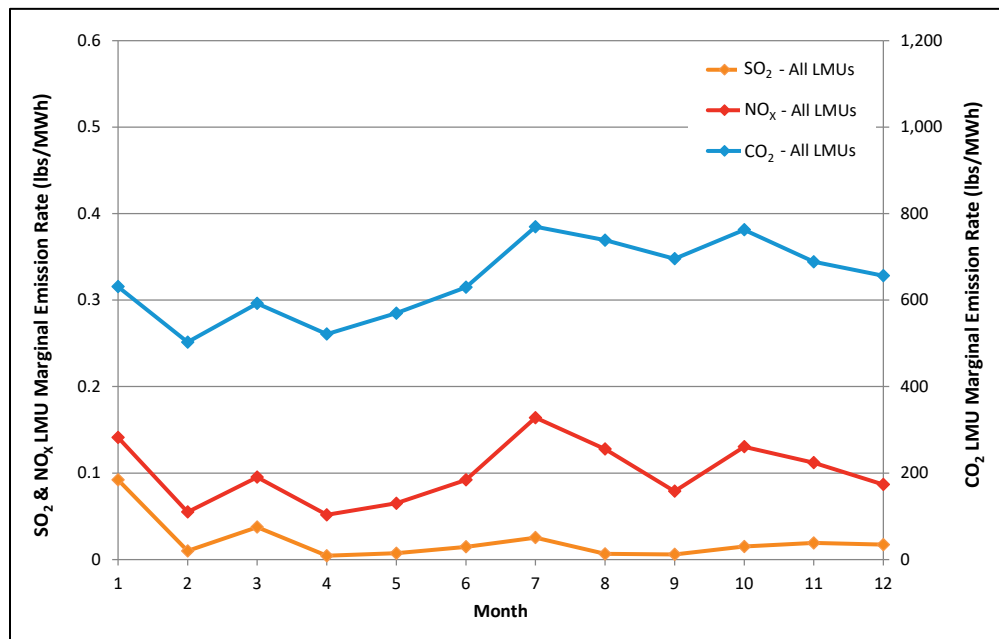


Figure 5-7: 2019 time-weighted monthly LMU marginal emission rates—all LMUs (lbs/MWh).

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

Table 5-4
2019 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	0.19	0.18	0.17	0.19	0.18
Annual Emissions (SO ₂ and CO ₂)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO ₂		0.16	0.10		0.12
CO ₂		975	966		970

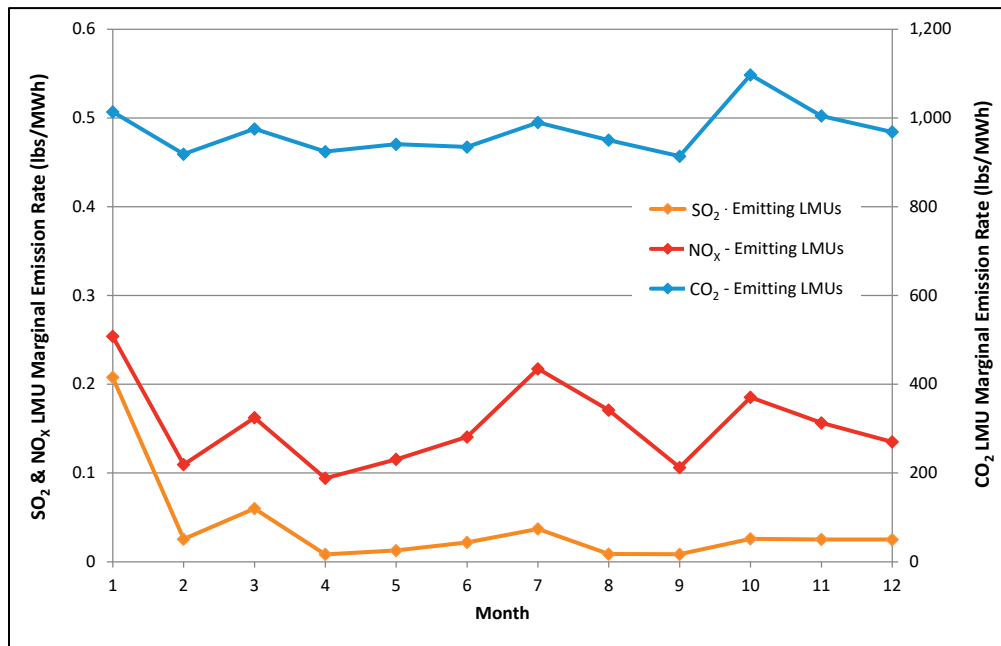


Figure 5-8: 2019 time-weighted monthly LMU marginal emission rates—emitting LMUs (lbs/MWh).

5.3.1.3 2010 to 2019 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.

