The Regional Greenhouse Gas Initiative
an initiative of Eastern States of the US

CO_2 Emissions from Electricity Generation and Imports in the Regional Greenhouse Gas Initiative: 2023 Monitoring Report

December 16, 2025

The 2023 Monitoring Report on CO_2 Emissions from Electricity Generation and Imports in the Regional Greenhouse Gas Initiative (2023 Electricity Monitoring Report) relates to the states participating in the Regional Greenhouse Gas Initiative (RGGI) in 2023: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont and Virginia.[1] The opinions expressed in this report do not necessarily reflect those of any of the states participating in RGGI, and reference to any specific product, service, process, or method does not constitute an implied or expressed recommendation or endorsement of it. Further, RGGI, Inc., and the states participating in RGGI make no warranties or representations, expressed or implied, as to the fitness for particular purpose or merchantability of any product, apparatus, or service, or the usefulness, completeness, or accuracy of any processes, methods, or other information contained, described, disclosed, or referred to in this report. RGGI, Inc. and the states participating in RGGI make no representation that the use of any product, apparatus, process, method, or other information will not infringe privately owned rights and will assume no liability for any loss, injury, or damage resulting from, or occurring in connection with, the use of information contained, described, disclosed, or referred to in this report.

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort of Eastern states to reduce emissions of carbon dioxide (CO_2), a greenhouse gas that causes global warming.

RGGI, Inc. is a non-profit corporation created to provide technical and administrative services to the states participating in the Regional Greenhouse Gas Initiative.

[1] This report summarizes data for the eleven states participating in RGGI in 2023: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia. New Jersey resumed participation in RGGI in 2020, Virginia participated from 2021 to 2023..

Table of Contents

Executive Summary

The 2023 Electricity Monitoring Report is the fifteenth report in a series of annual monitoring reports, summarizing the data for the period from 2006 through 2023, for electricity generation, net electricity imports, and related carbon dioxide (CO_2) emissions for the states participating in the Regional Greenhouse Gas Initiative (RGGI) in 2023. For the purposes of this report, the “RGGI Region” is defined as: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia.

These monitoring reports were called for in the 2005 RGGI Memorandum of Understanding (MOU) in response to expressed concerns about the potential for the RGGI CO_2 Budget Trading Program to cause CO_2 emissions from generation serving load in the RGGI Region to shift towards sources that are not subject to RGGI.[2] If this potential shift results in an overall net increase in emissions, it is referred to as “emissions leakage."

In the New England and Mid-Atlantic states, CO_2 emissions from the regional electric power sector are a function of highly dynamic wholesale electricity markets. The cost of compliance with the RGGI CO_2 Budget Trading Program is only one of multiple factors that influence the dispatch of electric generation, and resulting CO_2 emissions, through the operation of these markets. As a result, this report presents data without assigning causality to any one of the factors influencing observed trends.

A key metric presented in this report that may provide a preliminary or potential indication of emissions leakage, or a lack thereof, is electric generation and related CO_2 emissions from all non-RGGI electric generation serving electricity load in the RGGI Region. Because this report does not establish the causes of observed trends, it should be emphasized that this report does not provide indicators of CO_2 emissions leakage.

The 2023 Electricity Monitoring Report tracks electricity generation, net electricity imports, and related CO_2 emissions for the RGGI Region during the three-year current period of 2021 to 2023 relative to 2006 to 2008, a three-year base period prior to the start of the first RGGI control period. The report also tracks the same categories for the 2023 annual averages in the RGGI Region and compares these to the 2006 to 2008 base period.

The observed trends in electricity demand, electricity generation, and net electricity imports show there has been a small decrease in CO_2 emissions from total non-RGGI electric generation serving load in the RGGI Region during the period of 2021 to 2023 when compared to the base period, as well as during the 2023 calendar year when compared to the base period.

[2] The Memorandum of Understanding called for monitoring electricity imports into the RGGI participating states commencing from the start of the RGGI CO_2 Budget Trading Program and reporting the results of such monitoring on an annual basis beginning in 2010.

Summary of Results

Change in Annual Average Electric Load (Demand for Electricity) and Annual Average Generation

RGGI Region 2021 to 2023 Annual Average Compared to Baseline

- The annual average **electric load** in the RGGI Region from 2021 to 2023 decreased by 40.0 million MWh, or 6.9 percent, compared to the base period average for 2006 to 2008. (See Figures 1 and 2.)

- The annual average **electric generation** from all sources in the RGGI Region from 2021 to 2023 decreased by 35.9 million MWh, or 7.8 percent, compared to the base period. (See Figures 1 and 2.)

- The annual average **net imports** into the RGGI Region from 2021 to 2023 increased by 6.0 million MWh, or 5.1 percent, compared to the base period. (See Figures 1 and 2.)

RGGI Region 2023 Annual Average Compared to Baseline

- The annual average **electric load** in the RGGI Region for 2023 decreased by 49.4 million MWh, or 8.5 percent, compared to the base period average for 2006 to 2008. (See Figures 3, 4, and 5.)

- The annual average **electric generation** from all sources in the RGGI Region in 2023 decreased by 37.4 million MWh, or 8.1 percent, compared to the base period. (See Figures 3, 4, and 5.)

- The annual average **net imports** into the RGGI Region in 2023 decreased by 1.3 million MWh, or 1.1 percent, compared to the base period. (See Figures 3, 4, and 5.)

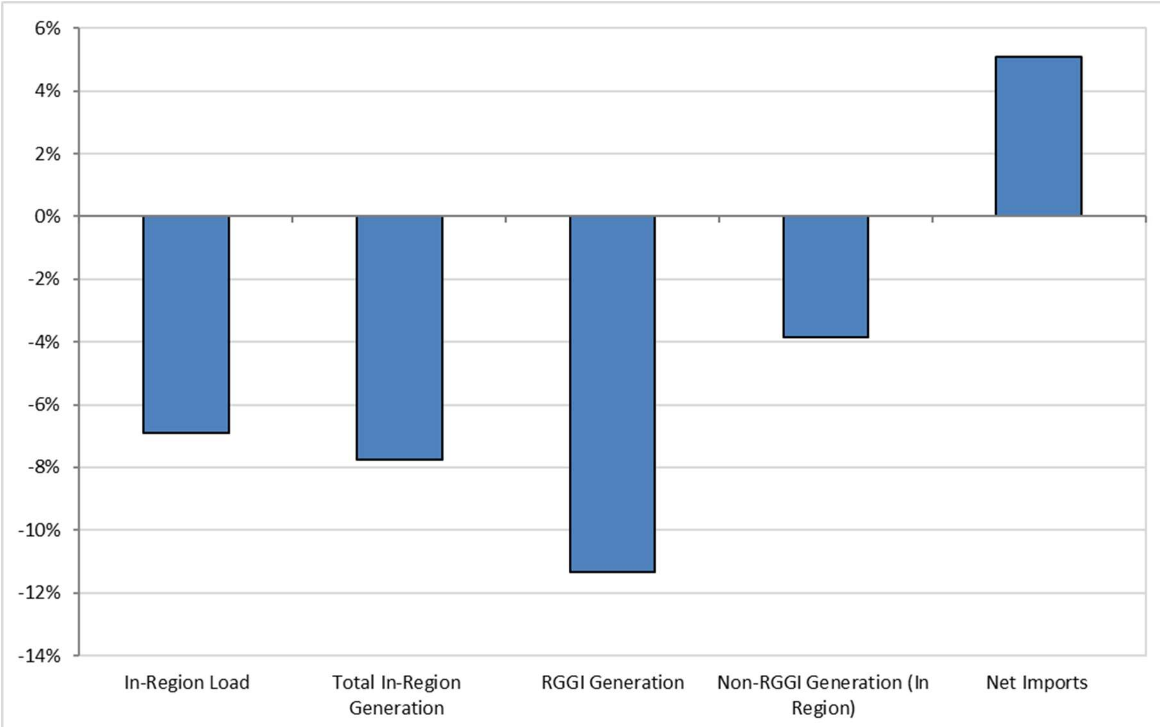

Figure 1. Percentage change in electricity load and generation serving the RGGI Region for 2021 to 2023, relative to the base period of 2006 to 2008.

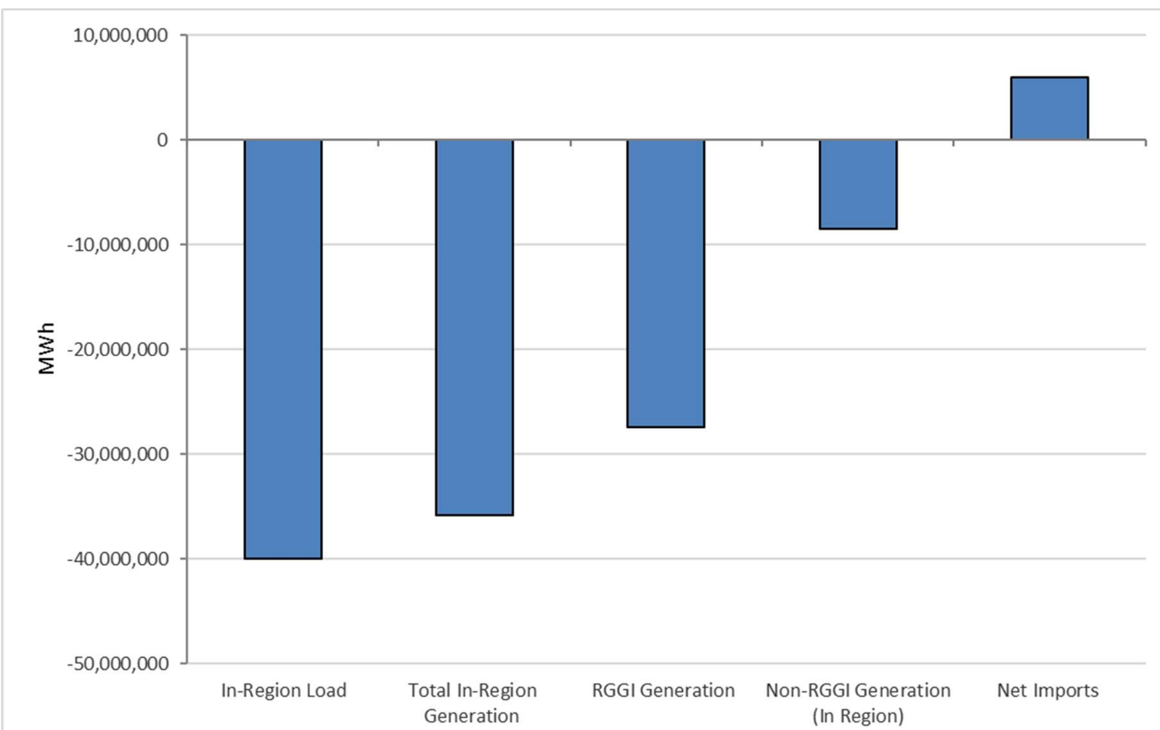

Figure 2. Change in MWhs of annual average electricity load and generation serving the RGGI Region for 2021 to 2023, relative to the base period of 2006 to 2008.

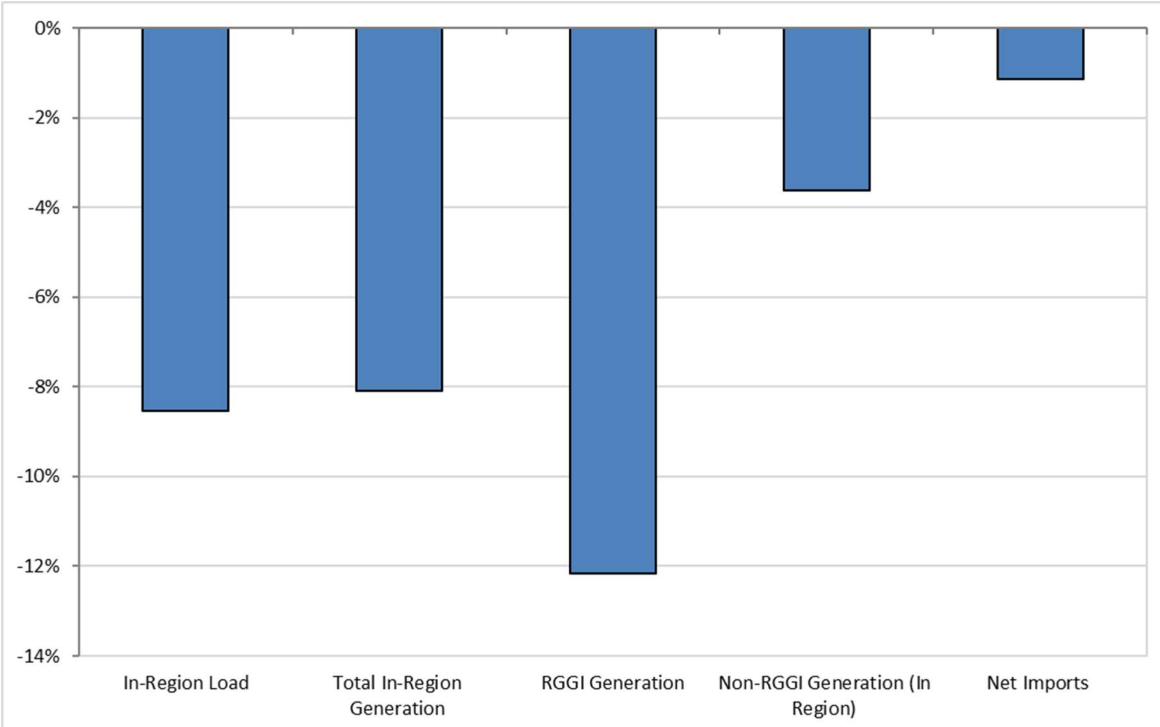

Figure 3. Percentage change in annual average electricity load and generation serving the RGGI Region for 2023, relative to the base period of 2006 to 2008.

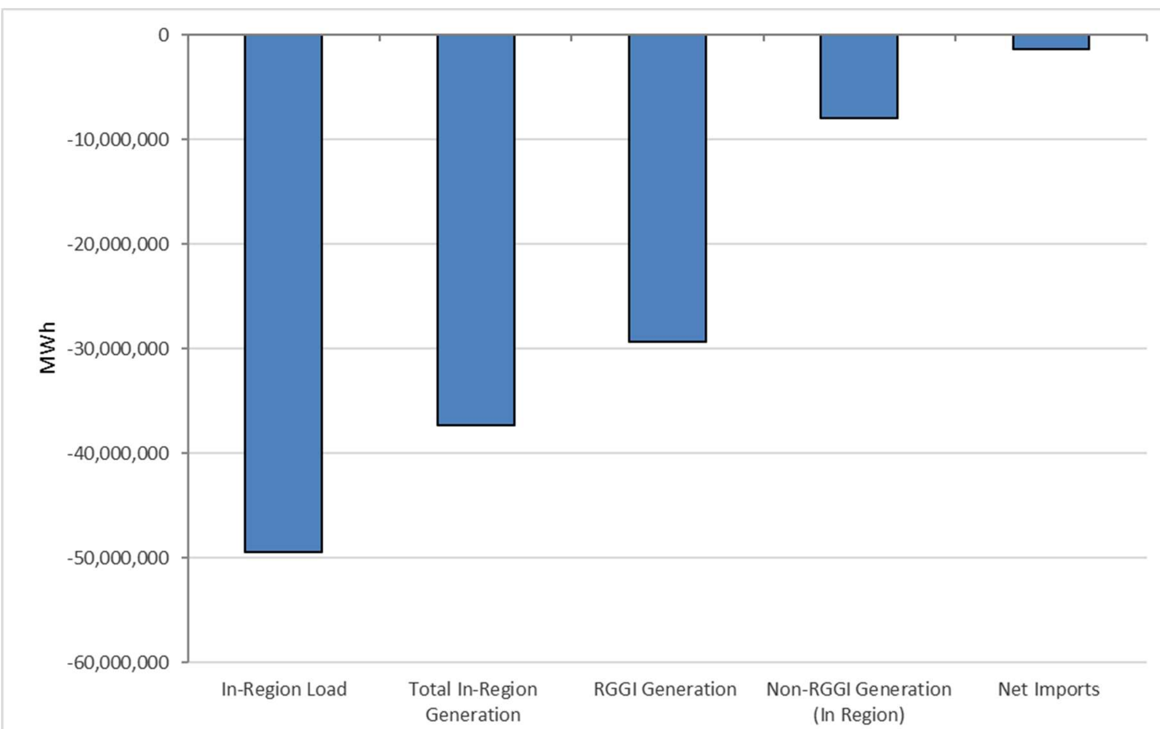

Figure 4. Change in MWhs of annual average electricity load and generation serving the RGGI Region for 2023, relative to the base period of 2006 to 2008.

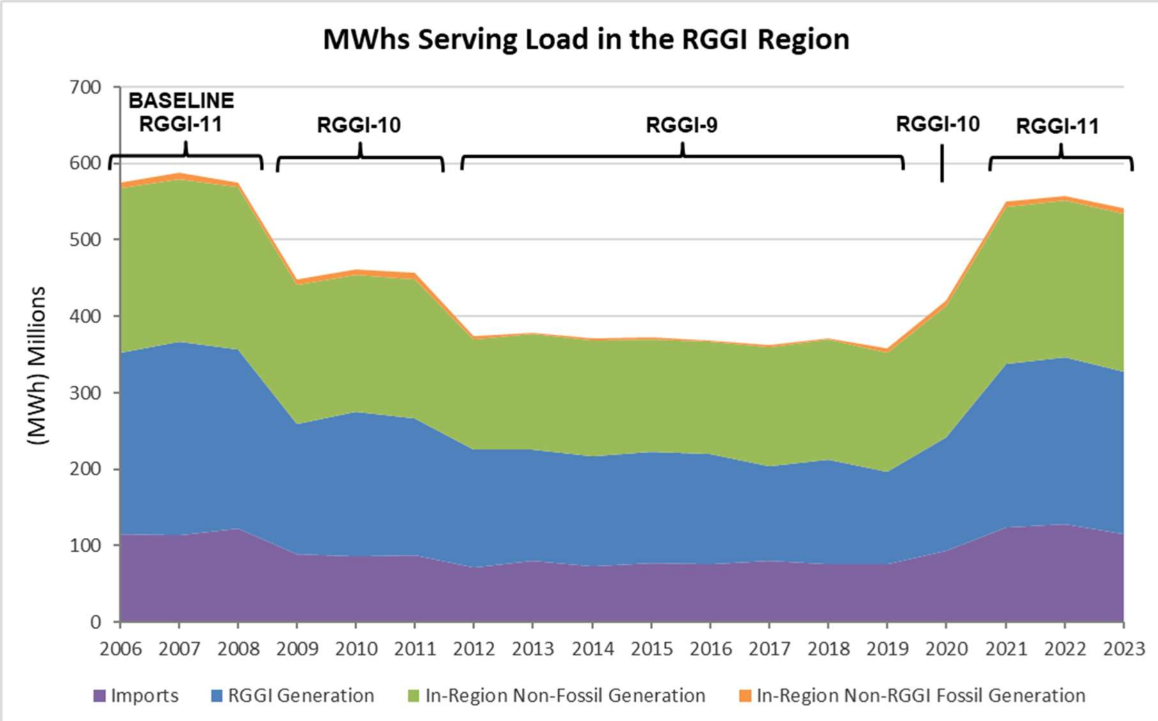

Figure 5. MWhs of generation serving load in the RGGI Region from 2006-2023. Annual averages for baseline years and 2021 to 2023 represent RGGI-11; 2008 to 2011 and 2020 represent RGGI-10; 2012 to 2019 represent RGGI-9.

Change in Annual Average Non-RGGI Emissions, Non-RGGI Emissions Rate, and Non-RGGI Generation

RGGI Region 2021 to 2023 Annual Average Compared to Baseline

- The monitoring results indicate there was a decrease of 20.3 million short tons of CO_2, or 23.0 percent, in **CO_2 emissions** from all non-RGGI electric generation serving load in the RGGI region for 2021 to 2023 relative to the base period of 2006 to 2008.

- The annual average **CO_2 emissions rate** from all non-RGGI electric generation sources serving load in the RGGI Region for 2021 to 2023 decreased by 117 lb CO_2/MWh to 405 lb CO_2/MWh, or 22.4 percent, compared to the base period rate of 523 lb CO_2/MWh.

- The annual average **electric generation** from all non-RGGI electric generation sources serving load in the RGGI Region for 2021 to 2023 decreased by 2.5 million MWh, or 0.7 percent, compared to the base period of 2006 to 2008.

RGGI Region 2023 Annual Average Compared to Baseline

- For the 2023 calendar year, the **CO_2 emissions** from all non-RGGI electric generation serving load relative to the base period decreased by 22.8 million short tons, or 25.8 percent.

- The **CO_2 emissions rate** from this category in 2023 decreased by 124 lb CO_2/MWh to 399 lb CO_2/MWh, or 23.7 percent, compared to the base period rate of 523 lb CO_2/MWh.

- The **electric generation** from this category in 2023 decreased by 9.3 million MWh, or 2.8 percent, compared to the base period of 2006 to 2008.

Change in Annual Average RGGI Emissions, RGGI Emissions Rate, and RGGI Generation

RGGI Region 2021 to 2023 Annual Average Compared to Baseline

- The annual average **CO_2 emissions** from RGGI electric generation sources from 2021 to 2023 for the RGGI Region decreased by 93.6 million short tons of CO_2, or 47.7 percent, compared to the base period of 2006 to 2008. (See Figures 6 and 7.)

- The annual average **CO_2 emissions rate** from RGGI electric generation sources from 2021 to 2023 for the RGGI Region decreased by 666 lb CO_2/MWh to 959 lb CO_2/MWh, or 41.0 percent, compared to the base period rate of 1,625 lb CO_2/MWh

- The annual average **electric generation** from RGGI electric generation sources from 2021 to 2023 for the RGGI Region decreased by 27.4 million MWh, or 11.3 percent, compared to the base period of 2006 to 2008. (See Figures 1 and 2.)

RGGI Region 2023 Annual Average Compared to Baseline

- For the 2023 calendar year, **CO_2 emissions** from RGGI electric generation sources decreased by 98.3 million short tons of CO_2, or 50.1 percent, compared to the base period. (See Figures 8 and 9.)

- **CO_2 emissions rate** from RGGI electric generation sources in 2023 decreased by 701 lb CO_2/MWh to 925 lb CO_2/MWh, or 43.1 percent, compared to the base period rate of 1,625 lb CO_2/MWh.

- **Electric generation** from RGGI electric generation sources in 2023 decreased by 29.4 million MWh, or 12.2 percent, compared to the base period. (See Figures 3 and 4.)

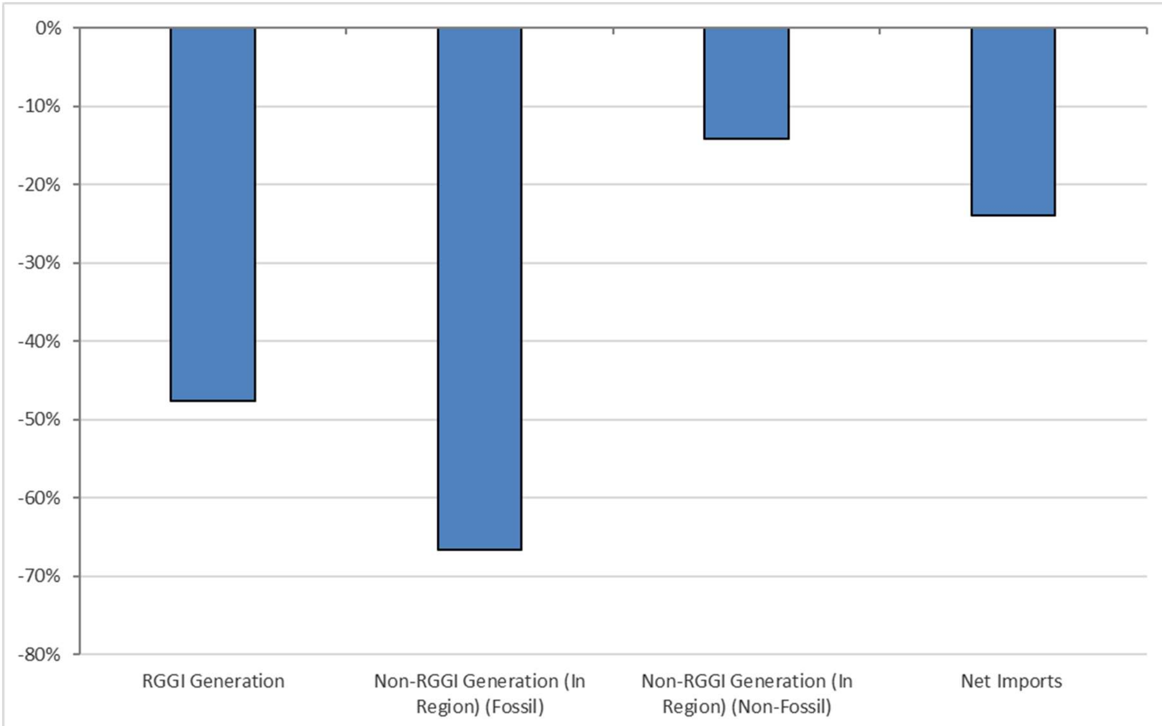

Figure 6. Percent change in CO_2 emissions from generation serving load in the RGGI Region for 2021 to 2023, relative to the base period of 2006 to 2008.

