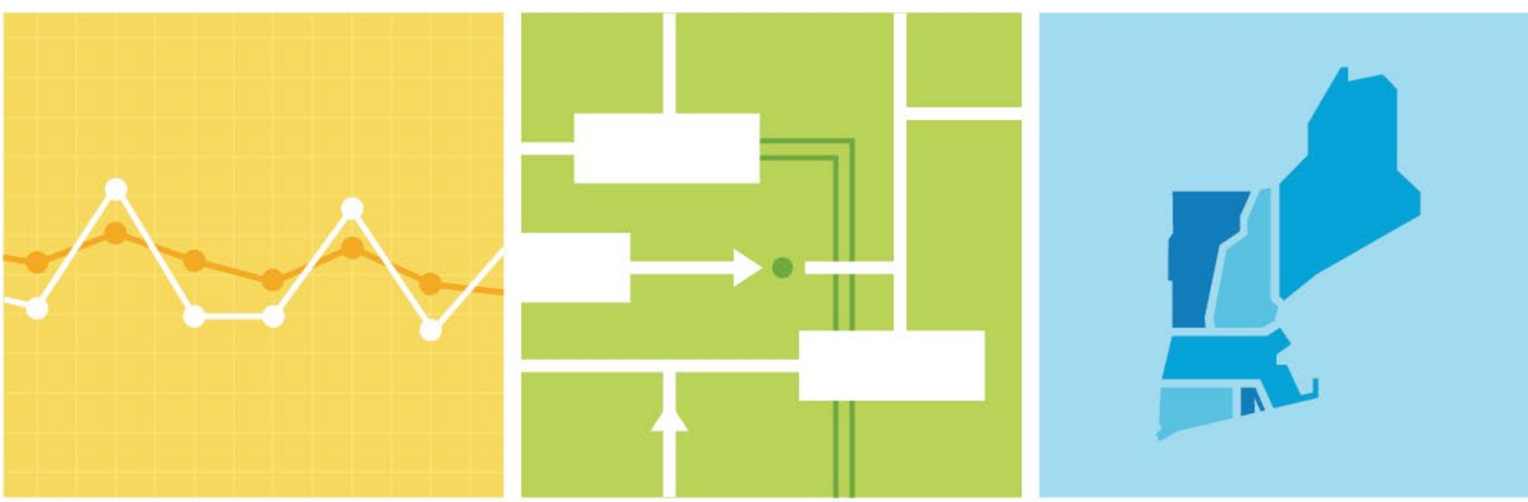
2023 ISO New England Electric Generator Air Emissions Report

OCTOBER 16, 2024



Contents

Figures

Section 1
Executive Summary

1.1 Purpose of ISO New England Emissions Report

The 2023 ISO New England (ISO) *Electric Generator Air Emissions Report* (*Emissions Report*) provides a comprehensive analysis of New England's 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, load-weighted and time-weighted marginal emissions, and a review of relevant system conditions. The main factors analyzed are as follows:

- Average emissions (ktons) and emission rates (lbs/MWh)
- Marginal emission rates (lbs/MWh and lbs/MMBtu)
- Marginal heat rates (MMBtu/MWh)

This executive summary provides a high-level overview of system conditions and an assessment of key monthly and annual emission trends from the 2023 emissions analysis. A spreadsheet appendix provides comprehensive data on the relevant system conditions, average CO_2 emissions rates for imports/exports, marginal heat rates, and emissions data for the following time periods of interest:

- On-peak versus off-peak hours
- Ozone season versus non-ozone season
- Monthly variations
- 10+ historical years
- High electric demand days (HEDDs)

For a detailed overview on the background, data sources, and methodologies for the Emissions Report, refer to the [ISO New England Electric Generator Air Emissions Report: Background and Methodology].

1.2 Methodology

New England generation excludes behind-the-meter (BTM) generators and imports. This report provides two different average CO_2 emissions and emission rates:

- New England generation only
- New England generation plus net imports (i.e. emissions from imports – emissions from exports)

Average emissions and emission rates for NO_X and SO_2 are calculated for New England generation only.

Marginal emission rates and heat rates in this report are calculated based on the locational marginal unit (LMU), or the last unit dispatched to balance the system, which sets the price. The percentage that each generator is marginal is calculated using both a load-weighted and time-weighted approach. The load-weighted approach reflects the share of the load served by the marginal unit, while the time-weighted approach accounts for the time intervals during which a resource was marginal and assumes that multiple marginal resources within that time interval contribute equally to meeting the load. The marginal emission rates are determined by calculating the percentage of time (time-weighted approach) and load (load-weighted approach) a generator was marginal, and multiplying those percentages by the generator's emission rates. This number is then divided by the total on-peak or off-peak hours in the year. The rates are divided into two scenarios for both the time-weighted and load-weighted LMUs:

- All LMUs **-** includes all Locational Marginal Units (including imports) identified by the 5-minute locational marginal prices (LMPs)
- Emitting-LMUs **-** excludes all non-emitting units, such as nuclear, pumped storage, hydro-electric generation, and other renewables (such as wind, etc.) with no associated air emissions

1.3 Data Sources

Approximately 32% of the total NO_X emissions, 39% of the SO_2 emissions and 79% of the CO_2 emissions in this report are calculated using the emissions data reported in EPA's Clean Air Markets Program (CAMPD) database. Data from NEPOOL GIS and eGRID are used to estimate emissions from generators that do not report to CAMPD. Over 93% of the emissions data used in this report comes from a combination of CAMPD, NEPOOL GIS, and eGRID. Estimates for the remaining generators relies on emissions data from units with similar attributes.

1.4 Overview of 2023 System Conditions

The New England region experienced a mild weather year in 2023, with fewer periods of tight system conditions and scarcity than the prior year. As a result, the 2023 New England wholesale electricity demand or Net Energy Load (NEL) was 4% less than the 2022 NEL, and generation was lower in 2023 (101,289 GWh) than in 2022 (103,887 GWh), a 3% decrease.[1] The reduction in demand and generation was largely due to milder winter and summer weather conditions and increased penetration of BTM solar, which further reduced load.

The year-over-year changes in the regional generation mix over the last five years are illustrated in Figure 1. The darkest shaded bars represent the 2023 generation data, and the lighter shaded bars represent generation for prior years. Between 2022 and 2023, generation from high carbon-emitting resources such as oil and coal fell by 83% and 44%, respectively. It is important to note that while this reduction seems large, overall generation from oil and coal in 2022 was already very small compared to other resources. The reduction in oil generation between 2022 and 2023 was 1,523 GWh and the reduction in coal generation was 139 GWh, but given total generation in 2023 was 101,289 GWh, these reductions are relatively insignificant.

Non-emitting renewable resources including wind and solar also generated less (a 5% reduction) year-over-year. Nuclear, another key non-emitting resource type, experienced planned refueling outages in 2023 that drove a 15% reduction in generation. The reduced output from nuclear and imports from neighboring regions (a 10% reduction) were offset by a 3% increase in natural gas generation and 25% increase in hydro generation. Following similar trends from prior years,

[1] NEL = New England Generation – Pumping Load + Net Imports

natural gas remained the primary source of energy production in 2023 (55%), followed by nuclear generation (23%).