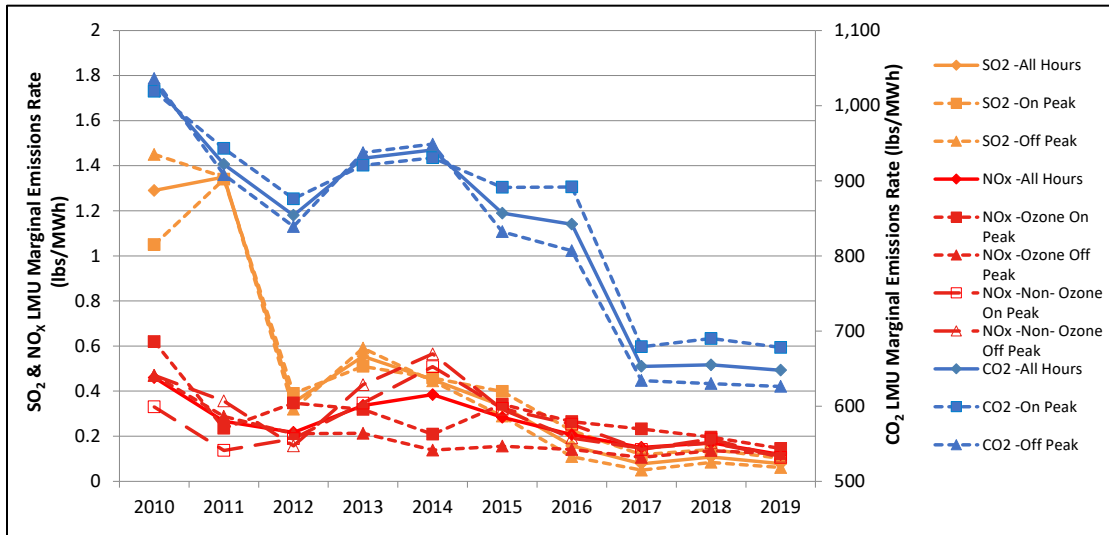


Figure 5-9: Time-weighted LMU marginal emission rates, 2010 to 2019—all LMUs (lbs/MWh).

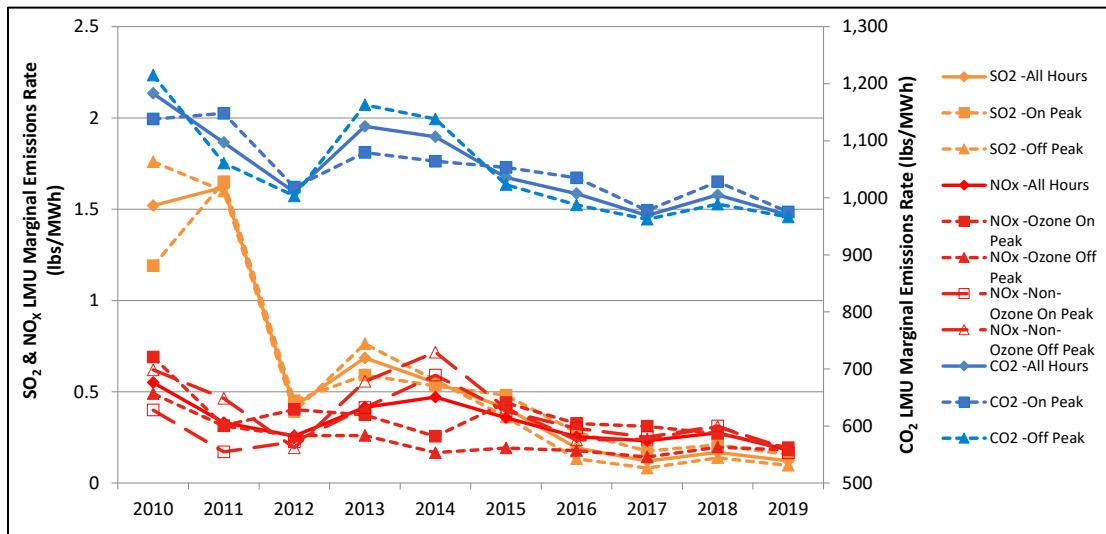


Figure 5-10: Time-weighted LMU marginal emission rates, 2010 to 2019—emitting LMUs (lbs/MWh).

5.3.2 Marginal Emission Rates Using the Load-Weighted Approach

5.3.2.1 All-LMU Scenario

The 2019 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 5.918 MMBtu/MWh used as the conversion factor. Figure 5-11, which shows the monthly load-weighted LMU marginal emission rates, can be compared with **Error! Reference source not found.** (showing the 2019 percentage of load for which various fuel types were marginal for all LMUs) and Figure 5-3 (showing the 2019 ISO New England system monthly average NO_x, SO₂, and CO₂ emission rates). Appendix Table 19 lists the values behind Figure 5-11.