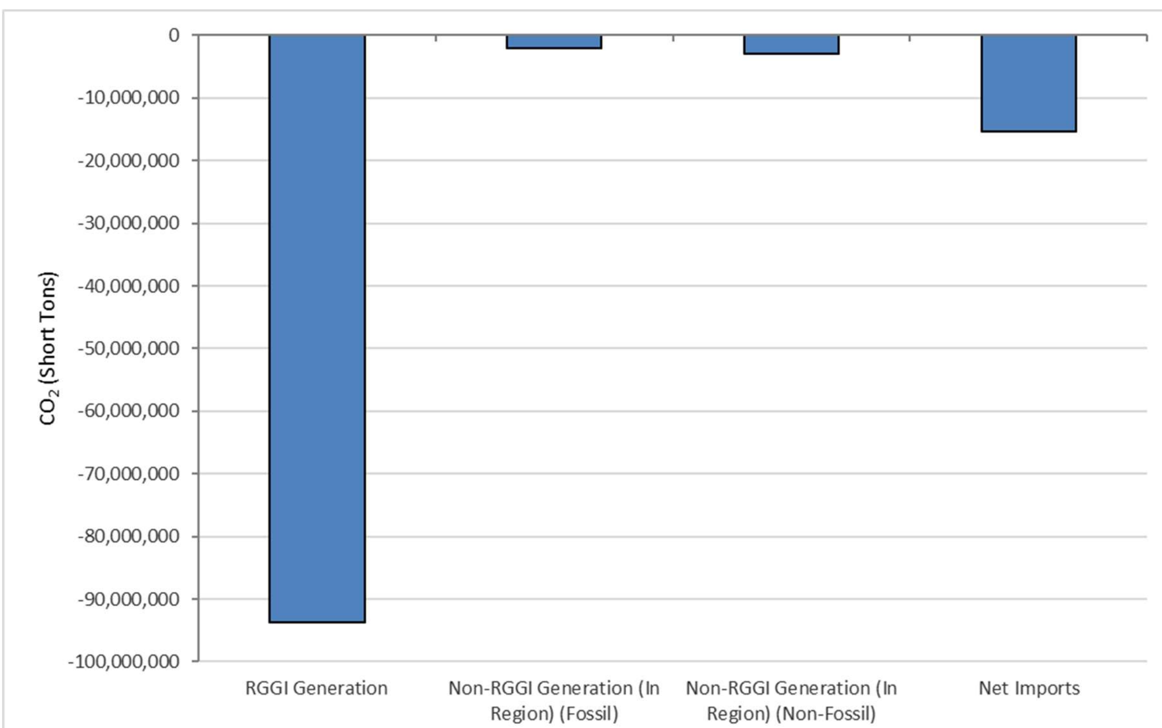

Figure 7. Change in annual average CO_2 emissions from generation serving load in the RGGI Region for 2021 to 2023, relative to the base period of 2006 to 2008.

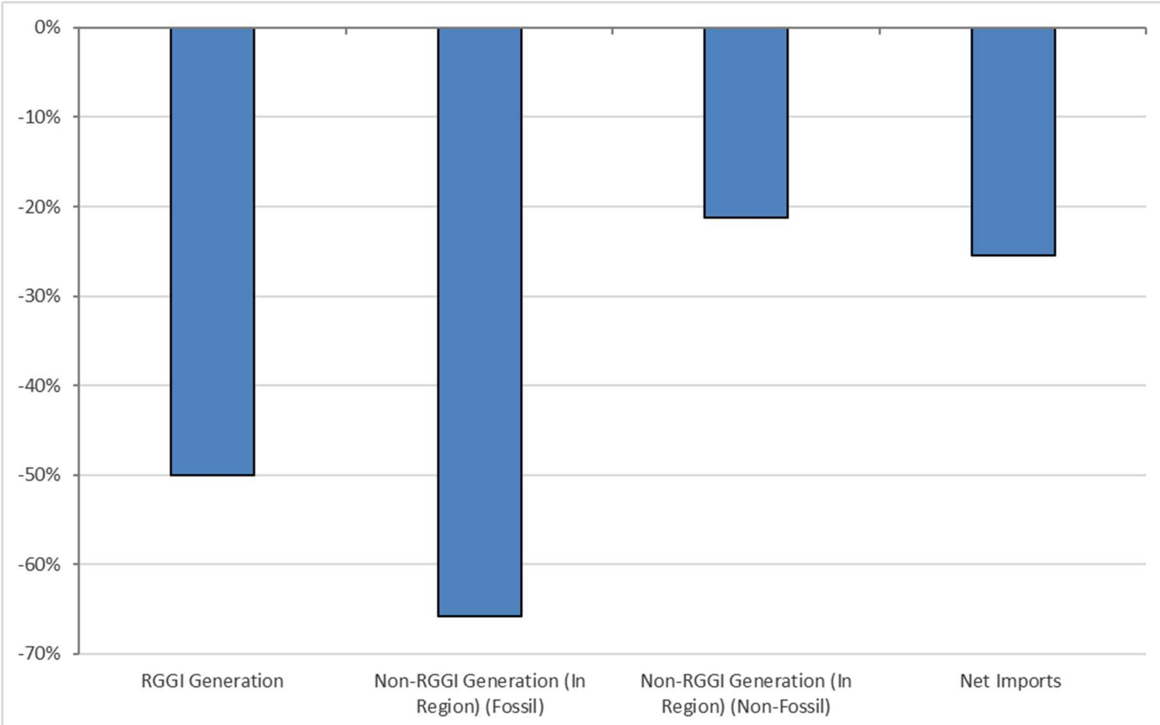

Figure 8. Percent change in annual average CO_2 emissions from generation serving load in the RGGI Region for 2023, relative to the base period of 2006 to 2008.

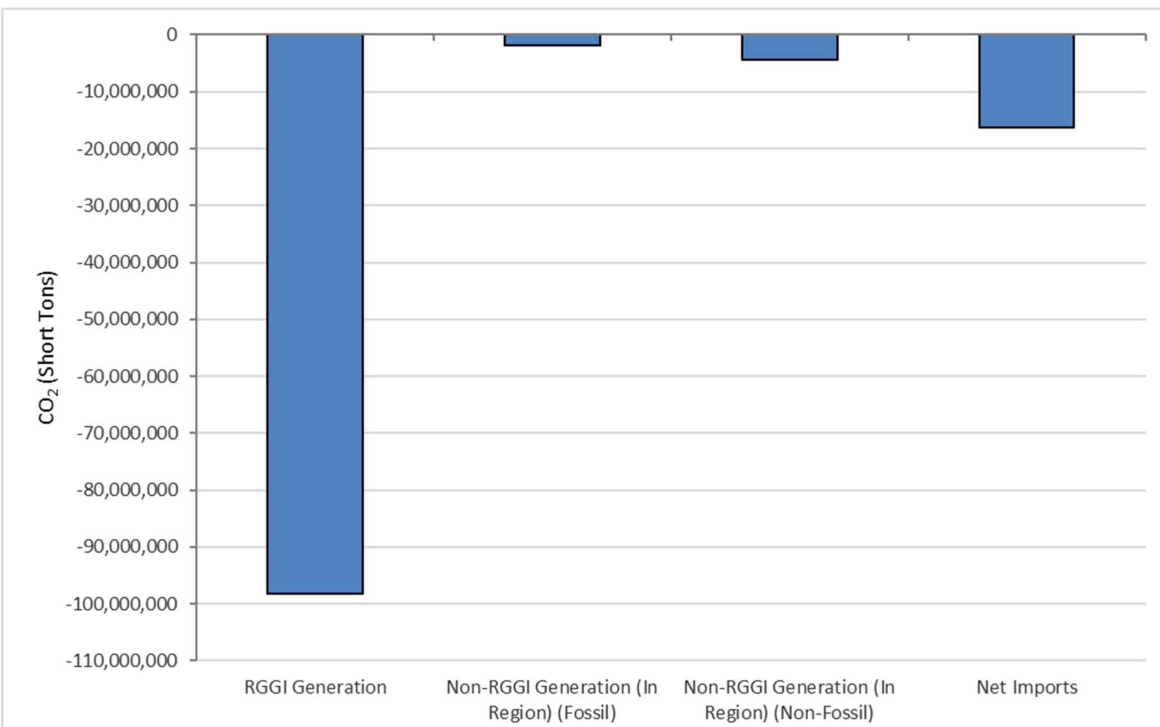

Figure 9. Change in annual average CO_2 emissions from generation serving load in the RGGI Region for 2023, relative to the base period of 2006 to 2008.

Conclusions

It should be emphasized that this report does not provide indicators of CO_2 emissions leakage, but rather tracks electricity generation and imports, and related CO_2 emissions, in the RGGI Region. A key metric presented in this report that may provide a preliminary or potential indication of emissions leakage, or a lack thereof, is electric generation and related CO_2 emissions from all non-RGGI electric generation serving electric load in the region.

Monitoring results show that there has been a decrease in the amount of non-RGGI electric generation serving load in the RGGI Region as well as a decrease in the CO_2 emissions rate of this generation. Specifically, there has been a 23.0 percent decrease in average annual CO_2 emissions from non-RGGI electric generation serving load in the RGGI Region during the period of 2021 to 2023 when compared to the base period of 2006 to 2008, and a 25.8 percent decrease for the RGGI Region in the calendar year 2023 when compared to the base period.

I. Background

The 2023 Electricity Monitoring Report summarizes monitoring data and tracks trends for electricity demand, net electricity imports, electricity generation from multiple categories of generation sources (including net electricity imports), and the CO_2 emissions related to these categories of electric generation in the RGGI Region, for the period from 2006 through 2023. This monitoring was called for in the 2005 RGGI MOU in response to expressed concerns about the potential for the RGGI CO_2 Budget Trading Programs[3] to result in "emissions leakage".[4] The monitoring approach that was used to compile the data summarized in this report was specified in a March 2007 report from the RGGI Staff Working Group, *Potential Emissions Leakage and the Regional Greenhouse Gas Initiative (RGGI): Evaluating Market Dynamics, Monitoring Options, and Possible Mitigation Mechanisms*.[5]

The report should not be used to draw definitive conclusions about whether CO_2 emissions leakage has occurred, as it does not address the causes of observed trends among different categories of electric generation serving load in the RGGI Region. This report is an analysis of CO_2 emissions only and does not speak to other greenhouse gases.

II. Monitoring Approach

The data summarized in this report track electricity generation and electricity use in each of the three independent system operator (ISO) regions fully or partially subject to the RGGI CO_2 Budget Trading Program: ISO-New England (ISO-NE), New York ISO (NYISO), and PJM. The data track total MWh of electricity used to serve electric load in each ISO (or portion of an ISO subject to RGGI, in the case of PJM), the actual or estimated short tons of CO_2 emissions related to the generation of this electricity, and the associated lb CO_2/MWh emission rate.

Throughout this report, references to "electric generation" and "electric load" include only that portion of electric generation or electric load dispatched or served through the regional transmission system administered by ISOs and tracked by individual ISOs. This excludes most electric generation output and electric load typically known as "behind-the-meter," which refers to electric generation that is not dispatched by ISOs, and electric load met through on-site electric generation facilities (e.g., industrial cogeneration and other smaller distributed generation resources, such as combined heat and power and solar photovoltaics). The electric generation MWh output that is used on-site is not included in the monitoring results.[6]

---

[3] RGGI is comprised of state CO_2 Budget Trading Programs. Under each of these state programs, a regulated power plant must hold CO_2 allowances equal to its emissions to demonstrate compliance at the end of a three-year control period. Beginning in 2015, a regulated power plant must hold CO_2 allowances equal to 50% of its emissions to demonstrate compliance during each of the first two years of a three-year control period. CO_2 allowances are issued by participating states in a finite amount, or "budget", resulting in a regional cap on CO_2 emissions from the electric generation sector in the RGGI region. Regulated power plants are fossil fuel-fired electric generating units with an electric generation capacity of 25 megawatts (MWe) or greater.

[4] Specifically, the MOU called for monitoring electricity imports into the RGGI participating states from the start of the RGGI CO_2 Budget Trading Program and reporting the results of such monitoring on an annual basis beginning in 2010.

[5] The report also specified requested changes that were made to generator attribute tracking systems for ISO-NE and PJM to facilitate RGGI monitoring. The report is available at https://www.rggi.org/sites/default/files/Uploads/Design-Archive/Staff-Working-Group/il_report_final_3_14_07.pdf.

[6] Behind-the-meter electric generators eligible for credit under state renewable portfolio standards typically voluntarily report electric generation to the ISO-NE Generation Information System (GIS), NY Generation Attribute Tracking System (NYGATS), and PJM Generation Attribute Tracking System (GATS), which are discussed in Section IV. Methodology.

For each year 2006 through 2023, the following categories of data are presented for the RGGI Region as well as for each ISO:

- RGGI Generation: Electric generation (MWh), CO_2 emissions (short tons), and emission rate (lb CO_2/MWh) for electric generating units subject to a CO_2 allowance compliance obligation under state CO_2 Budget Trading Program regulations.[7]

- Non-RGGI Generation: Electricity generation (MWh), CO_2 emissions (short tons), and emission rate (lb CO_2/MWh) for all non-RGGI electric generation serving electric load in the RGGI Region. This includes both in-region electric generation and net electricity imports. In addition to total non-RGGI generation, data for the following subcategories of non-RGGI generation are also presented:

  - Non-RGGI In-Region Generation: Electric generation from electric generation units located in the RGGI Region that are not subject to a CO_2 allowance compliance obligation (e.g., generators under 25 megawatts electrical (MWe) capacity and non-fossil fuel-fired electric generators)[8].

  - Net Imports: Electric generation from net electricity imports (MWh) from adjacent control areas, or portion of a control area, outside the RGGI Region (can be fossil or non-fossil generation).[9]

III. Evaluation of Monitoring Data

This section addresses issues considered in evaluation of the monitoring data, including the selection of base periods for comparison of data and general monitoring limitations.

Base Period

This report compares monitoring data for the period from 2021 to 2023 to a base period of 2006 to 2008 for the RGGI Region. The report also tracks the same categories for the 2023 annual averages in the RGGI Region and compares these to the base period. The period of 2006 to 2008 represents the three years immediately prior to the start of the first RGGI control period. It was selected as the base period to provide a point of comparison to the three-year control periods of RGGI.

In monitoring reports from 2009, 2010, 2011, and 2020 data comparisons were made to the base period for the ten-state region (RGGI-10). For 2012 through 2019, data

---

These behind-the-meter electric generators that report to ISO-NE GIS, NYGATS, and PJM GATS are included in the monitoring results. CO_2 emissions data for behind-the-meter electric generation that is RGGI-affected are also included in this report. In addition, only electricity output from cogeneration facilities is reported by ISOs, meaning that the average lb CO_2/MWh emission rate for all reporting years in this report is for electricity generation dispatched to the ISO grid only and does not account for behind-the-meter MWh output or useful steam output from cogeneration facilities.

[7] For the purposes of this report, this category does not include electric generators that may be subject to a state CO_2 Budget Trading Program regulation, or portion of such regulation, but that are not subject to a CO_2 allowance compliance obligation that requires the generator to submit CO_2 allowances equivalent to its CO_2 emissions. For example, under Maryland's CO_2 Budget Trading Program regulations, certain industrial cogenerators may be subject to alternative CO_2 compliance obligations under certain conditions in lieu of submission of CO_2 allowances.

[8] In New York, generators including and over 15 MWe capacity are subject to CO_2 allowance compliance obligation.

[9] For individual ISOs, net imports represent actual annual net electricity flows between ISOs, as reported by the ISOs. For PJM, net electricity imports represent inferred transfers of electricity from the non-RGGI geographic portion of PJM into the RGGI geographic portion of PJM.

comparisons were made to the base period for the nine-state region (RGGI-9), reflecting the states participating in RGGI during that time.[10] The monitoring report for 2021 introduced Virginia and compares data for the eleven-state region (RGGI-11).

Key Metrics

A key metric presented in this report that may provide a preliminary or potential indication of emissions leakage, or a lack thereof, is electric generation and related CO_2 emissions from all non-RGGI electric generation serving electric load in the RGGI Region. This includes electric generation in the RGGI Region from electric generating units that are not subject to a CO_2 allowance compliance obligation under a state CO_2 Budget Trading Program (e.g., small fossil units not subject to RGGI or non-fossil units not subject to RGGI), as well as net imports of electricity into the RGGI Region. If CO_2 emissions leakage were to occur, it would manifest as an increase in CO_2 emissions from this category of non-RGGI electric generation, assuming all other factors that impact electricity system dispatch and CO_2 emissions (such as electricity demand, relative fossil fuel prices, and wholesale electricity prices) did not change. As a result, an increase in CO_2 emissions from this category of electric generation in a year subsequent to implementation of RGGI, relative to a baseline prior to the implementation of RGGI, could be an indicator of *potential* CO_2 emissions leakage.

General Limitations

It should be emphasized that this report does not provide indicators of CO_2 emissions leakage, but rather tracks electricity generation and net electricity imports and related CO_2 emissions in the RGGI Region for 2021 to 2023, relative to baseline years prior to implementation of RGGI. Determining whether CO_2 emissions leakage has occurred requires the evaluation of a hypothetical counterfactual – the amount of CO_2 emissions from non-RGGI electric generation that would occur, assuming there is no shift in electric generation to CO_2-emitting non-RGGI electric generators as a result of the implementation of the RGGI CO_2 Budget Trading Program. In theory, an increase in CO_2 emissions or CO_2 emission rate from non-RGGI electric generation as compared to a historical baseline year could occur in a scenario in which CO_2 emissions leakage does not occur. Conversely, leakage could theoretically occur in a scenario in which CO_2 emissions and CO_2 emission rate for non-RGGI electric generation *decreased* as compared to a historical baseline year, as such emissions could have decreased further under a hypothetical counterfactual in which no CO_2 emissions leakage occurs.

Changes in these data over time may point to *potential* CO_2 emissions leakage as a result of states implementing the CO_2 Budget Trading Program, or a lack thereof, but may also be the result of wholesale electricity market and fuel market dynamics unrelated to the implementation of the CO_2 Budget Trading Program, or a combination of these factors.

The analysis of lifecycle CO_2 emissions or reductions from fuels used in non-RGGI non-fossil-fuel units is also not within the scope of this report. For example, the direct emissions of CO_2 and the lb CO_2/MWh emission rates from non-RGGI non-fossil fuel

[10] ISO-NE data for years 2006-2015 was adjusted and corrected by the ISO-NE states in the 2016 Electricity Monitoring Report to account for misclassifications of certain generators. New York Control Area (NYCA) data for years 2006-2009 was adjusted and corrected by New York State Department of Public Service (NYSDPS) in the 2011 Electricity Monitoring Report to account for misclassifications of certain generators. The impacts on RGGI and non-RGGI generation and emissions were not significant. All reports available at https://www.rggi.org/allowance-tracking/emissions.

units in this report do not reflect the biomass lifecycle carbon reduction of atmospheric CO_2 levels resulting from uptake of CO_2 from the atmosphere as a result of forest and biomass growth. Likewise, for municipal solid waste combustors, direct emissions of CO_2 are presented with no analysis of the lifecycle of the waste components.

IV. Methodology

Data Sources

For ISO-NE and PJM, the data presented are primarily from the NEPOOL Generation Information System (GIS) and PJM Generation Attribute Tracking System (GATS),[11] supplemented by ISO electricity import/export data, and CO_2 emissions data for RGGI electric generation from the RGGI CO_2 Allowance Tracking System (RGGI COATS) and emissions statement data reported to state environmental agencies in the RGGI participating states. For non-RGGI electric generation, CO_2 emissions are based on CO_2 emissions for individual electric generation facilities in the NEPOOL GIS and PJM GATS tracking systems. A summary of data sources for ISO-NE and PJM is provided in Appendix A.

For NYISO, MWh data for 2006-2015 were compiled by the NYS DPS from NYISO data (MWh generation data) and, beginning in 2016, MWh data were compiled by the NYS DPS from NYISO data (MWh generation data) fed into the New York Generation Attribute Tracking System (NYGATS), which began operation for the 2016 calendar year. NYGATS also captures PJM, NEPOOL, and Hydro Quebec and Ontario data (MWh electricity net import data). This MWh data was supplemented by CO_2 emissions data compiled by the New York State Department of Environmental Conservation (NYSDEC), the EPA, and validated self-reporting in NYGATS. CO_2 emissions data for RGGI electric generation units were compiled from RGGI COATS and from NYSDEC emissions statement program data. CO_2 emissions data for fossil fuel-fired electric generation units that are non-RGGI were taken or extrapolated from reports compiled by NYSDEC, the EPA, and validated self-reporting in NYGATS. A summary of data sources for NYISO is provided in Appendix A.

For each ISO, CO_2 emissions related to net electricity imports from each adjacent control area[12] are the product of a lb CO_2/MWh emission rate and the reported MWh of net imports. The CO_2 emission rate for electricity imports is based on the system average CO_2 emission rate for the respective exporting adjacent control area.[13] For ISO-NE and NYISO, net electricity imports are based on actual flow data for electricity transfers between adjacent control areas.[14] For PJM, net electricity imports are inferred and

[11] These ISO tracking systems track every MWh of electric generation for each electric generator that participates in the ISO wholesale market. Modifications were made to both systems at the request of the RGGI Staff Working Group to facilitate the tracking presented in this report. (See Staff Working Group, *Potential Emissions Leakage and the Regional Greenhouse Gas Initiative (RGGI): Evaluating Market Dynamics, Monitoring Options, and Possible Mitigation Mechanisms,* pp. 18-26; available at https://www.rggi.org/sites/default/files/Uploads/Design-Archive/Staff-Working-Group/il_report_final_3_14_07.pdf.) These systems do not fully capture the portion of electric generation that is "behind the meter" and used to serve on-site electric load (e.g., MWh supplied from industrial cogeneration to meet on-site industrial electricity load).
[12] For PJM, this represents inferred imports from the non-RGGI geographic portion of PJM.
[13] This assumes that power transferred originates in the adjacent control area and is delivered for use in the receiving control area. This assumption does not account for the wheeling of power through control areas.
[14] The exception is net import data from Hydro Quebec into NYISO, which represents net scheduled electricity imports. Scheduled flows are those flows that are scheduled at an ISO interface for a defined period, while actual flows are the metered flows at an ISO interface for a defined period. Differences between the two can arise from transactions scheduled on contract paths that do not fully correspond to the physical paths on which the electricity related to the transaction actually flows.

represent “transfers” of electricity from the non-RGGI geographic portion of PJM into the RGGI geographic portion of PJM (Delaware, Maryland, New Jersey, and Virginia). This data is compiled from PJM GATS, which reports data for both the non-RGGI and RGGI geographic portions of PJM. Inferred net imports are based on total MWh load in the RGGI geographic portion of PJM minus total electric generation in the RGGI geographic portion of PJM. Any shortfall in generation relative to load is assumed to be met through an inferred “import” of electricity from the non-RGGI geographic portion of PJM into the RGGI geographic portion of PJM.[15]

When aggregating individual ISO net import data, the reported regional net imports of electricity and related CO_2 emissions from net imports presented in this report represent net imports from adjacent regions not subject to the RGGI CO_2 Budget Trading Program. Some of the individual ISO net import subtotals represent net imports from another ISO or portion of an ISO that is also subject to the RGGI CO_2 Budget Trading Program (e.g., from ISO-NE into NYISO and vice versa). To avoid inappropriate double counting of MWh and related CO_2 emissions, the net import subtotals from adjacent ISOs or portion of an ISO subject to the RGGI CO_2 Budget Trading Program were not included when rolling up the individual ISO data into regional summary totals, as the electricity and CO_2 emissions represented by these net imports are included in the electric generation subtotals for each ISO. In rolling up total regional net imports, NYISO net imports from PJM represent a prorated portion of total net imports from PJM that are assumed to originate from the non-RGGI geographic portion of PJM. For each year, this proration is based on the percentage of total PJM MWh generation that occurred in the non-RGGI geographic portion of PJM.

