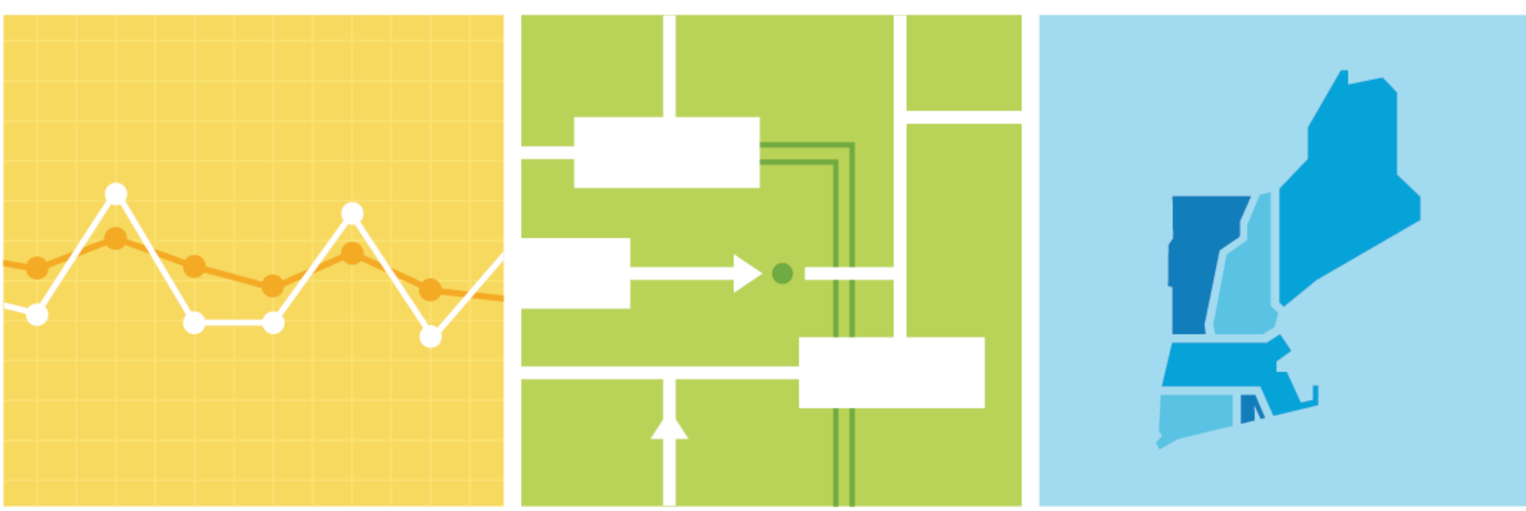
2021 ISO New England Electric Generator Air Emissions Report

System Planning

APRIL 2023



Contents

Figures

Tables

Section 1
Executive Summary

This 2021 ISO New England (ISO) *Electric Generator Air Emissions Report* (*Emissions Report*) provides a comprehensive analysis of New England's native electric generator air emissions (nitrogen oxides [NO_X], sulfur dioxide [SO_2], and carbon dioxide [CO_2]), along with CO_2 emissions associated with imported energy, and a review of relevant system conditions. The main factors analyzed are as follows:

- Average[1] and marginal emissions (in thousand short tons [ktons])[2]
- Average and marginal emission rates (pounds per megawatt-hour [lbs/MWh] and pounds per million British thermal units [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 over time in response to stakeholder needs. It was initially motivated by the need to determine the reductions in New England's aggregate NO_X, SO_2, and CO_2 generating unit air emissions resulting from demand-side management (DSM) programs. The use of these emission rates was subsequently broadened to reflect the emission-reduction benefits of energy-efficiency and conservation programs and renewable resources within the New England region.

During the ten-year period from 2012 through 2021, total average air emissions (ktons) from native generation have decreased overall: NO_X by 39%, SO_2 by 87%, and CO_2 by 20%. 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).

[1] "Average" emissions refers to emissions from the generation of electricity over a period of time, either by native generation located within the ISO New England balancing authority area, or native generation plus imports.

[2] The 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.

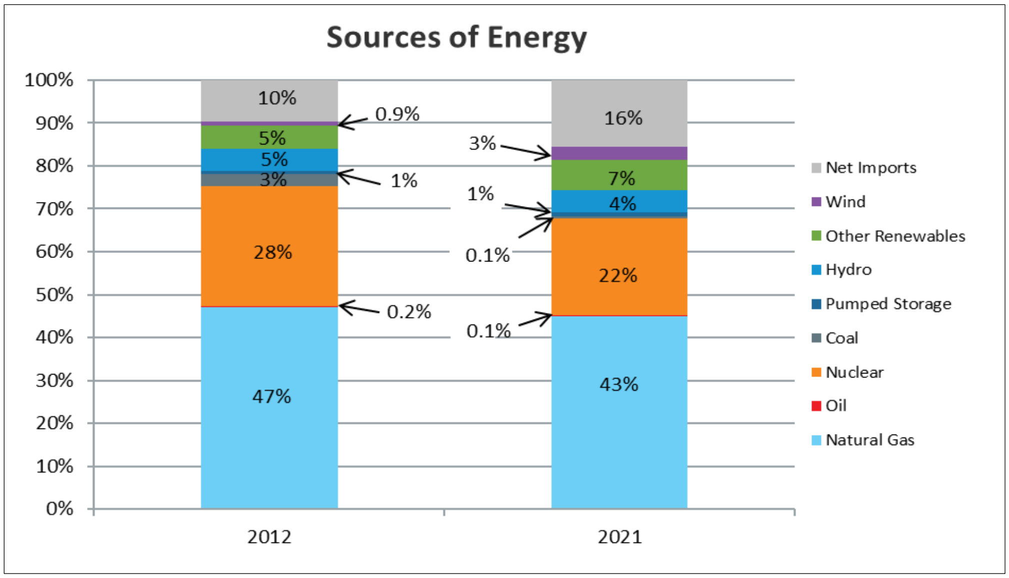


Figure 1-1: Percentage energy generation by resource type, 2012 compared with 2021.

Compared with the 30-year average for heating and cooling days (i.e., an indicator of weather), 2021 had a 38% warmer summer and a 10% cooler winter. From 2020 to 2021, the net energy for load[3] and generation[4] by native ISO New England resources increased by 1.6% and 7.1%, respectively. The net energy (i.e., imports minus exports) that ISO New England received from neighboring systems in 2021 was approximately 20% lower than the previous year. From 2020 to 2021, coal- and oil-fired generation increased by 281% and 53%, respectively, while natural gas-fired generation increased by 9%. The increased use of coal- and oil-fired generation was due to lower temperatures in January and February than the previous year. On average, New England's winter temperatures were 2.5 degrees cooler than last winter. Generation by wind and solar resources increased by about 10%, while hydroelectric generation declined by 5% respectively. Nuclear generation increased by 6%.

Table 1-1 shows the total 2020 and 2021 ISO New England average annual emissions (ktons) and average annual emission rates (lbs/MWh) of NO_X, SO_2 and CO_2. Compared to 2020, both the 2021 average emissions and the emission rates from native generation increased for CO_2 and SO_2. The average emissions for NO_X also increased, but the emission rates decreased in 2021. The CO_2 average emissions (ktons) with imports included are higher than the emissions for the native generation only, but the emission rates with imports are lower than for the native generation only due to the lower average emission rate of the imports.

[3] 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.

[4] In this report, "generation" refers to energy production (MWh) and not capacity (MW).

Table 1-1
2020 and 2021 ISO New England Average Emissions (ktons) and Emission Rates (lbs/MWh)

Annual Average Emissions and Emission Rates						
	2020 Emissions (ktons)	2021 Emissions (ktons)	Total Emissions % Change	2020 Emission Rate (lbs/MWh)	2021 Emission Rate (lbs/MWh)	Emission Rate % Change
Native Generation						
NO_X	12.09	12.44	2.9	0.25	0.24	-4.0
SO_2	1.88	2.11	12.2	0.04	0.04	0.0
CO_2	31,028	33,439	7.8	654	658	0.6
Native Generation Plus Imports						
CO_2	33,168	34,555	4.2	560	574	2.4

The annual marginal emission rates are 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 2021 marginal emission metrics using two different approaches: a time-weighted approach, which is the method that has historically been used, and a load-weighted approach, which has been used since 2018 along with the time-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 resource 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 resource 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 SO_2 and NO_X, have exhibited an overall decrease during the past ten years. Compared with 2012, the 2021 LMU SO_2 annual marginal rates have declined by approximately 93% for the all-LMU scenario and 90% for the emitting-LMU scenarios. There was a slight increase in the CO_2 annual marginal rates of 0.60%, which could be attributed to more coal-and-gas fired generators on the margin in 2021.

The load-weighted LMU annual marginal rates have only been calculated since the 2018 Emissions Report, and so a long-term history of those rates is not available. Table 1-2 shows that the increase in the annual marginal emission rates from 2020 to 2021 using the load-weighted approach are similar to those of the time-weighted approach. Both approaches resulted in increases in the CO_2 rates, with the greatest change (4.6%) occurring for the emitting LMUs scenario using the time-weighted approach. Slight increases in all of the SO_2 rates were also observed. There were no changes in the NO_X rates except for the emitting LMUs scenario using the time-weighted approach, for which there was a 6.3% increase.

Table 1-2
2020 and 2021 Time-Weighted and Load-Weighted LMU Marginal Emission Rates (lbs/MWh)

LMU Marginal Emissions						
	Time-Weighted			Load-Weighted		
All LMUs	2020 Annual Rate	2021 Annual Rate	Percent Change 2020 to 2021	2020 Annual Rate	2021 Annual Rate	Percent Change 2020 to 2021
	(lb/MWh)	(lb/MWh)	(%)	(lb/MWh)	(lb/MWh)	(%)
All LMUs						
NO_X	0.11	0.11	0.0	0.10	0.10	0.0
SO_2	0.02	0.03	50.0	0.02	0.03	50.0
CO_2	706	719	1.8	742	758	2.2
Emitting LMUs						
NO_X	0.16	0.17	6.3	0.13	0.13	0.0
SO_2	0.03	0.04	33.3	0.03	0.04	33.3
CO_2	971	1,016	4.6	904	910	0.7

The above table also shows the impacts of using the load-weighted rather than the time-weighted approach for calculating marginal emission rates. For the all-LMU scenario, this is most apparent in the higher CO_2 rates. The load-weighted approach takes into consideration the fact that most of the wind generators 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 generators to the marginal emission rates, resulting in higher marginal rates. With the time-weighted approach, these constrained wind resources are given equal weight with other resources that set price for the remainder of the region, resulting in lower marginal emission rates.

Figure 1-2 summarizes the 2021 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 simple cycle natural gas-fired generators and oil-fired units on the margin was higher than on average during the year.

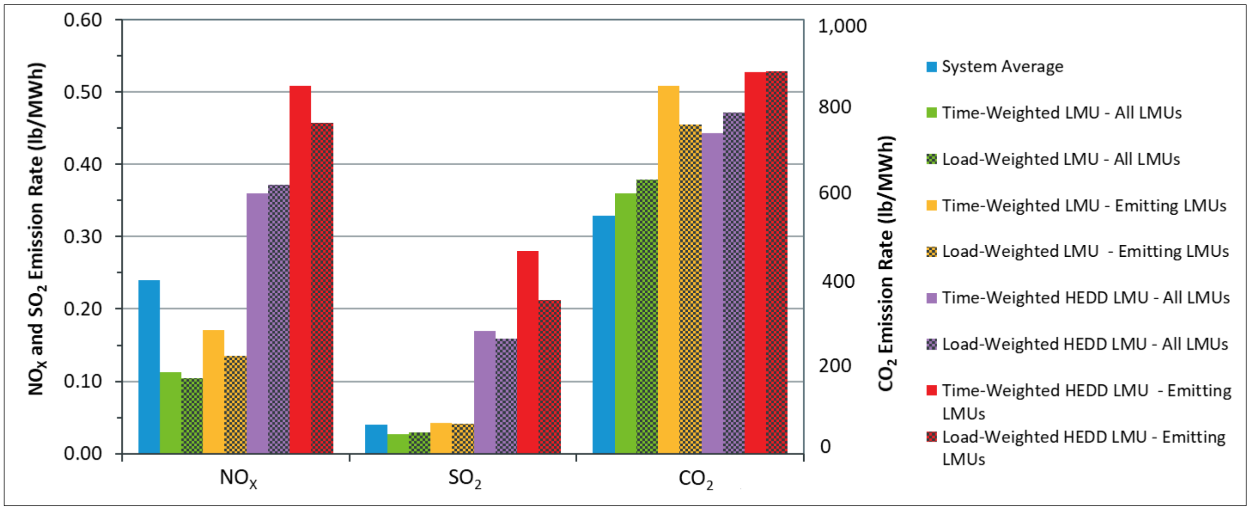


Figure 1-2: Comparison of 2021 ISO New England native generation average and marginal emission rates (lbs/MWh).

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 2021 calculated all-LMU marginal heat rate of 5.676 MMBtu/MWh was 0.2% higher than the 2020 value of 5.664 MMBtu/MWh. The LMU marginal heat rate for the emitting units increased by 2.3% from 7.728 MMBtu/MWh in 2020 to 7.902 MMBtu/MWh in 2021.

The marginal heat rates were also calculated using the load-weighted approach, which resulted in 2021 marginal heat rates of 6.313 MMBtu/MWh and 7.558 MMBtu/MWh for the all-LMU and emitting-LMU scenarios, respectively. When compared to the 2020 values, these marginal heat rates were approximately 11% higher for the all-LMU scenario. Conversely, the heat rates decreased by 4% for the emitting-LMU scenario.

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.[5] Such applications were filed under the Massachusetts ERC banking and trading program, which became effective on January 1, 1994. The ERC program allows inventoried sources of NO_X, volatile organic compounds (VOC), and carbon monoxide (CO) in Massachusetts to earn bankable and tradable emission credits by reducing actual power plant emissions below regulatory requirements.

Also in 1994, the *1993 Marginal Emission Rate Analysis* (*1993 MEA Report*) was published, which provided expanded analysis of the impact of DSM programs on power plant NO_X, sulfur dioxide (SO_2), and carbon dioxide (CO_2) air emissions for 1993. MEA reports were published annually from 1994 to 2007 to provide similar annual environmental analyses for these years.[6] For the 2008 emissions analysis, members of ISO New England's Environmental Advisory Group (EAG) requested that the *MEA Report* be restructured to include both average and marginal emissions for the ISO New England generation system, rather than focusing primarily on marginal emissions.[7] In response, the report was revised and renamed the *ISO New England Electric Generator Air Emissions Report* (*Emissions Report*), to reflect the importance of average 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 response to a request by the EAG, the ISO added to the *2018 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.

Estimated CO_2 emissions from imports are included for the first time in the *2020 Emissions Report*. That information was used to estimate total CO_2 emissions from all of the electricity serving ISO-NE load, not just native generation. Stakeholders can use the calculated marginal emissions to track air

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[5] Massachusetts Executive Office of Energy and Environmental Affairs, "BWP AQ [Bureau of Waste Prevention—Air Quality] 18—Creation of Emission Reduction Credits," webpage (2020), https://www.mass.gov/doc/bwp-aq-18-creation-of-emission-reduction-credits-erc-form-instructions-march-2008/download

[6] 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.

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

emissions from ISO New England's electric generation system and to estimate the impact that DSM programs and non-emitting renewable energy projects (i.e., wind and solar units) have on reducing ISO New England's NO_X, SO_2, and CO_2 power plant air emissions. The *2021 Emissions Report* focuses on analysis and observations over the past decade (2012 to 2021). The Appendix includes data for years before 2012, 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 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 did not typically vary their output to balance supply with demand on the system. Other non-emitting resources, such as hydroelectric, pumped storage, wind, solar, and nuclear generators 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 3.4). 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 technology type[8]. The marginal emission rates calculated with the load-weighed LMU approach are included in this *2021 Emissions Report* along with the time-weighted LMU marginal emission rates.