Table 5-5
2019 Load-Weighted LMU Marginal Emission Rates—All 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	0.12	0.11	0.10	0.11	0.13
Annual Emissions (SO ₂ and CO ₂)					
Air Emission	Annual				Annual Average (All Hours)
	On-Peak		Off-Peak		
SO ₂	0.03		0.02		0.03
CO ₂	749		697		719

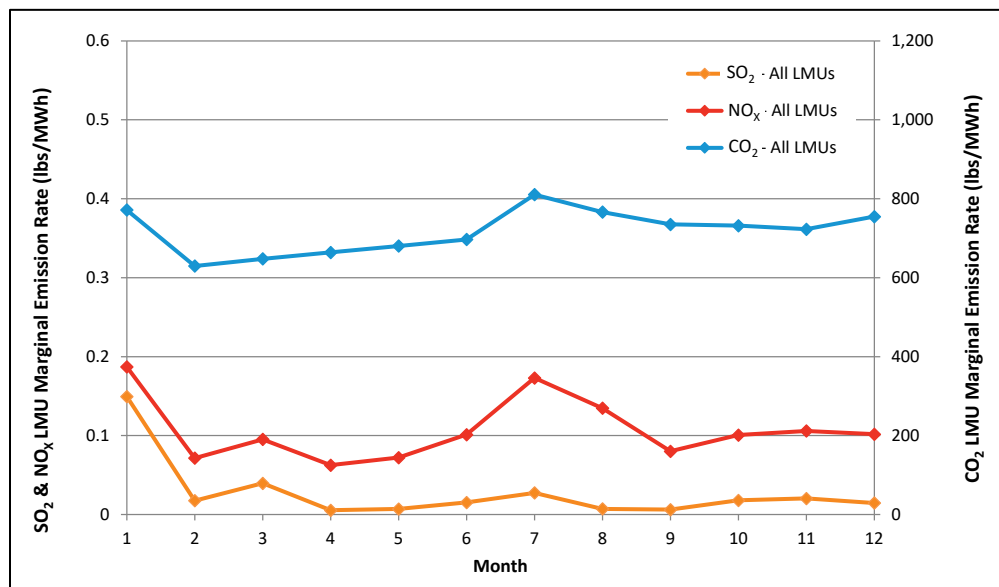


Figure 5-11: 2019 load-weighted monthly LMU marginal emission rates—all LMUs (lbs/MWh).

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 7.716 MMBtu/MWh. The values for the monthly rates shown in Figure 5-12 are shown in Appendix Table 21.

Table 5-6
2019 Load-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	0.14	0.15	0.13	0.15	0.15
Annual Emissions (SO ₂ and CO ₂)					
Air Emission	Annual				Annual Average (All Hours)
	On-Peak		Off-Peak		
SO ₂	0.05		0.03		0.04
CO ₂	950		938		943

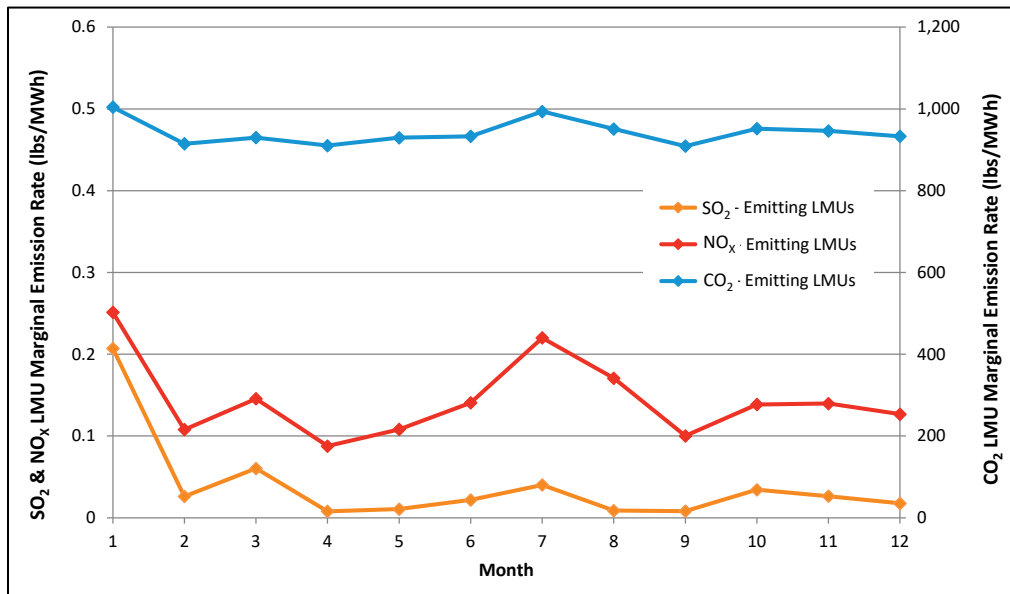


Figure 5-12: 2019 load-weighted monthly LMU marginal emission rates—emitting LMUs (lbs/MWh).