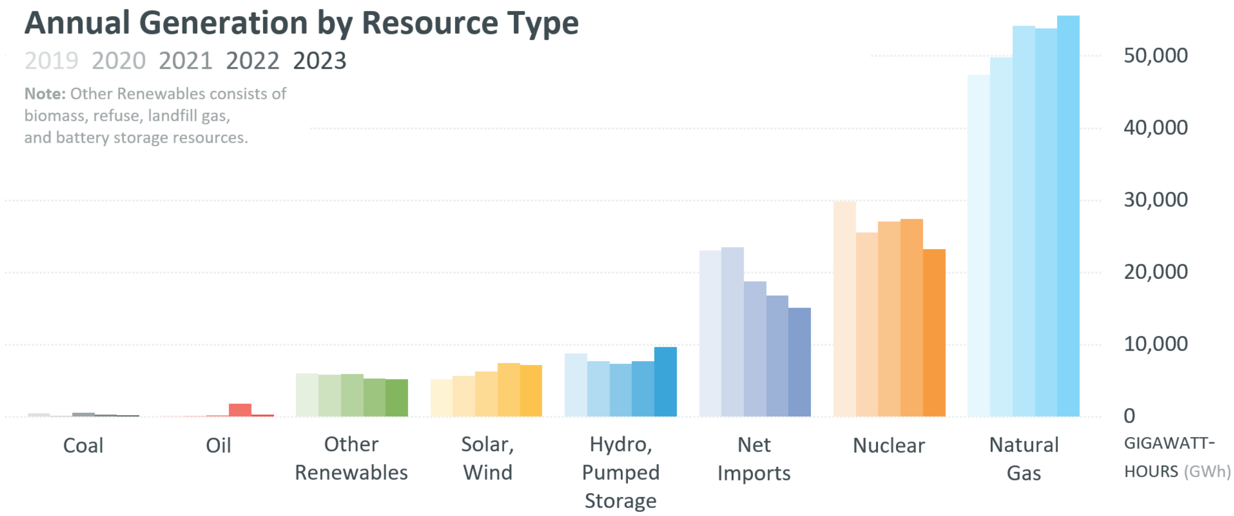


Figure 1: ISO New England annual generation by resource type, 2019 to 2023 (GWh)

The amount of energy generated by each resource does not just vary from year-to-year – it can also vary significantly from month-to-month, depending on factors such as weather and current system conditions. Figure 2 shows the 2023 monthly energy production by resource type, which includes both New England generation and net imports. The black line represents the total energy for each month, shown on the right axis.

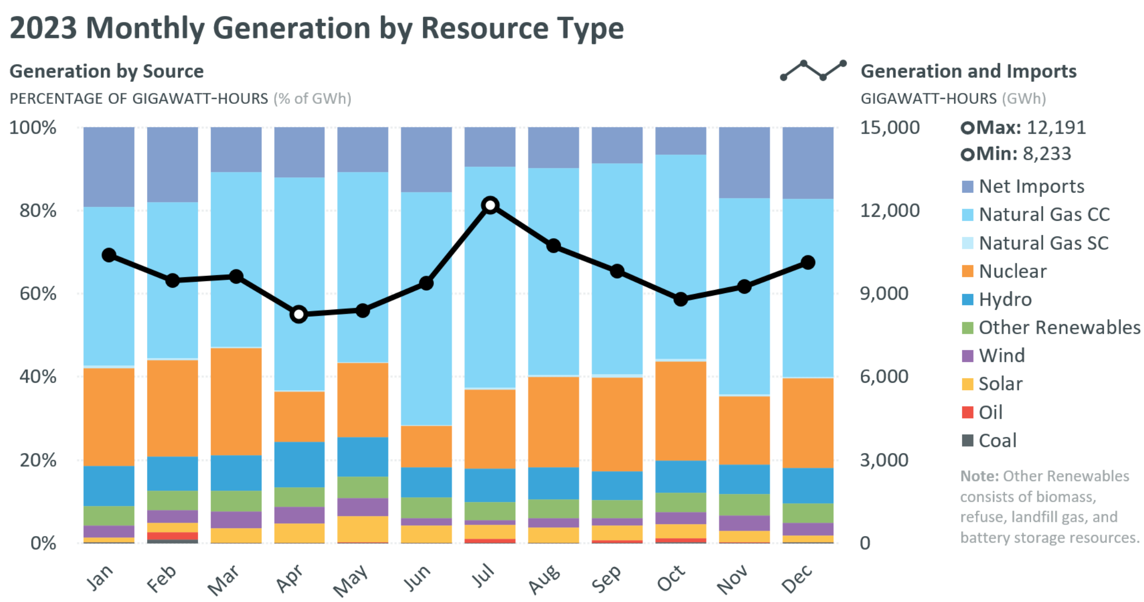


Figure 2: 2023 ISO New England monthly generation by resource type, including imports (%, GWh, GWh)[2]

[2] The natural gas data in Figure 2 and elsewhere in the report has been categorized as combined cycle (CC) and simple cycle (SC).

Oil and coal-fired generation was highest in February, which included a two-day cold snap over February 3 and 4, when temperatures dropped to -10^{0}F. The region typically experiences natural gas pipeline constraints during such temperatures, and fewer imports from neighboring regions were available through this cold snap. As a result, coal and oil resources were more economical to run than natural gas. Despite sub-zero temperatures, demand was low, since the cold snap fell partially on a weekend; peak demand days generally occur on weekdays.

Energy generation was lowest in April, at 8,233 GWh. Two heat waves in July made this month the highest for annual peak generation, at 12,191 GWh. The heat waves in July and one in September increased oil and coal-fired generation at those times, since these resources were most economical to meet cooling demand. The heat waves also coincided with the top five high electric demand days (HEDDs) for 2023: July 6, July 27-28, and September 6-7. HEDDs are typically characterized by high temperatures that lead to increased cooling demand. During peak energy demand periods, such as HEDDs, the ISO relies on peaking units, which are used less throughout 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. The temperatures in New England during the top five HEDDs in 2023 ranged from 86^{0}F to 88^{0}F, approximately 3^{0}F cooler than the top-five HEDDs in 2022. The cooler HEDD temperatures also resulted in a 2% decrease in the summer peak demand year-over-year, from 24,445 MW in 2022 down to 24,043 MW in 2023. Of note, periods of tight system conditions in October due to unplanned outages led to a slight uptick in oil and coal generation.

Figure 3 provides a side-by-side comparison of the region's sources of energy in 2014 and 2023. Over the last ten years, wind and solar generation has more than doubled, making up 6% of the total energy generated in 2023. Wind and solar generation have now effectively replaced most coal and oil generation; coal and oil generated just 0.5% of the total energy in 2023, compared to 4.6% in 2014. Another notable change in the last decade is the reduction in nuclear generation, which can be attributed to the retirement of the Pilgrim Nuclear Power Station in 2019. The related decrease in nuclear output is almost proportional to the increase in natural gas generation over the same period. Overall, the past ten years have seen the region's generation mix shifting away from high carbon-emitting resources like oil and coal to relatively lower-to-zero emission resources such as natural gas, wind, and solar. Wind and solar have largely replaced coal and oil generation, while increased natural gas generation has compensated for the reduction in net imports and nuclear generation.