2.2 History of Marginal Heat Rate Methodologies

A thermal power plant's heat rate is a measure of its efficiency in converting fuel (in British thermal units (Btus)) to electricity (kWh); the lower the heat rate, the more efficient the electrical generator. A power 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.[9] 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 3.5, 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.

[8] 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.

[9] 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 average emission rate, marginal emission rate, and marginal heat rate are shown. The time periods studied are also described.

3.1 Data Sources

3.1.1 Native Generation

The primary source of data for the ISO New England native generation average emissions and marginal emission rate calculations for NO_x, SO_2, and CO_2 was the US EPA Clean Air Markets Program Data (CAMPD).[10] The database contains measured 2021 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).[11]

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 eGRID2020 were used.[12] 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 2021 megawatt-hours of energy production (generation), from the ISO's database used for energy market settlement purposes, to calculate tons of emissions.

For calculating average emissions, approximately 23% of the total NO_X emissions, 21% of the SO_2 emissions and 76% of the CO_2 emissions were based on EPA's Clean Air Markets data. When emissions data obtained from NEPOOL GIS are also included, those percentages increase to over 86% of total NO_X, SO_2, and CO_2 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 (BAA) are not part of this analysis.

[10] EPA's Clean Air Markets Program data (2022) are available at https://campd.epa.gov/ , and the Clean Air Power Sector Programs emissions data (2023) are available at http://www.epa.gov/airmarkets/. Generators report emissions to EPA under the Acid Rain Program, which covers generators 25 MW or larger. Generators subject to RGGI also report CO_2 emissions to EPA. Additional details for the monitoring, recordkeeping, and reporting requirements of SO_2, NO_X, and CO_2 emissions, volumetric flow, and opacity data from affected units under 40 CFR Part 75 are available at https://www.epa.gov/airmarkets/emissions-monitoring-and-reporting.

[11] 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.

[12] The U.S. EPA's eGRID2020 database (2022) is available at https://www.epa.gov/egrid.

3.1.2 Imports

CO_2 emission rates for 2021 imports are based on the eGRID2020 database for imports from NYISO, and on Canada's Greenhouse Gas Inventory Report[13] for imports from New Brunswick and Quebec. To calculate tons of emissions, the emission rates were multiplied by the imported energy values reported in the Net Energy and Peak Load by Source spreadsheet[14] for each neighboring BAA. The assumed emission rate for exports is the ISO-NE annual native generation emission rate. This rate was used to calculate total emissions associated with exports by multiplying the rate by the amount of exported energy.

The assumed CO_2 emission rates for New York, New Brunswick, and Quebec are 428 lbs/MWh, 698 lbs/MWh, and 3.7 lbs/MWh, respectively. Those values result in the CO_2 emission rates and total annual emissions for imports and exports shown below.

Table 3-1
2021 Import and Export Emission Rates (lbs/MWh) and Emissions (ktons)

Source	CO_2 Emission Rate (lbs/MWh)	GWh	CO_2 Emissions (ktons)
Imports	199	22,157	2,210
Exports	658	-3,362	-1,106

3.2 Average Emission Rate Calculation for Native Generation

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

$$\text{Annual Native Generation Emission Rate (lbs/MWh)} = \frac{\text{Total Annual Emissions (lbs)}_{\text{All ISO-NE Generators}}}{\text{Total Annual Energy (MWh)}_{\text{All ISO-NE Generators}}}$$

3.3 Average Emission Rate Calculation for Native Generation Plus Imports

The calculation for determining the average emission rate for native generation plus net imports is similar to the formula above, but with the addition of emissions from imports and subtraction of emissions from exports. Emissions from imports are calculated by multiplying the average emission rate (lbs/MWh) reported by the balancing authority that is the source of the energy, by the energy (MWh) imported across the tie line(s) from that BAA. Emissions from energy exported from New England are calculated by multiplying the average annual emission rate for ISO-NE native generation by the amount of energy exported to other BAAs.

[13] Canadian greenhouse gas emissions reported as consumption intensity (g CO_2 eq/kWh) are located at https://publications.gc.ca/collections/collection_2021/eccc/En81-4-2019-3-eng.pdf
[14] https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/net-ener-peak-load

$$\text{Annual Avg. Emission Rate } \left(\frac{\text{lbs}}{\text{MWh}}\right) = \frac{\text{Annual Emissions (lbs)}_{\text{ISO-NE Generators}} + (\text{Annual Emissions(lbs)}_{\text{Imports}} - \text{Annual Emissions(lbs)}_{\text{Exports}})}{\text{Annual Energy (MWh)}_{\text{ISO-NE Generators}} + (\text{Annual Energy(MWh)}_{\text{Imports}} - \text{Annual Energy(MWh)}_{\text{Exports}})}$$

3.4 Marginal Emission Rate Calculation

The Locational Marginal Unit (LMU) is identified by the LMP, which is set by the cost of the resource 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 CAMPD database were grouped into on-peak and off-peak periods (defined in Section 3.6) 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 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 generator's storage pond, and external transactions were also assumed to have no emissions.

3.5 Marginal Heat Rate Calculation

The marginal heat rate was calculated by first calculating a heat rate for each individual generator[15]. 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:

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

[15] 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.

3.6 Time Periods Analyzed

The 2021 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:[16]

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

Because the ozone and non-ozone seasons are only relevant to NO_X emissions, the SO_2 and CO_2 emission rates were only calculated for the following time periods:

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

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

Section 4
Data and Assumptions

This section highlights the key parameters and assumptions modeled in the *2021 Emissions Report*, including weather, emissions data, installed capacity, and system generation.

4.1 2021 New England Weather

Because the weather significantly affects the demand for energy and peak loads, comparing 2021 temperatures, total energy use and both cooling and heating degree days to previous years can provide some perspective.

New England winter monthly temperatures in 2021 were below average. The January 2021 weather was colder than the previous year: the average temperature of 29^{0}F was lower than January 2020 but higher than the 20-year average January temperature of 27^{0}F. In summer 2021 (June through September), higher humidity in New England contributed to a 0.3% increase in average loads, compared to the prior summer. In 2021, the Temperature-Humidity Index (THI) was 70^{0}F compared to 69^{0}F in summer 2020. In both June and August 2021, the THI was higher than in 2020, leading to an increased air-conditioning demand, and therefore, higher loads. In June 2021, loads averaged 14,846 MW, a 1,121 MW increase from June 2020 (13,725 MW). In August 2021, loads averaged 16,217 MW, up from 15,441 MW in August 2020. In July 2021, cooler temperatures led to lower loads compared to July 2020. The average load in July 2021 was 14,818 MW, a 1,725 MW decrease from 2020.

The 2021 summer peak electricity demand of 25,801 MW was 2.7% higher than the 2020 summer peak of 25,121 MW. There were 437 cooling degree days in 2021, which is 38% higher than the 30-year average.[17] With respect to the winter months, there were 5,437 heating degree days, which is 10% higher than the 30-year average.

New England's historical cooling and heating degree days for 2001 through 2021 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 ISO New England Generating 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

[17] Over the 30-year span from 1991 to 2020, the average number of cooling degree days (CDDs) was 316, and the average number of heating degree days (HDDs) was 6,048. The equations used in calculating the THI-based CDDs, which are used in the ISO's energy forecast models, may be found at https://www.iso-ne.com/static-assets/documents/2022/09/lf2023-methodology.pdf

- 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 2021 summer capacity for ISO New England generation as obtained from *ISO New England's 2022–2031 Forecast Report of Capacity, Energy, Loads and Transmission* (CELT).[18] 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.[19]

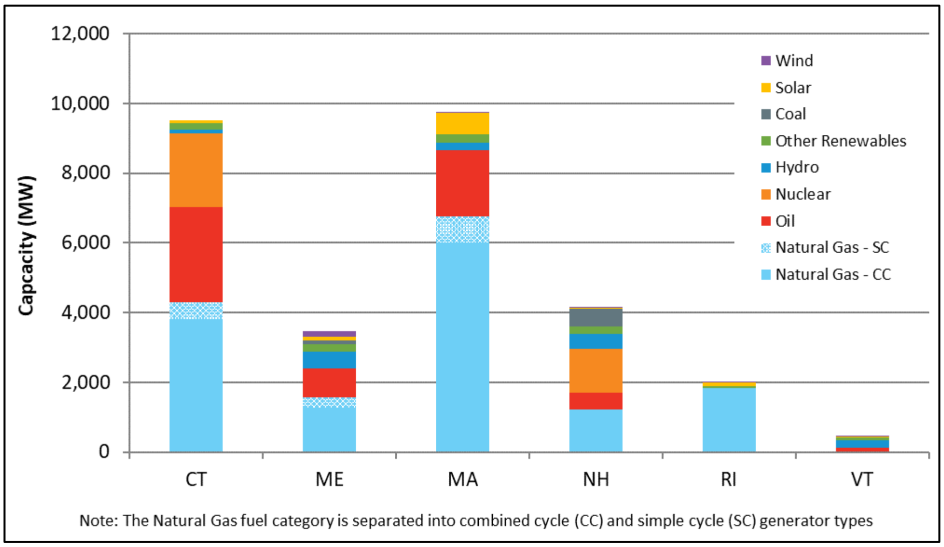

Figure 4-1: 2021 ISO New England generator summer capacity by state (MW).

Figure 4-2 illustrates the new generating capacity added to the ISO New England system from 2012 through 2021. A total of 4,407 MW was added, with combustion turbines and combined-cycle plants capable of burning natural gas or distillate oil making up about 66% of this new capacity. The remaining additions over the prior ten years consist primarily of renewable generation, including 24% of total capacity from wind and solar resources.

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[18] The ISO New England *CELT Report* is typically issued in May of each year. The *2022 CELT Report* (using the seasonal claimed capabilities (SCC) as of April 1, 2022) was used to completely capture all the new capacity additions that occurred during the prior calendar year, 2021. The capacity may also include generators that retired in 2021. The CELT reports are available at iso-ne.com/celt.

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

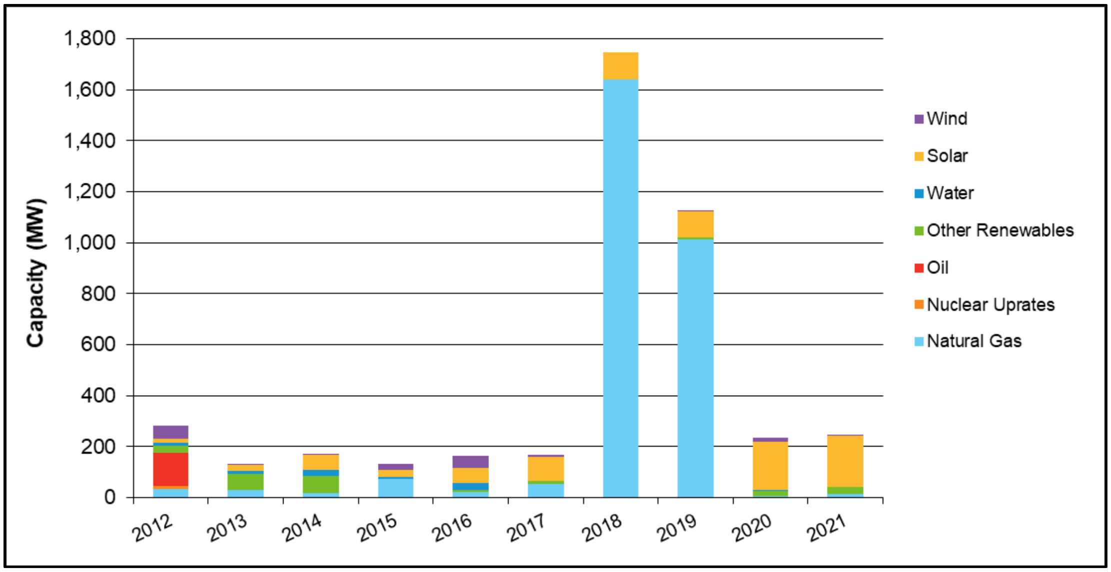


Figure 4-2 : ISO New England capacity additions, 2012 to 2021 (MW).
Note: The generator additions and uprate values are based on the summer Seasonal Claimed Capabilities, as reported in the 2022 CELT Report.

Several large generators in New England have retired in the past ten years. The retirements, as shown in Figure 4-3, total 2,213 MW of coal, 1,332 MW of residual oil, and 1,281 MW of nuclear generation since late 2012.

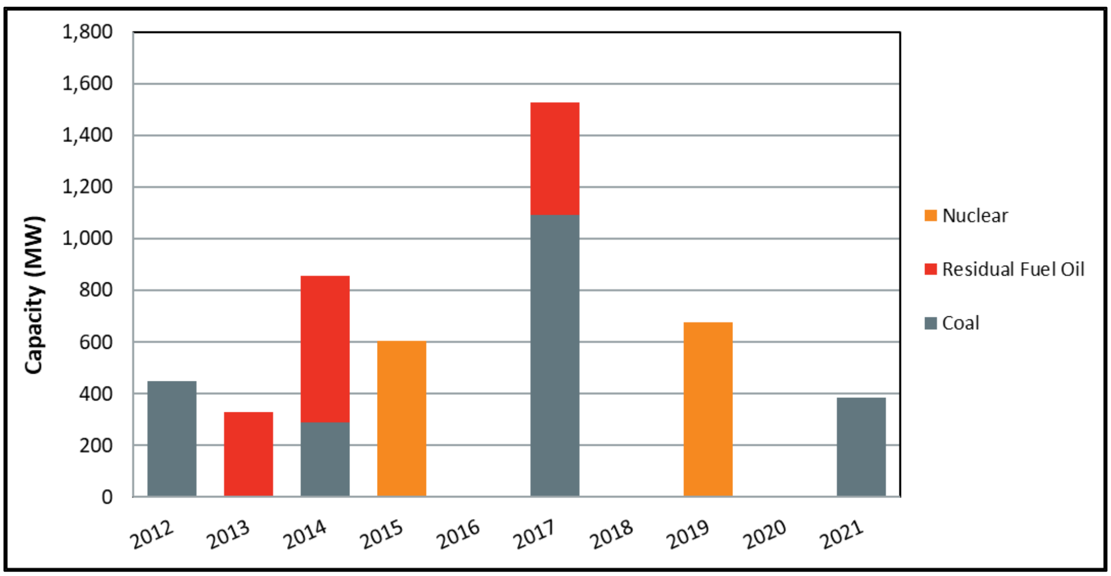


Figure 4-3: ISO New England major retirements,[20] 2012 to 2021 (MW)[21].

[20] 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.
[21] The retirement date shown is not necessarily the year in which the retirement occurred. In the case of units that retired late in the year, the retirement is included in the following year because that is when the impact would primarily have been observed.

4.3 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 2021 monthly energy production by resource 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 39% to 62% of the total native generation in each month,[22] or an annual average of 45% of total system energy when taking net imports into account. During the winter months, the use of firmly-contracted natural gas pipeline transportation capacity being held by the regional gas utilities[23] reduce the daily amount of residual pipeline capacity available for use by the regional gas-fired power generators. Almost all gas-fired resources in New England lack 365-day firm gas supply and transportation contracts. These constraints on winter gas availability limit energy production from gas-fired generation and drive the need for other fuels to be substituted to support the reliability of New England's BPS.