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

As shown in Table 5-7, the 2019 load-weighted marginal emission rates for the all-LMU scenario are 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 only 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 4-10, 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 NO_x and CO₂ load-weighted marginal emission rates are lower than the time-weighted rates, and the SO₂ rate is the same as the time-weighted rate. The lower load-weighted rates are due to the fact that some emitting LMUs, primarily wood-burning plants, are located in export-constrained areas. Refer to Figure 4-15 for a comparison of the annual marginality calculated with the time-weighted vs. load-weighted approaches for the emitting-LMU scenario.

**Table 5-7
2019 Time-Weighted and Load-Weighted LMU Marginal Emission Rates (lbs/MWh)**

LMU Marginal Emissions			
	2019 Time-Weighted Annual Rate	2019 Load-Weighted Annual Rate	2019 Load-Weighted vs. 2019 Time-Weighted
	(lbs/MWh)	(lbs/MWh)	(%)
All LMUs			
NO_x	0.101	0.108	6.9
SO₂	0.021	0.028	33.3
CO₂	648	719	11.0
Emitting LMUs			
NO_x	0.155	0.145	-6.5
SO₂	0.039	0.039	0.0
CO₂	970	943	-2.8

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. This results in other generator types becoming marginal more often under the load-weighted approach.

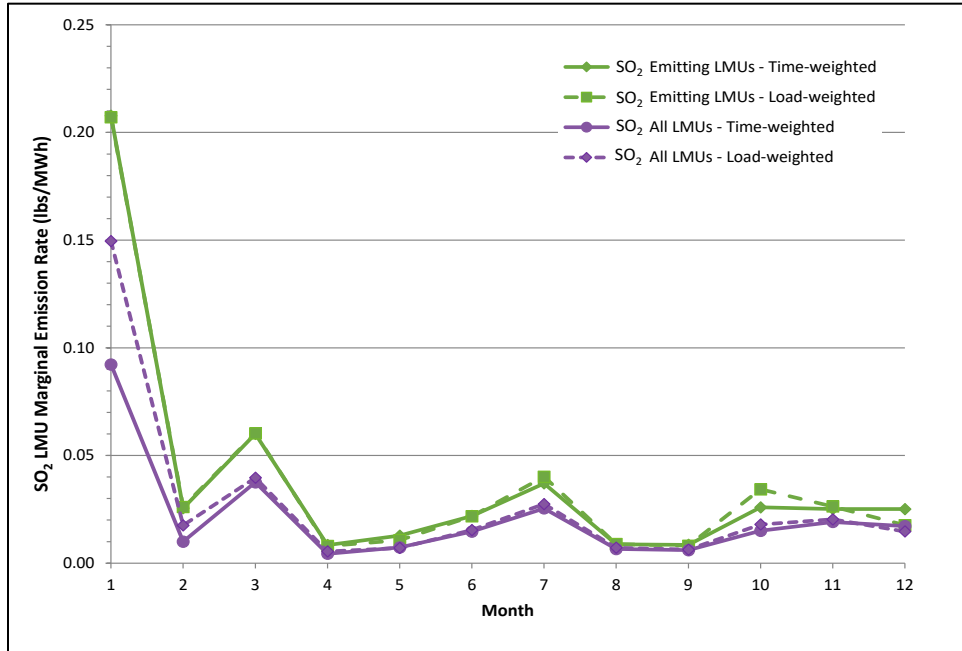


Figure 5-13: 2019 time- and load-weighted monthly LMU marginal SO₂ emission rates.