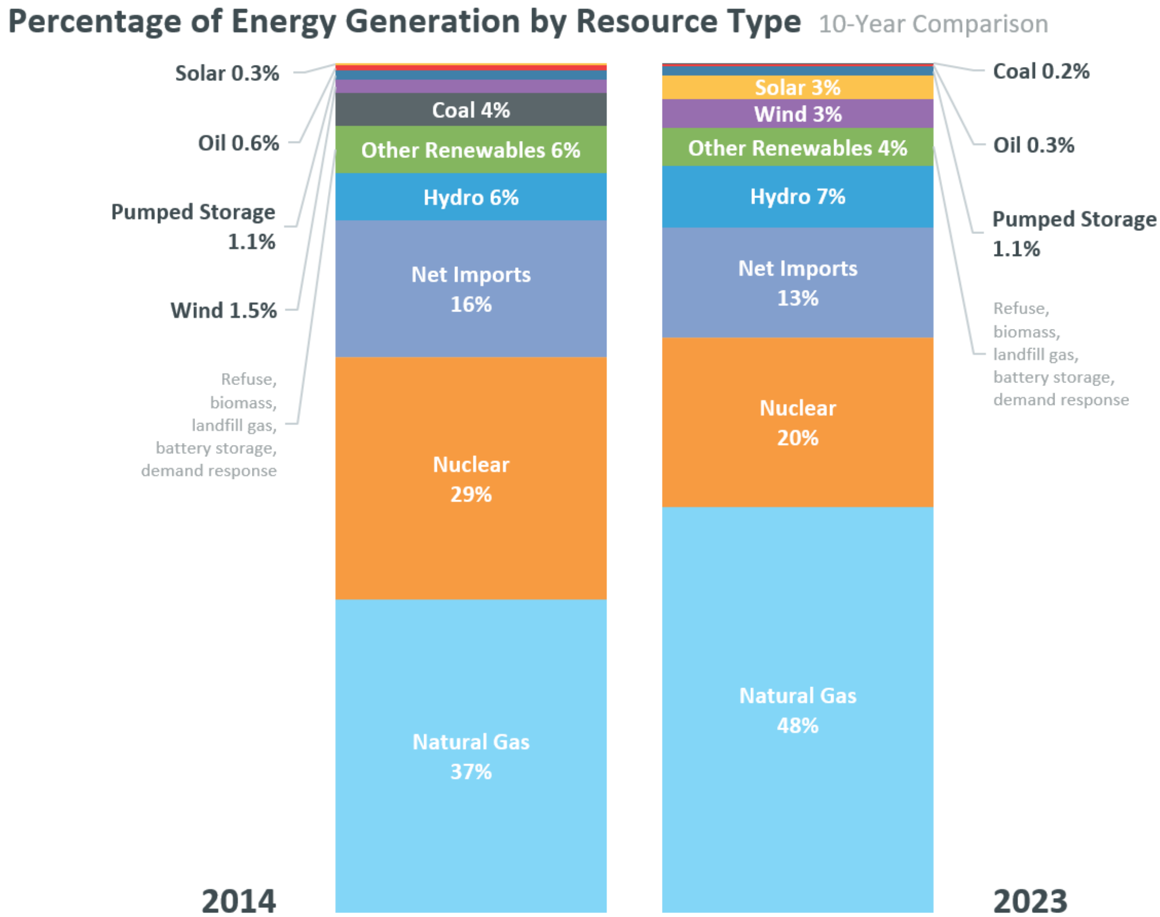


Figure 3: Percentage of energy generation by resource type, 2014 compared with 2023

1.5 Results and Observations

This section describes results for 2023's New England generation emissions, which include the average emissions, as well as, marginal emission rates and heat rates for the all-LMUs and emitting-LMUs scenarios, using both the time-weighted and load-weighted approaches. The spreadsheet appendix provides additional figures and tables on the historical, annual, and monthly emissions data.

1.5.1 Average Emissions

The total CO_2 emissions in 2023 were 32,050 kilotons (ktons) from New England generation, or 33,215 ktons when including regional generation and net imports. Note that the emissions from net imports are calculated based on assumed annual average emission rates taken from the latest eGRID (for New York imports) and the National Inventory Report: Greenhouse Gas Sources and Sinks in Canada (for Canadian imports). The assumed emission rates for imports are:

- 680 lbs/MWh for New Brunswick
- 3.9 lbs/MWh for Quebec

- 504 lbs/MWh for New York

The region saw a 4% reduction in CO_2 emissions from electric generation compared to the previous year. Notably, SO_2 emissions were almost halved from last year, at 1.77 ktons in 2023, down from 3.38 ktons in 2022. Emissions of NO_X were reduced by 13%, from 12.30 ktons to 10.66 ktons. The emission reductions for all three pollutants were largely attributable to lower load, lower peak demand, and less coal and oil-fired generation compared to 2022.

Figure 4 shows the monthly variation in emission rates for 2023. Rates for SO_2 and NO_X peaked in February, due in part to the cold snap discussed in Section 1.4. The CO_2 emission rate peaked in June, due to reduced nuclear generation, which was at its lowest level of the year that month (see Figure 2). This reduction in nuclear generation was made up by more generation from carbon-emitting resources, such as natural gas, resulting in a higher emission rate. Outside of these events, average emission rates did not vary much from month-to-month. The annual average emission rate for CO_2 was 633 lbs/MWh (571 lbs/MWh with net imports). NO_X and SO_2 annual average emission rates were 0.21 lbs/MWh and 0.03 lbs/MWh, respectively.

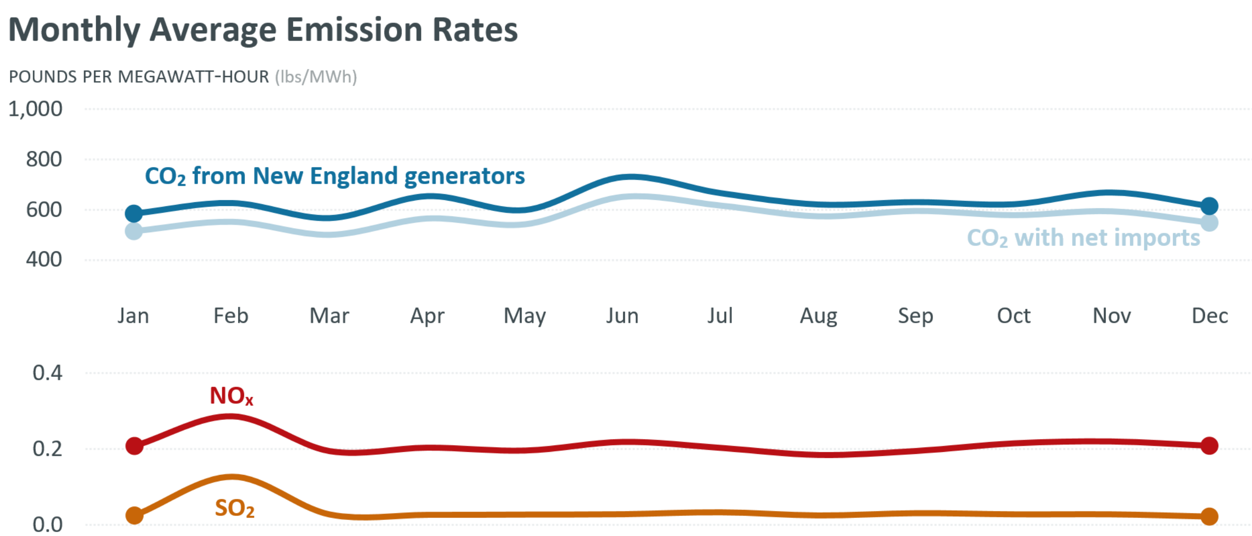


Figure 4: 2023 ISO New England monthly average emission rates (lbs/MWh)

Regional SO_2, CO_2, and NO_X average annual emissions (ktons) from electric generation declined significantly between 2014 and 2023, as illustrated in Figure 5. SO_2 decreased by 85%, CO_2 by 18%, and NO_X by 48%. The annual average emission *rates* (lbs/MWh) also decreased for all three pollutants over the same period: SO_2 by 84%, CO_2 by 13%, and NO_X by 45%, as illustrated in Figure 6. This downward trend in emissions coincided with the region's transition from oil and coal to resources with relatively lower and zero emissions resources, such as natural gas, solar, and wind.