Monitoring Limitations

The monitoring approach used in this report is subject to certain inherent limitations. These limitations primarily involve tracking for the PJM ISO, as well as how net exports from PJM to NYISO are addressed when rolling up ISO-specific data into regional totals.

For ISO-NE and NYISO, net electricity import data is based on the tracking of actual electricity flows between adjacent control areas.[16] This type of tracking is not possible for the RGGI portion of PJM, as PJM is dispatched as a single control area and electricity flows between geographic subsets of PJM on a state-by-state basis are not available. As a result, “electricity imports” into the four-state RGGI portion of PJM (Delaware, Maryland, New Jersey, and Virginia) from the rest of PJM must be inferred.

This also means that net electricity exports from the non-RGGI portion of PJM into NYISO cannot be determined based on actual electricity flows, as the actual monitored flows of electricity between PJM and NYISO do not allow for a differentiation between these two geographic subsets of PJM. As a result, certain assumptions must be made to prorate the portion of net exports from the non-RGGI portion of PJM into NYISO. For this report, this proration is based on the annual percentage of electric generation in the non-RGGI portion of PJM for a respective reporting year as a percentage of total PJM generation for that year. The actual monitored net electricity flows from PJM into NYISO are multiplied by this percentage to derive an estimate of net electricity exports from

[15] This category of data does not technically represent an import of electricity, as PJM is dispatched as a single control area.
[16] The exception is net import data from Hydro Quebec into NYISO, which represents net scheduled electricity imports.

non-RGGI PJM into NYISO. These assumed flows may not be fully representative of the actual electric generation source of net exports from non-RGGI PJM into NYISO.

A more modest monitoring limitation involves the electric generation data tracked by the three ISOs. ISO tracking does not include electric generation that is not dispatched into the ISO. This typically involves the portion of industrial cogeneration of electricity used on-site at industrial facilities as well as smaller distributed combined heat and power and renewable energy generation, which is sometimes referred to as "behind-the-meter" generation.[17]

V. Monitoring Results

Monitoring results are provided in this section for the RGGI Region. These results provide a compilation of data from each ISO fully or partially subject to the RGGI CO_2 Budget Trading Program: ISO-NE, NYISO, and PJM. ISO-NE and NYISO are fully subject to RGGI. For PJM, monitoring data is compiled for the four-state portion of PJM subject to RGGI (Delaware, Maryland, New Jersey, and Virginia). Monitoring data for each ISO is presented in Appendix B.

Monitoring results for the RGGI Region for 2006 through 2023 are summarized in Table 1.[18]

[17] See footnote 6.

[18] Note that reported regional net electricity imports represent net imports from adjacent control areas or a portion of a control area not subject to the RGGI CO_2 Budget Trading Program. As a result, the net electricity imports and related CO_2 emissions as reported in tabular summaries for each ISO provided in Appendix B may not add up to the reported total regional net imports and related CO_2 emissions. This is because some of the individual ISO net import subtotals represent net imports from another ISO that is also subject to the RGGI CO_2 Budget Trading Program. In order to avoid inappropriate double counting of MWh and related CO_2 emissions, these net import subtotals were not included when rolling up the individual ISO data into regional summary totals, as the electricity and CO_2 emissions represented by these net imports are included in the electric generation subtotals for each ISO.

Table 1. 2006 – 2023 Monitoring Summary for the RGGI Region

Annual averages for 2006–2008 (baseline) and 2021-2023 represent the eleven-state RGGI Region; 2009–2011 and 2020 represent the ten-state region; and 2012–2019 represent the nine-state region.

	Electricity Serving In-Region Demand (MWh)							In-Region Electricity Generation (MWh)					*Summary Data*
MWh	**Total in RGGI**	**Net Imports - from Ontario to NYISO**	**Net Imports - from Quebec to NY & NE**	**Net Imports - from New Brunswick to NE**	**Net Imports - from non-RGGI PJM to NY**	**Net Imports - from non-RGGI PJM to RGGI PJM**	**Total Net Imports - from All Adjoining ISOs**	**RGGI-Affected Units**	**Non-RGGI Fossil Fuel-Fired Units**	**Non-Fossil Fuel-Fired Units**	**All Non-RGGI Units**	**All Units[19]**	**Non-RGGI Generation (Non-RGGI Generation within RGGI + Net Imports)**
2006	575,341,396	3,672,282	8,982,749	1,047,000	7,127,777	94,471,071	115,300,879	237,171,138	8,586,664	214,518,761	223,105,425	460,040,517	338,406,304
2007	587,583,886	2,637,442	11,912,292	896,000	7,583,487	91,096,901	114,126,122	253,427,269	9,031,667	211,215,555	220,247,222	473,457,764	334,373,344
2008	575,302,585	6,162,902	15,141,014	1,285,000	7,998,554	91,516,082	122,103,552	234,028,384	6,099,402	212,922,487	219,021,889	453,199,033	341,125,441
2009	448,024,418	6,463,657	17,065,805	1,569,000	7,073,143	56,299,698	88,471,303	170,193,462	6,878,516	182,940,955	189,819,471	359,553,115	278,290,774
2010	461,285,678	3,872,635	13,549,209	737,000	10,460,586	58,001,518	86,620,948	188,761,300	8,535,101	178,157,745	186,692,846	374,663,730	273,313,794
2011	455,494,331	3,318,681	18,681,204	846,000	9,566,928	55,406,781	87,819,594	178,659,038	8,384,905	182,172,364	190,557,269	367,674,737	278,376,863
2012	372,082,306	5,749,461	22,312,689	643,000	7,926,652	34,442,085	71,073,887	155,235,421	4,799,815	143,617,952	148,417,767	301,007,419	219,491,654
2013	374,872,244	7,593,954	24,566,017	3,711,000	8,700,473	35,843,247	80,414,691	145,869,082	2,007,905	150,478,150	152,486,055	294,458,553	232,900,746
2014	364,133,729	7,180,281	22,052,178	3,527,050	8,239,526	32,656,507	73,655,542	143,200,529	1,900,663	151,930,514	153,831,177	292,306,718	227,486,719
2015	365,508,854	8,302,624	22,375,396	4,108,000	7,144,877	35,680,933	77,611,830	145,083,447	1,918,121	147,569,738	149,487,859	289,855,382	227,099,689
2016	363,036,567	7,668,000	21,843,000	4,842,000	7,936,937	33,910,113	76,200,050	143,952,781	2,189,384	146,001,202	148,190,586	286,897,517	224,390,636
2017	352,974,095	7,720,948	25,290,091	4,305,000	7,551,092	35,770,266	80,637,398	122,751,238	2,423,227	156,000,097	158,423,325	273,959,695	239,060,722
2018	362,498,067	6,586,515	24,803,861	4,044,000	10,145,908	30,085,536	75,665,820	137,696,834	2,704,807	155,822,346	158,527,153	288,396,056	234,192,973
2019	349,348,654	6,504,484	23,188,032	3,233,000	10,623,631	32,136,849	75,685,996	121,206,951	5,255,907	155,896,924	161,152,831	273,980,264	236,838,827
2020	411,031,375	7,472,000	23,953,000	2,585,000	8,510,135	51,196,818	93,716,953	147,954,082	7,033,711	172,244,676	179,278,386	319,008,422	272,995,340
2021	540,603,673	5,666,080	24,427,857	2,598,000	10,161,996	81,775,715	124,629,648	212,767,313	6,949,787	205,699,251	212,649,038	417,665,029	337,278,685
2022	547,599,840	4,576,000	23,080,000	1,998,000	10,833,854	88,515,715	129,003,569	217,486,360	7,015,345	204,493,986	211,509,331	420,362,471	340,512,899
2023	529,976,163	3,976,000	13,200,000	1,943,000	13,987,234	82,731,330	115,837,564	212,155,901	6,185,513	206,621,025	212,806,538	415,817,799	328,644,101

[19] See Appendix A, Table 2, Table Note 1.

CO_2	Tons of CO_2 from Electricity Serving In-Region Demand							Tons of CO_2 from in-Region Electricity Generation					*Summary Data*
	Total in RGGI	**Net Imports - from Ontario to NYISO**	**Net Imports - from Quebec to NY & NE**	**Net Imports - from New Brunswick to NE**	**Net Imports - from non-RGGI PJM to NY**	**Net Imports - from non-RGGI PJM to RGGI PJM**	**Total Net Imports - from All Adjoining ISOs**	**RGGI-Affected Units**	**Non-RGGI Fossil Fuel-Fired Units**	**Non-Fossil Fuel-Fired Units**	**All Non-RGGI Units**	**All Units**	**Non-RGGI Generation Serving Load in ISO (Non-RGGI Generation within ISO + Net Imports)**
2006	288,202,644	769,120	39,607	547,053	4,520,246	59,911,033	65,787,059	196,899,415	2,823,523	22,692,647	25,516,170	222,415,585	91,303,229
2007	294,306,225	604,715	157,573	408,896	4,767,491	57,269,645	63,208,319	208,990,940	3,496,900	18,610,066	22,106,967	231,097,906	85,315,285
2008	271,611,447	1,154,884	41,725	736,564	4,979,177	56,969,639	63,881,990	183,246,713	2,551,322	21,931,423	24,482,745	207,729,458	88,364,735
2009	177,625,188	712,496	67,723	968,535	4,213,398	33,537,149	39,499,301	122,132,458	3,167,099	12,826,331	15,993,430	138,125,888	55,492,731
2010	196,597,792	554,950	37,339	406,202	6,339,400	35,150,499	42,488,390	135,539,916	3,803,201	14,766,284	18,569,485	154,109,402	61,057,875
2011	176,616,407	336,556	47,363	410,324	5,706,392	33,048,520	39,549,155	118,568,748	3,757,279	14,741,225	18,498,504	137,067,252	58,047,660
2012	135,245,703	602,081	66,408	297,690	4,287,069	18,627,737	23,880,985	94,444,691	2,326,801	14,593,226	16,920,027	111,364,718	40,801,012
2013	132,502,930	795,236	54,159	1,186,296	4,822,624	19,867,713	26,726,027	87,832,266	977,602	16,967,034	17,944,636	105,776,903	44,670,664
2014	130,934,994	603,144	34,032	1,088,614	4,534,250	17,971,031	24,231,071	88,388,059	755,832	17,560,032	18,315,864	106,703,923	42,546,935
2015	126,587,068	697,420	27,131	1,313,206	3,602,223	17,989,208	23,629,188	85,615,455	787,341	16,555,084	17,342,425	102,957,880	40,971,613
2016	122,037,120	337,392	28,893	1,761,339	3,908,557	16,699,087	22,735,269	81,757,562	808,151	16,736,138	17,544,289	99,301,851	40,279,558
2017	107,727,436	298,260	33,453	1,471,090	3,599,881	17,052,989	22,455,673	67,329,900	762,950	17,178,913	17,941,863	85,271,763	40,397,536
2018	112,572,773	45,447	35,544	1,248,169	4,692,013	13,913,167	19,934,339	73,787,322	845,883	18,005,228	18,851,111	92,638,433	38,785,451
2019	101,072,961	44,881	30,673	926,581	4,995,026	15,110,127	21,107,288	62,062,380	867,081	17,036,213	17,903,294	79,965,674	39,010,582
2020	118,703,387	63,811	39,605	826,348	3,880,520	23,345,135	28,155,419	73,371,853	1,092,426	16,083,690	17,176,116	90,547,968	45,331,535
2021	171,655,771	48,388	35,005	830,503	5,193,704	41,794,827	47,902,428	104,345,723	914,947	18,492,672	19,407,619	123,753,343	67,310,047
2022	176,969,236	39,079	30,530	726,798	5,464,407	44,645,785	50,906,599	105,805,182	1,031,332	19,226,124	20,257,456	126,062,638	71,164,054
2023	163,613,171	33,955	21,826	492,612	6,849,712	40,514,502	47,912,607	98,087,209	1,010,523	16,602,832	17,613,355	115,700,564	65,525,962

lb CO_2/ MWh	Emissions Rate for Electricity Serving In-Region Demand							Emissions Rate for In-Region Electricity Generation					*Summary Data*
	Total in RGGI	Net Imports - from Ontario to NYISO	Net Imports - from Quebec to NY & NE	Net Imports - from New Brunswick to NE	Net Imports - from non-RGGI PJM to NY	Net Imports - from non-RGGI PJM to RGGI PJM	Total Net Imports - from All Adjoining ISOs	RGGI-Affected Units	Non-RGGI Fossil Fuel-Fired Units	Non-Fossil Fuel-Fired Units	All Non-RGGI Units	All Units	Non-RGGI Generation Serving Load in ISO (Non-RGGI Generation within ISO + Net Imports)
2006	1,002	419	9	1,045	1,268	1,268	1,141	1,660	658	212	229	967	540
2007	1,002	459	26	913	1,257	1,257	1,108	1,649	774	176	201	976	510
2008	944	375	6	1,146	1,245	1,245	1,046	1,566	837	206	224	917	518
2009	793	220	8	1,235	1,191	1,191	893	1,435	921	140	169	768	399
2010	852	287	6	1,102	1,212	1,212	981	1,436	891	166	199	823	447
2011	775	203	5	970	1,193	1,193	901	1,327	896	162	194	746	417
2012	727	209	6	926	1,082	1,082	672	1,217	970	203	228	740	372
2013	707	209	4	639	1,109	1,109	665	1,204	974	226	235	718	372
2014	719	168	3	617	1,101	1,101	658	1,234	795	231	238	730	374
2015	693	168	2	639	1,008	1,008	609	1,180	821	224	232	710	361
2016	672	88	3	728	985	985	597	1,136	738	229	237	692	359
2017	610	77	3	683	953	953	557	1,097	630	220	227	623	338
2018	621	14	3	617	925	925	527	1,072	625	231	238	642	331
2019	579	14	3	573	940	940	558	1,024	330	219	222	584	329
2020	578	17	3	639	912	912	601	992	311	187	192	568	332
2021	635	17	3	639	1,022	1,022	769	981	263	180	183	593	399

2022	646	17	3	728	1,009	1,009	789	973	294	188	192	600	418
2023	617	17	3	507	979	979	827	925	327	161	166	556	399

RGGI Region 2021 to 2023 Annual Average Compared to Baseline

The monitoring results indicate that the 2021 to 2023 annual average electricity load in the RGGI Region decreased by 40.0 million MWh, or 6.9 percent, compared to the 2006 to 2008 base period. Annual average electric generation from all sources in the RGGI Region decreased by 35.9 million MWh, or 7.8 percent, compared to the base period.

Annual average electric generation from RGGI generation in 2021 to 2023 decreased by 27.4 million MWh, or 11.3 percent, compared to the three-year base period, and annual average CO_2 emissions from RGGI generation decreased by 93.6 million short tons, or 47.7 percent. The annual average CO_2 emission rate of RGGI generation decreased by 666 lb CO_2/MWh from 1,625 to 959 lb CO_2/MWh, a decrease of 41.0 percent.

Annual average electric generation from non-RGGI generation sources located in the ten-state RGGI Region decreased by 8.5 million MWh, or 3.8 percent, during this period, and annual average CO_2 emissions from this category decreased by 4.9 million short tons, or 20.6 percent. The annual average CO_2 emission rate of non-RGGI electric generation located in the RGGI Region decreased by 37.8 lb CO_2/MWh, or 17.4 percent.

For 2021 to 2023, annual average electric generation from all non-RGGI electric generation serving load in the RGGI Region decreased by 2.5 million MWh, a decrease of 0.7 percent, compared to the annual average generation for the base period. The CO_2 emissions from this category decreased by 20.3 million short tons, a reduction of 23.0 percent, and the CO_2 emission rate decreased by 117 lb CO_2/MWh from 523 to 405 lb CO_2/MWh, a reduction of 22.4 percent.

Annual average net electricity imports into the RGGI Region increased by 6.0 million MWh, or 5.1 percent, in 2021 to 2023 compared to the 2006 to 2008 base period. CO_2 emissions related to these net electricity imports during this period decreased by 15.4 million short tons, or 23.9 percent, and the average CO_2 emission rate of the electric generation supplying these imports decreased by 303 lb CO_2/MWh from 1,098 to 795 lb CO_2/MWh, a reduction of 27.6 percent.

RGGI Region 2023 Annual Average Compared to Baseline

The monitoring results indicate the 2023 annual average electricity load in the RGGI Region decreased by 49.4 million MWh, or 8.5 percent, compared to the 2006 to 2008 base period. The annual average 2023 electric generation from all sources in the RGGI Region decreased by 37.4 million MWh, or 8.1 percent, compared to the base period.

Compared to the annual average during the 2006 to 2008 base period, 2023 RGGI generation decreased by 29.4 million MWh, or 12.2 percent, and CO_2 emissions from RGGI generation decreased by 98.3 million short tons of CO_2, or 50.1 percent. Compared to the base period, the CO_2 emission rate of RGGI electric generation in 2023 decreased by 701 lb CO_2/MWh from 1,625 to 925 lb CO_2/MWh, a reduction of 43.1 percent.

Compared to the annual average during the 2006 to 2008 base period, 2023 electric generation from non-RGGI generation sources located in the RGGI Region decreased by 8.0 million MWh, or 3.6 percent. CO_2 emissions from this category decreased by 6.4

million short tons, or 26.7 percent, and the CO_2 emission rate decreased by 52.1 lb CO_2/MWh from 218 to 166 lb CO_2/MWh, or 24.0 percent.

For 2023, annual average electric generation from all non-RGGI electric generation serving load in the RGGI Region decreased by 9.3 million MWh, a decrease of 2.8 percent, compared to the annual average generation for the base period. The CO_2 emissions from this category decreased by 22.8 million short tons, or 25.8 percent, and the CO_2 emission rate decreased by 124 lb CO_2/MWh from 523 to 399 lb CO2/MWh, a reduction of 23.7 percent. (See Figures 10, 11, and 12.)

Compared to the annual average during the 2006 to 2008 base period, 2023 net electricity imports into the RGGI Region decreased by 1.3 million MWh, or 1.1 percent (See Figure 13). CO_2 emissions related to these net electricity imports decreased by 16.4 million short tons of CO_2, or 25.4 percent, during this period. (See Figure 14). The average CO_2 emission rate of the electric generation supplying these imports decreased by 271 lb CO_2/MWh from 1,098 to 827 lb CO_2/MWh, a reduction of 24.7 percent.

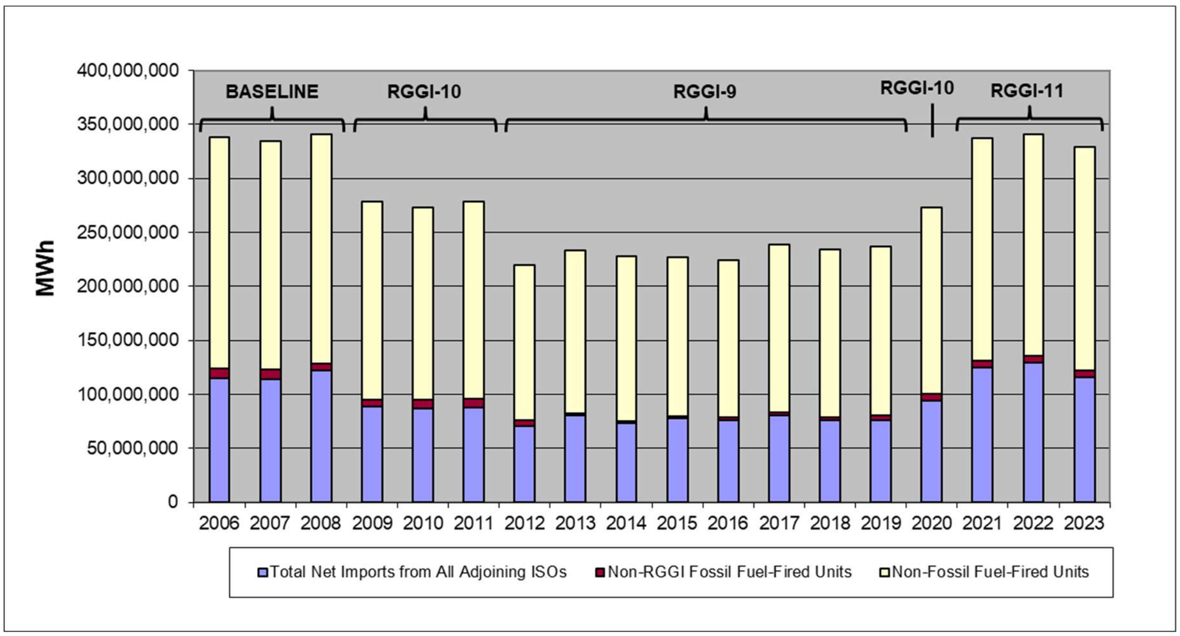

Figure 10. Non-RGGI Generation Serving Load in the RGGI Region (MWh). Annual averages for baseline years and 2021 to 2023 represent RGGI-11; 2009 to 2011 and 2020 represent RGGI-10; 2012 to 2019 represent RGGI-9.

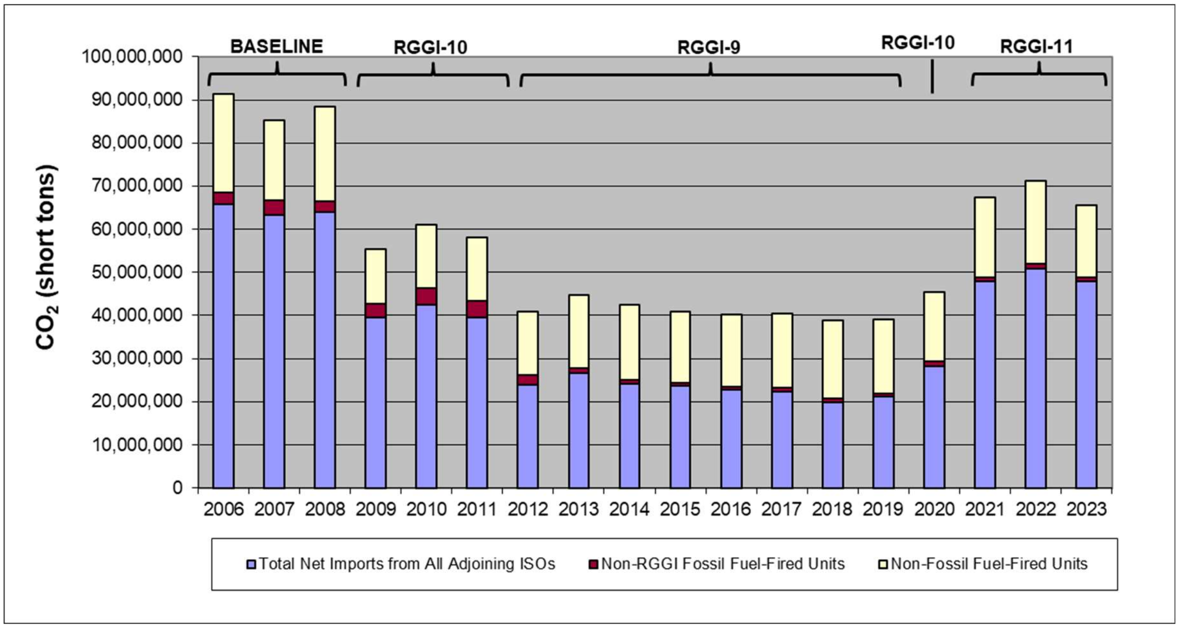

Figure 11. CO_2 Emissions from Non-RGGI Generation Serving Load in the RGGI Region (short tons CO_2). Annual averages for baseline years and 2021 to 2023 represent RGGI-11; 2009 to 2011 and 2020 represent RGGI-10; 2012 to 2019 represent RGGI-9.