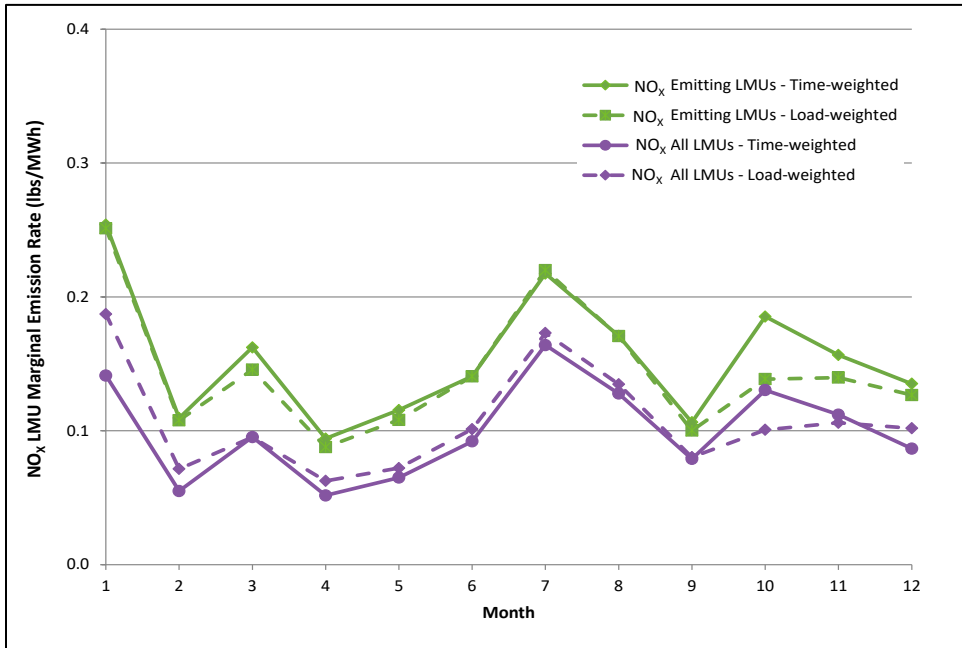


Figure 5-14: 2019 time- and load-weighted monthly LMU marginal NO_x emission rates.

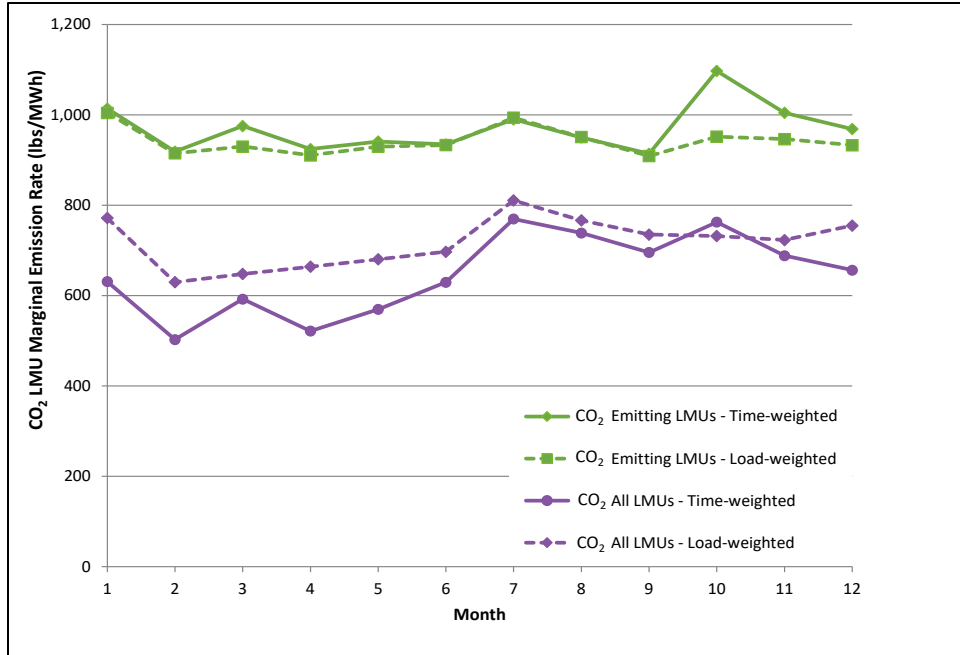


Figure 5-15: 2019 time- and load-weighted monthly LMU marginal CO₂ emission rates.

5.3.4 Additional Observations

Both the time-weighted and load-weighted approaches resulted in significant decreases in marginal emission rates from 2018 to 2019, as shown in Table 5-8. This is due to the increase in natural gas-fired generation and decrease in oil- and coal-fired generation that can be seen in the various figures in Section 4.5, Locational Marginal Unit Scenarios.

Table 5-8
2018 and 2019 Annual Time-Weighted and Load-Weighted LMU Marginal Emission Rates (lbs/MWh)

	LMU Marginal Emission Rates					
	Time-Weighted			Load-Weighted		
	2018 Annual Rate	2019 Annual Rate	Percent Change 2018 to 2019	2018 Annual Rate	2019 Annual Rate	Percent Change 2018 to 2019
	(lbs/MWh)	(lbs/MWh)	(%)	(lbs/MWh)	(lbs/MWh)	(%)
All LMUs						
NO _x	0.17	0.10	-41.2	0.20	0.11	-45.0
SO ₂	0.11	0.02	-81.8	0.13	0.03	-76.9
CO ₂	655	648	-1.1	745	719	-3.5
Emitting LMUs						
NO _x	0.28	0.15	-46.4	0.27	0.15	-44.4
SO ₂	0.17	0.04	-76.5	0.16	0.04	-75.0
CO ₂	1,005	970	-3.5	971	943	-2.9

5.4 Marginal Emission Rates for High Electric Demand Days

Using the LMU methodology, the top-five high electric demand days in 2019 were examined. In 2019, the top five HEDDs were July 20, 21, 29, and 30, and August 19. The temperatures in New England during these days ranged from 88° to 93°F. Peak daily loads ranged from 23,365 MW on Monday, August 19, to a high of 24,361 MW on Tuesday, July 30. Table 5-9 shows the average LMU marginal emission rate during these five days.