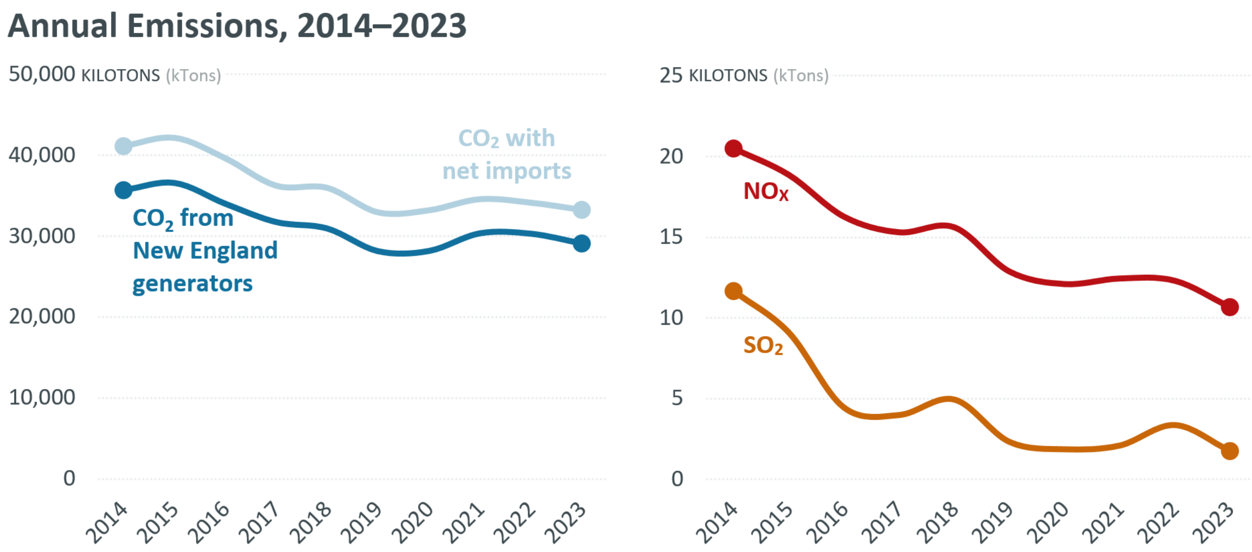


Figure 5: ISO New England average annual emissions, 2014 to 2023 (ktons)

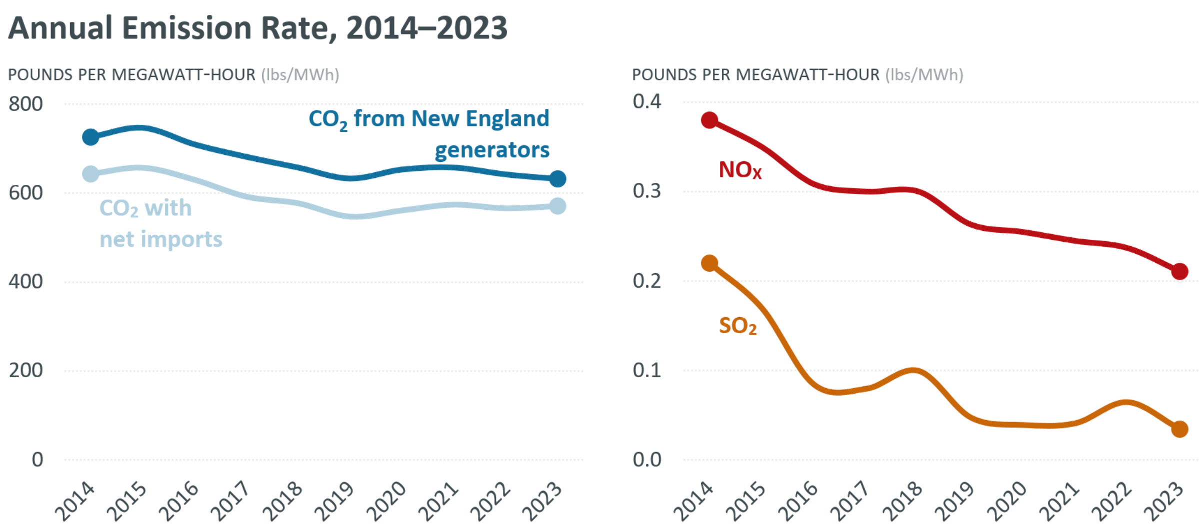


Figure 6: ISO New England annual average emission rates, 2014 to 2023 (lbs/MWh)

1.5.2 Marginal Emission Rates

As described in Section 1.2, marginal emission rates are determined using both a time-weighted and load-weighted approach, based on the locational marginal units (LMUs). LMUs are identified from historical real-time generation dispatch records. The load-weighted approach reflects the load served by the marginal unit and assumes that in a constrained system, more than one marginal resource contributes to meeting load, but not all marginal resources contribute equally. The time-weighted approach, on the other hand, reflects the time intervals for which a resource was marginal and assumes that if multiple marginal resources are meeting load within a time interval, each resource is meeting an equal share of the load. Each approach also analyzes two scenarios: the all-

LMUs (all marginal units, with or without air emissions) and emitting-LMUs (excludes all non-emitting marginal units).

The portions of load and time that a resource type was marginal in the 2023 all-LMUs scenario are illustrated in Figure 7 and Figure 8. The major difference between the load-weighted and time-weighted approach for the all-LMUs scenario is the marginality of wind resources. In the load-weighted approach, wind was only marginal for 0.4% of the load compared to 8% of the time intervals under the time-weighted approach. Since many wind resources are located in "export-constrained" areas, their contribution to meeting load is much less than other resource types. "Export-constrained" areas are areas whose transmission network for exporting electricity outside the area is at maximum capacity. As a result, wind generators often cannot set the price outside of the constrained area, and do not contribute significantly to system-wide production. Consequently, the load-weighted CO_2 marginal emission rates for the all-LMUs scenario are typically higher than the time-weighted rates, as shown in Figure 11.

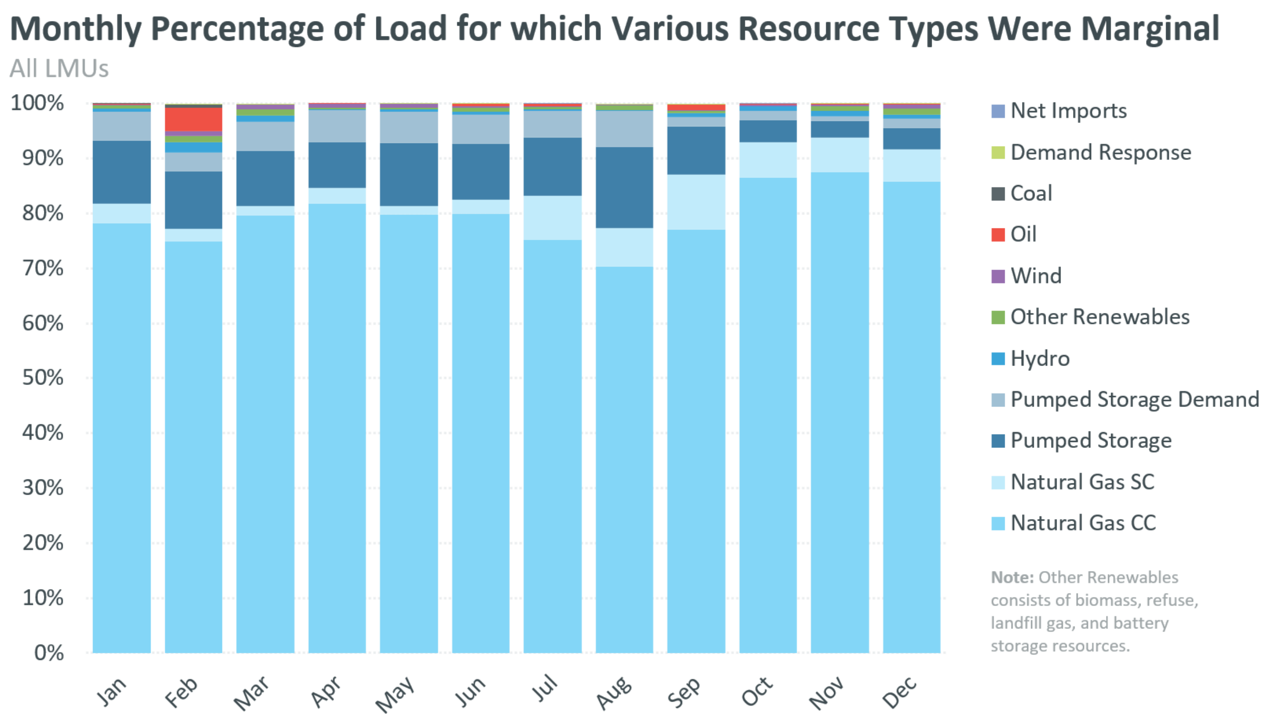


Figure 7: 2023 percentage of load for which various resource types were marginal —all LMUs