Although oil- and coal-fired generation were 0.4% and 0.5%, respectively, of the annual total of native generation plus imports in 2021, the contribution of coal to total generation in the month of January (1.7%) and February (2.6%) was somewhat higher than the annual average, and the contribution of oil to total generation was higher during the months of June and August (1.2%, 1.1%, respectively), due to the higher demand in those months. The percentage of natural-gas-fired generation also increased in the summer months to meet the higher demand, as is typically the case.

Combined hydro-electric, solar, and wind generation accounted for 8% to 25% of the total 2021 native generation, or an annual average of 11% in terms of total system energy with imports. These resource types exhibit seasonal differences in their energy output 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 11% to 21% of total energy.

[22] The share of annual native energy production for natural gas-fired generation was 52% in 2021 and 2020.
[23] Firm customers of regional gas LDCs include residential, commercial, and industrial (RCI) customers.

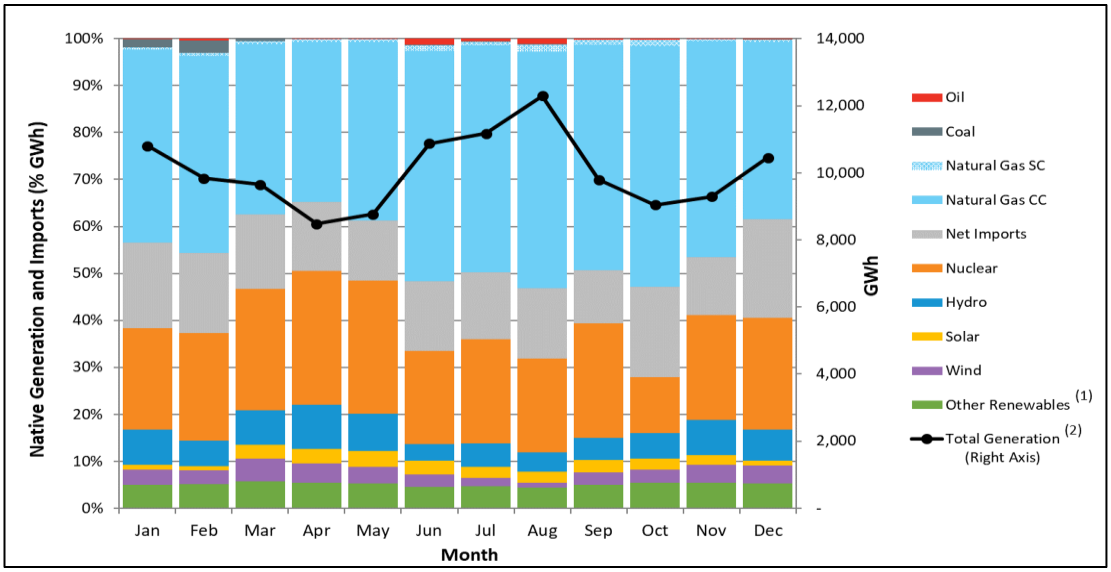


Figure 4-4: 2021 ISO New England monthly generation by resource type, including imports (% GWh, GWh).

Figure 4-5 shows the native generation (MWh) by fuel type from 2017 to 2021 based on the resource's primary fuel type listed in the *2022 CELT Report*, as well as net imports during that same period. In 2021, there was an increase in native generation in all fuel categories except for hydro. Prior to 2021, there was an overall declining trend in coal, oil, and nuclear generation. However, a colder winter in 2021 resulted in an additional 412 GWh of coal-fired generation, which is a 281% increase from the previous year. Natural-gas-fired generation in 2021 was about 4,432 GWh higher than in 2020, increasing by about 9%. Nuclear generation increased by about 1,495 GWh, or 6%, and hydro-electric generation was 5% lower in 2021. Solar and wind together, which increased by 589 GWh, or 10% over 2020, have grown by 50% (2,106 GWh) over the past five years. The overall native generation of 101,661 GWh[24] in 2021 was 7.1% more than in 2020.

Net imports were 20% lower in 2021 than in 2020, from 23,531 GWh to 18,796 GWh.

[24] This total does not include the 31 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).

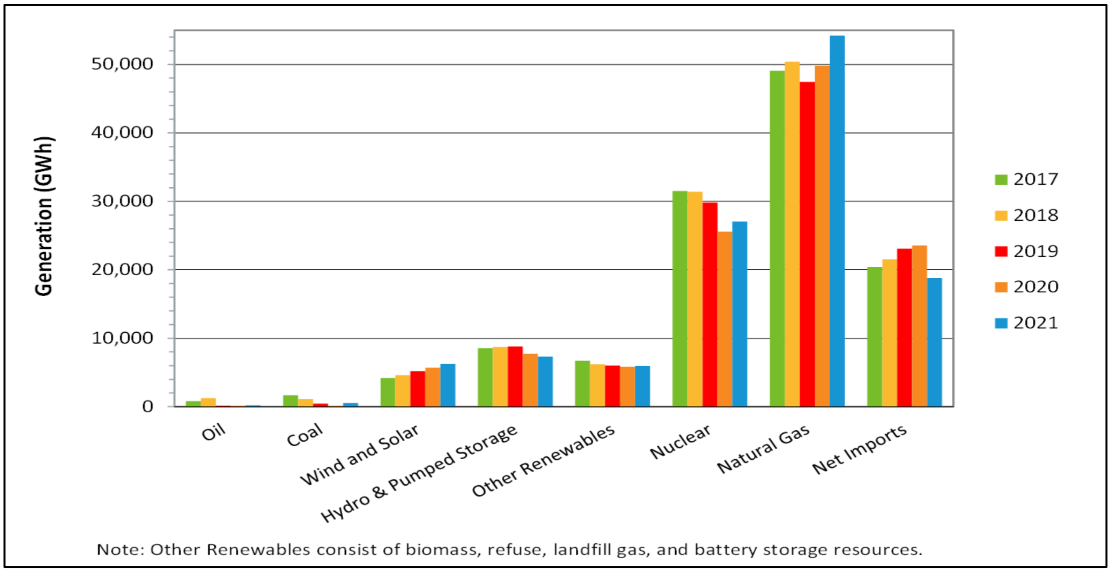


Figure 4-5: ISO New England annual generation by resource type, 2017 to 2021 (GWh).

4.4 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 resource 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.

4.4.1 All LMUs

4.4.1.1 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 resource type's time on the margin and month-to-month variations for the time-weighted approach. Natural gas was marginal 48% to 84% of the time. The months when natural gas generators were marginal in the higher end of that range were June through August. Oil-fired generation was on the margin an average of 0.5% during the year, and was marginal a maximum of 1.5% of the time in February when temperatures were slightly colder than normal. Coal-fired generation was on the margin a maximum of 1.4% of the time. Other Renewables, which consist of biomass and refuse resources, were marginal an average of 3% of the time, but reached peaks of 8% and 10% in October and November. In 2021, the time that wind was marginal ranged from 4% in August to a maximum of 27% in March. Note that Figure 4-6 includes a breakdown of the pumped storage category into pumped storage generation and pumped storage demand[25], which were marginal an average of 7% and 5% of the time, respectively.

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

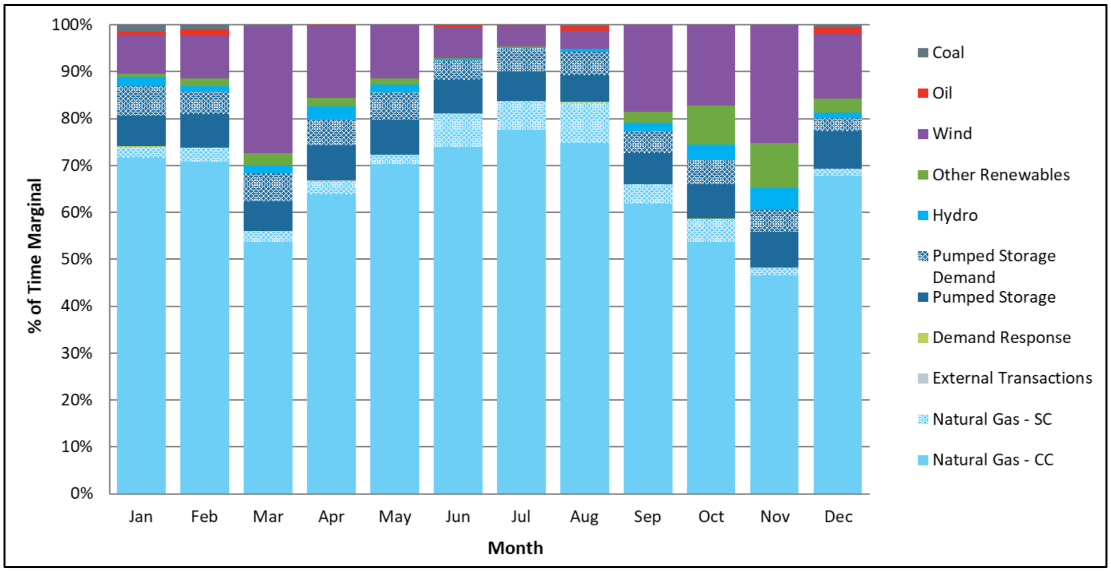


Figure 4-6: 2021 percentage of time various resource types were marginal —all LMUs.

Figure 4-7 shows the historical percentage of time that each resource type was marginal within a calendar year. Natural gas has been the primary marginal fuel type during the past five years. From 2020 to 2021, the percentage of time that natural gas was marginal decreased by 2%. The amount of time that oil was the marginal fuel increased from 0.2% to 0.5%, and coal increased from 0.1% to 0.3%. The percentage of time that the Other Renewables category was marginal increased from 14% to 16%. In 2021, as in 2020, wind often displaced gas as the price-setting fuel. Though wind was marginal 13% of the time in 2021, it was usually marginal for only a small share of total system load. Wind generators are often located in export-constrained areas and can only deliver the next increment of load in a small number of locations because the transmission network that moves energy out of their constrained area is at maximum capacity. At the system level, wind was the marginal fuel type for approximately 1% of the total load,[26] as shown in the next section.

[26] 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/.

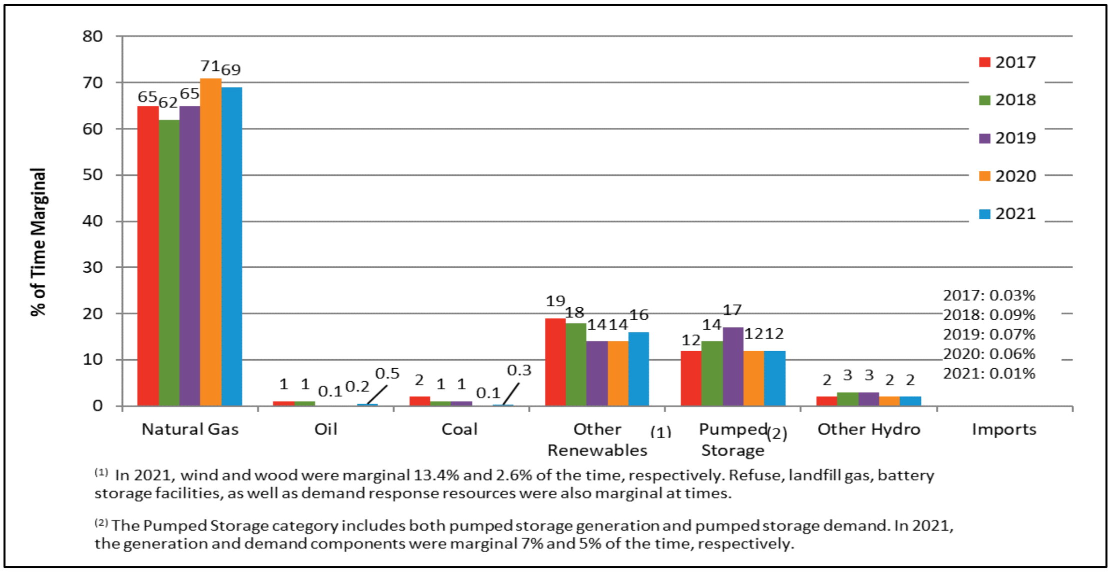


Figure 4-7: Annual percentage of time various resource types were marginal —all LMUs, 2017 to 2021.

4.4.1.2 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% in August to a maximum of 0.7% in April. 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 78% to 87% of the system load, and pumped storage generation, which was marginal for 7% to 15% of the load.

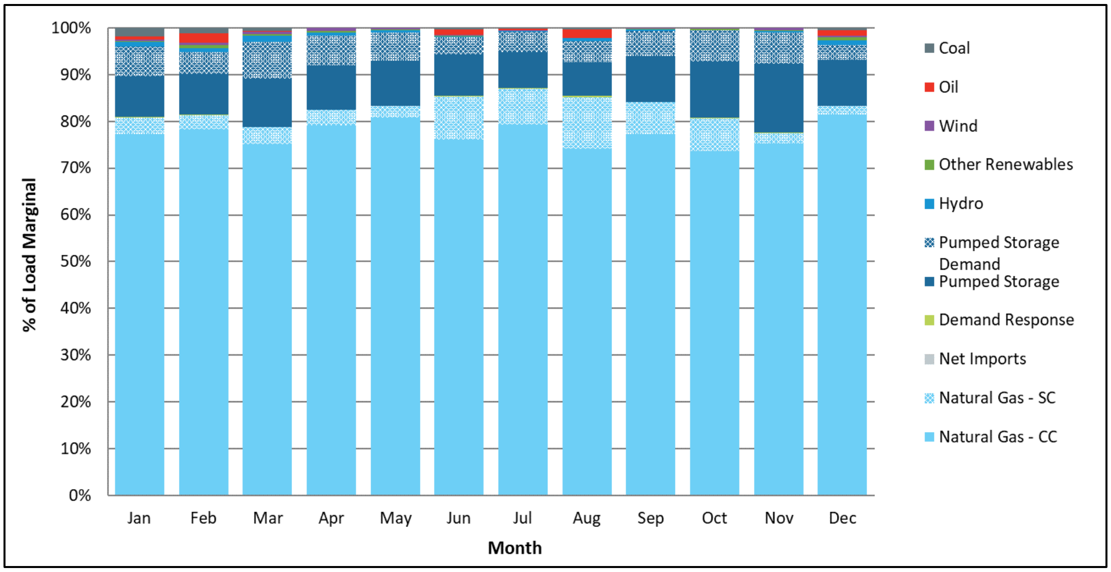


Figure 4-8: 2021 percentage of load for which various resource types were marginal —all LMUs.

Figure 4-9 shows the average percentage of load for which the resource types were marginal in 2018 through 2021, the four years for which the load-weighed analysis has been performed. The percentage of natural gas on the margin increased by 1% in 2021; oil and coal increased by 0.3%. Other renewables, hydro, and pumped storage marginality remained the same. The percentage of imports on the margin decreased to 0.001%.