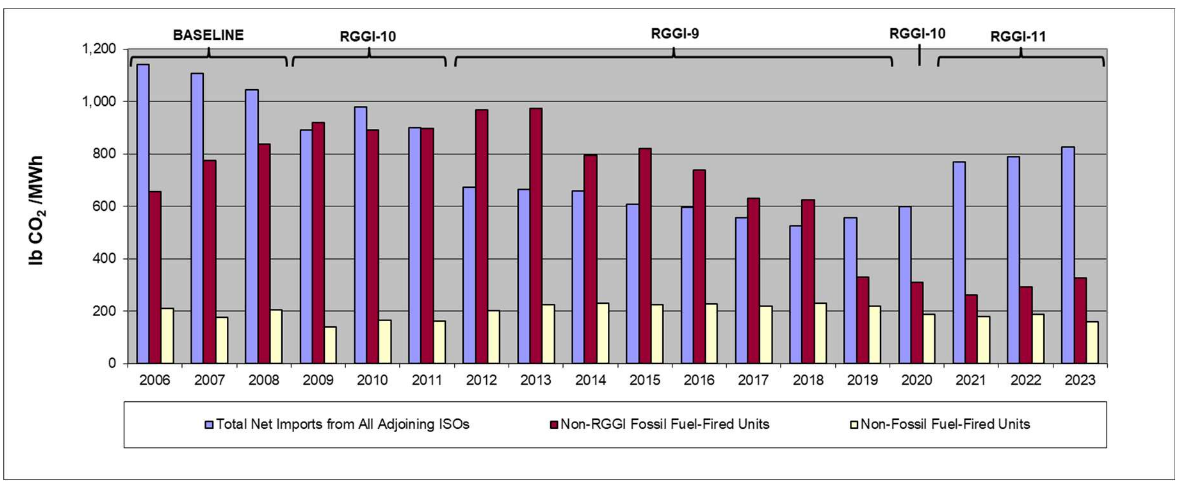

Figure 12. CO_2 Emission Rate for Non-RGGI Generation Serving Load in the RGGI Region (lb CO_2/MWh). Annual averages for baseline years and 2021 to 2023 represent RGGI-11; 2009 to 2011 and 2020 represent RGGI-10; 2012 to 2019 represent RGGI-9.

\

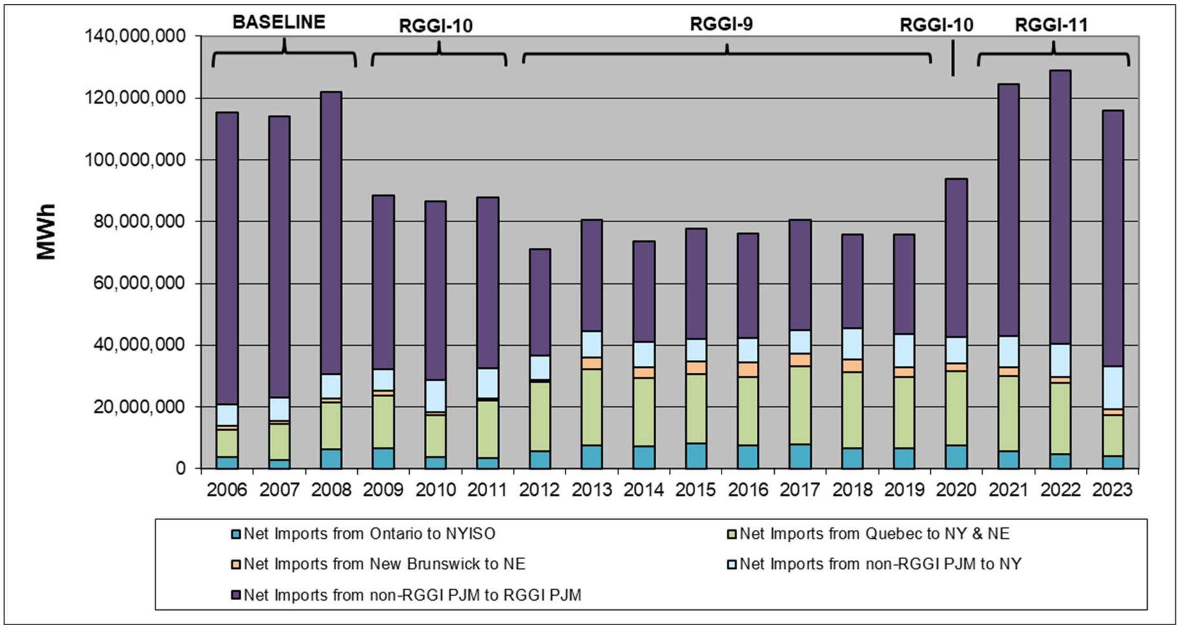

Figure 13. Net Electricity Imports to the RGGI Region (MWh). Annual averages for baseline years and 2021 to 2023 represent RGGI-11; 2009 to 2011 and 2020 represent RGGI-10; 2012 to 2019 represent RGGI-9.

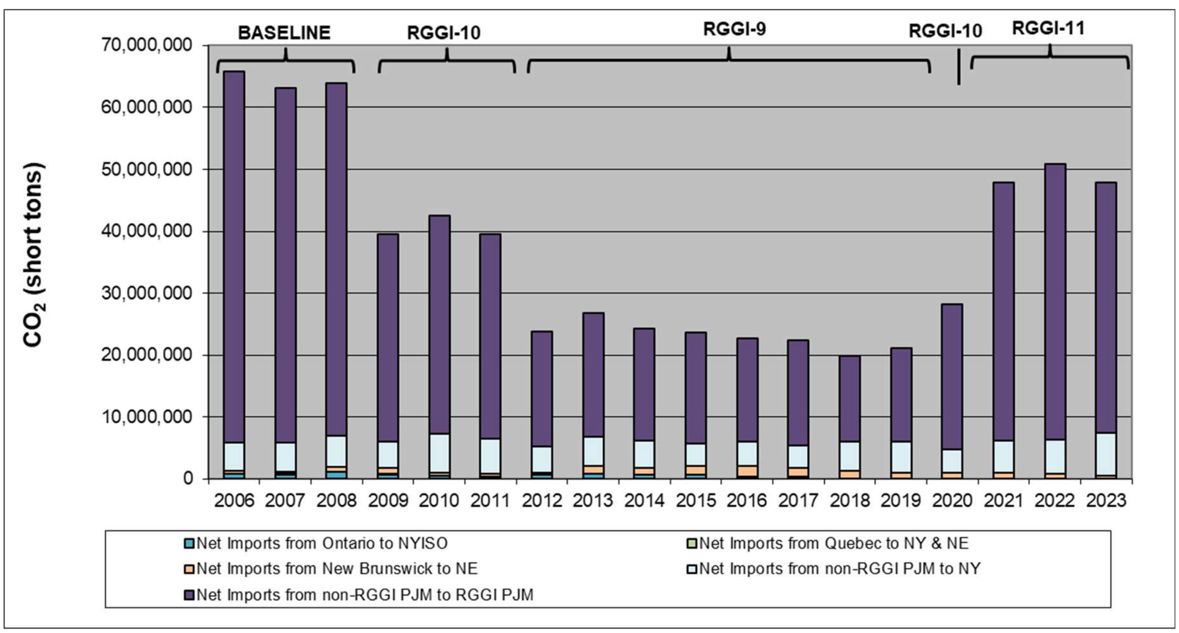

Figure 14. CO_2 Emissions Related to Net Electricity Imports to the RGGI Region (short tons CO_2). Annual averages for baseline years and 2021 to 2023 represent RGGI-11; 2009 to 2011 and 2020 represent RGGI-10; 2012 to 2019 represent RGGI-9.

VI. Discussion

As mentioned earlier in this report, multiple market factors interact to influence the dispatch of electric generation. CO_2 allowance costs have been relatively modest compared to other factors that impact wholesale electricity prices.

The wholesale electricity price is paid by market participants such as utilities, who then supply power to end-use retail consumers at retail rates. Retail rates are influenced by the wholesale price, but also include other costs such as delivery charges, administrative costs, and premiums for shielding retail rates from wholesale price volatility. Retail rates vary by state and are approved by state public utility commissions. Finally, consumer energy bills depend not just on the retail rate, but on the amount of power used by the end-use consumer. Improved energy efficiency can cause consumer bills to decline even as wholesale and/or retail rates increase. Without taking any of RGGI's benefits into account, CO_2 allowance costs accounted for 9.7 percent of the average all-in wholesale electricity price for ISO-NE, 19.2 percent of the average all-in wholesale electricity price for the New York Control Area (NYCA)[20], and 6.2 percent of the average all-in locational marginal price on a per MWh basis for PJM in 2023.[21] However, the wholesale price is only one of many factors which determine the amount that consumers pay.

When RGGI's benefits are taken into account, independent reports indicate that RGGI is generating net bill savings for consumers. Independent reports from the Analysis Group studied RGGI's first, second, third, and fourth three-year control periods, finding that RGGI is reducing consumer energy bills and generating net economic benefits on the order of $5 billion.[22] In particular, the reports found that energy efficiency programs funded by RGGI investments reduce demand for electricity, resulting not only in direct savings for those consumers making the efficiency investments, but also in downward pressure on wholesale prices that reduce costs for all electricity ratepayers. The Analysis Group reports also do not include additional potential economic gains from co-benefits such as public health improvements and avoided climate change impacts.

[20] NYISO refers to the New York Independent System Operator, which is the organization responsible for managing New York's electricity grid. The New York Control Area (NYCA) refers to the physical area that falls under NYISO's jurisdiction. Throughout the report the terms are used interchangeably.

[21] For 2023, the average all-in wholesale electricity price was $50.10/MWh for ISO-NE and $39.12/MWh for the NYCA, and the load-weighted average locational marginal price was $31.08/MWh for PJM (energy only) (see *ISO-NE Monthly Wholesale Load Cost Report; NYISO Power Trends 2024; 2023 State of the Market Report for PJM)*. The CO_2 allowance component is based on a 2023 average CO_2 allowance spot price of $13.58 per CO_2 allowance (See Potomac Economics, *Annual Report on the Market for RGGI CO_2 Allowances: 2023*). For PJM, the CO_2 allowance component of the Locational Marginal Price (LMP) for 2023 was $1.93 per MWh (See *2023 State of the Market Report for PJM*). ISO-NE and the NYCA do not report the CO_2 allowance component of wholesale electricity prices. The New England and New York analyses used a 2023 average CO_2 allowance spot price of $13.58 as a starting point for deriving a CO_2 allowance wholesale price component. For both ISO-NE and the NYCA, the CO_2 emission rate of the assumed marginal unit was used to translate the annual average spot price for CO_2 allowances into a dollar per MWh value. For ISO-NE, this resulted in an average CO_2 allowance wholesale price component of approximately $4.85 per MWh. For the NYCA, this resulted in an average CO_2 allowance wholesale price component of $7.51 per MWh.

[22] "The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States." Analysis Group. May 2023.
"The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeastern and Mid-Atlantic States." Analysis Group. April 2018.
"The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeastern and Mid-Atlantic States." Analysis Group. July 2015.
"The Economic Impact of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States." Analysis Group. November 2011.

Wholesale prices fell from 2008 to 2010. In 2010, higher fuel prices, increased economic activity, and hot weather led to an increase in wholesale prices in 2010 relative to 2009. Average electricity prices decreased in 2011 relative to 2010, primarily due to a decrease in natural gas prices and mild winter temperatures in late 2011.[23] This decline in electricity prices continued through 2012 as the price of natural gas continued to fall and temperatures remained mild through the winter. Higher natural gas prices, especially during winter months, resulted in higher electricity prices in 2013.[24] The first quarter of 2014 saw cold weather, with milder weather experienced in the following three quarters, and the net effect was an overall increase in prices in 2014[25]. Wholesale prices fell in 2015 and then reached a low in 2016 due to a warm winter that resulted in less demand for natural gas.[26] 2017 saw a slight increase in wholesale prices across the three ISOs. Cold temperatures in early 2018 raised natural gas prices, which further increased average electricity prices in 2018.[27] In 2019, wholesale prices decreased in all ISOs, with prices dropping to a record low in the NYCA's market.[28] This was due to a mild summer, resulting in lower demand, and reductions in natural gas prices, which decreased by 20 to 40 percent from 2018 to 2019 depending on the region.[29]

Annual averages and wholesale prices for calendar year 2020 were greatly affected by COVID-19, making 2020 a unique year. Starting in the spring there were work-from-home and social-distancing measures, travel restrictions, and the closing of businesses, which affected energy supply and demand. After accounting for weather, cumulative load in PJM was 3.4 percent lower when compared to 2019.[30] The NYCA also noted a significant decrease, falling as low as 10 percent lower than expected levels, then increasing in late summer and fall but still lower than forecasted levels.[31] While there was a significant decrease in demand from commercial customers, there was a rise in in residential use, affecting daily load patterns -- the NYCA saw an increase in demand in residential areas, such as Long Island.

Although wholesale electricity prices hit record lows in 2020, market prices rebounded in 2021 due to an increase of natural gas prices, higher demand for electricity, and extreme weather. In the NYCA, electricity demand increased by almost 1.5 percent from 2020 to 2021[32], while average natural gas prices more than doubled due to liquified natural gas exports growing faster than domestic production[33]. Additionally, transmission congestion and fluctuations in capacity requirements, driven by generator retirements in New York, further contributed to price increases.[34] Of PJM's increase in average LMP, 72.7 percent was driven by increased fuel and emissions costs, primarily due to higher natural gas prices.[35] ISO-NE, where natural gas has been the primary fuel type of the past five years[36], experienced a 38 percent increase in cooling degree days and a 10 percent

[23] See, for example, Monitoring Analytics, *2011 State of the Market Report for PJM*, Section 1, Introduction.
[24] See, for example, *NYISO 2013 Annual Report*, p. 13.
[25] See, for example *NYISO 2014 Annual Report,* p. ii.
[26] See, for example, *ISO-NE 2018 Annual Markets Report*, p. 4.
[27] See, for example, *NYISO Power Trends 2019,* p. 30.
[28] See, for example, *NYISO Power Trends, 2020*, p. 7
[29] Potomac Economics, *2019 State of the Market Report for the New York ISO Markets*, p. 4.
[30] Monitoring Analytics, *2020 State of the Market for PJM*; Volume 2, Energy Market, p. 2.
[31] Potomac Economics, *2020 State of the Market Report for the New York ISO Markets*, p. 11.
[32] *NYISO Power Trends, 2022,* p. 27
[33] Potomac Economics, *2021 State of the Market Report for New York ISO Markets,* p. i.
[34] Potomac Economics, *2021 State of the Market Report for New York ISO Markets,* p. 4.
[35] Monitoring Analytics, *2021 State of the Market for PJM*; Volume 2, Energy Market, p. 1.
[36] *ISO-NE 2021 Air Emissions Report,* p. 20.

increase in heating degree days, which affected net energy load and generation.[37] Furthermore, Texas' winter storm in February 2021 caused rippled effects across the country, spiking energy prices as supply shortages impacted multiple regions.[38]

These trends continued into 2022, when wholesale electricity prices reached the highest levels in more than a decade across all three ISOs[39]. In the NYCA, wholesale electricity prices were also impacted by the accelerated deactivation of fossil fuel generators in response to the "Peaker Rule", which reduced the margin between supply and demand.[40] The contribution of natural gas expenses to the total energy price of electricity continued to rise, almost doubled from 2021 to 2022 in the region[41], driven by the conflict between Russia and Ukraine, which heightened global uncertainty around natural gas inventories and prices, while significantly expanding the demand for LNG production and export to satisfy European demand.[42]

Following the spike in wholesale electricity prices in 2022, each ISO in the RGGI Region experienced a sharp decrease in 2023. In PJM, this was the largest decline observed since 1999, driven primarily by lower costs for fuel (natural gas, coal, and oil), emissions allowances, and other consumables.[43] NYCA saw a reduction in wholesale electricity prices consistent with lower natural gas prices.[44] ISO-NE experienced a milder winter and summer, and a shift in generation mix, including an increase of natural gas and hydro generation.[45]

A number of market drivers have changed dramatically during the 2006 through 2022 monitoring timeframe. These changes are due to several factors, including additional investments in energy efficiency and renewable energy (funded in part by RGGI auction proceeds); complementary state clean energy programs and policies; lower natural gas prices (changes in relative fuel prices); changes in the generation mix, including additional renewable generation; and weather trends. An analysis of these changes, and their estimated impact on CO_2 emissions in the ten-state RGGI Region from 2006 to 2009, was completed by the New York State Energy Research and Development Authority (NYSERDA).[46] A 2015 peer-reviewed study in the journal *Energy Economics* examined a similar set of factors and found that RGGI played a significant role in the observed emissions decline in the region.[47] A 2019 research report by the Congressional Research Service cited both studies towards a conclusion that the RGGI cap, the market signal sent by the allowance price, and the reinvestment of proceeds have worked

[37] *ISO-NE 2021 Air Emissions Report,* p. 2.

[38] Monitoring Analytics, *2021 State of the Market for PJM*; Volume 2, Energy Market, p. 440.

[39] Monitoring Analytics, *2022 State of the Market for PJM*; Volume 2, Energy Market, p. 3, *NYISO Power Trends, 2023,* p. 25,

[40] *NYISO Power Trends, 2023,* p. 7.

[41] Potomac Economics, *2022 State of the Market Report for New York ISO Markets,* p. i,

[42] *NYISO Power Trends, 2023*, p. 27, *ISO-NE 2022 Air Emissions Report,* p. 2.

[43] Monitoring Analytics, *2023 State of the Market for PJM*; Volume 2, Energy Market, p. 4.

[44] *NYISO Power Trends, 2024,* p. 33.

[45] *2023 ISO New England Electric Generator Air Emissions Report,* p.2.

[46] New York State Energy Research and Development Authority (NYSERDA), *Relative Effects of Various Factors on RGGI Electricity Sector CO_2 Emissions: 2009 Compared to 2006*, November 2010; available at Retrospective_Analysis_Draft_White_Paper.pdf.

[47] Murray, Brian C. and Peter T. Maniloff. "Why Have Greenhouse Emissions in RGGI States Declined? An Econometric Attribution to Economic, Energy Market, and Policy Factors." *Energy Economics*. August 2015.

together to help support a shift towards cleaner generation and regional emissions reductions.[48]

A key factor impacting the potential for emissions leakage is the relative cost of electric generation inside and outside the RGGI Region (both with and without the incorporation of CO_2 allowance costs), and the relationship of this cost differential with physical transmission capability, the all-in market costs of inter-region power transmission, and the market impacts of transferring significant incremental amounts of power into the RGGI Region. The dynamic and highly specific nature of market factors and physical constraints that may cause or mitigate emissions leakage make both a retrospective analysis and future projections of emissions leakage difficult. The factors that may result in emissions leakage are likely to be both temporally and geographically specific.

The dynamics of a competitive wholesale electricity market could drive emissions leakage if there is a sufficient net financial incentive to shift electric generation to units not subject to CO_2 regulation. The extent of this impact is likely to depend, at least in part, on the market value of CO_2 allowances (and the related \$/MWh CO_2 costs incorporated into bids by generators subject to the RGGI CO_2 Budget Trading Program) in relation to other economic factors associated with the generation and delivery of electricity. If the cost of RGGI CO_2 compliance on a per MWh basis is lower than the aggregate per MWh price signal of mitigating market factors, which are discussed below, no net market dynamic driving emissions leakage would be expected to occur. Market factors that may impact the economics of importing incremental power in response to a CO_2 allowance price signal[49] include:

- ***Existing Generator Economics****:* Including a CO_2 compliance cost into the generation costs of an individual electric generator may make that generator uneconomic relative to a competitor. Whether this occurs depends on the operating costs of each electric generator, both with and without CO_2 compliance costs. Key factors that influence electric generator operating costs include fuel prices, generator heat rate (Btu of fuel input per kWh of electric generation output), and costs for air pollutant emissions such as nitrogen oxides (NO_X), sulfur dioxide (SO_2), and CO_2. As a result, inclusion of a CO_2 allowance cost must be sufficient to supplant any preexisting generator cost differentials in order to shift generation from a RGGI source to a non-RGGI source.

- ***Existing Locational Generation Price Differentials***: Locational Marginal Pricing (LMP) can be expected to affect the market response to the imposition of a CO_2 allowance cost adder to generation in the RGGI Region. LMP is the cost of supplying the last MWh of generation dispatched at a specific location, which reflects transmission constraints and the marginal cost of generation units. LMP is based on the principle that the generation of power has different values at different points in the electric power network. Transmission resources are finite, and transmission "congestion" occurs when available, low-cost electric generation supply cannot be delivered to the demand location due to transmission network limitations. When electricity from the least-cost electric generation source in a region cannot be delivered to electricity load in a

[48] Congressional Research Service. *The Regional Greenhouse Gas Initiative: Lessons Learned and Issues for Congress,* July 2019, available at https://fas.org/sgp/crs/misc/R41836.pdf.
[49] Some of these factors may also impact the economics of shifting dispatch to smaller in-region fossil fuel-fired electric generation in the RGGI region that is not subject to regulation of CO_2.

transmission-constrained area, higher cost units in this constrained area are dispatched to meet that load. The result is that the wholesale price of electricity in the constrained area is higher than in the unconstrained area.

Differential LMPs between regions represent the presence of transmission constraints and line losses that require the dispatch of higher priced electric generation in a certain region. Electricity demand can have a large impact on LMPs in a specific region.

- ***Congestion Charges***: Congestion charges and the standard cost of transmitting electricity may make significant incremental imports into the RGGI Region uneconomic as a response to a modest generation price differential resulting from RGGI CO_2 allowance costs. As an example, in PJM, power transmission is subject to congestion charges, which are based on the difference between LMPs at the source (generator location, or "generator bus") and LMPs at the sink (electric distribution utility location, or "load serving entity (LSE) bus"). Thus, in addition to standard transmission charges, entities importing power into the RGGI Region would need to pay congestion charges based on the differential between LMPs in the uncapped non-RGGI Region where the generator is located and LMPs in the capped RGGI Region where the electricity is delivered.[50]

- ***Line loss charges***: The greater the distance that electricity is transmitted, and the more power transmitted through a power line, the greater the loss of the power initially put into the line, based on the physics of the electricity transmission network. As a result, the costs of transmission line-losses impact the economics of importing power. In PJM, line losses are accounted for in the calculation of LMP through the application of a line loss "penalty factor." If the dispatch of an electric generator would result in an increase in system line losses in a certain location, a positive penalty factor is applied to the generator's bid into the wholesale market, making the unit look less economically attractive to dispatch.[51]

- ***Long-Term Contracts***: Existing long-term power purchase agreements can be expected to mitigate emissions leakage. These agreements mandate the purchase of power from particular sources for pre-set time periods, delaying the response to changes in market conditions.

- ***Reliability Constraints***: Reliability constraints also play a role in determining the dispatch of electric generation units, to the extent that units supply needed generation capacity and ancillary services in a specified region or location on the electricity grid.

[50] For example, the congestion component of the 2022 average day-ahead, load weighted LMP in the Delmarva Power & Light zone (Delaware and Maryland) of PJM was -$2.13 per MWh. For the Baltimore Gas & Electric zone (Maryland), the congestion component was $7.60 per MWh. Source: Monitoring Analytics, *2023 State of the Market for PJM*; Section 11, Table 11-6, p. 622.

[51] For example, the line loss component of the 2022 average day-ahead, load weighted LMP in the Delmarva Power & Light zone (Delaware and Maryland) of PJM was $0.62 per MWh. Similarly, for the Baltimore Gas & Electric zone (Maryland), the line loss component of LMP was $1.15 per MWh. Source: Monitoring Analytics, *2023 State of the Market for PJM*; Section 11, Table 11-6, p. 622.