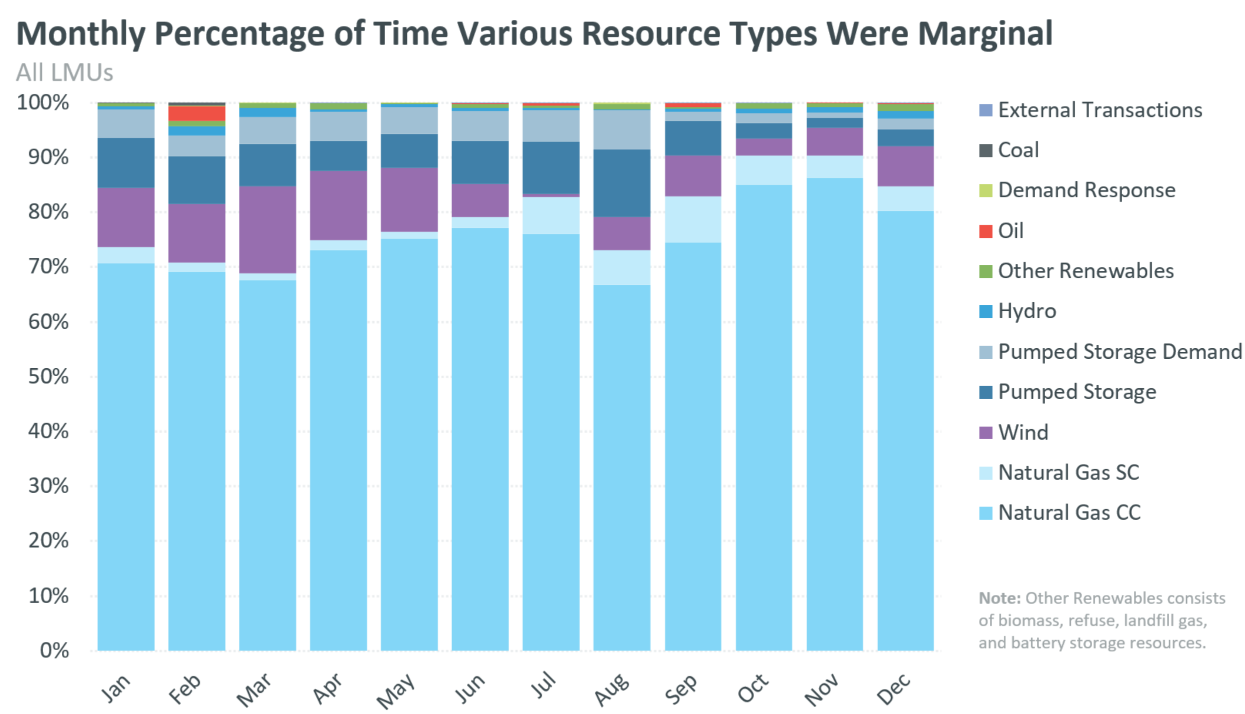


Figure 8: 2023 percentage of time for which various resource types were marginal —all LMUs

The marginality of Other Renewables differs between the load and time-weighted approach for emitting LMUs. Like wind resources, many biomass plants are located in export-constrained areas, and therefore, contribute less to load. As a result, the Other Renewables' load-weighted marginality was often less than the time-weighted. Figure 9 and Figure 10 highlight this difference, particularly during the months of April, August, and October.

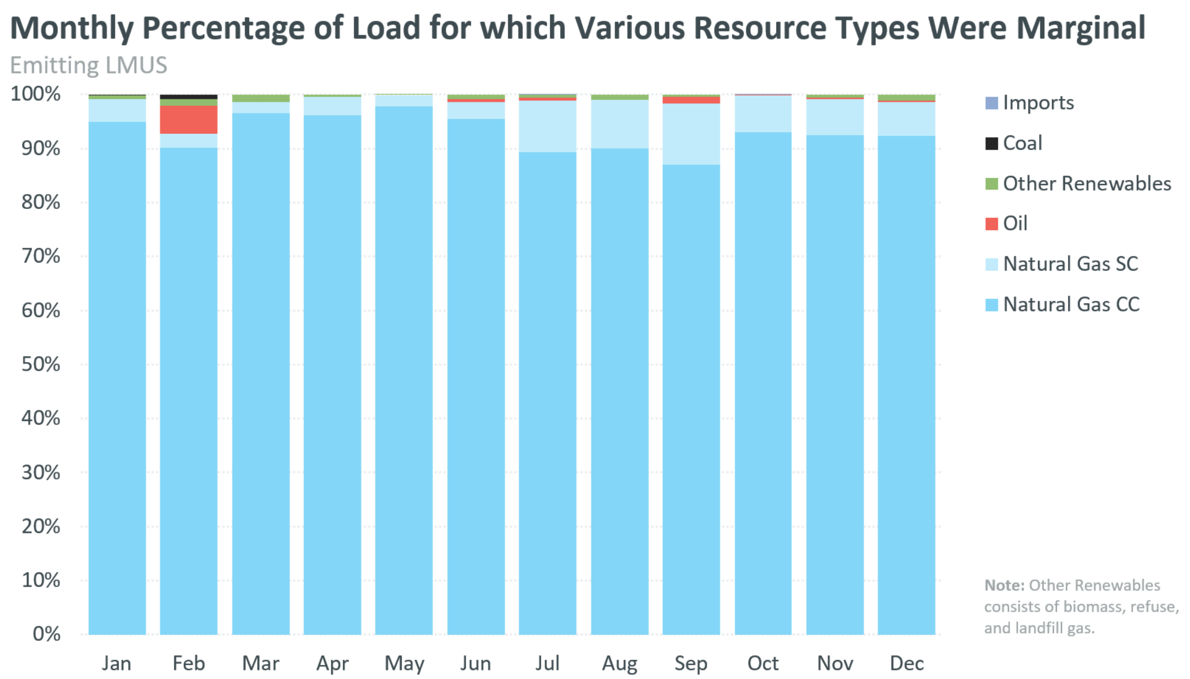


Figure 9: 2023 percentage of load for which various resource types were marginal — emitting-LMUs