Table 5-9
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	0.29	0.40	0.31	0.41
SO₂	0.07	0.09	0.07	0.11
CO₂	832	1,103	881	1,117

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 SO₂, NO_x, and CO₂ have exhibited an overall decrease during the past ten years. Compared with 2010, the 2019 LMU SO₂ annual marginal rates have declined by over 97% 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 78% and 72% for the all-LMU and emitting-LMU scenarios, respectively, since 2010. During that period, the CO₂ rates have declined by 37% for the all-LMU scenario and 18% for the emitting-LMU scenario.

The greatest drop in the time-weighted all-LMU marginal CO₂ 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 higher than the time-weighted rates. They are higher by 7% for NO_x, 33% for SO₂, and 11% for CO₂. For the emitting LMU-scenario, the NO_x and CO₂ load-weighted rates are 6% and 3% lower than the time-weighted rates, but there is no difference in the SO₂ rates for the two approaches.

In 2019, the on-peak marginal rates for SO₂ and CO₂, and NO_x during the ozone season, were generally higher than the off-peak rates for both the time-weighted and load-weighted approaches. This is likely due to the operation of older, less-efficient peaking units (jets or gas/combustion turbines) dispatched to meet peak load.

There were clear differences in the LMU marginal emission rates when using the load-weighted rather than the time-weighted approach, due to the inability of constrained resources in northern New England to directly set price for the region as a whole. In the case of the all-LMU scenario, the load-weighted rates were higher than the time-weighted rates by 7% for NO_x, 33% for SO₂, and 11% for CO₂ because of the lower amount of wind units on the margin. In contrast, with the emitting-LMU scenario, the load-weighted marginal rates were 7% lower than the time-weighted rates for NO_x and 3% lower for CO₂, and there was no difference in the SO₂ rates. These lower rates were due to constrained biomass units, which generally have relatively high emission rates.

The time-weighted and load-weighted LMU marginal emission rates both exhibited substantial decreases from 2018 to 2019. Looking at the available historical data for the time-weighted data, a slight uptick in the LMU marginal emission rates had occurred in 2018 due primarily to the significant amount of time that oil units were marginal during the January cold wave that year. However, in 2019, the NO_x, SO₂, and CO₂ rates all continued to trend downward. The changes in both the time- and load-weighted marginal rates for SO₂ and NO_x in 2019 were more dramatic than the changes in the system rates. The SO₂ rates in particular exhibited a significant drop in the annual average marginal rates, decreasing by 75% to 82%. In comparison, the SO₂ system rate decreased by 50% in 2019. The LMU marginal emission rates for NO_x decreased by 41% and 46% in 2019, but there was only a 13% decrease in the system rate. For CO₂, the marginal rates decreased by 1% to 4%, while the system rate decreased by 4%.

Section 6 Appendix

Appendix Table 1
ISO New England Total Cooling and Heating Degree Days, 2000 to 2019

Year	Total Cooling Degree Days	Difference from Average (%)	Total Heating Degree Days	Difference from Average (%)
2000	211	-35.9%	6,380	6.0%
2001	319	-3.1%	5,870	-2.5%
2002	353	7.3%	5,938	-1.3%
2003	350	6.4%	6,628	10.1%
2004	249	-24.3%	6,332	5.2%
2005	417	26.7%	6,331	5.2%
2006	334	1.5%	5,532	-8.1%
2007	287	-12.8%	6,153	2.2%
2008	278	-15.5%	6,027	0.2%
2009	223	-32.2%	6,272	4.2%
2010	403	22.5%	5,636	-6.3%
2011	354	7.6%	5,802	-3.6%
2012	350	6.4%	5,285	-12.2%
2013	398	20.9%	6,137	2.0%
2014	238	-27.7%	6,299	4.7%
2015	334	1.5%	6,080	1.0%
2016	351	6.7%	5,705	-5.2%
2017	309	-6.1%	5,839	-3.0%
2018	499	51.6%	6,060	0.7%
2019	325	-1.3%	6,046	0.5%
Average	329		6,018	

Appendix Table 2
2019 ISO New England Summer Generating Capacity (MW, %)^(a, b)