- ***Other Factors***: Other relevant factors may include standard transmission pricing, relative fuel prices, natural gas supply and costs that can be influenced by pipeline constraints, and relative heat rates of generation units.[52]

VII. Conclusions

This report presents data and trends for electricity generation, net electricity imports, and related CO_2 emissions of electric generation serving load in the RGGI Region without assigning causality to any one of the factors influencing observed trends. Monitoring results show that there has been a decrease in the amount of non-RGGI electric generation serving load in the RGGI Region and the CO_2 emissions rate of this generation. Overall, the monitoring results show that there has been a 23.0 percent decrease in average annual CO_2 emissions from non-RGGI electric generation serving load in the RGGI Region during the period of 2021 to 2023 when compared to the annual average annual CO_2 emissions during the base period of 2006 to 2008, and a 25.8 percent decrease in the calendar year 2023 when compared to the base period.

Emissions leakage may manifest through an increase in CO_2 emissions from this aggregate category of non-RGGI electric generation, all other factors being equal. However, given that the monitoring results presented in this report do not address causality, the results should be evaluated in context with market dynamics. Changes in factors such as electricity demand, relative fossil fuel prices, and wholesale electricity prices, can also play a role in changing emissions and generation trends.

When taking only costs into account and not including RGGI's economic benefits, the average CO_2 allowance price in 2023 represented approximately 19.2 percent or less of the average wholesale electricity price and/or average all-in locational marginal price in the three ISOs fully or partially subject to RGGI. The monitoring results are consistent with market dynamics given the CO_2 allowance prices that result in CO_2 compliance costs on a per MWh basis. The price signal from RGGI allowances prices is likely lower than the aggregate per MWh price signal of mitigating market factors discussed in this report that would counter emissions leakage.

This report is the fifteenth in a series of annual monitoring reports, as called for in the 2005 RGGI MOU. Ongoing monitoring will further evaluate changes in market and non-market drivers that impact CO_2 emissions related to electricity generation and imports in the RGGI Region.

[52] Heat rate is a measure of electric generator energy efficiency, represented as Btu of fuel input per kWh of electricity output.

Appendix A. ISO Monitoring Sources

Table 2. Summary of Data Sources for ISO-NE

	Electricity Demand (Annual)					*Electricity Generation (Annual)*				
Code	**A-1**	**A-2**	**A-2**	**A-2**	**A-3**	**B-1**	**B-2**	**B-3**	**B-4**	**B-5**
Monitoring Category	Total Electricity Use in ISO-NE	Net Electricity Imports - from New York	Net Electricity Imports - from Quebec	Net Electricity Imports - from New Brunswick	Total Net Electricity Imports - from All Adjoining ISOs	RGGI-Affected Units	Non-RGGI Units (Fossil Fuel-Fired)	Non-RGGI Units (Non-Fossil Fuel-Fired)	All Non-RGGI Units (Fossil and Non-Fossil)	All Units
MWh	ISO-NE[1]	NYS PSC Calculation (2014-2018) ISO-NE[1] (2019-2023)	ISO-NE[1]	ISO-NE[1]	Sum of A2s	NEPOOL-GIS[2]	NEPOOL-GIS[2]	NEPOOL-GIS[2]	Sum of B-2 and B-3	ISO-NE[1]
CO_2 Tons	Sum of A-3 and B-5	MWh multiplied by CO_2/MWh	MWh multiplied by CO_2/MWh	MWh multiplied by CO_2/MWh	Sum of A-2s	State reported data for 2006-2008; RGGI COATS for 2009 to 2023.[4] Includes only sources subject to a state CO_2 Budget Trading Program CO_2 allowance compliance obligation. Does not include biomass-derived CO_2 emissions.	NEPOOL-GIS[2]	NEPOOL-GIS[2]	Sum of B-2 and B-3	Sum of B-1 and B-4
CO_2 lb/MWh	CO_2 tons divided by MWh	NYISO A-2 in Table 3 below	Environment and Climate Change Canada[3]	Environment and Climate Change Canada[3]	CO_2 tons divided by MWh	CO_2 tons divided by MWh	CO_2 tons divided by MWh	CO_2 tons divided by MWh	CO_2 tons divided by MWh	CO_2 tons divided by MWh

Table Notes:
1. ISO-NE, Historical Data Reports, "Net Energy and Peak Load by Source" (Annual Summary). Available at https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/net-ener-peak-load. Note that B-5 MWh calculated as the sum of the above NEPOOL GIS-based B-1 to B-4 will differ from B-5 MWh from the ISO-NE website, as the website is updated if errors found, while NEPOOL GIS data is frozen at time of certificate creation.
2. NEPOOL Generation Information System. Available at https://www.nepoolgis.com/.
3. *National Inventory Report 1990–2023: Greenhouse Gas Sources and Sinks in Canada*, Environment and Climate Change Canada, 2025. In Part 3. Available at https://unfccc.int/sites/default/files/resource/2025NIR%20-%20Part%203.pdf. Note that New Brunswick and Quebec emission factors are updated for every year, as compared to the previous year's report.
4. Historical 2006 – 2008 CO_2 emissions data reported by RGGI participating states compiled from CO_2 emissions data reported to U.S. EPA pursuant 40 CFR Part 75 and from CO_2 emissions and fuel use data reported to state emissions statement programs. 2009 through 2023 CO_2 emissions data is from data reported to the RGGI CO_2 Allowance Tracking System (RGGI COATS), available at rggi-coats.org.

Table 3. Summary of Data Sources for NYISO

	Electricity Demand (Annual)						*Electricity Generation (Annual)*				
Code	**A-1**	**A-2**	**A-2**	**A-2**	**A-2**	**A-3**	**B-1**	**B-2**	**B-3**	**B-4**	**B-5**
Monitoring Category	Total Electricity Use in NYISO	Net Electricity Imports - from Hydro Quebec	Net Electricity Imports - from ISO-NE	Net Electricity Imports - from Ontario	Net Electricity Imports - from PJM	Total Net Electricity Imports - from All Adjoining ISOs	RGGI-Affected Units	Non-RGGI Units (Fossil Fuel-Fired)	Non-RGGI Units (Non-Fossil Fuel-Fired)	All Non-RGGI Units (Fossil and Non-Fossil)	All Units
MWh	NYS PSC Calculation/Gold Book (2006-2015); NYGATS from NYISO/Gold Book (2016-2023)	Hydro Quebec[1]/Gold Book (2006-2015); NYGATS from NYISO/Gold Book (2016-2023)	ISO-NE[2]/Gold Book (2006-2015); NYGATS from NYISO/NEPOOL GIS/Gold Book(2016-2023)	Ontario Independent Electricity System Operator[3]	PJM Annual State of the Market Report[4]	Sum of A-2s	NYS PSC Calculation[5] (2006-2015); NYISO/Gold Book (2016-2023)	NYS PSC Calculation [5,8] (2006-2015); NYISO/Gold Book(2016-2023)	NYS PSC Calculation[5] (2006-2015); NYISO/Gold Book(2016-2023)	Sum of B-2 and B-3	Sum of B-1 and B-4
CO_2 Tons	Sum of A-3 and B-5	MWh multiplied by CO_2/MWh	MWh multiplied by CO_2/MWh	MWh multiplied by CO_2/MWh	MWh multiplied by CO_2/MWh	Sum of A-2s	MWh multiplied by CO_2/MWh	MWh multiplied by CO_2/MWh	MWh multiplied by CO_2/MWh	Sum of B-2 and B-3	Sum of B-1 and B-4
CO_2 lb/MWh	CO_2 tons divided by MWh	Environment and Climate Change Canada[6]	ISO-NE system average (2006-2015); NYS PSC Calculation (2016-2023)	Environment and Climate Change Canada[6]	PJM GATS[7]	CO_2 tons divided by MWh	NYS PSC Calculation	NYS PSC Calculation	NYS PSC Calculation	CO_2 tons divided by MWh	CO_2 tons divided by MWh

Table Notes:

1. Hydro Quebec response to information request.
2. ISO-NE, Historical Data Reports, "Net Energy and Peak Load by Source" (Annual Summary). Available at https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/net-ener-peak-load.
3. Ontario IESO response to information request.
4. Monitoring Analytics, *State of the Market for PJM* (2006 through 2023 reports).
5. NYS PSC calculation based on MWh for each generator reported by NYISO and assignment of each generator to appropriate monitoring classification.
6. *National Inventory Report 1990–2023: Greenhouse Gas Sources and Sinks in Canada*, Environment and Climate Change Canada, 2025. In Part 3. Available at https://unfccc.int/sites/default/files/resource/2025NIR%20-%20Part%203.pdf. Note that New Brunswick and Quebec emission factors are updated for every year, as compared to the previous year's report.
7. PJM Generation Attribute Tracking System, accessible at https://www.pjm-eis.com/.
8. MWh and CO_2 emissions data include Linden Cogeneration, units 005001 – 009001, and Bayonne Energy Center, units CTG1 – CTG8, as these units are physically located in New Jersey, but dispatch electricity into NYISO.

Table 4. Summary of Data Sources for RGGI PJM

	Electricity Demand (Annual)				*Electricity Generation (Annual)*				
Code	**A-1**	**A-2**	**A-2**	**A-3**	**B-1**	**B-2**	**B-3**	**B-4**	**B-5**
Monitoring Category	Total Electricity Use in RGGI PJM	Net Electricity Imports - from Non-RGGI PJM	Net Electricity Imports - from NYISO	Total Net Electricity Imports - from All Adjoining ISOs	RGGI-Affected Units	Non-RGGI Units (Fossil Fuel-Fired)	Non-RGGI Units (Non-Fossil Fuel-Fired)	All Non-RGGI Units (Fossil and Non-Fossil)	All Units
MWh	Sum of A-3 and B-5	PJM GATS[1]	PJM GATS[1]	Sum of A-2s	PJM GATS[1]	PJM GATS[1]	PJM GATS[1]	Sum of B-2 and B-3	Sum of B-1 and B-4
CO_2 Tons	Sum of A-3 and B-5	PJM GATS[1]	MWh multiplied by CO_2/MWh	Sum of A-2s	State reported data for 2006-2008; RGGI COATS for 2009 through 2023. Includes only sources subject to a state CO_2 Budget Trading Program CO_2 allowance compliance obligation; does not include Maryland LIESA sources; does not include Linden Cogeneration units 005001-009001.[2,3]	PJM GATS[1]	PJM GATS[1]	Sum of B-2 and B-3	Sum of B-1 and B-4
CO_2 lb/MWh	CO_2 tons divided by MWh	CO_2 tons divided by MWh	B-5	CO_2 tons divided by MWh	CO_2 tons divided by MWh	CO_2 tons divided by MWh	CO_2 tons divided by MWh	CO_2 tons divided by MWh	CO_2 tons divided by MWh

Table Notes:
1. PJM Generation Attribute Tracking System, accessible at https://www.pjm-eis.com/.
2. Historical 2006 – 2008 CO_2 emissions data reported by RGGI participating states compiled from CO_2 emissions data reported to U.S. EPA pursuant 40 CFR Part 75 and from CO_2 emissions and fuel use data reported to state emissions statement programs. 2009 through 2023 CO_2 emissions data is from data reported to the RGGI CO_2 Allowance Tracking System (RGGI COATS), available at rggi-coats.org.
3. MWh and CO_2 emissions data do not include Maryland Limited Industrial Exemption Set-aside (LIESA) sources. LIESA sources for 2009-2023 include Severstal Sparrows Point LLC, Luke Paper Company, and Cove Point LNG Terminal. LIESA sources refer to certain industrial cogenerators under Maryland's CO_2 Budget Trading Program regulations that are subject to alternative CO_2 compliance obligations under certain conditions in lieu of submission of CO_2 allowances.

Appendix B. ISO-Specific Monitoring Results

Detailed monitoring results for ISO-NE, NYISO, and the RGGI portion of PJM are presented below.[53]

ISO-NE

Monitoring results for ISO-NE for 2006 through 2023 are summarized below in Table 5 and Figures 15 through 24. Annual averages for calendar years 2006 to 2008 represent the baseline.

Table 5. 2006 – 2023 Monitoring Summary for ISO-NE

MWh	Electricity Demand					Electricity Generation					*Summary Data*
	Total in ISO	Net Imports - from NYISO	Net Imports - from Quebec	Net Imports - from New Brunswick	Total Net Imports - from All Adjoining ISOs	RGGI-Affected Units	Non-RGGI Fossil Fuel-Fired Units	Non-Fossil Fuel-Fired Units	All Non-RGGI Units	All Units[54]	Non-RGGI Generation Serving Load in ISO (Non-RGGI Generation within ISO + Net Imports)
2006	134,243,000	-877,000	6,023,000	1,047,000	6,193,000	66,235,352	7,994,499	54,056,195	62,050,694	128,050,000	68,243,694
2007	136,869,000	-2,477,000	7,727,000	896,000	6,146,000	69,488,412	8,430,445	53,020,870	61,451,315	130,723,000	67,597,315
2008	134,000,000	-1,529,000	9,495,000	1,285,000	9,251,000	66,518,558	5,416,213	52,665,469	58,081,682	124,749,000	67,332,682
2009	128,801,000	-3,031,000	10,826,000	1,569,000	9,363,000	60,473,925	6,443,028	52,979,865	59,422,893	119,437,000	68,785,893
2010	131,956,000	-4,412,000	9,214,000	737,000	5,539,000	65,238,708	8,074,341	53,893,367	61,967,708	126,416,000	67,506,708
2011	130,752,000	-2,262,000	11,558,000	846,000	10,142,000	62,957,969	7,886,924	51,306,677	59,193,601	120,610,000	69,335,601
2012	129,590,000	-1,073,000	13,077,000	643,000	12,648,000	62,129,238	4,314,475	53,144,056	57,458,531	116,942,000	70,106,531
2013	131,001,000	1,322,000	13,928,000	3,711,000	18,961,000	57,766,430	1,637,377	56,533,777	58,171,154	112,041,000	77,132,154
2014	127,176,000	3,908,078	13,212,403	3,527,050	20,647,531	53,539,784	1,739,519	57,802,685	59,542,204	108,357,000	80,189,735
2015	126,955,000	3,911,358	12,978,000	4,108,000	20,997,358	58,406,246	1,742,545	52,483,133	54,225,678	107,916,000	75,223,036
2016	124,416,000	1,335,255	12,285,000	4,842,000	18,462,255	55,090,362	2,024,903	53,702,585	55,727,488	105,572,000	74,189,743
2017	121,220,000	1,478,998	14,495,000	4,305,000	20,278,998	49,456,967	2,335,299	57,986,601	60,321,901	102,564,000	80,600,898
2018	123,472,000	3,285,809	13,966,000	4,044,000	21,295,809	52,512,178	2,505,743	56,550,010	59,055,753	103,740,000	80,351,562

[53] Short tons of CO_2 emitted and the lb CO_2/MWh emission rates in this report do not represent total lifecycle reductions or contributions of greenhouse gases. Such analysis is outside the scope of this report.
[54] See Appendix A, Table 2, Table Note 1.

2019	119,237,000	5,739,000	14,091,000	3,233,000	23,063,000[55]	45,498,548	5,093,268	55,677,702	60,770,970	97,890,000	83,833,970
2020	116,875,000	7,070,000	13,969,000	2,585,000	23,624,000	45,866,660	6,827,056	50,475,331	57,302,386	94,945,000	80,926,386
2021	118,789,000	2,490,004	13,700,000	2,598,000	18,788,004	50,561,269	6,833,812	52,048,241	58,882,053	101,692,000	77,670,056
2022	118,927,000	1,165,000	13,602,000	1,998,000	16,765,000	51,491,119	6,888,577	54,181,524	61,070,101	103,928,000	77,835,101
2023	114,726,000	2,611,000	10,548,000	1,943,000	15,102,000	52,819,362	6,071,308	51,556,970	57,628,278	101,303,000	72,730,278

CO_2	**Electricity Demand**					**Electricity Generation**					***Summary Data***
	Total in ISO	**Net Imports - from NYISO**	**Net Imports - from Quebec**	**Net Imports - from New Brunswick**	**Total Net Imports - from All Adjoining ISOs**	**RGGI-Affected Units**	**Non-RGGI Fossil Fuel-Fired Units**	**Non-Fossil Fuel-Fired Units**	**All Non-RGGI Units**	**All Units**	**Non-RGGI Generation Serving Load in ISO (Non-RGGI Generation within ISO + Net Imports)**
2006	42,202,458	-404,953	26,557	547,053	168,657	47,783,423	2,294,218	9,049,196	11,343,414	59,126,837	11,512,070
2007	50,079,316	-1,155,569	25,468	455,316	-674,785	49,434,978	2,963,453	8,586,395	11,549,849	60,984,826	10,875,064
2008	54,286,213	-671,104	26,166	736,564	91,627	44,508,400	1,820,953	8,425,083	10,246,036	54,754,436	10,337,663
2009	44,334,489	-1,287,840	42,961	968,535	-276,344	38,815,561	2,733,899	9,198,068	11,931,967	50,747,528	11,655,623
2010	49,139,981	-1,932,583	25,392	406,202	-1,500,990	41,682,538	3,331,687	10,359,631	13,691,318	55,373,857	12,190,329
2011	43,513,964	-933,856	29,303	410,324	-494,228	35,599,032	3,294,100	11,029,838	14,323,938	49,793,256	13,829,710
2012	38,748,137	-410,272	38,920	297,690	-73,661	31,657,173	1,815,918	11,240,839	13,056,757	44,713,885	12,983,095
2013	45,985,934	522,082	30,706	1,186,296	1,739,082	30,173,526	604,510	13,469,005	14,073,514	44,247,040	15,812,597
2014	45,016,852	1,054,224	20,390	1,088,614	2,163,233	27,665,118	584,114	14,605,525	15,189,639	42,854,758	17,352,872
2015	45,213,688	1,011,086	15,736	1,313,206	2,340,028	28,867,519	609,582	13,155,735	13,765,317	42,632,836	16,105,345
2016	42,138,496	414,597	16,250	1,761,339	2,192,186	26,013,525	635,083	13,123,557	13,758,641	39,772,166	15,950,827
2017	40,398,875	421,514	19,174	1,471,090	1,911,777	23,990,894	677,682	13,818,521	14,496,203	38,487,097	16,407,980
2018	40,274,183	966,028	20,013	1,248,169	2,234,210	23,873,039	650,362	13,516,572	14,166,934	38,039,973	16,401,145
2019	37,257,184	1,683,331	18,639	926,581	2,628,551	20,465,688	719,228	13,443,717	14,162,945	34,628,633	16,791,496
2020	37,751,635	2,111,456	23,097	826,348	2,960,901	21,713,725	920,191	12,156,818	13,077,009	34,790,734	16,037,910
2021	38,111,360	847,846	19,632	830,503	1,697,982	23,969,439	842,796	11,601,144	12,443,940	36,413,379	14,141,922

[55] The total for 2019 includes 1,349,000 MWhs wheeled through from Canada via New York.

2022	39,613,615	417,653	17,992	726,798	1,162,443	24,709,035	935,742	12,806,396	13,742,138	38,451,173	14,904,580
2023	36,608,075	976,919	17,441	492,612	1,486,971	24,094,406	947,805	10,078,893	11,026,698	35,121,103	12,513,669

lb CO_2/ MWh	**Electricity Demand**					**Electricity Generation**					***Summary Data***
	Total in ISO	**Net Imports - from NYISO**	**Net Imports - from Quebec**	**Net Imports - from New Brunswick**	**Total Net Imports - from All Adjoining ISOs**	**RGGI-Affected Units**	**Non-RGGI Fossil Fuel-Fired Units**	**Non-Fossil Fuel-Fired Units**	**All Non-RGGI Units**	**All Units**	**Non-RGGI Generation Serving Load in ISO (Non-RGGI Generation within ISO + Net Imports)**
2006	629	923	9	1,045	54	1,443	574	335	366	923	337
2007	732	933	7	1,016	-220	1,423	703	324	376	933	322
2008	810	878	6	1,146	20	1,338	672	320	353	878	307
2009	688	850	8	1,235	-59	1,284	849	347	402	850	339
2010	666	876	6	1,102	-542	1,278	825	384	442	876	361
2011	666	826	5	970	-97	1,131	835	430	484	826	399
2012	598	765	6	926	-12	1,019	842	423	454	765	370
2013	702	790	4	639	183	1,045	738	476	484	790	410
2014	708	540	3	617	210	1,033	672	505	510	791	433
2015	712	517	2	639	223	989	700	501	508	790	428
2016	677	621	3	728	237	944	627	489	494	753	430
2017	667	570	3	683	189	970	580	477	481	750	407
2018	652	588	3	617	210	909	519	478	480	733	408
2019	625	587	3	573	228	900	282	483	466	708	401
2020	646	597	3	639	251	947	270	482	456	733	396
2021	642	681	3	639	181	948	247	446	423	716	364
2022	666	717	3	728	139	960	272	473	450	740	383
2023	**638**	**748**	**3**	**507**	**197**	**912**	**312**	**391**	**383**	**693**	**344**

ISO-NE 2021 to 2023 Annual Average Compared to Baseline

The monitoring results indicate that the annual average electricity load in ISO-NE for 2021 to 2023 decreased by 17.6 million MWh, or 13.0 percent, compared to the annual average for the baseline period of 2006 to 2008. Electric generation from all sources in ISO-NE decreased by 17.1 million MWh, or 13.4 percent, compared to the base period.

For ISO-NE, annual average electric generation from RGGI generation in 2021 to 2023 decreased by 15.8 million MWh during this period, or 23.4 percent, and annual average CO_2 emissions from RGGI electric generation in ISO-NE decreased by 23.0 million short tons of CO_2, or 48.7 percent. The CO_2 emission rate of RGGI electric generation decreased by 461 lb CO_2/MWh, or 32.9 percent.

Annual average electric generation from non-RGGI electric generation sources for ISO-NE in 2021 to 2023 decreased by 1.3 million MWh, or 2.2 percent, during this period, and CO_2 emissions from this category of electric generation increased by 1.4 million short tons of CO_2, an increase of 12.3 percent. The annual average CO_2 emission rate of non-RGGI electric generation located in ISO-NE increased by 53.7 lb CO_2/MWh, an increase of 14.7 percent.

When the 2021 to 2023 annual average is compared to the 2006 to 2008 base period annual average, electric generation from all non-RGGI electric generation serving load in ISO-NE increased by 8.4 million MWh, or 12.3 percent. The CO_2 emissions from this category of electric generation increased by 2.9 million short tons of CO_2, or 27.0 percent, and the CO_2 emission rate increased by 41.7 lb CO_2/MWh, or 12.9 percent. (See Figures 15, 16, and 17.)

Annual average net electricity imports into ISO-NE for 2021 to 2023 increased by 9.7 million MWh compared to the base period annual average for 2006 to 2008. (See Figure 18). Annual average CO_2 emissions related to these net electricity imports increased by 1.6 million short tons of CO_2 during this period.[56] The annual average CO_2 emission rate of the electric generation supplying these imports increased by 221 lb CO_2/MWh. (See Figure 19).

[56] ISO-NE net exports to NYISO doubled from 2008 to 2009 and increased again in 2010. Negative values for MWh and CO_2 tons indicate that more MWh were exported (from New England to New York) than imported. As a result, the increase in net exports to NYISO in 2009 and 2010 increased the amount of CO_2 emissions debited from the ISO-NE net import total, resulting in a negative CO_2 emissions value for total CO_2 emissions related to total net electricity imports in 2009, 2010, 2011, and 2012 for ISO-NE. In 2013, the trend was reversed as NE imported more than was exported to NY.