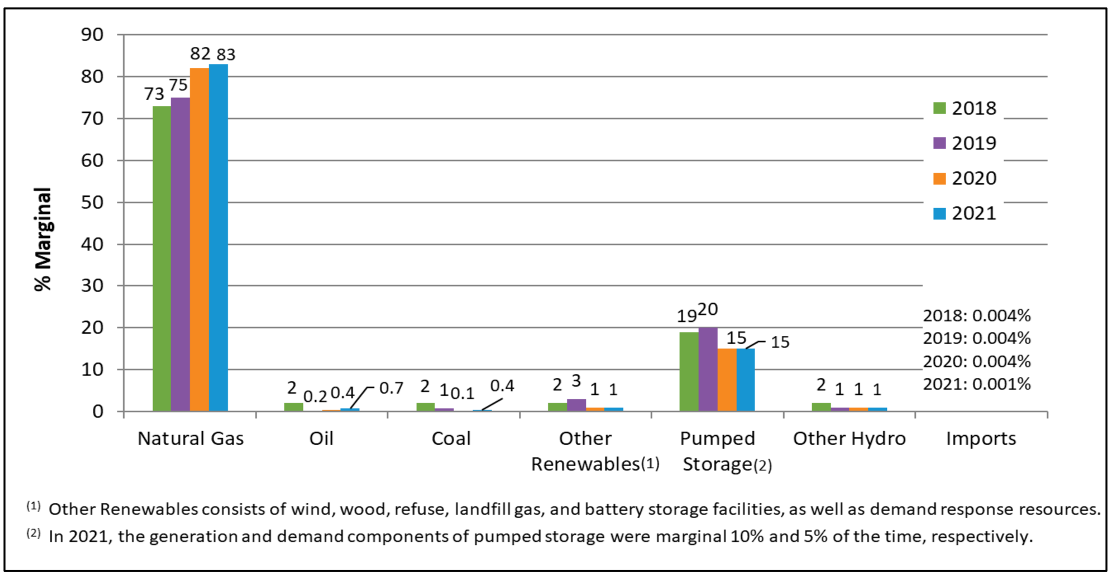
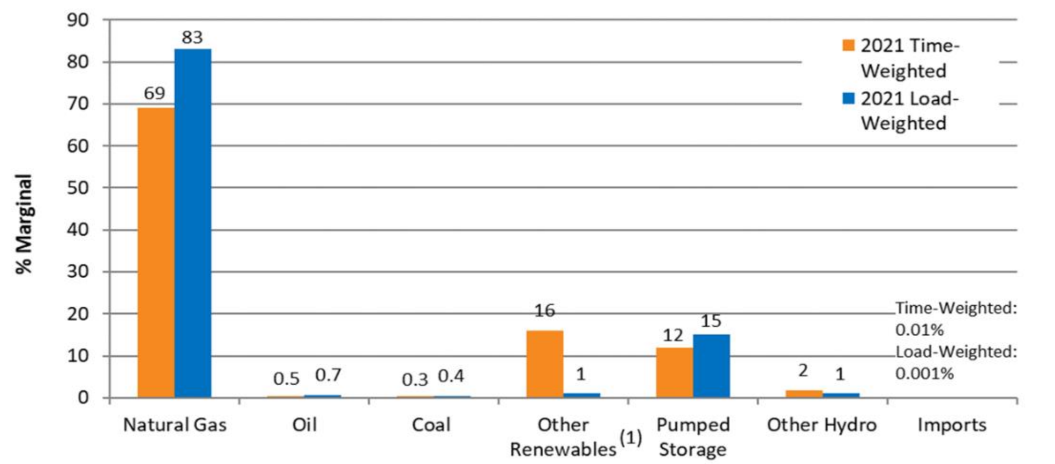


Figure 4-9: Annual percentage of load for which various resource types were marginal – all LMUs, 2018 to 2021.

4.4.1.3 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 and hydro-electric resources are also constrained, their marginality using the load-weighted approach is lower than with the simple time-weighted analysis.



(1) In the Other Renewables category, wind was marginal 13.4% of the time based on the time-weighted approach, but only 0.3% for the load-weighted. The remaining marginal units in that category consists of wood/wood waste solids, refuse plants, and demand response resources.

Figure 4-10: Comparison of 2021 annual marginality for various resource types using the time-weighted vs. load-weighted approach —all LMUs.

4.4.2 Emitting LMUs

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

4.4.2.1 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 generators were marginal 85% to 99% of the time. The simple-cycle natural gas-fired peaking units were marginal an average of 5% of the time during the year, but peaked at 9% and 11% during the months of highest demand in June and August.

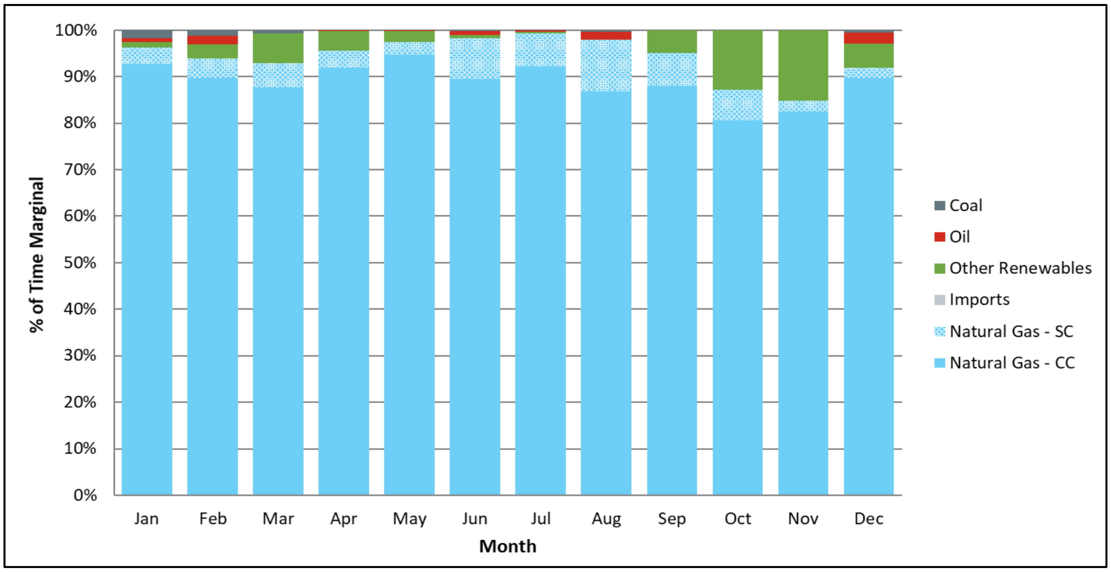


Figure 4-11: 2021 percentage of time various resource types were marginal —emitting LMUs.

Figure 4-12 shows that during the past five years, the percentage of time that natural gas-fired generators have been on the margin has been fairly consistent, while other renewables has been increasing and the amount of marginal oil- and coal-fired generation has been falling, with the exception of a slight increase in 2021.

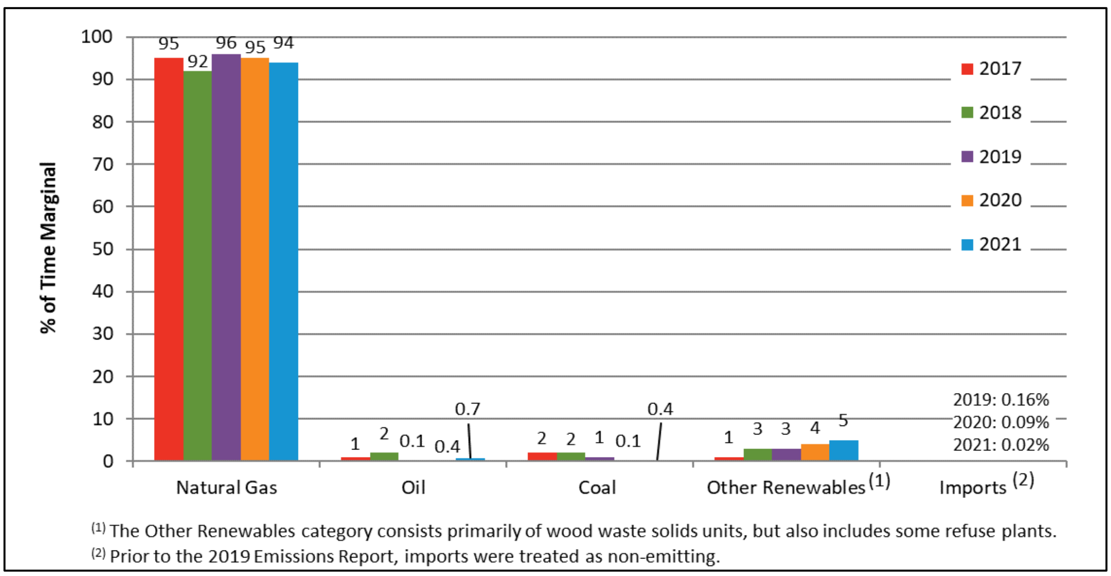


Figure 4-12: Annual percentage of time various resource types were marginal – emitting LMUs, 2017 to 2021.

4.4.2.2 Load-Weighted Approach – Emitting LMUs

Figure 4-13 shows the monthly 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 0.3% of the annual total (vs. 5% using the time-weighted approach), and a corresponding higher percentage of natural gas-fired generation on the margin. Figure 4-14 shows the annual marginal percentages, which increased for oil and coal in 2021, but decreased for natural gas.

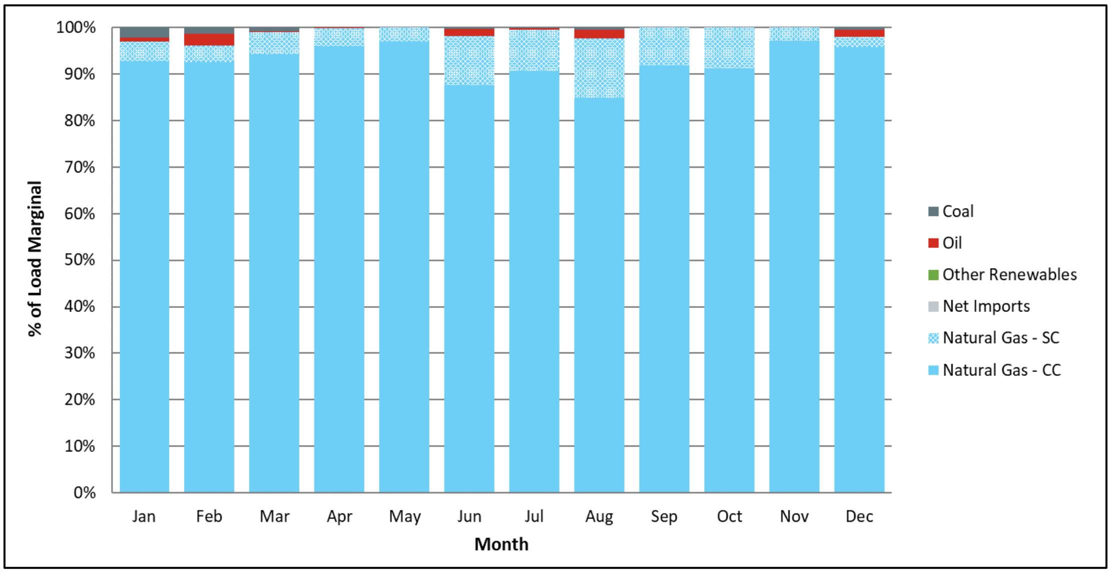


Figure 4-13: 2021 percentage of load for which various resource types were marginal —emitting LMUs.

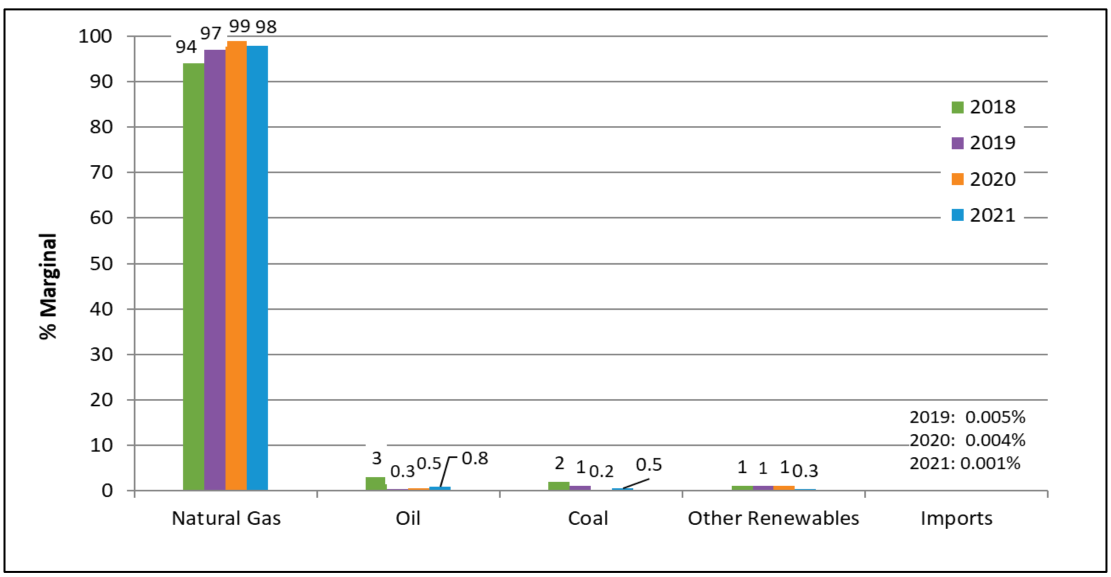


Figure 4-14: Annual percentage of load for which various resource types were marginal – emitting LMUs, 2018 to 2021.

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

Figure 4-15 is a comparison of the 2021 time-weighted and load-weighted results for emitting LMUs. The impact of constrained wood-burning generators 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 generators on the margin.

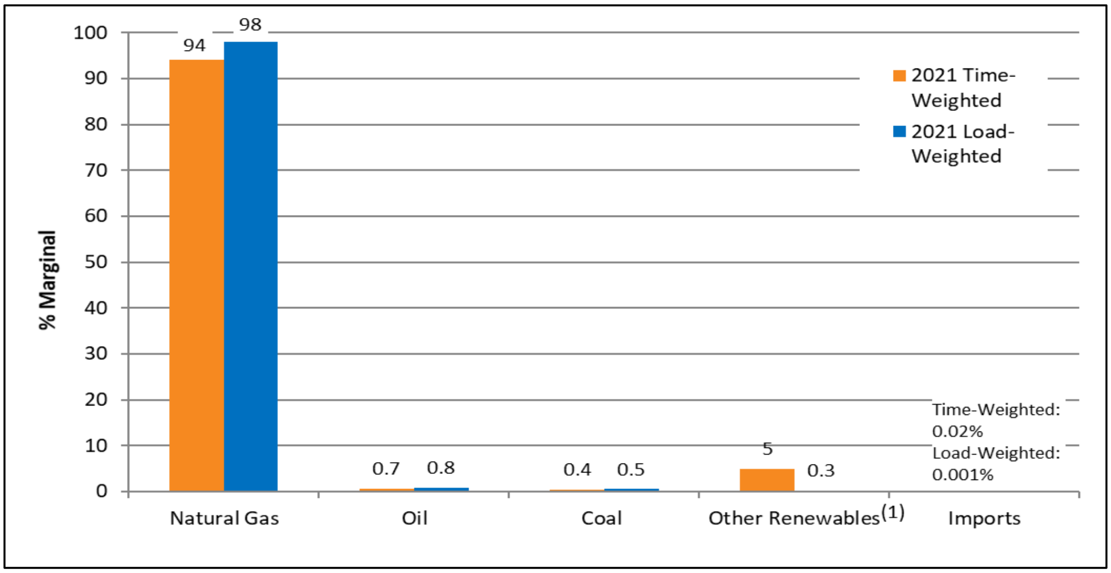


Figure 4-15: Comparison of 2021 annual marginality for various resource types using the time-weighted vs. load-weighted approach —emitting LMUs.

4.5 High Electric Demand Days

In New England, high electric demand days (HEDDs) are typically characterized by high temperatures leading to elevated cooling (energy) demand. During peak energy demand periods, such as HEDDs, the ISO relies on peaking units, which are utilized less during the rest of the year, but respond quickly to meet system demand. These peaking units are often jet (aero-derivative) or combustion turbines with higher emission rates. Therefore, examining the marginal emission rates on HEDDs (see Section 5.4) reveals the emission rates associated with the units responding to higher system demand.