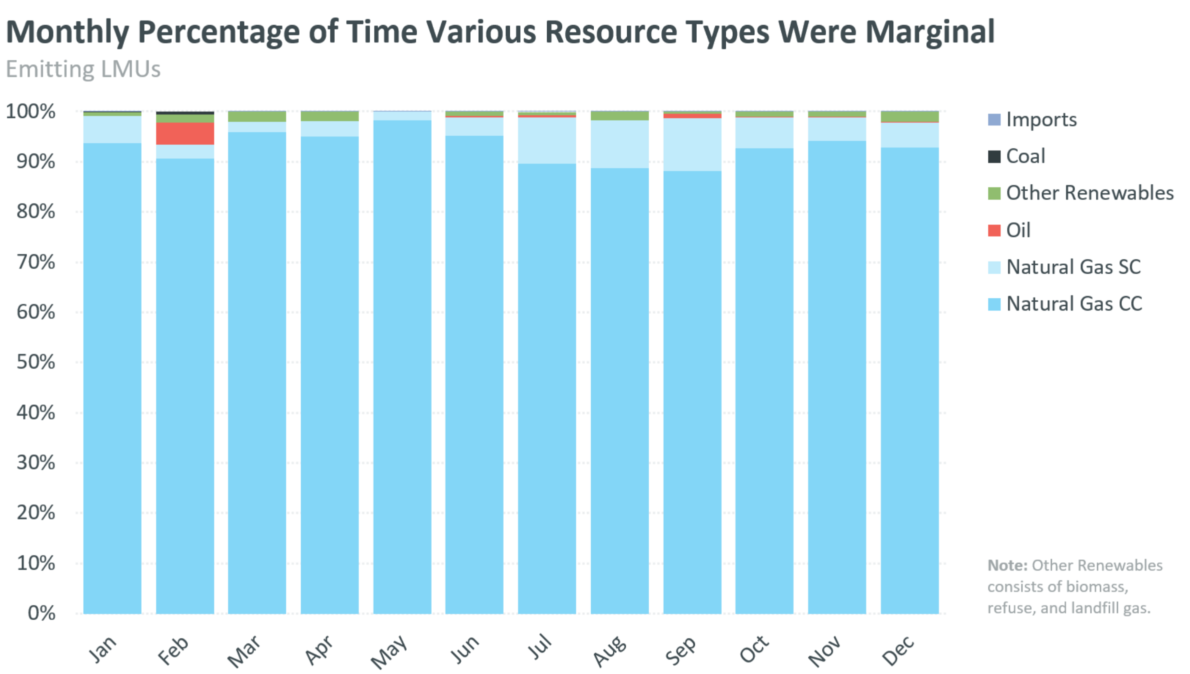


Figure 10: 2023 percentage of time for which various resource types were marginal — emitting-LMUs

Figure 11, Figure 12 and Figure 13 show the monthly variations in marginal emission rates (lbs/MWh) for CO_2, NO_X, and SO_2. The three prominent peaks in marginal emission rates coincided with months when coal and oil were marginal more frequently and for more of the load. February's cold snap and the resulting natural gas pipeline constraints typical of tight winter conditions made oil and coal resources more marginal that month. The heat waves in July and September also resulted in higher marginal emission rates as oil became the marginal resource.