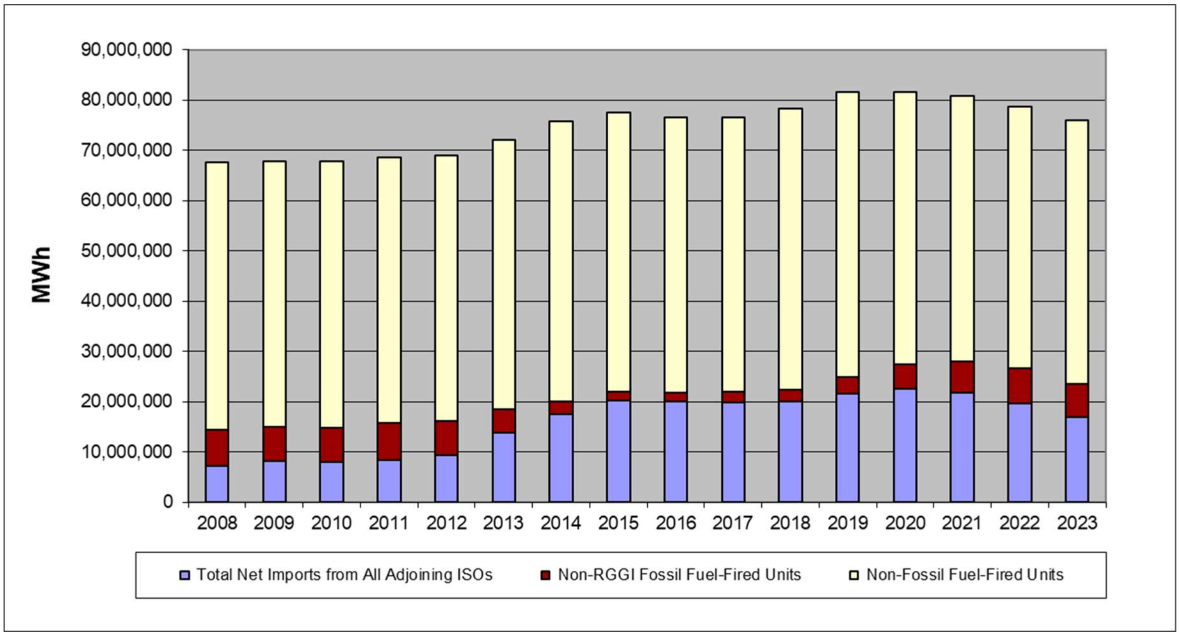

Figure 15. Non-RGGI Generation Serving Load in ISO-NE (MWh) (Three Year Trailing Average)

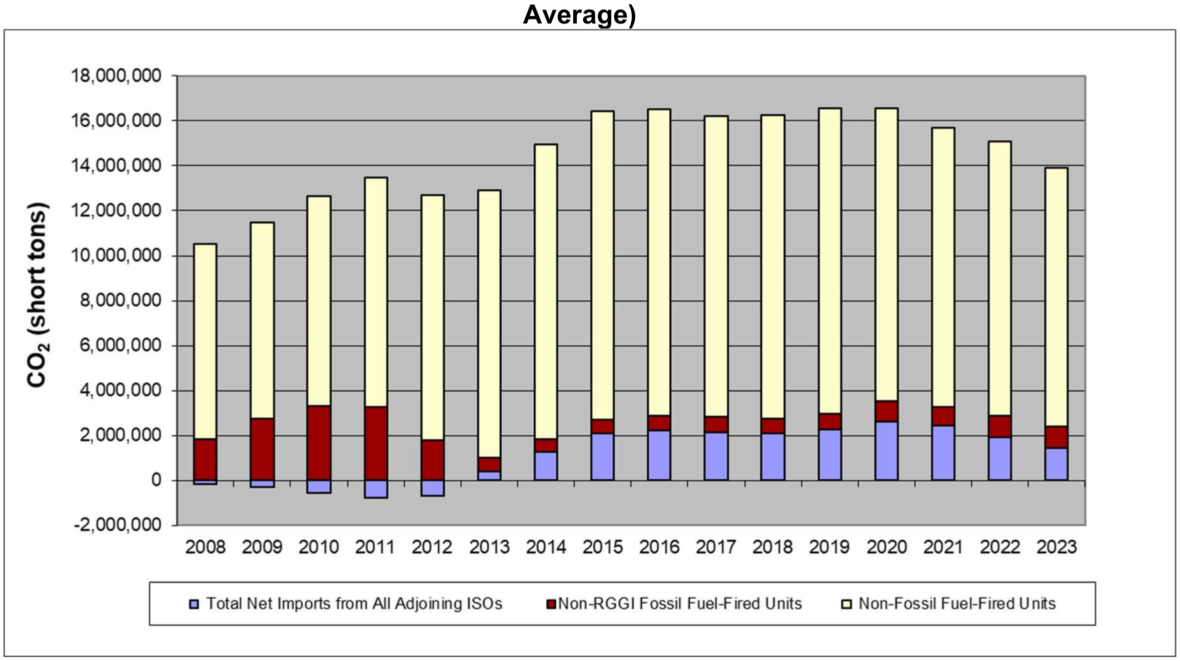

Figure 16. CO_2 Emissions from Non-RGGI Generation Serving Load in ISO-NE (short tons CO_2) (Three Year Trailing Average)

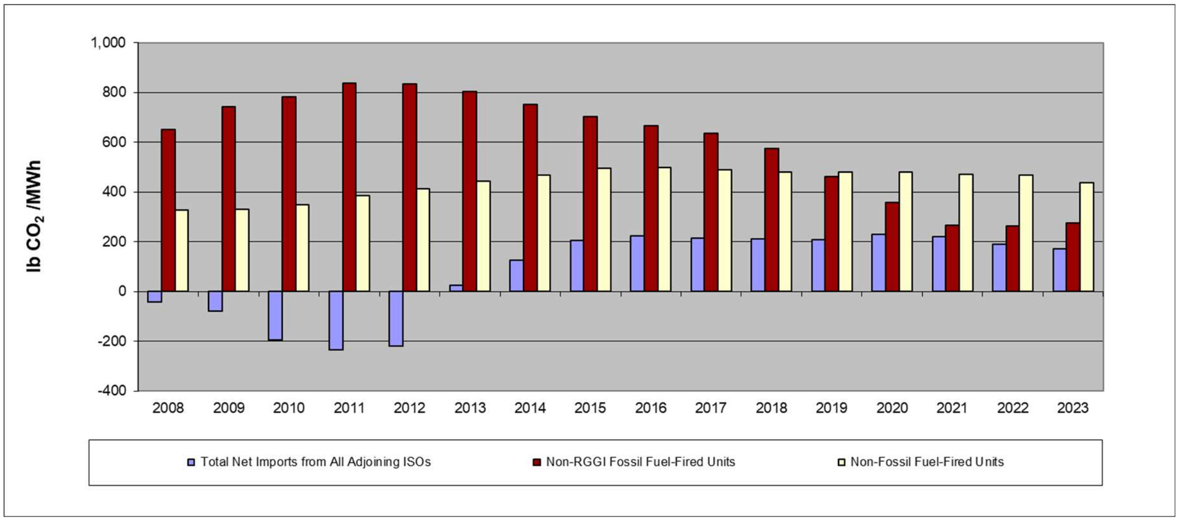

Figure 17. CO_2 Emission Rate for Non-RGGI Generation Serving Load in ISO-NE (lb CO2/MWh) (Three Year Trailing Average)

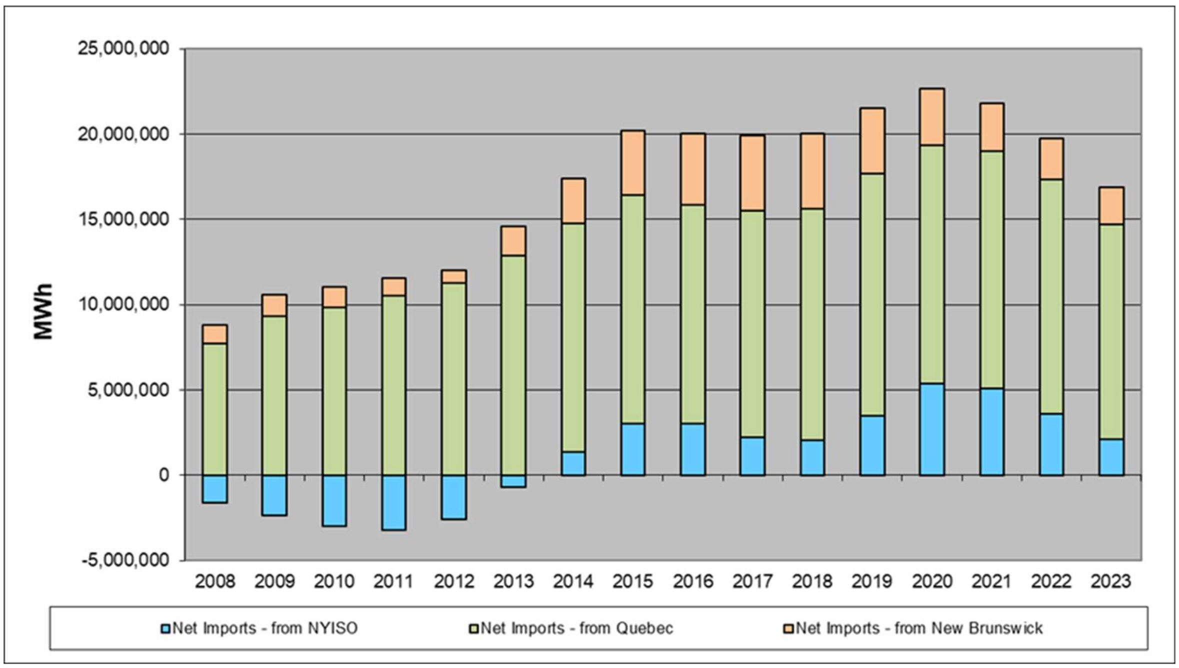

Figure 18. Net Electricity Imports to ISO-NE (MWh) (Three Year Lagging)

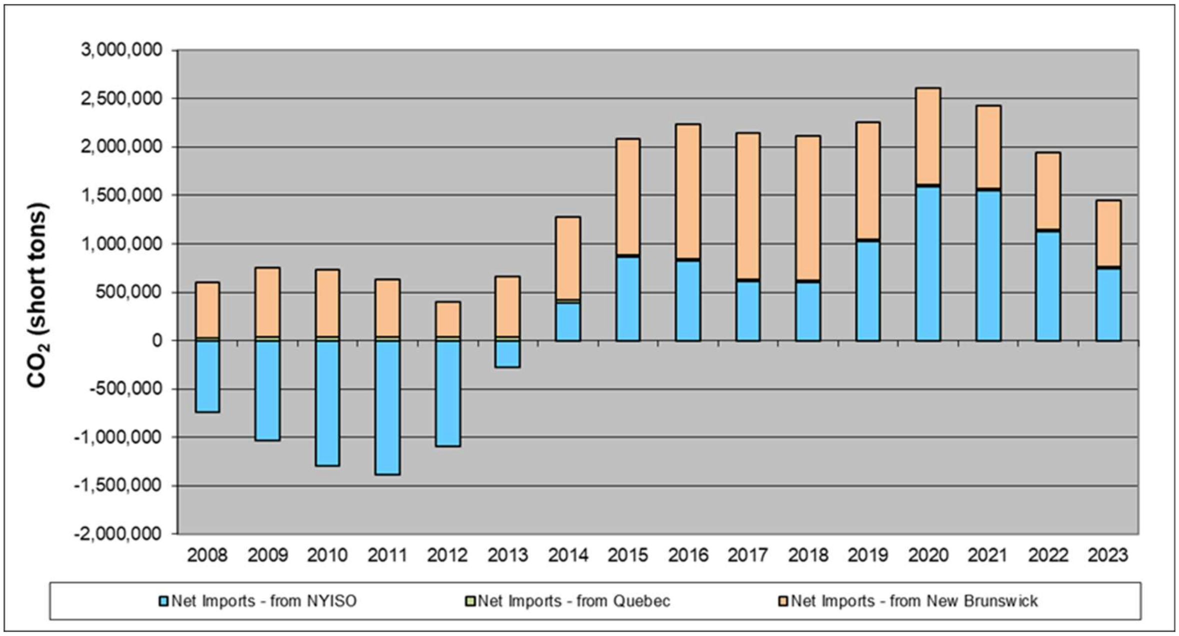

Figure 19. CO_2 Emissions Related to Net Electricity Imports to ISO-NE (short tons CO_2) (Three Year Lagging)

ISO-NE 2023 Annual Average Compared to Baseline

The monitoring results indicate the 2023 annual average electricity load in ISO-NE decreased by 20.3 million MWh, or 15.0 percent, compared to the 2006 to 2008 base period. The annual average 2023 electric generation from all sources in ISO-NE decreased by 17.5 million MWh, or 13.7 percent, compared to the base period.

Compared to the annual average during the 2006 to 2008 base period, 2023 RGGI electric generation in ISO-NE decreased by 14.6 million MWh, or 21.6 percent, and CO_2 emissions from RGGI generation in ISO-NE decreased by 23.1 million short tons of CO_2, or 49.0 percent. The CO_2 emission rate of RGGI electric generation decreased by 489 lb CO_2/MWh, a reduction of 34.9 percent.

Compared to the 2006 to 2008 annual average, 2023 electric generation from non-RGGI generation located in ISO-NE decreased by 2.9 million MWh, or 4.8 percent, and CO_2 emissions from this category decreased by 19,735 short tons of CO_2, a decrease of 0.2 percent. The CO_2 emission rate of non-RGGI electric generation located in ISO-NE increased by 17.9 lb CO_2/MWh, an increase of 4.9 percent.

Compared to the annual average during the 2006 to 2008 base period, electric generation in 2023 from all non-RGGI electric generation sources serving load in ISO-NE increased by 5.0 million MWh, an increase of 7.4 percent. Compared to the 2006 to 2008 annual average, 2023 CO_2 emissions from this category of electric generation increased by 1.6 million short tons of CO_2, an increase of 14.7 percent, and the CO_2 emission rate increased by 22.0 lb CO_2/MWh, an increase of 6.8 percent. (See Figures 20, 21, and 22).

Compared to the annual average during the 2006 to 2008 base period, 2023 net electricity imports into ISO-NE increased by 7.9 million MWh. (See Figure 23). CO_2 emissions related to these net electricity imports increased by 1.6 million short tons of CO_2 during this period. (See Figure 24). The CO_2 emission rate of the electric generation supplying these imports increased by 245 lb CO_2/MWh.

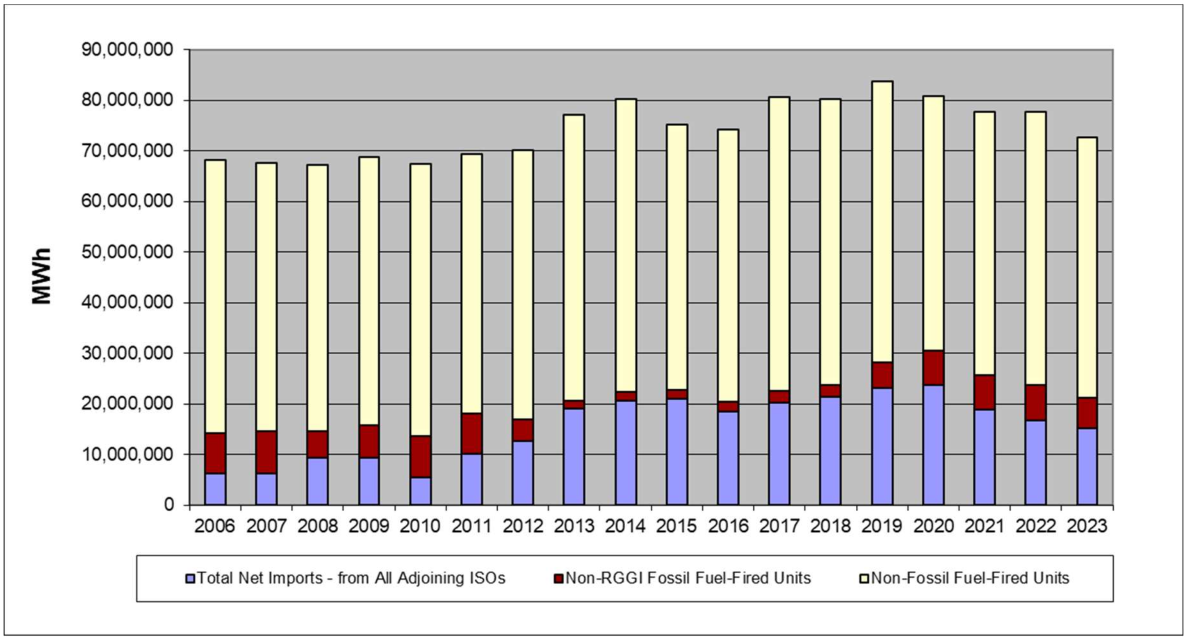

Figure 20. Non-RGGI Generation Serving Load in ISO-NE (MWh)

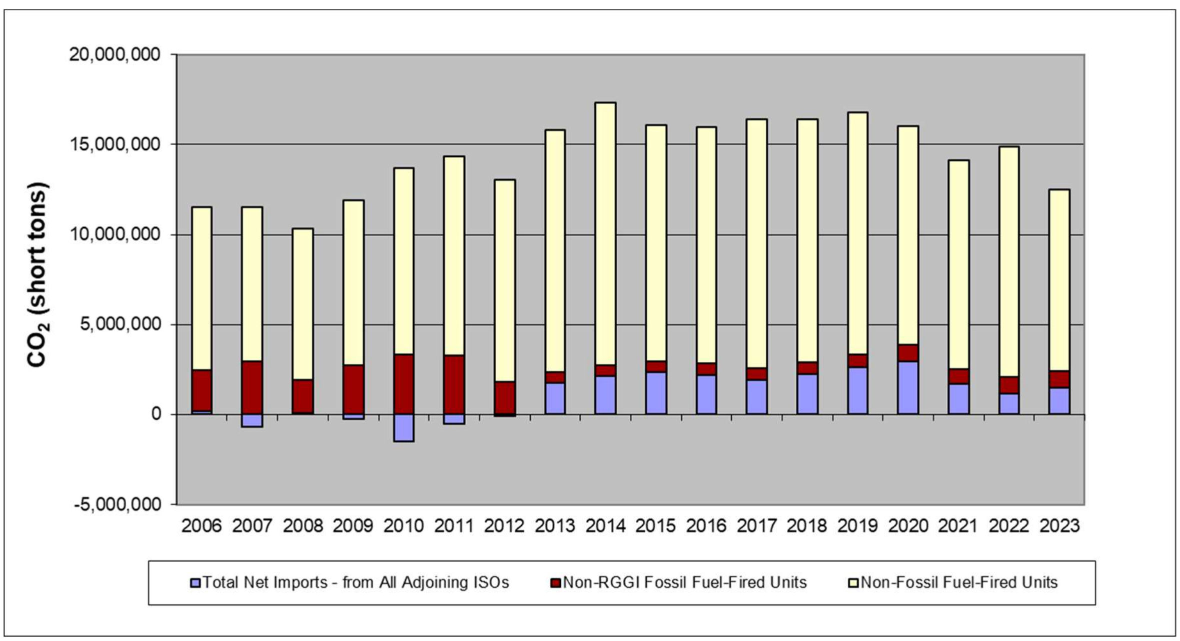

Figure 21. CO_2 Emissions from Non-RGGI Generation Serving Load in ISO-NE (short tons CO_2)

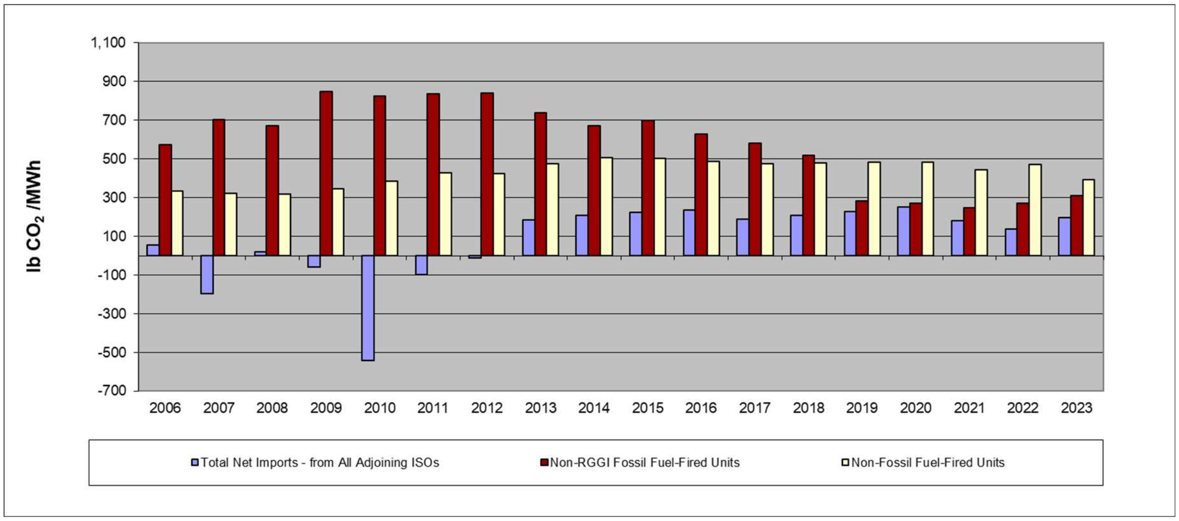

Figure 22. CO_2 Emission Rate for Non-RGGI Generation Serving Load in ISO-NE (lb CO_2/MWh)

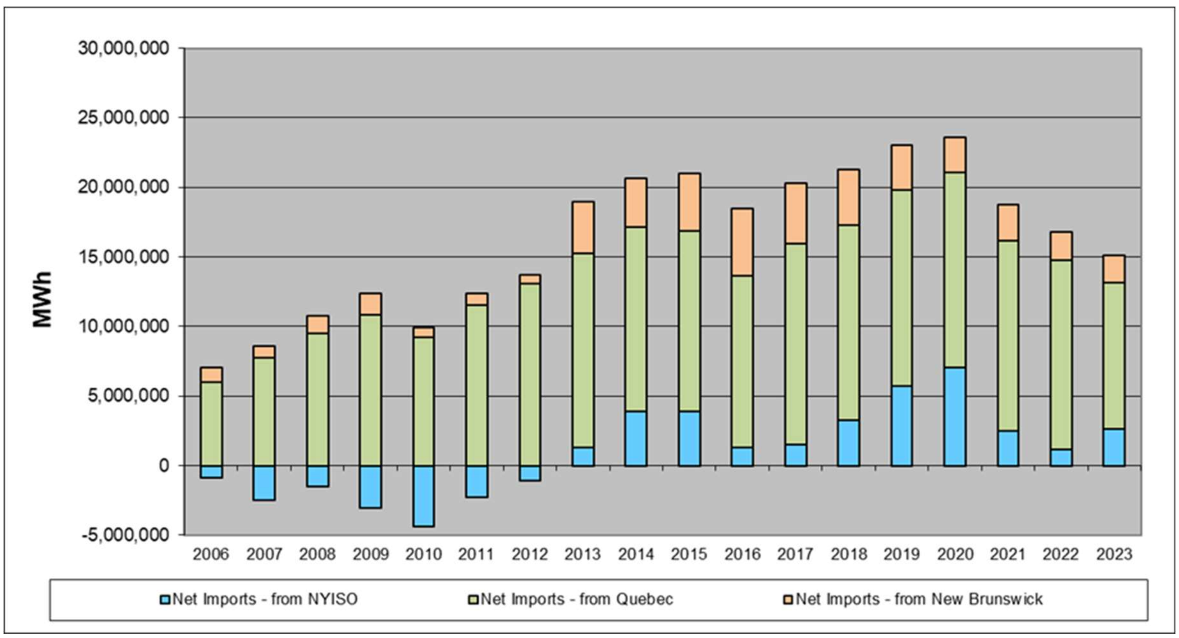

Figure 23. Net Electricity Imports to ISO-NE (MWh)

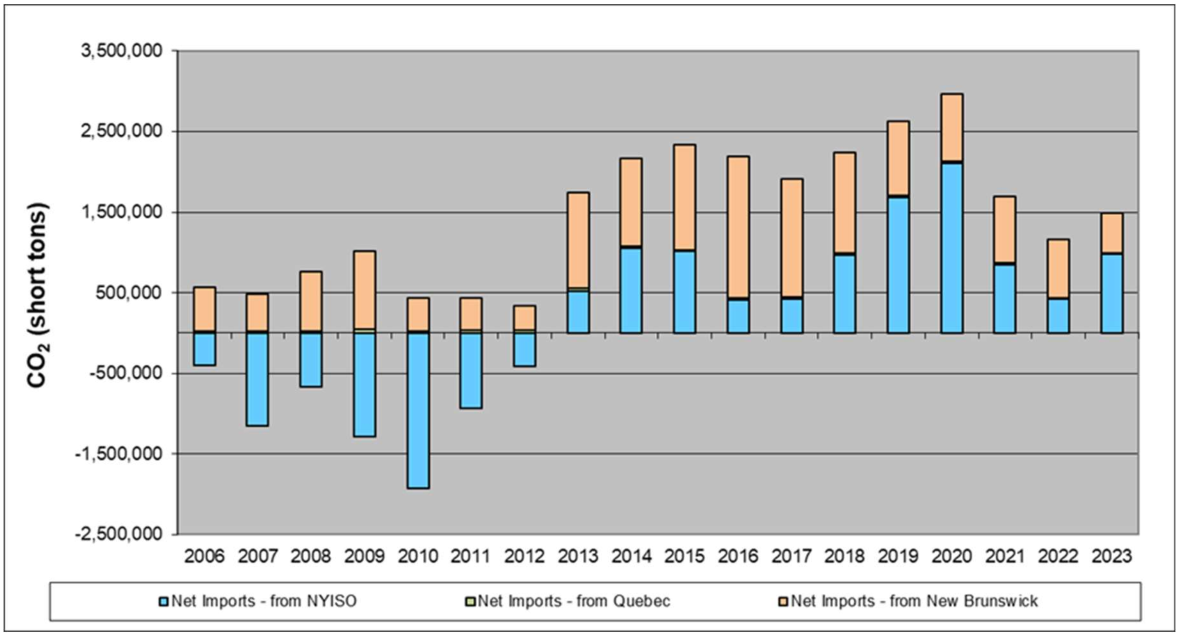

Figure 24. CO_2 Emissions Related to Net Electricity Imports to ISO-NE (short tons CO_2)

NYISO

Monitoring results for NYISO for 2006 through 2023 are summarized below in Table 6 and Figures 25 through 34. Annual averages for calendar years 2006 to 2008 represent the baseline.