Section 5
Results and Observations

This section presents the results for ISO New England's 2021 native generation emissions representing all generators. Results for CO_2 emissions from native generation plus imports are also included in the annual and 2021 monthly values. This section 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 2021 ISO New England Average Emissions

Results are presented for the following metrics:

- Aggregate native generation NO_X, SO_2, and CO_2 emissions for each state for 2021
- Aggregate NO_X, SO_2, and CO_2 native generation emissions, along with aggregate CO_2 emissions for native generation plus imports, for 2012 to 2021 average NO_X, SO_2, and CO_2 native generation emission rates, by state and for ISO New England as a whole
- Monthly variations in the native generation emission rates, as well as in the CO_2 emission rates for native generation plus imports, for 2021
- Annual average NO_X, SO_2, and CO_2 native generation emission rates, as well as CO_2 emission rates for native generation plus imports, for 2012 to 2021

5.1.1 Results

Figure 5-1 shows the 2021 aggregate NO_X, SO_2, and CO_2 air emissions for each state. The ISO New England total emissions from native generation for NO_X, SO_2, and CO_2 were 12.44 ktons, 2.11 ktons, and 33,439 ktons, respectively. The calculations for these emission levels were based on the actual generation of all generating units in ISO New England's BAA and the actual or assumed unit-specific emission rates.[27] 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.

[27] 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.

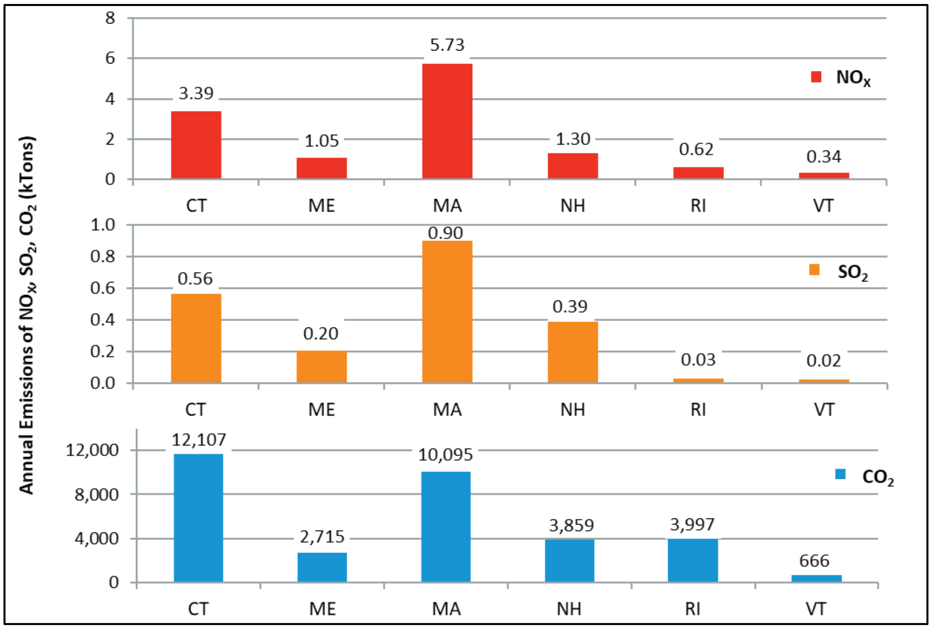


Figure 5-1: 2021 ISO New England average annual native generation emissions of NO_X, SO_2, and CO_2 (ktons).

Note: Average annual native generation 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 native generation annual aggregate NO_X, SO_2, and CO_2 air emissions for 2012 through 2021. Since 2012, NO_X emissions have declined by 39% and SO_2 by 87%, while CO_2 has decreased by about 20%. In addition, the figure shows the CO_2 emissions for native generation plus imports for the same period. Refer to Appendix Table 4 for the values behind this graph.

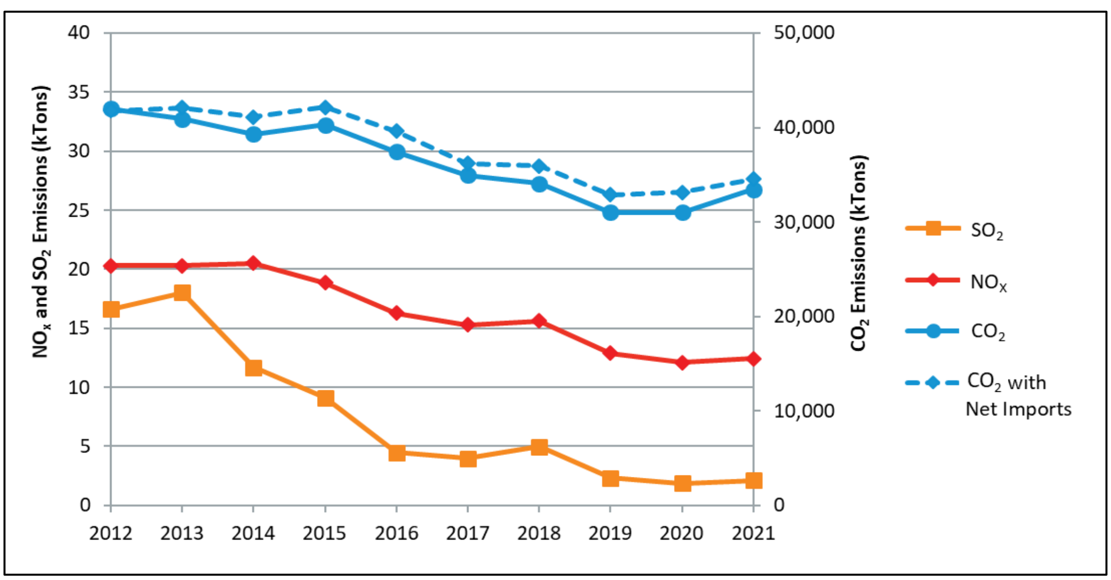


Figure 5-2: ISO New England average annual emissions, 2012 to 2021 (ktons).

Table 5-1 shows the 2021 average NO_X, SO_2, and CO_2 native generation air emission rates (lbs/MWh), by state and for New England 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
2021 ISO New England
Average Native Generation Emission Rates (lbs/MWh)

State	NO_X	SO_2	CO_2
Connecticut	0.16	0.03	562
Maine	0.23	0.04	593
Massachusetts	0.54	0.09	956
New Hampshire	0.15	0.05	450
Rhode Island	0.13	0.01	869
Vermont	0.35	0.02	693
New England	0.24	0.04	658

Monthly variations in the emission rates shown in Figure 5-3 reflect the generation by different resource types shown in Figure 4-4. In 2021, the highest CO_2 emission rates occurred in October, when the share of emissions from municipal solid waste, wood-burning, and natural gas generators was highest for the year. The highest SO_2 emission rates occurred in February when the percentage of coal-fired generators on the margin was higher than on average during the year. Higher NO_X emission rates occurred in February and October. The monthly CO_2 emission rates for native generation plus imports are also shown in the figure below. The average 2021 CO_2 rate of 199 lbs/MWh for imports is significantly lower than the CO_2 emission rate of 658 lbs/MWh for native generation, which results in a lower combined emission rate for native generation plus imports.

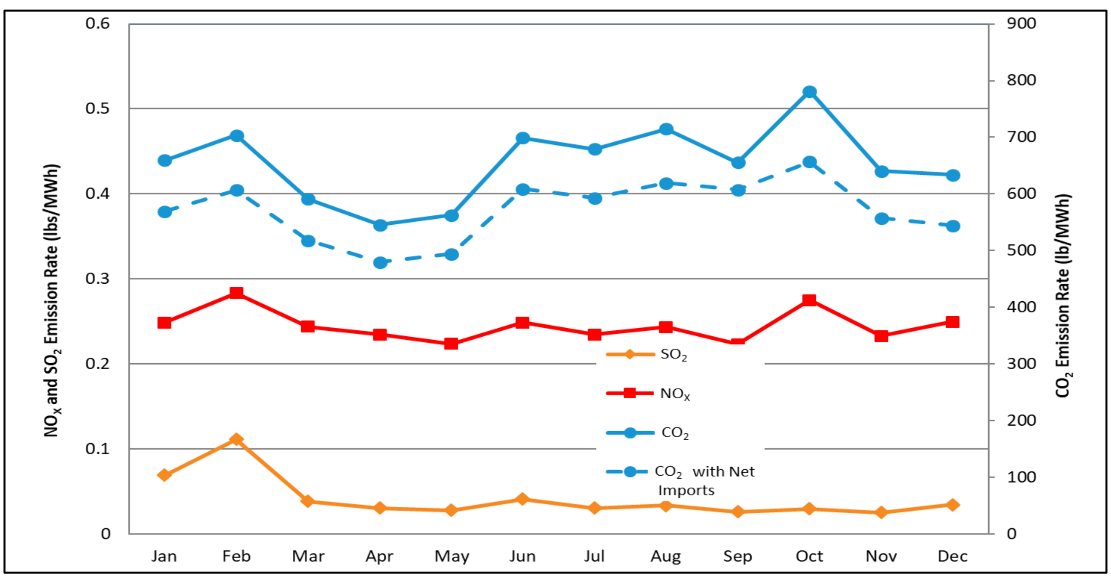


Figure 5-3: 2021 ISO New England monthly average emission rates (lbs/MWh).

Figure 5-4 illustrates the annual average NO_X, SO_2, and CO_2 air emission rates (lbs/MWh) for 2012 to 2021 using the calculation method presented in Section 3.2. Since 2012, the annual average NO_X emission rate has decreased by 30%, SO_2 by 85%, and CO_2 by 8%. The CO_2 emission rates that take imports into account follow a similar pattern, but are 10% to 13% lower than the rate without imports. Appendix Table 6 shows historical emission rates since 2001.

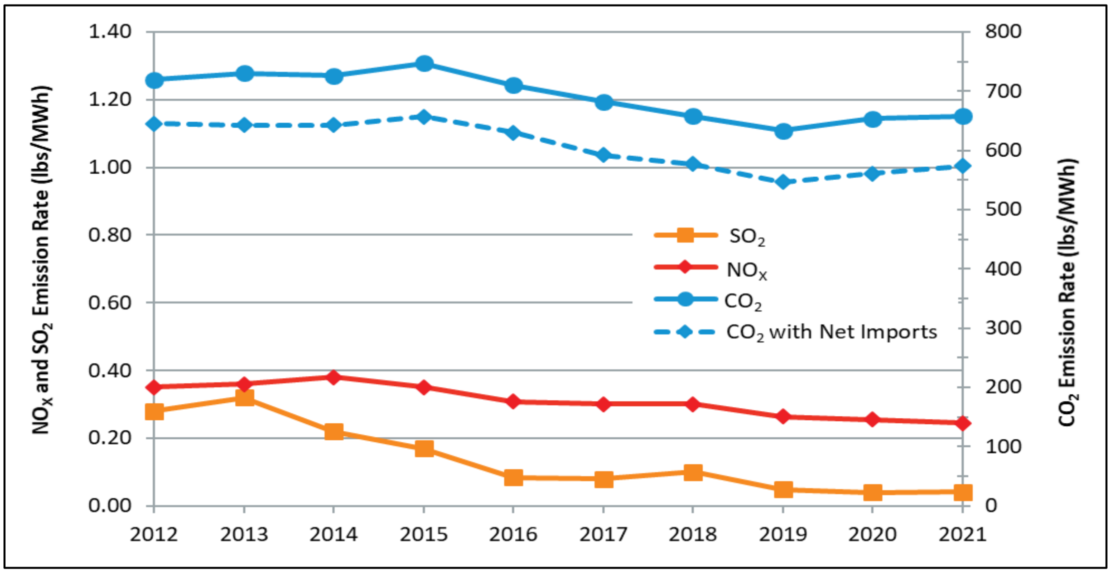


Figure 5-4: ISO New England annual average emission rates, 2012 to 2021 (lbs/MWh).

5.1.2 Additional Observations

Overall, the total native generation and emissions increased in 2021 from 2020. Generation in all fuel categories except hydro increased in 2021, which lead to an increase in total emissions (ktons) for NO_X, SO_2, and CO_2 by 2.9%, 12.2%, and 7.8%, respectively. Section 4.3 describes the changes in the generation mix and the impacts on average emissions can be seen in Table 5-2. Even though the total emissions increased in 2021, the emission rates (lbs/MWh) were similar to 2020 rates. The NO_x emission rate for native generation decreased by 4.0% and SO_2 remained the same. The CO_2 emission rates for native generation slightly increased by 0.6%, but a higher increase of 2.4% was observed when the emission rate from imports was accounted for.

Table 5-2
2020 and 2021 ISO New England Average Emissions (ktons)
and Emission Rates (lbs/MWh)

Average Emissions						
	2020 Emissions (ktons)	2021 Emissions (ktons)	Total Emissions % Change	2020 Emission Rate (lbs/MWh)	2021 Emission Rate (lbs/MWh)	Emission Rate % Change
Native Generation Only						
NO_X	12.09	12.44	2.9	0.25	0.24	-4.0
SO_2	1.88	2.11	12.2	0.04	0.04	0.0
CO_2	31,028	33,439	7.8	654	658	0.6
Native Generation Plus Imports						
CO_2	33,168	34,555	4.2	560	574	2.5

Overall, average 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 SO_2 emission controls on some of the remaining oil- and coal-fired generators
- Increasing amounts of wind and solar generation
- Increasing amounts of net energy imports

5.2 2021 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 2021. The 2021 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 2012 to 2021 are presented in Figure 5-6. The values behind Figure 5-6 are provided in Appendix Table 7.

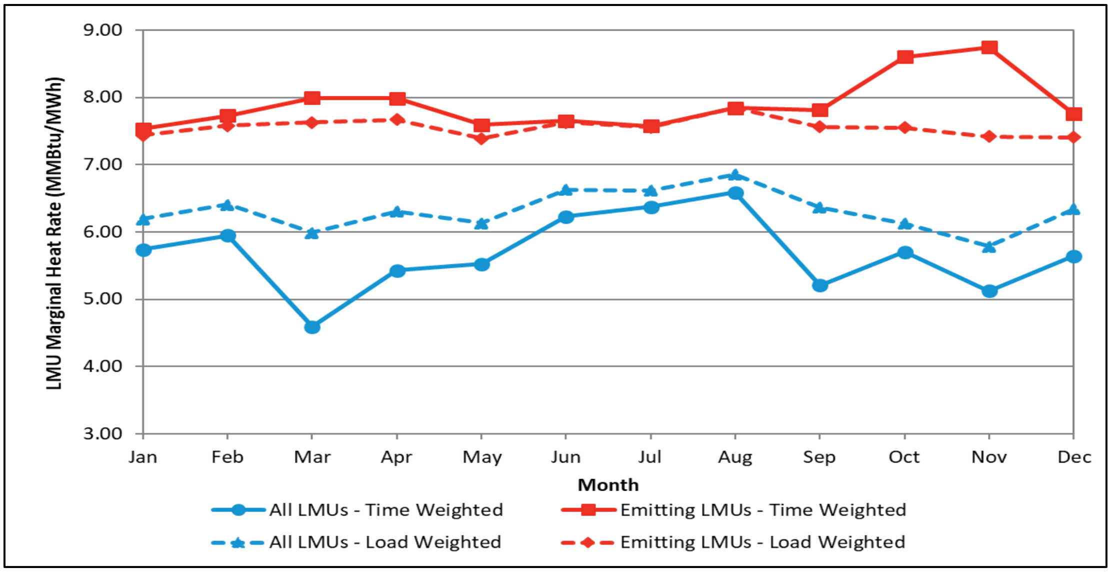


Figure 5-5: 2021 time- and load-weighted LMU monthly marginal heat rate (MMBtu/MWh).