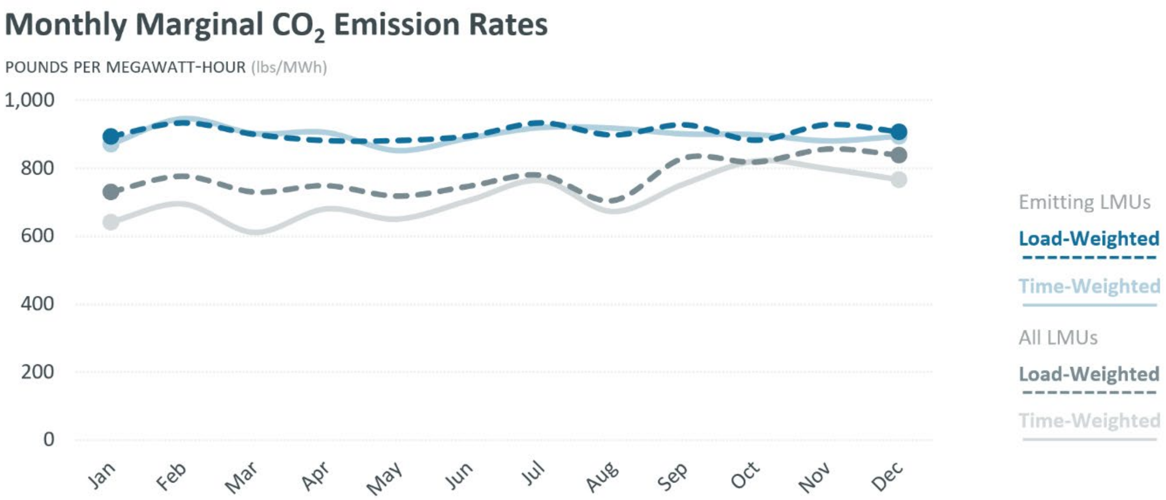


Figure 11: 2023 time- and load-weighted monthly LMUs marginal CO2 emission rates

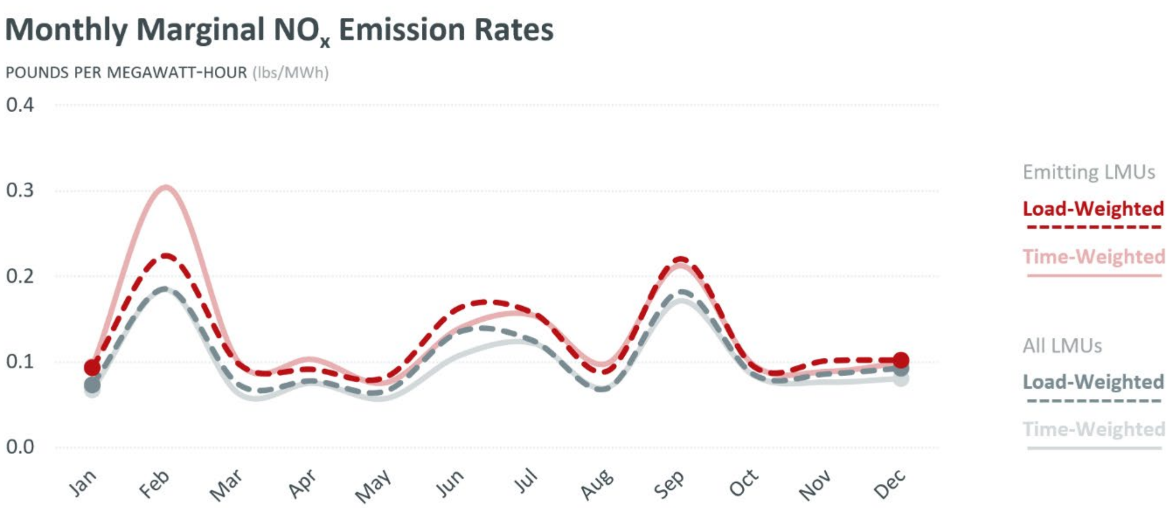


Figure 12: 2023 time- and load-weighted monthly LMUs marginal NOX emission rates

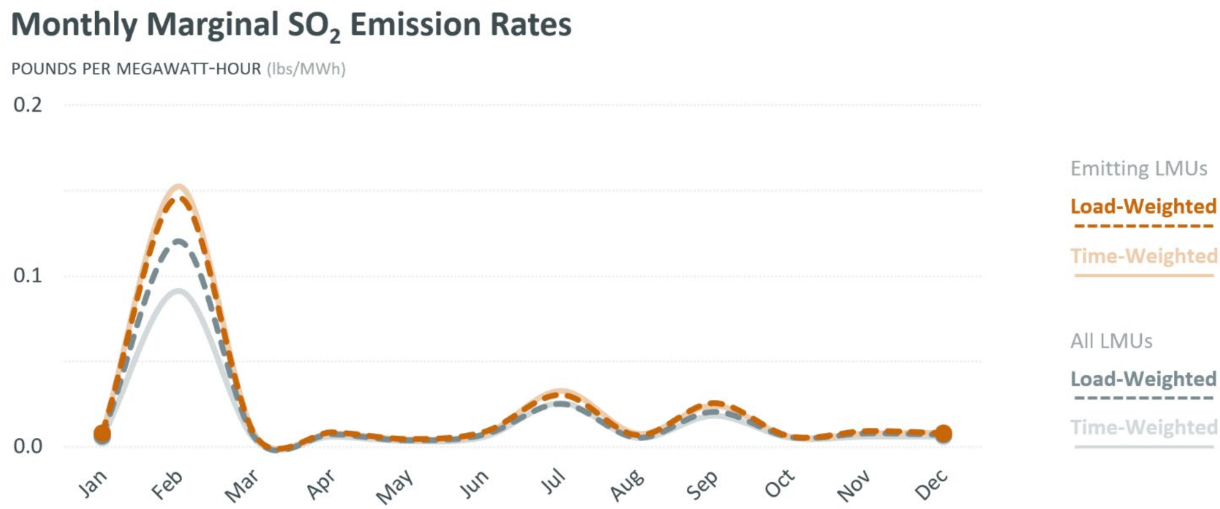


Figure 13: 2023 time- and load-weighted monthly LMUs marginal SO2 emission rates

Under both LMU scenarios, the 2023 time-weighted and load-weighted marginal emission rates for NO_X and SO_2 were lower by approximately 40% and 80% respectively compared to the previous year. However, the time-weighted CO_2 marginal emission rates for the all-LMUs scenario were slightly (1%) higher than last year because less wind was on the margin.

Figure 14 and Figure 15 show the decline in the marginal emission rates over the past decade. Time-weighted SO_2 annual marginal rates have declined by 97% and 96% respectively for the all-LMUs and emitting-LMUs scenarios respectively, while time-weighted marginal NO_X emission rates have decreased by 75% and 73% for the all-LMUs scenario and emitting-LMUs scenario respectively. CO_2 marginal emission rates since 2014 have declined less dramatically than SO_2 and NO_X, with a 24% decline for the all-LMUs scenario and 19% decline for the emitting-LMUs scenario.

Historical emission rate values can be found in Sections 3.3.1 and 3.3.2 of the spreadsheet appendix. Load-weighted approach values are not available for the 10-year timeframe, since this approach was first incorporated into the emissions analysis in 2018.

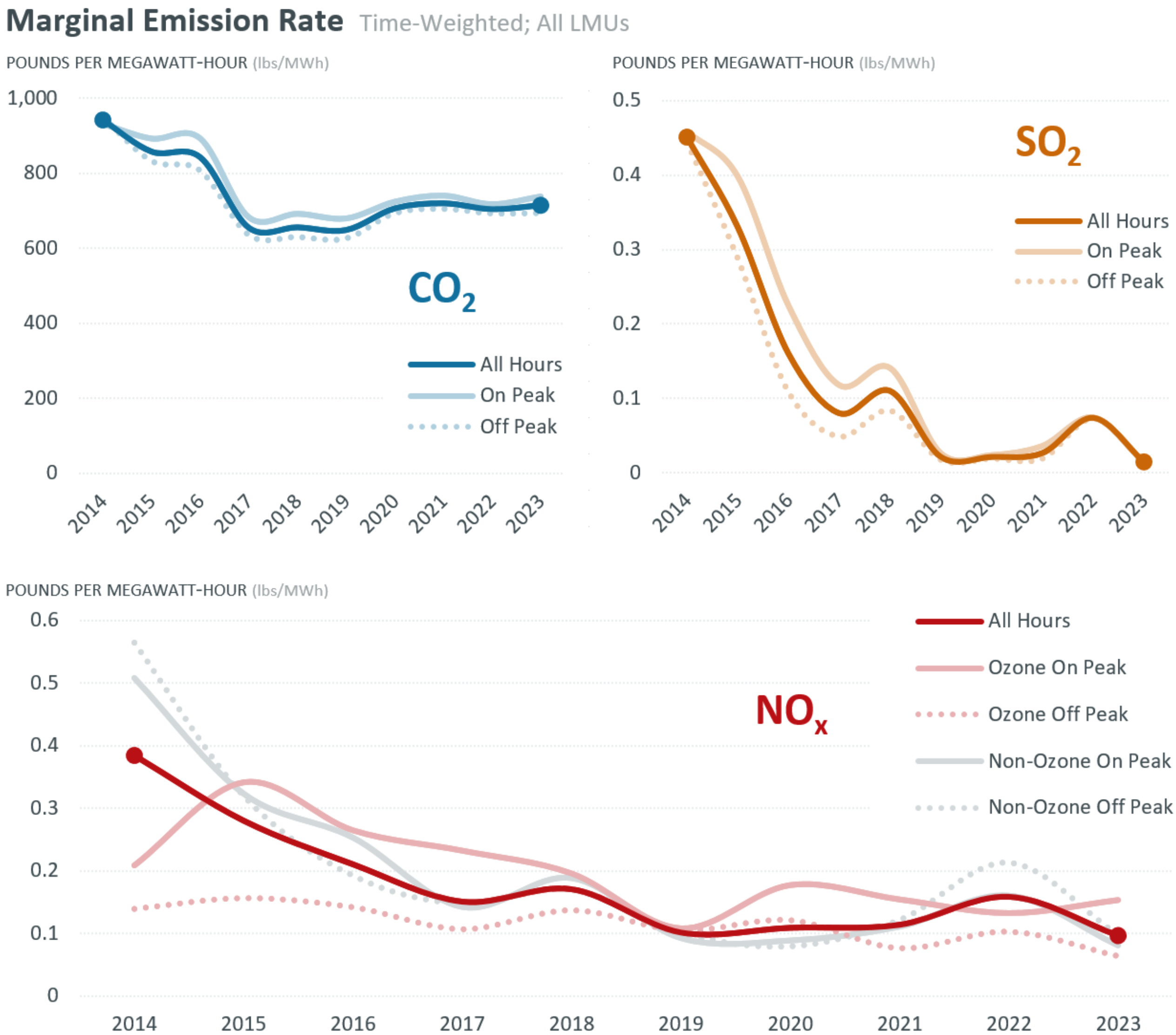


Figure 14: Time-weighted LMU marginal emission rates, 2014-2023 - all LMUs (lbs/MWh)