Table 6. 2006 – 2023 Monitoring Summary for the NYCA

	Electricity Demand						Electricity Generation					*Summary Data*
MWh	Total Annual Electricity Load in NYISO	Net Imports - from Quebec	Net Imports - from ISO-NE	Net Imports - from Ontario	Net Imports - from PJM	Total Net Electricity Imports	Annual Electric Generation - RGGI-Affected Units	Annual Electric Generation - Non-RGGI Fossil Fuel-Fired Units	Annual Electric Generation - Non-Fossil Fuel-Fired Units	Annual Electric Generation - All Non-RGGI Units	Total Annual Electric Generation - All Units	Non-RGGI Generation Serving Load in ISO (Non-RGGI Generation within ISO + Net Imports)
2006	166,654,414	2,959,749	877,000	3,672,282	9,559,000	17,068,031	73,384,236	234,031	75,968,116	76,202,147	149,586,383	93,270,178
2007	169,932,177	4,185,292	2,477,000	2,637,442	10,225,000	19,524,734	77,766,403	218,412	72,422,628	72,641,040	150,407,443	92,165,774
2008	168,646,767	5,646,014	1,529,000	6,162,902	10,690,000	24,027,916	68,739,716	499,577	75,379,558	75,879,135	144,618,851	99,907,051
2009	160,565,962	6,239,805	3,031,000	6,463,657	8,331,000	24,065,462	59,714,083	283,600	76,502,817	76,786,417	136,500,500	100,851,879
2010	164,282,144	4,335,209	4,412,000	3,872,635	12,305,000	24,924,844	65,897,420	316,800	73,143,080	73,459,880	139,357,300	98,384,724
2011	163,818,485	7,123,204	2,262,000	3,318,681	11,150,000	23,853,885	62,079,707	270,900	77,613,993	77,884,893	139,964,600	101,738,778
2012	163,689,994	9,235,689	1,073,000	5,749,461	8,408,800	24,466,950	64,755,295	294,400	74,173,349	74,467,749	139,223,044	98,934,699
2013	166,412,302	10,638,017	-1,322,000	7,593,954	9,190,966	26,100,937	63,327,437	289,100	76,694,828	76,983,928	140,311,365	103,084,865
2014	160,598,000	8,839,775	-3,908,078	7,180,281	8,721,704	20,833,682	62,927,206	89,400	76,747,712	76,837,112	139,764,318	97,670,794
2015	160,650,689	9,397,396	-3,911,358	8,302,624	7,558,163	21,346,825	61,837,274	118,500	77,348,090	77,466,590	139,303,864	98,813,415
2016	160,798,000	9,558,000	-1,335,255	7,668,000	8,399,813	24,290,558	62,357,630	113,000	74,479,557	74,592,557	136,950,187	98,883,115
2017	156,370,000	10,795,091	-1,478,998	7,720,948	7,948,559	24,985,600	52,086,140	59,700	79,238,560	79,298,260	131,384,400	104,283,860
2018	161,114,000	10,837,861	-3,285,809	6,586,515	10,776,410	24,914,977	56,411,918	143,500	79,643,605	79,787,105	136,199,023	104,702,082
2019	155,832,000	9,097,032	-4,345,905	6,504,484	11,206,632	22,462,243	51,953,426	107,900	81,303,132	81,411,032	133,364,458	103,873,275
2020	150,198,000	9,984,000	-7,070,000	7,472,000	9,639,000	20,025,000	55,882,513	153,700	74,136,787	74,290,487	130,173,000	94,315,487
2021	152,145,806	10,727,857	-2,490,004	5,666,080	13,231,822	27,135,755	59,651,185	38,900	65,319,966	65,358,866	125,010,051	92,494,621
2022	152,008,600	9,478,000	-1,165,000	4,576,000	14,082,000	26,971,000	64,706,800	28,500	60,302,500	60,331,000	125,037,800	87,302,000
2023	146,886,600	2,652,000	-2,611,000	3,976,000	18,249,000	22,266,000	61,418,600	54,200	63,148,000	63,202,200	124,620,800	85,468,200

CO_2	Electricity Demand						Electricity Generation					*Summary Data*
	Total Annual Electricity Load in NYISO	Net Imports - from Quebec	Net Imports - from ISO-NE	Net Imports - from Ontario	Net Imports - from PJM	Total Net Electricity Imports	Annual Electric Generation - RGGI-Affected Units	Annual Electric Generation - Non-RGGI Fossil Fuel-Fired Units	Annual Electric Generation - Non-Fossil Fuel-Fired Units	Annual Electric Generation - All Non-RGGI Units	Total Annual Electric Generation - All Units	Non-RGGI Generation Serving Load in ISO (Non-RGGI Generation within ISO + Net Imports)
2006	69,807,908	13,050	404,953	769,120	5,983,934	7,171,057	59,295,846	237,731	3,103,274	3,341,005	62,636,851	10,512,062
2007	71,578,150	13,794	1,155,569	604,715	6,349,725	8,123,803	60,916,627	231,122	2,306,598	2,537,720	63,454,347	10,703,090
2008	63,062,489	15,559	671,104	1,154,884	6,520,900	8,362,447	50,479,325	545,536	3,675,181	4,220,717	54,700,042	12,583,164
2009	48,529,761	24,762	1,287,840	712,496	4,736,174	6,761,271	39,512,286	280,875	1,975,329	2,256,204	41,768,490	9,017,475
2010	55,583,232	11,947	1,932,583	554,950	7,179,968	9,679,448	43,731,385	325,810	1,846,589	2,172,399	45,903,784	11,851,847
2011	48,275,690	18,060	936,289	336,556	6,389,108	7,680,012	38,551,439	280,209	1,764,030	2,044,239	40,595,678	9,724,251
2012	44,898,581	27,488	410,272	602,081	4,212,809	5,252,650	37,351,017	297,919	1,996,995	2,294,914	39,645,931	7,547,564
2013	42,408,931	23,453	-522,082	795,236	4,871,212	5,167,818	34,690,266	271,508	2,279,339	2,550,847	37,241,113	7,718,665
2014	42,040,391	13,642	-1,105,986	603,144	4,827,463	4,338,263	35,886,492	88,813	1,726,824	1,815,637	37,702,129	6,153,899
2015	40,890,195	11,395	-1,011,086	697,420	3,831,989	3,529,718	35,178,722	117,721	2,064,034	2,181,755	37,360,477	5,711,473
2016	39,501,402	12,643	-414,597	337,392	4,162,107	4,097,546	33,369,568	120,367	1,913,921	2,034,288	35,403,856	6,131,834
2017	33,305,807	14,279	-421,514	298,260	3,918,639	3,809,665	27,416,674	58,885	2,020,583	2,079,468	29,496,142	5,889,133
2018	37,528,404	13,602	-966,028	45,447	5,188,841	4,281,862	29,945,837	143,085	3,157,620	3,300,705	33,246,542	7,582,567
2019	32,979,231	11,417	-1,274,716	44,881	5,090,963	3,872,545	26,632,810	99,197	2,374,679	2,473,876	29,106,686	6,346,421
2020	32,088,052	12,530	-2,111,456	63,811	4,170,169	2,135,054	28,164,699	140,683	1,647,616	1,788,299	29,952,998	3,923,353
2021	35,513,613	13,463	-847,846	48,388	6,099,870	5,313,875	27,920,455	25,321	2,253,961	2,279,282	30,199,737	7,593,158
2022	38,702,814	11,895	-417,653	39,079	6,780,483	6,413,804	30,184,635	18,592	2,085,783	2,104,375	32,289,010	8,518,179
2023	38,009,262	3,328	-976,919	33,955	7,901,361	6,961,725	28,554,226	32,744	2,460,567	2,493,311	31,047,537	9,455,036

lb CO_2/ MWh	Electricity Demand						Electricity Generation					*Summary Data*
	Total Annual Electricity Load in NYISO	Net Imports - from Quebec	Net Imports - from ISO-NE	Net Imports - from Ontario	Net Imports - from PJM	Total Net Electricity Imports	Annual Electric Generation - RGGI-Affected Units	Annual Electric Generation - Non-RGGI Fossil Fuel-Fired Units	Annual Electric Generation - Non-Fossil Fuel-Fired Units	Annual Electric Generation - All Non-RGGI Units	Total Annual Electric Generation - All Units	Non-RGGI Generation Serving Load in ISO (Non-RGGI Generation within ISO + Net Imports)
2006	838	9	923	419	1,252	840	1,616	2,032	82	88	837	225
2007	842	7	933	459	1,242	832	1,567	2,116	64	70	844	232
2008	748	6	878	375	1,220	696	1,469	2,184	98	111	756	252
2009	604	8	850	220	1,137	562	1,323	1,981	52	59	612	179
2010	677	6	876	287	1,167	777	1,327	2,057	50	59	659	241
2011	589	5	828	203	1,146	644	1,242	2,069	45	52	580	191
2012	549	6	765	209	1,002	429	1,154	2,024	54	62	570	153
2013	510	4	790	209	1,060	396	1,096	1,878	59	66	531	150
2014	524	3	566	168	1,107	416	1,141	1,987	45	47	540	126
2015	509	2	517	168	1,014	331	1,138	1,987	53	56	536	116
2016	491	3	621	88	991	337	1,070	2,130	51	55	517	124
2017	426	3	570	77	986	305	1,053	1,973	51	52	449	113
2018	466	3	588	14	963	344	1,062	1,994	79	83	488	145
2019	423	3	587	14	909	345	1,025	1,839	58	61	436	122
2020	427	3	597	17	865	213	1,008	1,831	44	48	460	83
2021	467	3	681	17	922	392	936	1,302	69	70	483	164
2022	509	3	717	17	963	476	1,005	1,305	69	70	516	195
2023	518	3	748	17	866	625	1,036	1,028	78	79	498	221

NYISO 2021 to 2023 Annual Average Compared to Baseline

The monitoring results indicate that the 2021 to 2023 annual average electricity load in NYISO decreased by 18.0 million MWh, or 10.7 percent, compared to the annual average for the baseline period of 2006 to 2008. The 2021 to 2023 annual average electric generation from all sources in NYISO decreased by 23.3 million MWh, or 15.7 percent, compared to the base period.

In NYISO, annual average electric generation from RGGI generation for 2021 to 2023 decreased by 11.4 million MWh during this period, or 15.5 percent, and annual average CO_2 emissions from RGGI electric generation in NYISO decreased by 28.0 million short tons of CO_2, or 49.2 percent. The annual average CO_2 emission rate of RGGI electric generation decreased by 558 lb CO_2/MWh, a reduction of 36.0 percent.

Annual average electric generation from non-RGGI sources for NYISO in 2021 to 2023 decreased by 11.9 million MWh, or 15.9 percent, during this period, and average annual CO_2 emissions from this category decreased by 1.1 million short tons of CO_2, a decrease of 31.9 percent. The annual average CO_2 emission rate of non-RGGI electric generation located in NYISO decreased by 16.8 lb CO_2/MWh, a decrease of 18.7 percent.

The annual average electric generation from all non-RGGI electric generation serving load in NYISO for 2021 to 2023 decreased by 6.7 million MWh, or 7.0 percent, compared to the base period of 2006 to 2008. Annual average CO_2 emissions from this category of electric generation decreased by 2.7 million short tons of CO_2, or 24.3 percent, and the annual average CO_2 emission rate decreased by 42.7 lb CO_2/MWh, a decrease of 18.1 percent. (See Figures 25, 26, and 27.)

Net electricity imports into NYISO increased by 5.3 million MWh, or 26.0 percent, when comparing the annual average for the base period of 2006 to 2008 to the annual average for 2021 to 2023. (See Figure 28). Annual average CO_2 emissions related to these net electricity imports decreased by 1.7 million short tons of CO_2, or 21.0 percent, during this period. (See Figure 29). The annual average CO_2 emission rate of the electric generation supplying these imports decreased by 292 lb CO_2/MWh, a decrease of 37.0 percent.

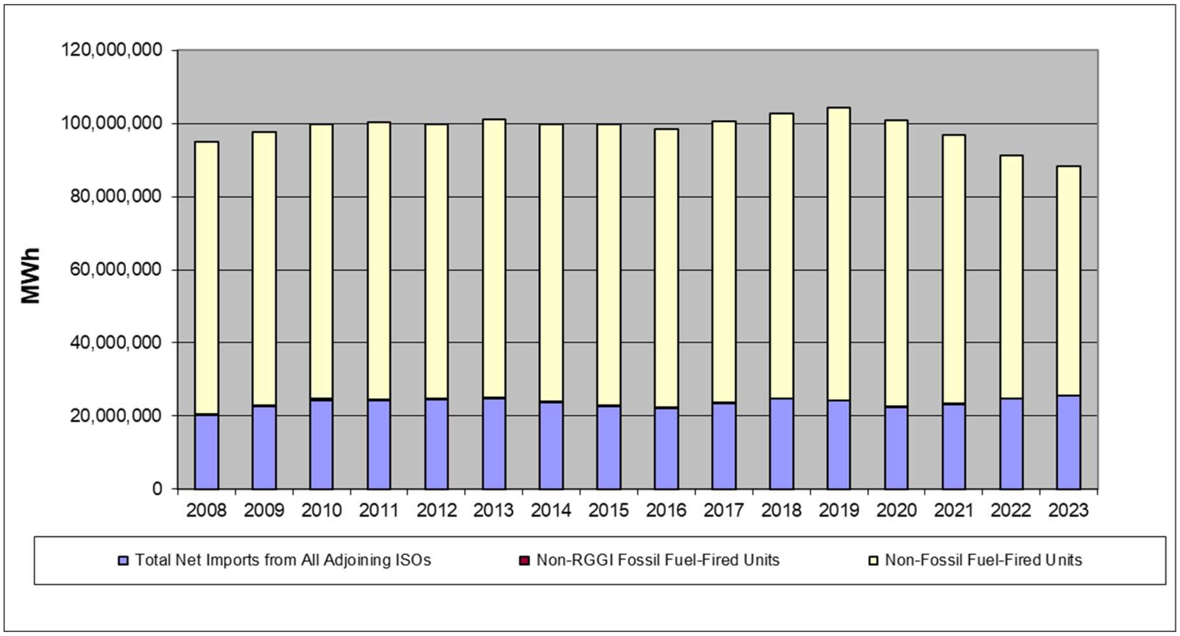

Figure 25. Non-RGGI Generation Serving Load in NYISO (MWh) (Three Year Trailing Average)

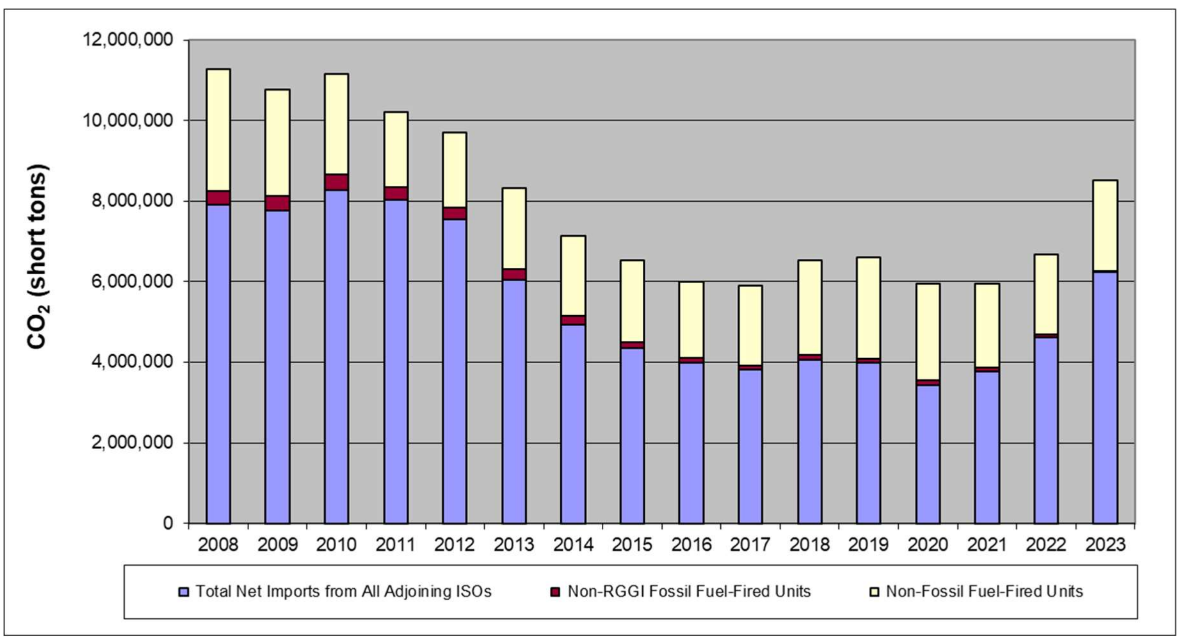

Figure 26. CO_2 Emissions from Non-RGGI Generation Serving Load in NYISO (short tons CO_2) (Three Year Trailing Average)

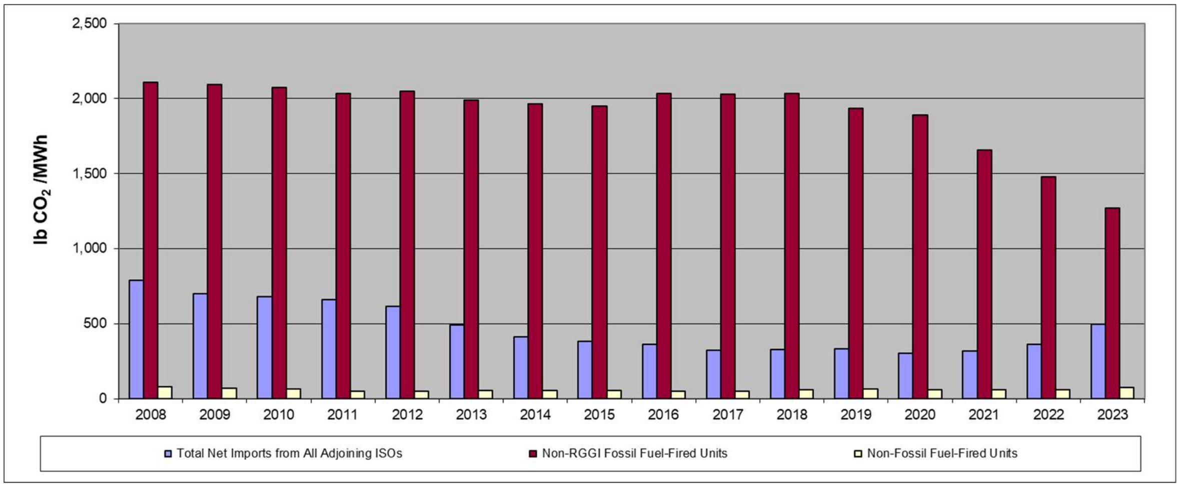

Figure 27. CO_2 Emission Rate for Non-RGGI Generation Serving Load in NYISO (lb CO_2/MWh) (Three Year Trailing Average)

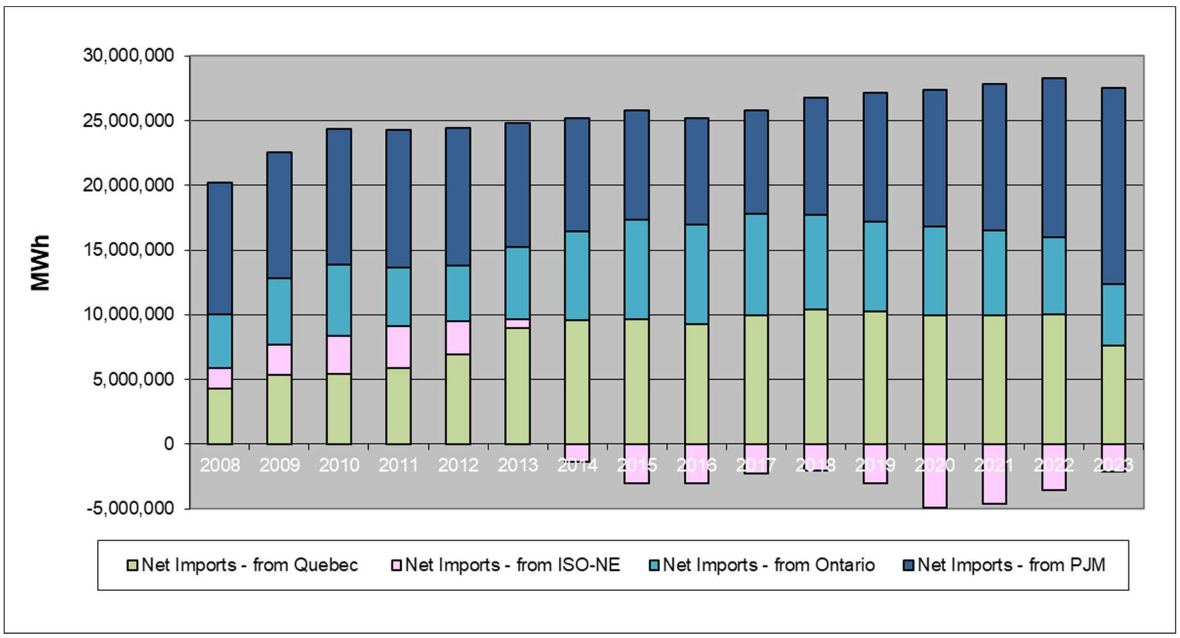

Figure 28. Net Electricity Imports to NYISO (MWh) (Three Year Trailing Average)

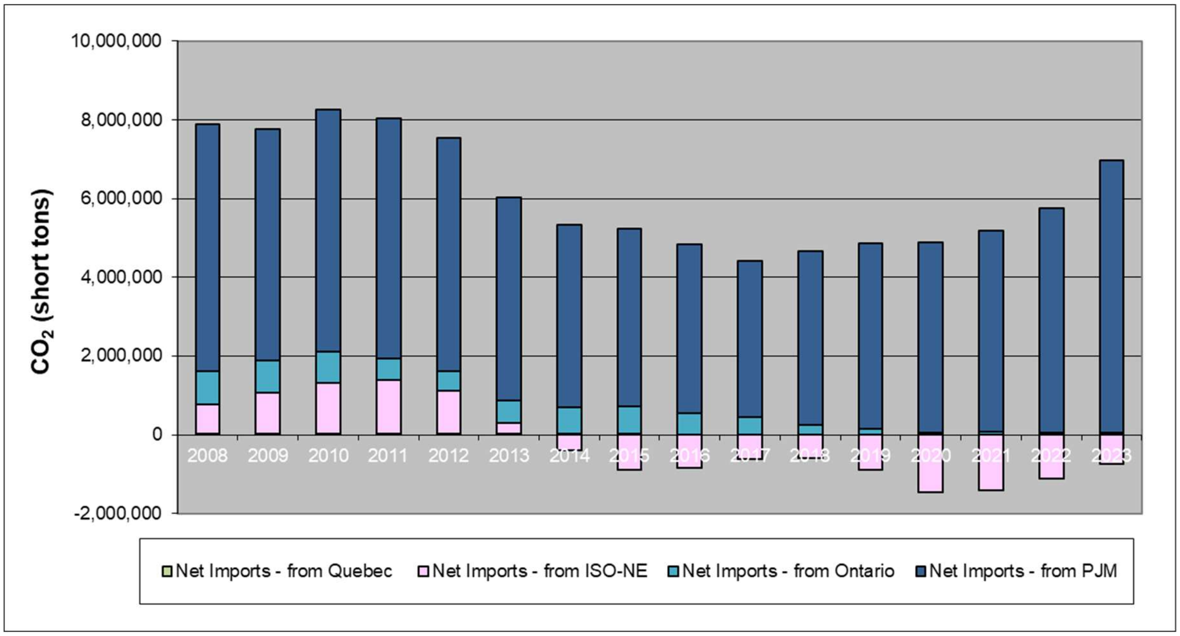

Figure 29. CO_2 Emissions Related to Net Electricity Imports to NYISO (short tons CO_2) (Three Year Trailing Average)

NYISO 2023 Annual Average Compared to Baseline

The monitoring results indicate the 2023 annual average electricity load in NYISO decreased by 21.5 million MWh, or 12.8 percent, compared to the 2006 to 2008 base period. The annual average 2023 electric generation from all sources in NYISO in 2023 decreased by 23.6 million MWh, or 15.9 percent, compared to the base period.