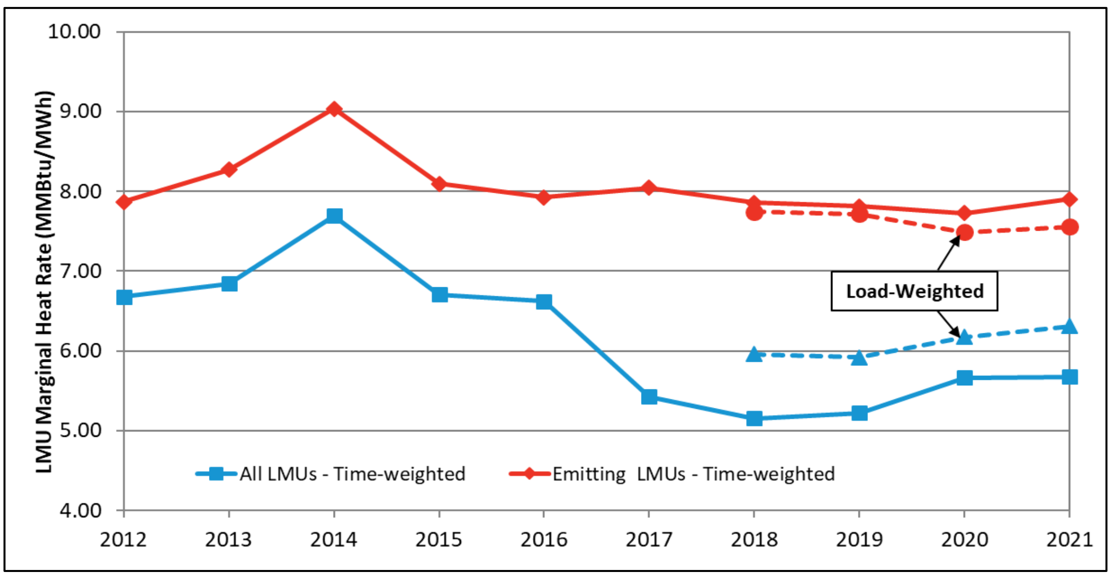


Figure 5-6: LMU annual marginal heat rate, 2012-2021 (MMBtu/MWh).

Prior to 2021, there was an overall trend of declining heat rates from 2012 through 2019 using the time-weighted LMU approach, with the exception of a spike in 2014. A steep drop in the heat rate in the all-LMU scenario occurred in 2017 due to the large amount of wind generators on the margin, which was a result of the DNE dispatch rules implemented in May 2016. In 2020 and then again in 2021, there was an increase in the marginal heat rates for the all-LMU scenario, using both the time- and load-weighted approaches. The marginal heat rates calculated using the load-weighted approach are included in the figure for the years 2018 through 2021. The 2021 load-weighted value for the all-LMU scenario was 11% 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 4% 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 2021 ISO New England Marginal Emission Rates

This section presents the 2021 calculated LMU-based marginal emission rates for the all-LMU and emitting-LMU scenarios, as defined in Section 4.4. The 2021 rates based on both the time-weighted and load-weighted LMU approaches are included; however, only time-weighted LMU results are available for years prior to 2018.

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

5.3.1 Marginal Emission Rates Using the Time-Weighted Approach

5.3.1.1 All-LMU Scenario

The time-weighted all-LMU marginal emission rates were calculated with all LMUs (units the LMP identified as marginal). Table 5-3 shows the rates in lbs/MWh. Appendix Table 8 shows these rates in lbs/MMBtu, with the associated marginal heat rate of 5.676 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 2021 percentage of time various resource types were marginal for all LMUs) and Figure 5-3 (showing the 2021 ISO New England monthly average NO_X, SO_2, and CO_2 emission rates). Appendix Table 9 lists the values behind Figure 5-7.

Table 5-3
2021 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	0.15	0.08	0.11	0.12	0.11
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.04	0.02		0.03
CO_2		739	705		719

(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.

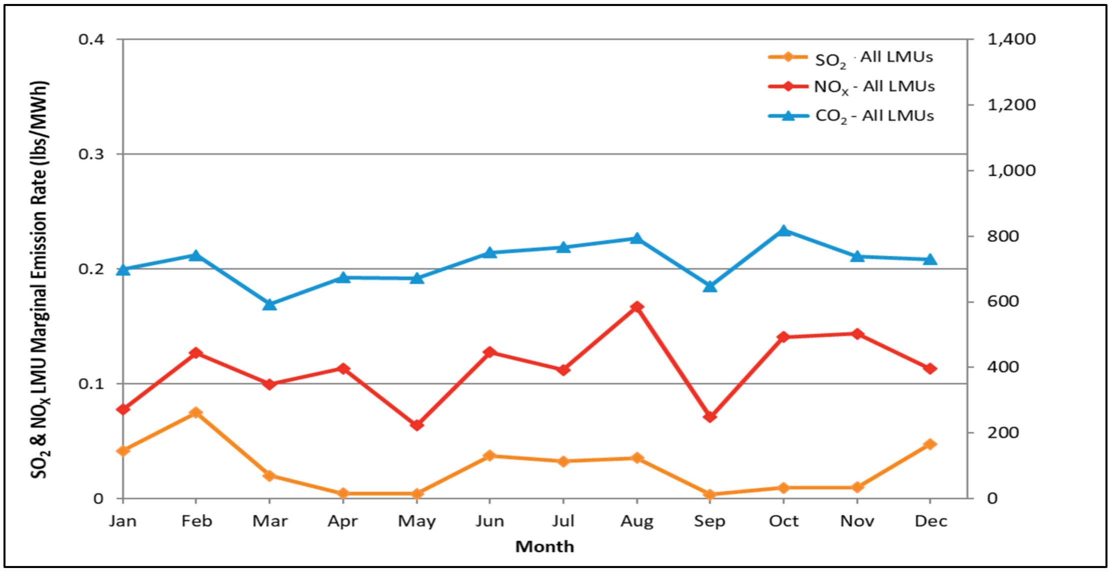


Figure 5-7: 2021 time-weighted monthly LMU marginal emission rates—all LMUs (lbs/MWh).

5.3.1.2 Emitting-LMU Scenario

Table 5-4 and Appendix Table 10 present the marginal emission rates for emitting LMUs only. The marginal heat rate for this scenario is 7.902 MMBtu/MWh. The values for the monthly rates shown in Figure 5-8 are shown in Appendix Table 11.

Table 5-4
2021 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	0.21	0.10	0.17	0.20	0.17
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		1,044	996		1,016

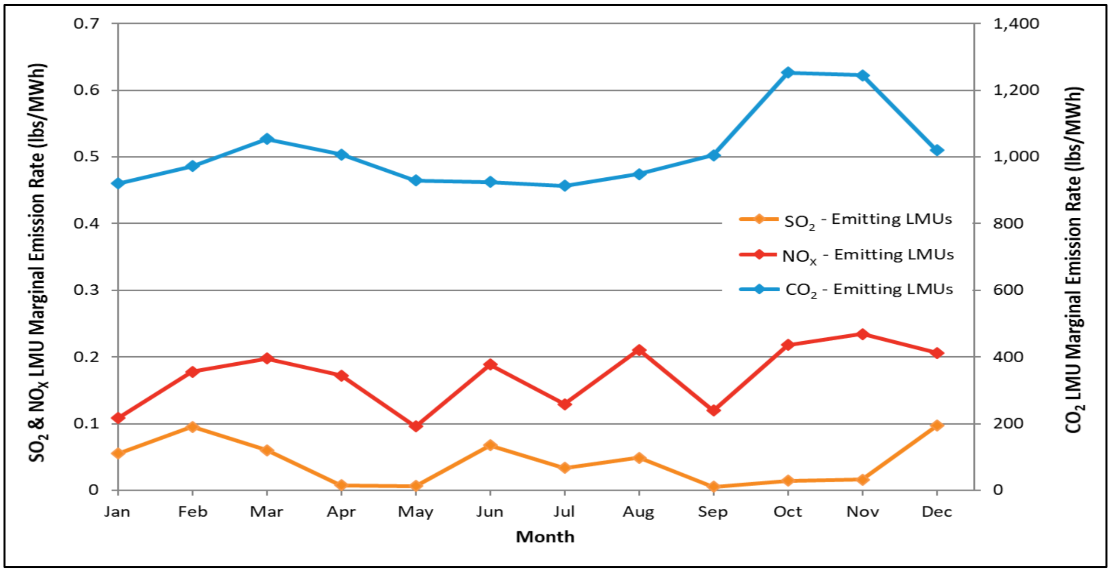


Figure 5-8: 2021 time-weighted monthly LMU marginal emission rates—emitting LMUs (lbs/MWh).

5.3.1.3 2012 to 2021 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.

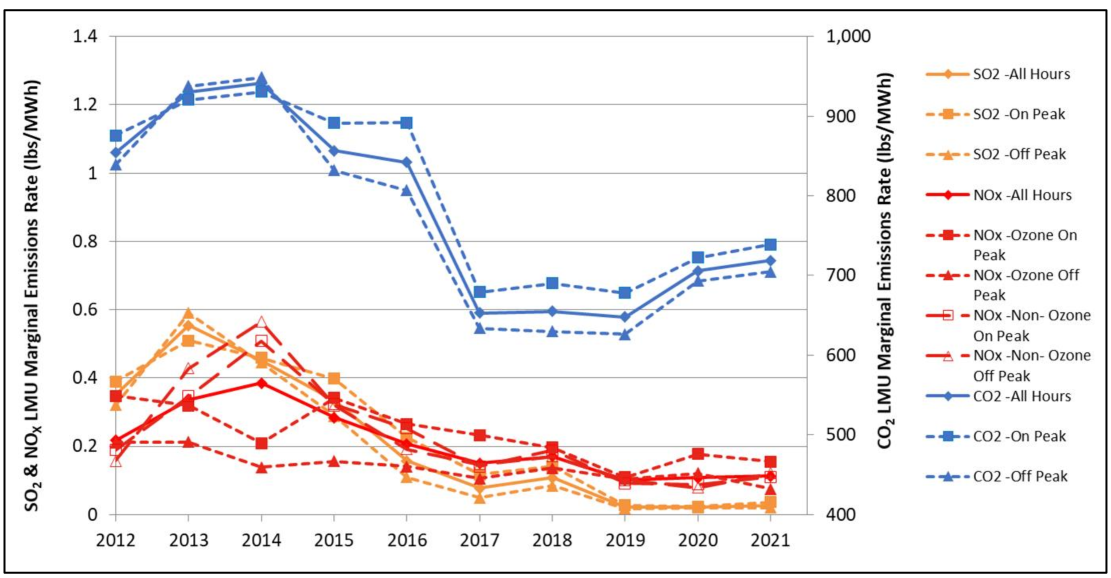


Figure 5-9: Time-weighted LMU marginal emission rates, 2012 to 2021—all LMUs (lbs/MWh).

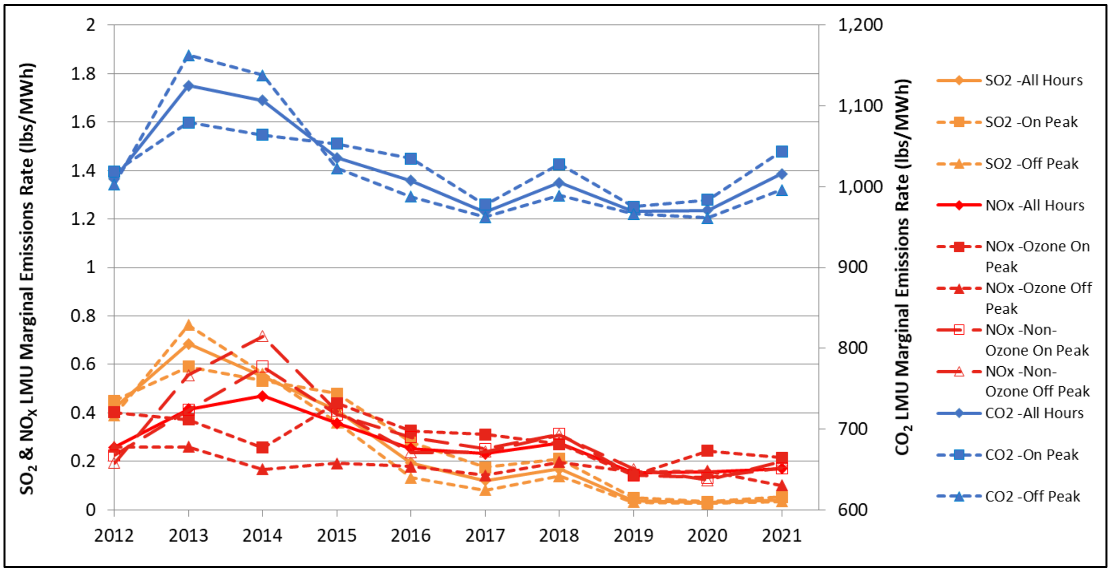


Figure 5-10: Time-weighted LMU marginal emission rates, 2012 to 2021—emitting LMUs (lbs/MWh).

5.3.2 Marginal Emission Rates Using the Load-Weighted Approach

5.3.2.1 All-LMU Scenario

The 2021 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 6.313 MMBtu/MWh used as the conversion factor. Figure 5-11, which shows the monthly load-weighted LMU marginal emission rates, can be compared with Figure 4-8 (showing the 2021 percentage of load for which various resource types were marginal for all LMUs) and Figure 5-3 (showing the 2021 ISO New England monthly average NO_X, SO_2, and CO_2 emission rates). Appendix Table 19 lists the values behind Figure 5-11.

Table 5-5
2021 Load-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MWh)

Ozone / Non-Ozone Season Emissions (NOx)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO_X	0.16	0.08	0.09	0.11	0.10
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.04	0.02		0.03
CO_2		775	747		758

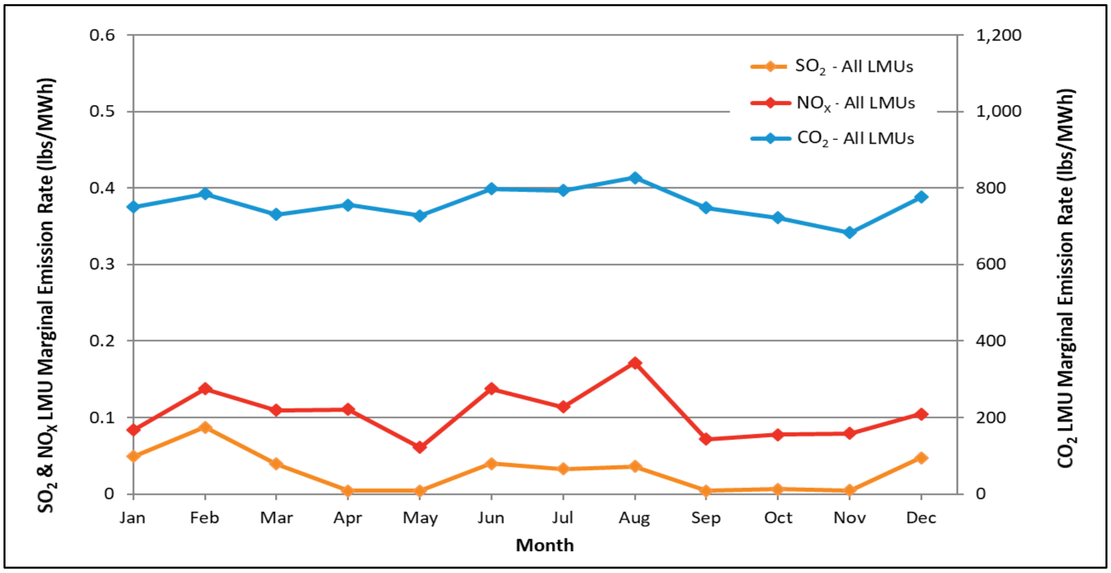


Figure 5-11: 2021 load-weighted monthly LMU marginal emission rates—all LMUs (lbs/MWh).