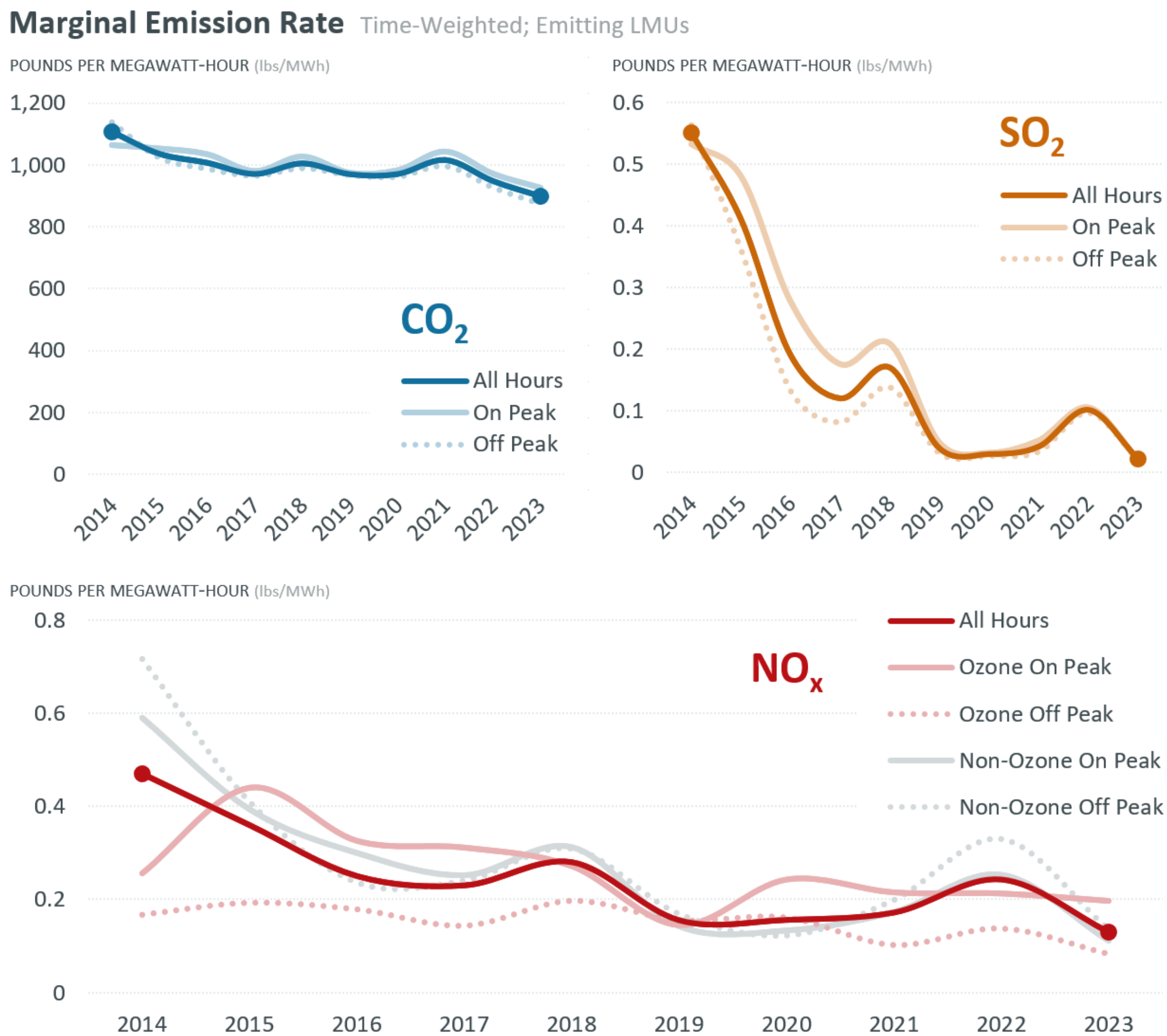


Figure 15: Time-weighted LMU marginal emission rates, 2014-2023 - emitting LMUs (lbs/MWh)

1.5.3 Marginal Heat Rates

The annual marginal heat rate reflects the average annual efficiency of all the marginal emitting units dispatched. Each generator's heat rate varies according to plant design, operating conditions, and power output. The lower the heat rate, the more efficient the generator is at converting fuel to electricity. Figure 16 illustrates declining marginal heat rates from 2014 through 2023 using the time-weighted all-LMUs approach. Between 2016 and 2017, the heat rate in the all-LMUs scenario dropped sharply due to the large amount of wind generators on the margin, a result of the Do Not Exceed (DNE) dispatch rules implemented in May 2016. The DNE incorporates wind and hydro intermittent units into economic dispatch and has since allowed these resources to set the price for energy. Prior to the DNE rule, these resources had to self-schedule their output and could not set the marginal price.

Between 2019 and 2020, the marginal heat rates for the all-LMUs scenario increased 8% under the time-weighted approach and 4% under the load-weighted approach. This increase coincided with the 2019 retirement of the Pilgrim Nuclear Power and the 2019 addition of several new gas-fired generators that consistently offered energy at a lower price than pumped-storage generators throughout 2020. Due to their lower price, they displaced pumped-storage generators as the marginal units more frequently.[3]

Marginal heat rates have not changed significantly since 2020. In 2023, the time-weighted all-LMUs marginal heat rate was 5.96 MMBtu/MWh, up slightly from 5.74 MMBtu/MWh in 2022. The load-weighted marginal heat rate was 6.43 MMBtu/MWh in 2023 compared to 6.33 MMBtu/MWh in 2022. Under the emitting-LMUs scenario, the 2023 marginal heat rate for the time-weighted and load-weighted approach was 7.50 MMBtu/MWh and 7.51 MMBtu/MWh, respectively. These values were slightly less than the 2022 time-weighted and load-weighted marginal heat rate of 7.67 MMBtu/MWh.

While the recent year-over-year changes in marginal heat rates have been minimal, overall efficiency in the region's fleet has improved significantly over the past decade, as indicated by the downward trend in rates between 2014 and 2023. This improvement can be attributed to the growth in wind and solar generation and declines in coil and oil mentioned in Section 1.4. The region has also shifted further towards natural gas generation, which is more efficient at converting fuel to electricity than other fossil fuel resources.

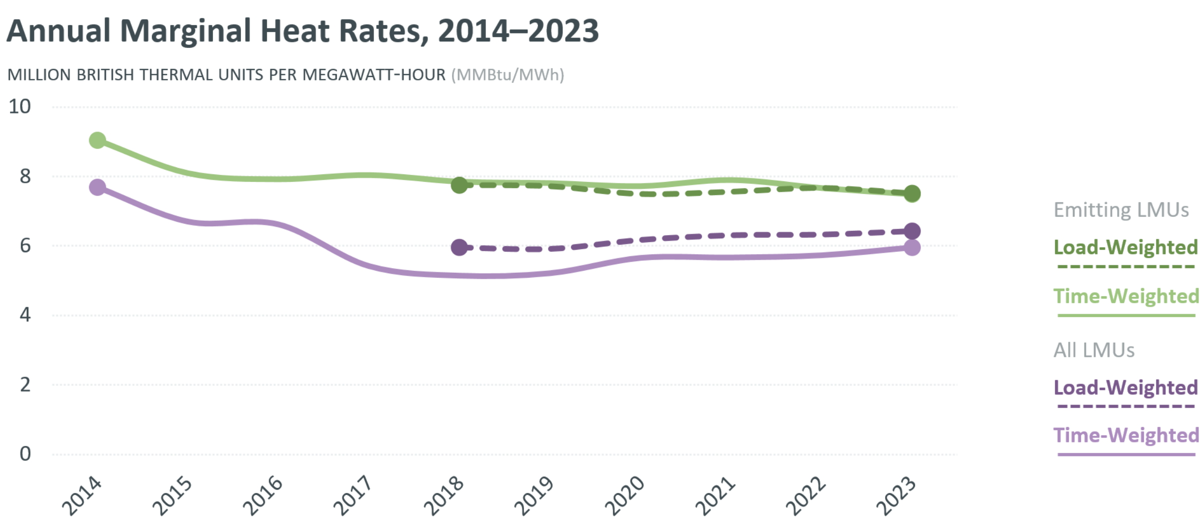


Figure 16: Annual marginal heat rates, 2014-2023 (MMBtu/MWh)

[3] Refer to the Marginal Resources in the Real-time Market section of the [2020 Annual Markets Report] for an in-depth discussion on the 2019-2020 marginal resource trends.

1.6 Conclusion

Compared to 2022, New England saw an overall reduction in average and marginal emissions of CO_2, SO_2, and NO_X from the electric sector in 2023. Emissions reductions were largely driven by mild summer and winter weather plus growth in BTM solar, which resulted in lower load and generation. Tight system conditions also occurred less frequently in 2023 than 2022, which decreased the region's reliance on stored fuel from higher carbon-emitting resources such as oil and coal.

In the last decade, the New England resource mix has shifted away from coal and oil resources and more towards natural gas, wind, and solar. This change in resource mix has contributed to a significant reduction in CO_2, SO_2, and NO_X emissions, and a decline in marginal heat rates.