Unit Type	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont	
	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%
Coal	369.8	3.8	-	-	-	-	533.3	13.0	-	-	-	-
Natural Gas	4,261.5	43.5	6,892.7	57.3	1,574.9	50.3	1,231.6	30.0	1,877.4	95.3	-	-
Nuclear	2,073.7	21.2	-	-	-	-	1,247.8	30.4	-	-	-	-
Oil	2,750.4	28.1	2,477.2	20.6	738.1	23.6	483.7	11.8	-	-	134.3	29.3
Hydro	81.6	0.8	161.2	1.3	501.8	16.0	394.3	9.6	0.4	0.0	213.6	46.6
Pumped Storage	28.4	0.3	1,759.5	14.6	-	-	-	-	-	-	-	-
Solar	39.5	0.4	494.8	4.1	4.7	0.2	1.9	0.0	55.8	2.8	11.2	2.4
Wind	-	-	9.7	0.1	112.6	3.6	27.3	0.7	9.4	0.5	18.1	3.9
Other Renewables	185.9	1.9	238.2	2.0	199.7	6.4	182.6	4.5	26.3	1.3	80.9	17.7
Total	9,790.8	100.0	12,033.4	100.0	3,131.8	100.0	4,102.6	100.0	1,969.2	100.0	458.1	100.0

(a) Sum may not equal total due to rounding.

(b) Seasonal Claimed Capability as of January 1, 2020.

Appendix Table 3
2019 ISO New England Winter Generating Capacity (MW, %)^(a, b)

Unit Type	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont	
	MW	%	MW	%	MW	%	MW	%	MW	%	MW	%
Coal	382.5	3.7	-	-	-	-	534.7	12.2	-	-	-	-
Natural Gas	4,682.4	45.1	7,689.8	60.8	1,724.3	49.0	1,373.0	31.3	2,113.6	97.5	-	-
Nuclear	2,096.7	20.2	-	-	-	-	1,251.4	28.5	-	-	-	-
Oil	2,916.9	28.1	2,704.9	21.4	759.4	21.6	503.0	11.5	-	-	167.7	30.2
Hydro	112.7	1.1	232.1	1.8	563.1	16.0	474.3	10.8	3.0	0.1	262.2	47.2
Pumped Storage	27.6	0.3	1,758.2	13.9	-	-	-	-	-	-	-	-
Solar	0.0	0.0	3.1	0.0	-	-	0.1	0.0	1.4	0.1	-	-
Wind	-	-	17.4	0.1	260.5	7.4	47.7	1.1	24.2	1.1	42.4	7.6
Other Renewables	170.7	1.6	249.7	2.0	211.5	6.0	202.4	4.6	25.1	1.2	82.7	14.9
Total	10,389.6	100.0	12,655.2	100.0	3,518.7	100.0	4,386.5	100.0	2,167.3	100.0	555.0	100.0

(a) Sum may not equal total due to rounding.
(b) Seasonal Claimed Capability as of January 1, 2020.

Appendix Table 4
ISO New England System
Annual Generator Emissions, 2001 to 2019 (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
2019	12.87	2.34	30,997	28,120
Percent Reduction, 2001-2019	78	99	42	42

(a) Since greenhouse gas data is often expressed in metric tons, an additional column showing CO₂ emissions in metric kilotons is included in this table. A metric ton is approximately 2,205 lbs.

**Appendix Table 5
2019 ISO New England System
Average Monthly Generator Emission Rates (lbs/MWh)**

Monthly System Emission Rates (lb/MWh)			
Month	NO_x	SO₂	CO₂
1	0.28	0.10	626
2	0.25	0.05	576
3	0.25	0.05	567
4	0.24	0.04	578
5	0.24	0.04	564
6	0.26	0.05	619
7	0.27	0.05	726
8	0.27	0.04	717
9	0.29	0.04	658
10	0.27	0.04	621
11	0.28	0.04	632
12	0.27	0.05	670

**Appendix Table 6
ISO New England System
Annual Average Generator Emission Rates, 1999 to 2019 (lbs/MWh)**

Year	Total Generation (GWh)	NO_x	SO₂	CO₂
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
2019	97,890	0.26	0.05	633
Percent Reduction, 1999 - 2019		81	99	37

Appendix Table 7
LMU Marginal Heat Rate, 2010 to 2019 (MMBtu/MWh)

LMU Marginal Heat Rate (MMBtu/MWh)				
Year	Time-Weighted		Load-Weighted	
	All Marginal LMUs	Emitting LMUs	All Marginal LMUs	Emitting LMUs
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
2019	5.223	7.815	5.918	7.716

Appendix Table 8
2019 Time-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MMBtu)

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	0.021	0.020	0.018	0.019	0.019
Annual Emissions (SO ₂ and CO ₂)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO ₂		0.005	0.003		0.004
CO ₂		130	120		124