5.3.2.2 Emitting-LMU Scenario

Table 5-6 and Appendix Table 20 present the load-weighted marginal emission rates for emitting LMUs only. The marginal heat rate for this scenario is 7.557 MMBtu/MWh. The values for the monthly rates shown in Figure 5-12 are provided in Appendix Table 21.

Table 5-6
2021 Load-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MWh)

Ozone / Non-Ozone Season Emissions (NOx)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO_X	0.20	0.09	0.11	0.15	0.13
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		931	894		910

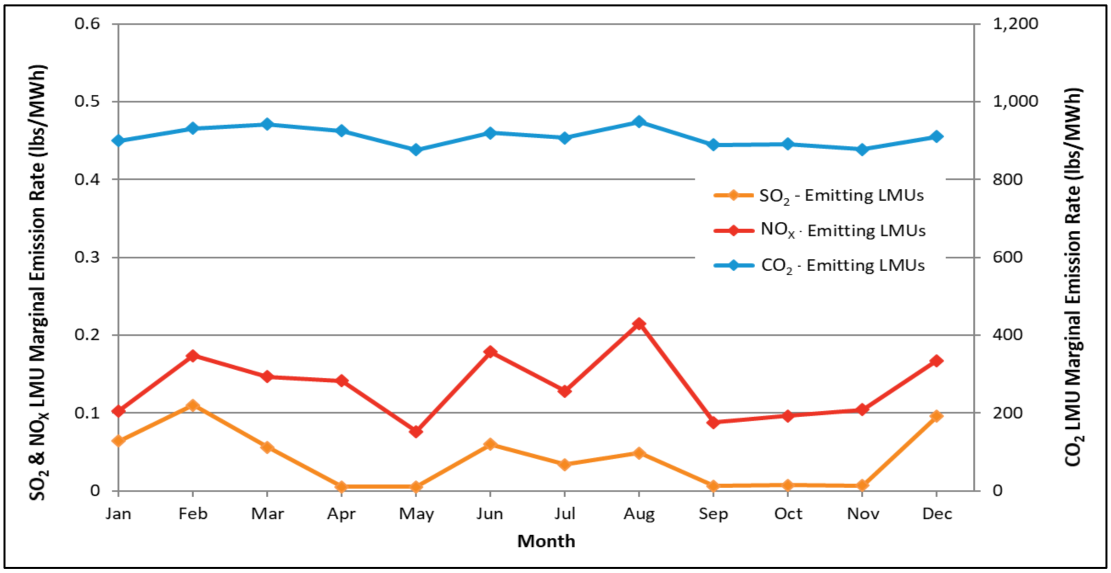


Figure 5-12: 2021 load-weighted monthly LMU marginal emission rates—emitting LMUs (lbs/MWh).

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

As shown in Table 5-7, the 2021 load-weighted marginal emission rate for CO_2 using the all-LMU scenario is higher than the time-weighted marginal emission rate, but the load-weighted NO_X rate is lower. The load-weighted approach takes into consideration the fact that most of the wind generators, as well as some biomass plants, 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 generators to the marginal emission rates, which has the impact of increasing the marginal rates. It also reduces the contribution of biomass plants, which has the opposite effect of reducing the marginal rates. With the time-weighted approach, these constrained wind and biomass resources are given equal weight with other generators that set price for the remainder of the region. In the case of CO_2, the lower amount of wind on the margin resulted in the load-weighted rates being higher than the time-weighted rates. For NO_X, the lower amount of biomass on the margin had a greater impact on the marginal rates, resulting in the load-weighted rates being slightly lower than the time-weighted rates. The contrast between the treatments of the LMUs can be seen in Figure 4-10, which compares the annual marginality for various resource types based on the time-weighted vs. load-weighted approach for all LMUs.

In the case of the emitting-LMU scenario, both the CO_2 and NO_X load-weighted marginal emission rates are lower than the time-weighted rates. 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. The SO_2 rates are the same for both approaches and scenarios.

Table 5-7
2021 Time-Weighted and Load-Weighted LMU Marginal Emission Rates (lbs/MWh)

LMU Marginal Emissions			
	2021 Time-Weighted Rate	2021 Load-Weighted Rate	2021 Load-Weighted vs. 2021 Time-Weighted
	(lbs/MWh)	(lbs/MWh)	(%)
All LMUs			
NO_X	0.11	0.10	-9.1%
SO_2	0.03	0.03	0.0%
CO_2	719	758	5.4%
Emitting LMUs			
NO_X	0.17	0.13	-23.5%
SO_2	0.04	0.04	0.0%
CO_2	1,016	910	-10.4%

Figure 5-13, Figure 5-14, and Figure 5-15 illustrate the differences between the load-weighted and time-weighted LMU monthly marginal emission rates for the all-LMU and emitting-LMU scenarios. In general, the greatest differences in the monthly rates for the all-LMU scenario occur during the non-summer months, when wind generators 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. This is most evident in the CO_2 marginal rates. For the emitting-LMU scenario, the differences resulting from the two approaches are most apparent in March, October, and November when Other Renewables, primarily consisting of wood-burning generators, are on the margin more often. This results in other generator types with lower emission rates becoming marginal more often under the load-weighted approach, as can be clearly seen in the NO_X and CO_2 marginal emission rate graphs.

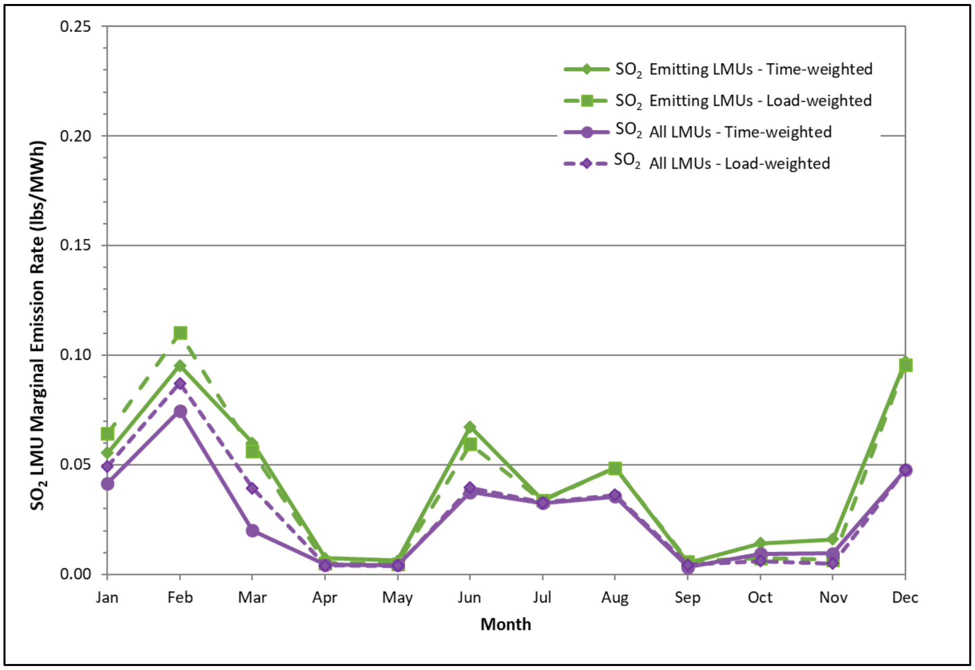


Figure 5-13: 2021 time- and load-weighted monthly LMU marginal SO_2 emission rates.

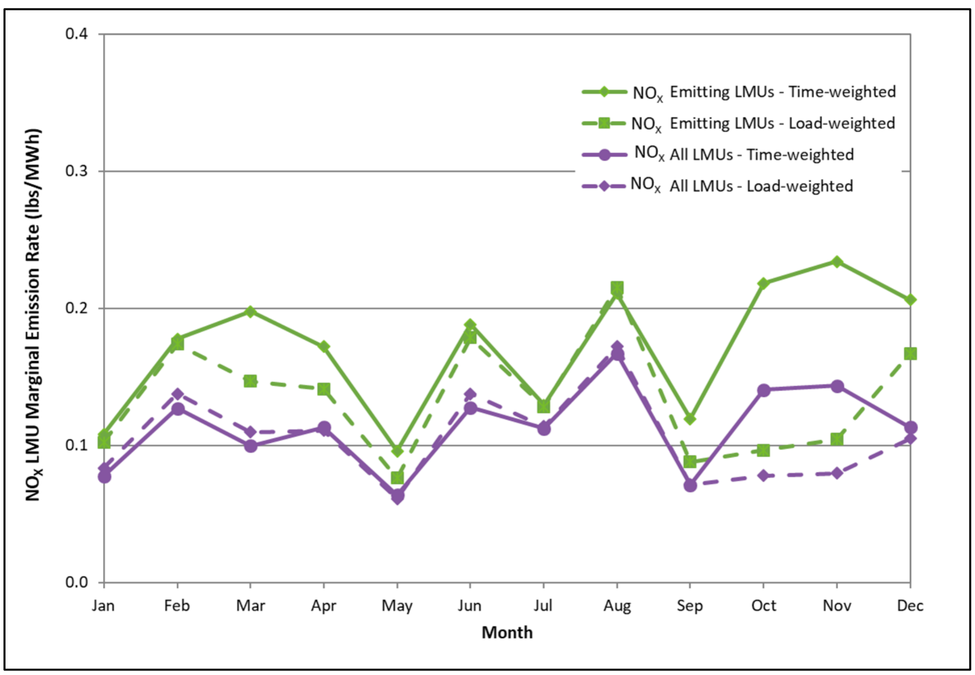


Figure 5-14: 2021 time- and load-weighted monthly LMU marginal NO_X emission rates.

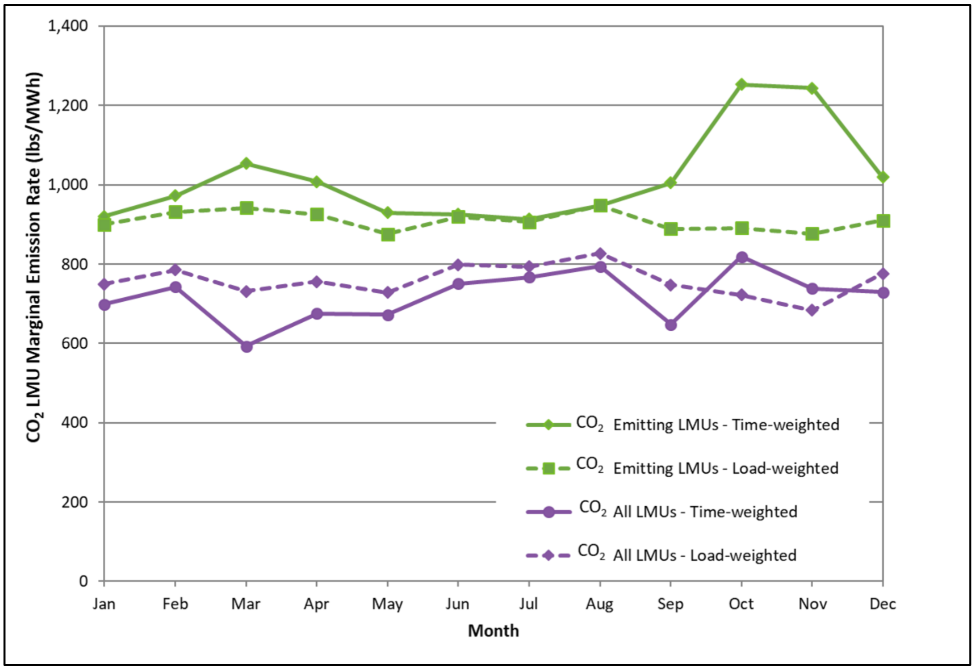


Figure 5-15: 2021 time- and load-weighted monthly LMU marginal CO_2 emission rates.

5.3.4 Additional Observations

As shown in Table 5-8, the 2021 time-weighted and load-weighted marginal emission rates for CO_2 and SO_2 were higher than the 2020 rates. This is due to an increase in both coal- and oil-fired generation on the margin, as can be seen in the various figures in Section 4.4, Locational Marginal Unit Scenarios. The emitting-LMU scenario using the time-weighted approach yielded a 6.3% increase in NO_x rates from 2020 to 2021. The higher NO_x rate is the result of the increased percentage of time that Other Renewables, primarily consisting of wood-burning generators were marginal. For all other scenarios and approaches, the NO_x rates were unchanged.

Table 5-8
2020 and 2021 Annual Time-Weighted and Load-Weighted LMU Marginal Emission Rates (lbs/MWh)

	LMU Marginal Emission Rates					
	Time-Weighted			Load-Weighted		
	2020 Annual Rate	2021 Annual Rate	Percent Change 2020 to 2021	2020 Annual Rate	2021 Annual Rate	Percent Change 2020 to 2021
	(lbs/MWh)	(lbs/MWh)	(%)	(lbs/MWh)	(lbs/MWh)	(%)
All LMUs						
NO_X	0.11	0.11	0.0	0.10	0.10	0.0
SO_2	0.02	0.03	50.0	0.02	0.03	50.0
CO_2	706	719	1.8	742	758	2.2
Emitting LMUs						
NO_X	0.16	0.17	6.3	0.13	0.13	0.0
SO_2	0.03	0.04	33.3	0.03	0.04	33.3
CO_2	971	1,016	4.6	904	910	0.7

5.4 Marginal Emission Rates for High Electric Demand Days

Using the LMU methodology, the top-five high electric demand days in 2021 were examined. In 2021, the top five HEDDs were June 28, 29 and 30, and August 12 and 26. The temperatures in New England during these days ranged from 91° to 95°F. Peak daily loads ranged from 25,053 MW on Monday, June 28, to a high of 25,801 MW on Tuesday, June 29. 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	0.36	0.51	0.37	0.46
SO_2	0.17	0.28	0.16	0.21
CO_2	887	1054	944	1059

5.5 Observations

ISO New England's power plant air emissions are directly dependent on the specific units available and dispatched to serve load for each hour of the year. Therefore, seasonal emissions can vary widely, primarily due to changes in economic and reliability dispatch, unit availability, fuel price and consumption, fuel switching, transmission topology, and load levels. The amount of imports, the use of pumped storage, and significant generator outages, such as a nuclear unit outage, also affect emissions. The LMU marginal emission rates reflect the dynamics of the ISO New England power system.

The time-weighted LMU annual marginal rates for SO_2, NO_X, and CO_2 have exhibited an overall decrease during the past ten years with a slight uptick in 2021. Compared with 2012, the 2021 LMU SO_2 annual marginal rates have declined by 92% and 90% for the all-LMU and emitting-LMU scenarios, respectively. In the case of marginal NO_X emission rates, there have been declines of 48% and 34% for the all-LMU and emitting-LMU scenarios, respectively, since 2012. The greatest drop in the time-weighted all-LMU marginal CO_2 rate over the past ten years occurred in 2017, due to wind generators being marginal a significant percentage of the time beginning that year. During the past ten years, the CO_2 rates have declined by 16% for the all-LMU scenario, but increased by 1% for the emitting-LMU scenario.

In 2021, the on-peak marginal rates for SO_2, NO_X, and CO_2 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. Because of these constraints, non-emitting wind generation is only marginal for a small percentage of the total system load (0.3% vs.