Appendix Table 9
2019 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	0.14	0.09	631
2	0.06	0.01	503
3	0.10	0.04	592
4	0.05	0.00	521
5	0.07	0.01	570
6	0.09	0.01	630
7	0.16	0.03	770
8	0.13	0.01	739
9	0.08	0.01	696
10	0.13	0.02	763
11	0.11	0.02	689
12	0.09	0.02	656

Appendix Table 10
2019 Time-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MMBtu)

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	0.018	0.020	0.018	0.022	0.020
Annual Emissions (SO ₂ and CO ₂)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO ₂		0.006	0.004		0.005
CO ₂		125	124		124

Appendix Table 11
2019 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	0.25	0.21	1,014
2	0.11	0.03	919
3	0.16	0.06	975
4	0.09	0.01	924
5	0.12	0.01	941
6	0.14	0.02	935
7	0.22	0.04	990
8	0.17	0.01	950
9	0.11	0.01	914
10	0.19	0.03	1,097
11	0.16	0.03	1,005
12	0.14	0.03	969

Appendix Table 12
NO_x Time-Weighted LMU Marginal Emission Rates, 2010 to 2019 —All LMUs (lbs/MWh)

Year	Ozone Season		Non-Ozone Season		Annual Average (All Hours)	Annual Average Percentage Change
	On-Peak	Off-Peak	On-Peak	Off-Peak		
2010	0.62	0.47	0.33	0.47	0.46	-
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
2019	0.11	0.10	0.09	0.10	0.10	-40.8
% Change 2010 - 2019	-82.5	-77.9	-72.2	-78.6	-78.1	

Appendix Table 13
NO_x Time-Weighted LMU Marginal Emission Rates, 2010 to 2019—Emitting LMUs (lbs/MWh)

Year	Ozone Season		Non-Ozone Season		Annual Average (All Hours)	Annual Average Percentage Change
	On-Peak	Off-Peak	On-Peak	Off-Peak		
2010	0.69	0.49	0.40	0.62	0.55	-
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
2019	0.14	0.16	0.14	0.17	0.15	-44.8
% Change 2010 - 2019	-79.1	-68.3	-64.4	-72.8	-71.9	

Appendix Table 14
SO₂ Time-Weighted LMU Marginal Emission Rates, 2010 to 2019—All LMUs (lbs/MWh)

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2010	1.05	1.45	1.29	-
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
2019	0.03	0.02	0.02	-80.47
% Change 2010 - 2019	-97.5	-98.8	-98.3	

Appendix Table 15
SO₂ Time-Weighted LMU Marginal Emission Rates, 2010 to 2019—Emitting LMUs (lbs/MWh)

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2010	1.19	1.76	1.52	-
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
2019	0.05	0.03	0.04	-77.0
% Change 2010 - 2019	-95.9	-98.2	-97.4	

Appendix Table 16
CO₂ Time-Weighted LMU Marginal Emission Rates, 2010 to 2019—All LMUs (lbs/MWh)

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2010	1,019	1,036	1,029	-
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
2019	678	626	648	-1.1
% Change 2010 - 2019	-33.5	-39.6	-37.0	

Appendix Table 17
CO₂ Time-Weighted LMU Marginal Emission Rates, 2010 to 2019—Emitting LMUs (lbs/MWh)

Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
2010	1,138	1,215	1,183	-
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
2019	975	966	970	-3.5
% Change 2010 - 2019	-14.3	-20.5	-18.0	

Appendix Table 18
2019 Load-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MMBtu)

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	0.020	0.019	0.016	0.018	0.018
Annual Emissions (SO ₂ and CO ₂)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO ₂		0.006	0.004		0.005
CO ₂		126	118		121

Appendix Table 19
2019 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	0.19	0.15	772
2	0.07	0.02	630
3	0.10	0.04	648
4	0.06	0.01	664
5	0.07	0.01	680
6	0.10	0.02	697
7	0.17	0.03	811
8	0.13	0.01	766
9	0.08	0.01	735
10	0.10	0.02	732
11	0.11	0.02	723
12	0.10	0.01	755

Appendix Table 20
2019 Load-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MMBtu)

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	0.018	0.020	0.017	0.020	0.019
Annual Emissions (SO ₂ and CO ₂)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO ₂		0.007	0.004		0.005
CO ₂		123	122		122

Appendix Table 21
2019 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	0.25	0.21	1,004
2	0.11	0.03	915
3	0.15	0.06	930
4	0.09	0.01	910
5	0.11	0.01	930
6	0.14	0.02	933
7	0.22	0.04	994
8	0.17	0.01	951
9	0.10	0.01	909
10	0.14	0.03	952
11	0.14	0.03	946
12	0.13	0.02	933