13.4% using the time-weighted approach for the all-LMU scenario), and biomass resources, which generally have relatively high emission rates, are also marginal less than when the time-weighted approach is used (0.2% vs. 2.6%). In the case of the all-LMU scenario, the lower amount of wind on the margin causes the load-weighted rates to be higher than the time-weighted rates, but the lower amount of biomass resources on the margin has the opposite effect. Thus, the load-weighted rates were higher than the time-weighted rates by 5.4% for CO_2, but the load-weighted NO_X rate, which was more heavily impacted by the lower amount of biomass on the margin, was 9.1% lower than the time-weighted rate. In contrast, with the emitting-LMU scenario, the load-weighted marginal rates were primarily lower than the time-weighted rates due to the constrained biomass resources: 23.5% lower for NO_X, and 10.4% lower for CO_2. The SO_2 rates were the same for all scenarios.

The 2021 time-weighted LMU marginal emission rates for SO_2 and CO_2 increased from 2020, but NO_X remained the same for the all-LMU scenario and increased for the emitting-LMU scenario. The load-weighted rates followed the same trend, except NO_X emission rates were the same for both scenarios. In 2021, the increases in the marginal emission rates for both SO_2 and CO_2 can be attributed to the larger amount of coal-and oil-fired generation on the margin.

When comparing the 2020 to 2021 changes in the average emission rates to the changes in the marginal rates, the change in the average CO_2 rates is similar to the change in the load-weighted marginal rates for the emit-LMU scenario. However, the opposite correlation was observed for the SO_2 and NO_x emission rates. The average emission rates from 2020 to 2021 did not change for SO_2, whereas both the load-weighted and time-weighted marginal rates increased. The marginal emission rates for NO_x either stayed the same or increased slightly while the annual average emissions rate saw a 4% decrease from 2020 to 2021.

Section 6
Appendix

Appendix Table 1
ISO New England Total Cooling and Heating Degree Days, 2001 to 2021

Year	Total Cooling Degree Days	Difference from Average (%)	Total Heating Degree Days	Difference from Average (%)
2001	319	-4.9%	5,870	-2.1%
2002	353	5.3%	5,938	-1.0%
2003	350	4.4%	6,628	10.5%
2004	249	-25.7%	6,332	5.6%
2005	417	24.4%	6,331	5.5%
2006	334	-0.4%	5,532	-7.8%
2007	287	-14.4%	6,153	2.6%
2008	278	-17.1%	6,027	0.5%
2009	223	-33.5%	6,272	4.6%
2010	403	20.2%	5,636	-6.0%
2011	354	5.6%	5,802	-3.3%
2012	350	4.4%	5,285	-11.9%
2013	398	18.7%	6,137	2.3%
2014	238	-29.0%	6,299	5.0%
2015	334	-0.4%	6,080	1.4%
2016	351	4.7%	5,705	-4.9%
2017	309	-7.8%	5,839	-2.7%
2018	499	48.8%	6,060	1.0%
2019	325	-3.2%	6,046	0.8%
2020	415	23.6%	5,513	-8.1%
2021	437	38.2%	5,437	10.1%
Average	344		5,949	

Appendix Table 2
2021 ISO New England Summer Generating Capacity (MW, %)[a. b]

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

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont		New England	
Unit Type	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**
Coal	-	-	-	-	102.6	3.0	533.3	12.8	-	-	-	-	635.9	2.0
Natural Gas	4,307.3	45.1	6,765.9	58.7	1,567.8	45.4	1,224.5	29.5	1,838.6	92.4	-	-	15,704.1	50.5
Nuclear	2,097.3	22.0	-	-	-	-	1,249.2	30.1	-	-	-	-	3,346.4	10.8
Oil	2,727.9	28.6	1,907.2	16.6	836.8	24.2	483.9	11.6	-	-	132.4	29.0	6,088.2	19.6
Hydro	105.9	1.1	188.7	1.6	475.7	13.8	420.6	10.1	2.1	0.1	214.9	47.1	1,407.9	4.5
Pumped Storage	28.4	0.3	1,794.6	15.6	-	-	-	-	-	-	-	-	1,823.0	5.9
Solar	78.6	0.8	593.6	5.2	108.0	3.1	1.6	0.0	109.2	5.5	9.6	2.1	900.6	2.9
Wind	-	-	9.8	0.1	138.4	4.0	30.8	0.7	5.5	0.3	20.0	4.4	204.6	0.7
Other Renewables	201.7	2.1	262.9	2.3	224.2	6.5	210.3	5.1	34.9	1.8	79.7	17.5	1,013.7	3.3
Total	9,546.9	100.0	11,522.7	100.0	3,453.6	100.0	4,154.2	100.0	1,990.3	100.0	456.7	100.0	31,124.3	100.0

(b) Seasonal Claimed Capability as of July 1, 2022.

Appendix Table 3
2021 ISO New England Winter Generating Capacity (MW, %)[(a, b)]

	Connecticut		Massachusetts		Maine		New Hampshire		Rhode Island		Vermont		New England	
Unit Type	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**
Coal	122.0	0.6	1,976.7	8.3	556.7	8.0	937.4	11.1	1.4	0.0	233.5	21.8	3,827.6	5.9
Natural Gas	4,634.3	23.3	7,532.2	31.5	1,723.0	24.8	1,374.4	16.2	2,044.7	48.7	-	-	17,308.5	26.9
Nuclear	2,096.7	10.6	-	-	-	-	1,247.4	14.7	-	-	-	-	3,344.1	5.2
Oil	2,887.0	14.5	2,117.2	8.9	743.9	10.7	505.3	6.0	-	-	173.2	16.2	6,426.7	10.0
Hydro	(34.5)	(0.2)	86.1	0.4	(37.0)	(0.5)	(189.5)	(2.2)	-	-	23.2	2.2	(151.8)	(0.2)
Pumped Storage	37.6	0.2	15.1	0.1	130.6	1.9	189.5	2.2	-	-	73.3	6.8	446.2	0.7
Solar	0.1	0.0	10.6	0.0	0.1	0.0	-	-	1.5	0.0	-	-	12.3	0.0
Wind	-	-	13.6	0.1	28.0	0.4	-	-	-	-	-	-	41.6	0.1
Other Renewables	10,107.1	50.9	12,170.5	50.9	3,795.5	54.7	4,411.7	52.0	2,154.1	51.3	567.6	53.0	33,206.5	51.5
Total	19,850.2	100.0	23,922.0	100.0	6,940.7	100.0	8,476.2	100.0	4,201.7	100.0	1,070.8	100.0	64,461.6	100.0

(a) Sum may not equal total due to rounding.
(b) Seasonal Claimed Capability as of January 1, 2022.

Appendix Table 4
ISO New England Average
Generator Emissions, 2001 to 2021 (kilotons)[(a)]

Year	Native Generation				Native Gen Plus Imports
	NOx	SO_2	CO_2		CO_2
	kilotons (short)	kilotons (short)	kilotons (short)	kilotons (metric)	kilotons (short)
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	46,292
2012	20.32	16.61	41,975	38,079	41,776
2013	20.32	18.04	40,901	37,105	42,127
2014	20.49	11.67	39,319	35,670	41,109
2015	18.86	9.11	40,312	36,570	42,137
2016	16.27	4.47	37,467	33,990	39,599
2017	15.30	4.00	34,969	31,723	36,205
2018	15.61	4.96	34,096	30,931	35,942
2019	12.87	2.34	30,997	28,120	32,906
2020	12.09	1.88	31,028	28,148	33,168
2021	12.44	2.11	33,439	30,335	34,543
Percent Reduction 2001-2021	80	99	41	41	

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

Appendix Table 5
2021 ISO New England
Average Monthly Generator Emission Rates (lbs/MWh)

	Monthly System Emission Rates (lb/MWh)			
Month	**NO_X**	**SO_2**	**CO_2**	**CO_2 with Imports**
1	0.25	0.07	659	569
2	0.28	0.11	703	607
3	0.24	0.04	591	518
4	0.23	0.03	545	480
5	0.22	0.03	563	494
6	0.25	0.04	699	609
7	0.23	0.03	679	593
8	0.24	0.03	715	620
9	0.22	0.03	656	607
10	0.27	0.03	781	657
11	0.23	0.03	640	558
12	0.25	0.03	634	544

Appendix Table 6
ISO New England
Annual Average Generator Emission Rates, 2001 to 2021 (lbs/MWh)

Year	Total Generation (GWh)	NO_x	SO_2	CO_2	CO_2 with Net Imports
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	708
2012	116,942	0.35	0.28	719	645
2013	112,040	0.36	0.32	730	643
2014	108,356	0.38	0.22	726	643
2015	107,916	0.35	0.17	747	657
2016	105,570	0.31	0.08	710	630
2017	102,562	0.30	0.08	682	592
2018	103,740	0.30	0.10	658	577
2019	97,890	0.26	0.05	633	547
2020	94,945	0.25	0.04	654	561
2021	101,692	0.24	0.04	658	574
Percent Reduction, 2001 - 2021		77	99	29	

Appendix Table 7
LMU Marginal Heat Rate, 2012 to 2021 (MMBtu/MWh)

LMU Marginal Heat Rate (MMBtu/MWh)				
	Time-Weighted		Load-Weighted	
Year	All Marginal LMUs	Emitting LMUs	All Marginal LMUs	Emitting LMUs
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
2020	5.664	7.728	6.178	7.491
2021	5.676	7.902	6.313	7.557

Appendix Table 8
2021 Time-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MMBtu)

Ozone / Non-Ozone Season Emissions (NOx)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO_X	0.027	0.013	0.019	0.021	0.020
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.006	0.003		0.005
CO_2		130	124		127

Appendix Table 9
2021 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	0.08	0.05	750
2	0.14	0.09	785
3	0.11	0.04	731
4	0.11	0.00	756
5	0.06	0.00	728
6	0.14	0.04	798
7	0.11	0.03	794
8	0.17	0.04	827
9	0.07	0.00	748
10	0.08	0.01	722
11	0.08	0.01	684
12	0.10	0.05	777

Appendix Table 10
2021 Time-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MMBtu)

Ozone / Non-Ozone Season Emissions (NOx)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NOX	0.027	0.013	0.022	0.025	0.022
Annual Emissions (SO2 and CO2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO2		0.007	0.004		0.005
CO2		132	126		129

Appendix Table 11
2021 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	0.10	0.06	900
2	0.17	0.11	932
3	0.15	0.06	942
4	0.14	0.01	925
5	0.08	0.00	876
6	0.18	0.06	920
7	0.13	0.03	907
8	0.22	0.05	948
9	0.09	0.01	889
10	0.10	0.01	891
11	0.10	0.01	877
12	0.17	0.10	910

Appendix Table 12
NO_X Time- and Load-Weighted LMU Marginal Emission Rates —All LMUs (lbs/MWh)

	Time-Weighted						Load-Weighted					
	Ozone Season		Non-Ozone Season				Ozone Season		Non-Ozone Season			
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change	On-Peak	Off-Peak	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
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	0.22	0.19	0.19	0.25	0.20	-
2019	0.11	0.10	0.09	0.10	0.10	-40.8	0.12	0.11	0.10	0.11	0.11	-46.2
2020	0.18	0.12	0.09	0.08	0.11	7.6	0.17	0.10	0.09	0.08	0.10	-5.9
2021	0.15	0.08	0.11	0.12	0.11	4.4	0.16	0.08	0.09	0.11	0.10	3.3
% Change 2012 - 2021	-55.4	-64.2	-41.8	-23.1	-48.0							

Appendix Table 13
NO_X Time- and Load-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MWh)

	Time-Weighted						Load-Weighted					
	Ozone Season		Non-Ozone Season				Ozone Season		Non-Ozone Season			
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change	On-Peak	Off-Peak	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
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	0.29	0.26	0.25	0.32	0.27	-
2019	0.14	0.16	0.14	0.17	0.15	-44.8	0.14	0.15	0.13	0.15	0.15	-46.1
2020	0.24	0.16	0.13	0.12	0.16	0.6	0.22	0.12	0.11	0.11	0.13	-9.1
2021	0.21	0.10	0.17	0.20	0.17	10.2	0.20	0.09	0.11	0.15	0.13	1.9
% Change 2012 - 2021	**-46.6**	**-60.9**	**-23.6**	**2.9**	**-33.6**							

Appendix Table 14
SO_2 Time- and Load-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MWh)

	Time-Weighted				Load-Weighted			
Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
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	0.16	0.11	0.13	-
2019	0.03	0.02	0.02	-80.5	0.03	0.02	0.03	-78.5
2020	0.02	0.02	0.02	-0.28	0.03	0.02	0.02	-19.4
2021	0.04	0.02	0.03	23.82	0.04	0.02	0.03	31.9
% Change 2012 - 2021	**-90.7**	**-93.9**	**-92.5**					

Appendix Table 15

SO_2 Time- and Load-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MWh)

	Time-Weighted				Load-Weighted			
Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
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	0.20	0.14	0.16	-
2019	0.05	0.03	0.04	-77.0	0.05	0.03	0.04	-76.3
2020	0.03	0.03	0.03	-23.9	0.03	0.03	0.03	-25.2
2021	0.05	0.03	0.04	41.2	0.05	0.03	0.04	41.1
% Change 2012 - 2021	**-88.3**	**-91.3**	**-89.9**					

Appendix Table 16

CO_2 Time- and Load-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MWh)

	Time-Weighted				Load-Weighted			
Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
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	779	720	745	-
2019	678	626	648	-1.1	749	697	719	-3.5
2020	723	693	706	8.9	765	725	742	3.3
2021	739	705	719	1.9	775	747	758	2.2
% Change 2012 - 2021	**-15.6**	**-16.0**	**-15.8**					

Appendix Table 17
CO_2 Time- and Load-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MWh)

	Time-Weighted				Load-Weighted			
Year	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change	On-Peak	Off-Peak	Annual Average (All Hours)	Annual Average Percentage Change
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	987	960	971	-
2019	975	966	970	-3.5	950	938	943	-2.9
2020	984	961	971	0.1	918	893	904	-4.2
2021	1,044	996	1,016	4.7	931	894	910	0.7
% Change 2012 - 2021	**2.4**	**-0.7**	**0.60**					

Appendix Table 18
2021 Load-Weighted LMU Marginal Emission Rates—All LMUs (lbs/MMBtu)

Ozone / Non-Ozone Season Emissions (NOx)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NO_X	0.021	0.010	0.012	0.014	0.014
Annual Emissions (SO_2 and CO_2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO_2		0.005	0.003	0.000	0.004
CO_2		100.694	97.064	0.000	98.579

Appendix Table 19
2021 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	0.08	0.05	750
2	0.14	0.09	785
3	0.11	0.04	731
4	0.11	0.00	756
5	0.06	0.00	728
6	0.14	0.04	798
7	0.11	0.03	794
8	0.17	0.04	827
9	0.07	0.00	748
10	0.08	0.01	722
11	0.08	0.01	684
12	0.10	0.05	777

Appendix Table 20
2021 Load-Weighted LMU Marginal Emission Rates—Emitting LMUs (lbs/MMBtu)

Ozone / Non-Ozone Season Emissions (NOx)					
Air Emission	Ozone Season		Non-Ozone Season		Annual Average (All Hours)
	On-Peak	Off-Peak	On-Peak	Off-Peak	
NOX	0.022	0.010	0.013	0.016	0.015
Annual Emissions (SO2 and CO2)					
Air Emission		Annual			Annual Average (All Hours)
		On-Peak	Off-Peak		
SO2		0.006	0.004	0.000	0.005
CO2		103.108	98.971	0.000	100.702

Appendix Table 21
2021 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	0.10	0.06	900
2	0.17	0.11	932
3	0.15	0.06	942
4	0.14	0.01	925
5	0.08	0.00	876
6	0.18	0.06	920
7	0.13	0.03	907
8	0.22	0.05	948
9	0.09	0.01	889
10	0.10	0.01	891
11	0.10	0.01	877
12	0.17	0.10	910