Compared to the annual average during the 2006 to 2008 base period, 2023 electric generation from RGGI generation in NYISO decreased by 11.9 million MWh, or 16.2 percent, and CO_2 emissions from RGGI generation in NYISO decreased by 28.3 million short tons of CO_2, a reduction of 49.8 percent. The CO_2 emission rate of RGGI electric generation decreased by 515 lb CO_2/MWh, a reduction of 33.2 percent.

Compared to the 2006 to 2008 base period, 2023 electric generation from non-RGGI generation located in NYISO decreased by 11.7 million MWh, or 15.6 percent, and CO_2 emissions from this category decreased by 873,170 short tons of CO_2, a reduction of 25.9 percent. The CO_2 emission rate of non-RGGI electric generation located in NYISO decreased by 10.7 lb CO_2/MWh, a reduction of 11.9 percent.

Compared to the annual average during the 2006 to 2008 base period, electric generation in 2023 from all non-RGGI electric generation sources serving load in NYISO decreased by 9.6 million MWh, a decrease of 10.1 percent. Compared to the base period, 2023 CO_2 emissions from this category of electric generation decreased by 1.8 million short tons of CO_2, a reduction of 16.0 percent, and the CO_2 emission rate decreased by 15.0 lb CO_2/MWh, a reduction of 6.3 percent. (See Figures 30, 31, and 32).

Compared to the annual average during the 2006 to 2008 base period, 2023 net electricity imports into NYISO increased by 2.1 million MWh, or 10.2 percent. (See Figure 33). CO_2 emissions related to these net electricity imports decreased by 937,899short tons of CO_2, or 11.9 percent. (See Figure 34). The CO_2 emission rate of the electric generation supplying these imports decreased by 166 lb CO_2/MWh, a reduction of 20.9 percent.

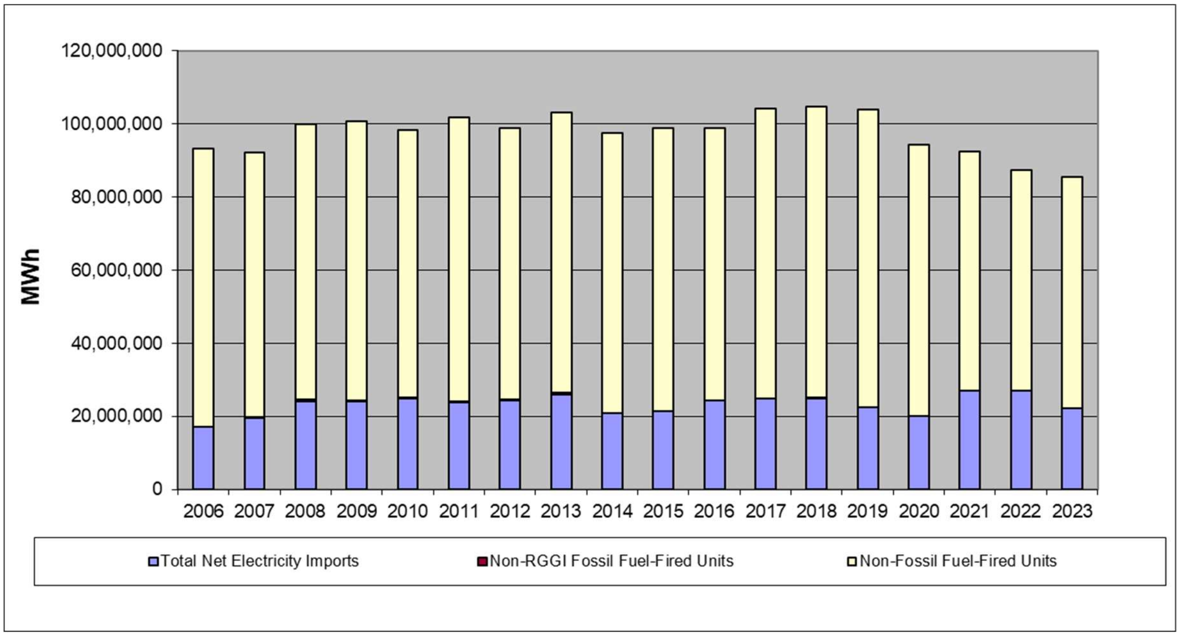

Figure 30. Non-RGGI Generation Serving Load in NYISO (MWh)

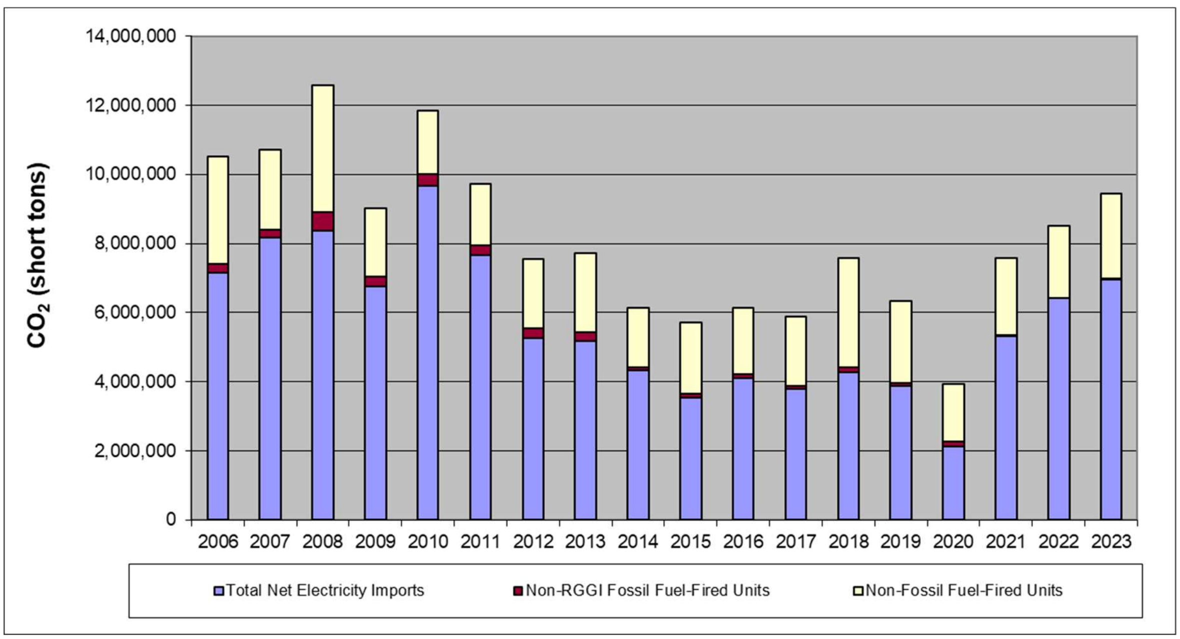

Figure 31. CO_2 Emissions from Non-RGGI Generation Serving Load in NYISO (short tons CO_2)

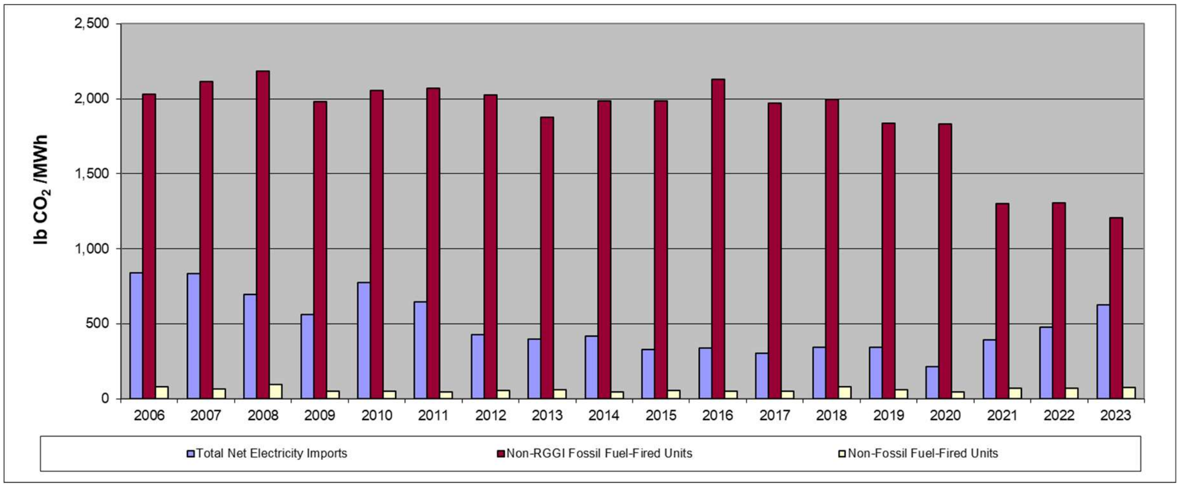

Figure 32. CO_2 Emission Rate for Non-RGGI Generation Serving Load in NYISO (lb CO_2/MWh)

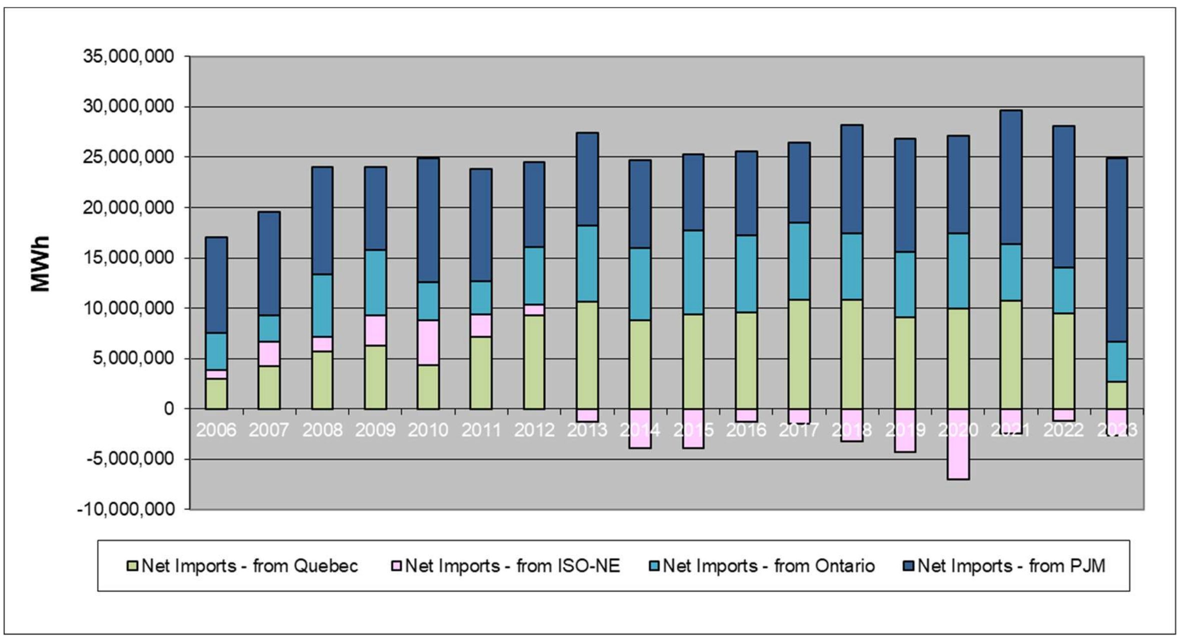

Figure 33. Net Electricity Imports to NYISO (MWh)

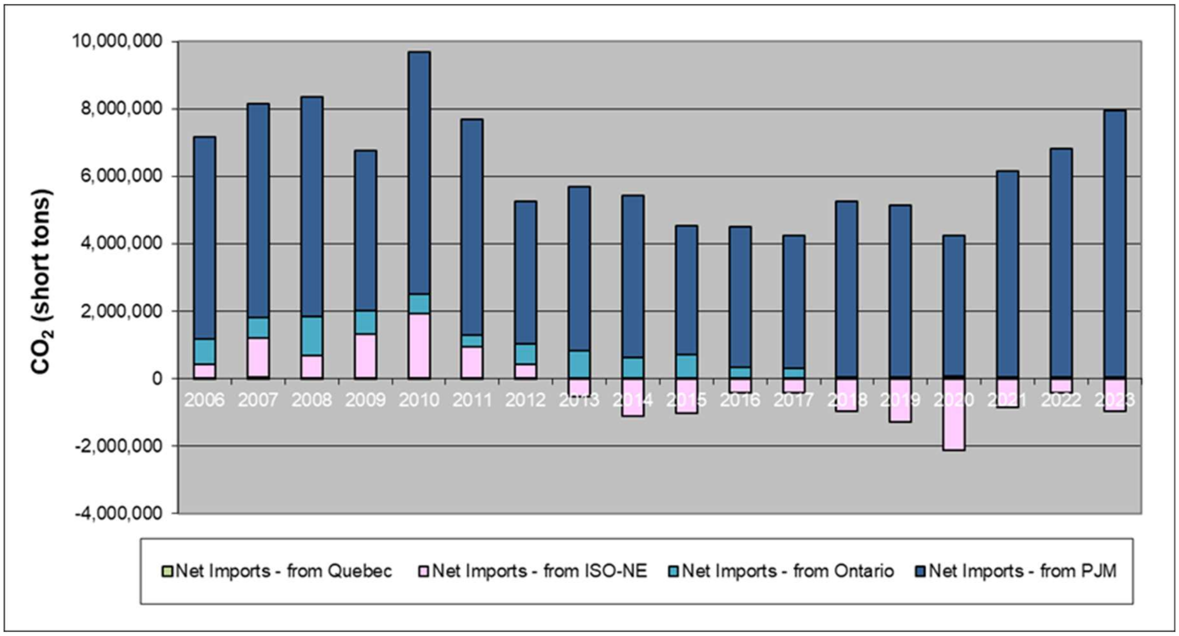

Figure 34. CO_2 Emissions Related to Net Electricity Imports to NYISO (short tons CO_2)

PJM (RGGI Portion)

Monitoring results for PJM for 2006 through 2023 are summarized below in Table 7 and Figures 35 through 39. Note that for PJM, the data presented below is for the RGGI geographic portion of PJM: Delaware, Maryland, New Jersey, and Virginia (RGGI PJM). Annual averages for calendar years 2006 to 2008 (baseline), 2021 to 2023 represent RGGI PJM. Annual averages for calendar years 2009 to 2011 and 2020 represent Delaware, Maryland, and New Jersey (RGGI PJM-2). Annual averages for calendar years 2012 to 2019 represent Delaware and Maryland only. Net "imports" represent inferred flows of electricity from the non-RGGI geographic portion of PJM (Non-RGGI PJM) to RGGI PJM to make up for shortfalls in electric generation relative to total electricity load for this subset of PJM.[57]

Table 7. 2006 – 2023 Monitoring Summary for RGGI PJM

	Electricity Demand				Electricity Generation					*Summary Data*
MWh	**Total Annual Electricity Load in ISO**	**Net Imports - from Non-RGGI PJM**	**Net Imports - from NYISO**	**Total Net Electricity Imports - from All Adjoining ISOs**	**Annual Electric Generation - RGGI-Affected Units**	**Annual Electric Generation - Non-RGGI Fossil Fuel-Fired Units**	**Annual Electric Generation - Non-Fossil Fuel-Fired Units**	**Annual Electric Generation - All Non-RGGI Units**	**Total Annual Electric Generation - All Units**	**Non-RGGI Generation Serving Load in ISO (Non-RGGI Generation within ISO + Net Imports)**
2006	274,443,982	94,471,071	-2,431,223	92,039,848	97,551,550	358,134	84,494,450	84,852,584	182,404,134	176,892,432
2007	280,782,709	91,096,901	-2,641,513	88,455,388	106,172,454	382,810	85,772,057	86,154,867	192,327,321	174,610,255
2008	272,655,818	91,516,082	-2,691,446	88,824,636	98,770,110	183,612	84,877,460	85,061,072	183,831,182	173,885,708
2009	158,657,456	56,299,698	-1,257,857	55,041,841	50,005,454	151,888	53,458,273	53,610,161	103,615,615	108,652,002
2010	165,047,534	58,001,518	-1,844,414	56,157,104	57,625,172	143,960	51,121,298	51,265,258	108,890,430	107,422,362
2011	160,923,846	55,406,781	-1,583,072	53,823,709	53,621,362	227,081	53,251,694	53,478,775	107,100,137	107,302,484
2012	78,802,312	34,442,085	-482,148	33,959,937	28,350,888	190,940	16,300,547	16,491,487	44,842,375	50,451,424
2013	77,458,942	35,843,247	-490,493	35,352,754	24,775,215	81,428	17,249,545	17,330,973	42,106,188	52,683,727
2014	76,359,729	32,656,507	-482,178	32,174,329	26,733,539	71,744	17,380,117	17,451,861	44,185,400	49,626,190
2015	77,903,165	35,680,933	-413,286	35,267,647	24,839,927	57,076	17,738,515	17,795,591	42,635,518	53,063,238
2016	77,822,567	33,910,113	-462,876	33,447,237	26,504,789	51,481	17,819,060	17,870,541	44,375,330	51,317,778

[57] This data is compiled from PJM GATS, which reports data for both the non-RGGI and RGGI geographic portions of PJM. Inferred net imports are based on total MWh load in the RGGI geographic portion of PJM minus total electric generation in the RGGI geographic portion of PJM. Any shortfall in generation relative to load is assumed to be met through an inferred "import" of electricity from the non-RGGI geographic portion of PJM into the RGGI geographic portion of PJM.

2017	75,384,095	35,770,266	-397,466	35,372,800	21,208,131	28,228	18,774,936	18,803,164	40,011,295	54,175,964
2018	77,912,067	30,085,536	-630,502	29,455,034	28,772,738	55,564	19,628,731	19,684,295	48,457,033	49,139,329
2019	74,279,654	32,136,849	-583,001	31,553,848	23,754,977	54,739	18,916,090	18,970,829	42,725,806	50,524,677
2020	143,958,375	51,196,818	-1,128,865	50,067,953	46,204,909	52,955	47,632,558	47,685,513	93,890,422	97,753,466
2021	269,668,867	81,775,715	-3,069,826	78,705,889	102,554,859	77,075	88,331,044	88,408,119	190,962,978	167,114,008
2022	276,664,240	88,515,715	-3,248,146	85,267,569	101,288,441	98,268	90,009,962	90,108,230	191,396,671	175,375,799
2023	268,363,563	82,731,330	-4,261,766	78,469,564	97,917,939	60,005	91,916,055	91,976,060	189,893,999	170,445,624

CO_2	Electricity Demand				Electricity Generation					*Summary Data*
	Total Annual Electricity Load in ISO	**Net Imports - from Non-RGGI PJM**	**Net Imports - from NYISO**	**Total Net Electricity Imports - from All Adjoining ISOs**	**Annual Electric Generation - RGGI-Affected Units**	**Annual Electric Generation - Non-RGGI Fossil Fuel-Fired Units**	**Annual Electric Generation - Non-Fossil Fuel-Fired Units**	**Annual Electric Generation - All Non-RGGI Units**	**Total Annual Electric Generation - All Units**	**Non-RGGI Generation Serving Load in ISO (Non-RGGI Generation within ISO + Net Imports)**
2006	159,221,364	59,911,033	-1,341,566	58,569,467	89,820,146	291,574	10,540,177	10,831,751	100,651,897	69,401,218
2007	162,463,477	57,269,645	-1,464,901	55,804,744	98,639,335	302,325	7,717,073	8,019,398	106,658,733	63,824,142
2008	153,805,789	56,969,639	-1,438,830	55,530,809	88,258,988	184,833	9,831,159	10,015,992	98,274,980	65,546,801
2009	78,593,331	33,537,149	-553,688	32,983,461	43,804,611	152,325	1,652,934	1,805,259	45,609,870	34,788,720
2010	87,087,382	35,150,499	-894,878	34,255,621	50,125,993	145,704	2,560,064	2,705,768	52,831,761	36,961,389
2011	78,909,078	33,048,520	-688,046	32,360,474	44,418,277	182,970	1,947,357	2,130,327	46,548,604	34,490,801
2012	45,342,236	18,627,737	-290,358	18,337,379	25,436,501	212,964	1,355,392	1,568,356	27,004,857	19,905,735
2013	43,873,524	19,867,713	-282,938	19,584,774	22,968,475	101,584	1,218,691	1,320,275	24,288,750	20,905,049
2014	43,832,735	17,971,031	-285,333	17,685,699	24,836,448	82,905	1,227,683	1,310,588	26,147,036	18,996,287
2015	40,731,169	17,989,208	-222,606	17,766,601	21,569,214	60,038	1,335,315	1,395,353	22,964,567	19,161,954
2016	40,573,262	16,699,087	-251,655	16,447,433	22,374,470	52,701	1,698,659	1,751,360	24,125,830	18,198,793
2017	34,169,771	17,052,989	-171,742	16,881,247	15,922,332	26,383	1,339,809	1,366,192	17,288,524	18,247,439
2018	34,987,263	13,913,167	-277,822	13,635,345	19,968,446	52,436	1,331,036	1,388,472	21,351,918	15,018,817
2019	31,119,015	15,110,127	-221,466	14,888,661	14,963,881	48,656	1,217,817	1,266,473	16,230,354	16,155,134
2020	48,857,336	23,345,135	-292,035	23,053,100	23,493,429	31,552	2,279,256	2,310,808	25,804,237	25,363,908
2021	98,016,496	41,794,827	-918,558	40,876,269	52,455,830	46,830	4,637,567	4,684,397	57,140,227	45,560,666

2022	99,029,376	44,645,785	-938,864	43,706,921	50,911,512	76,998	4,333,945	4,410,943	55,322,455	48,117,864
2023	88,934,787	40,514,502	-1,111,638	39,402,864	45,438,577	29,974	4,063,373	4,093,347	49,531,924	43,496,211

	Electricity Demand				**Electricity Generation**					***Summary Data***
lb CO_2/ MWh	**Total Annual Electricity Load in ISO**	**Net Imports - from Non-RGGI PJM**	**Net Imports - from NYISO**	**Total Net Electricity Imports - from All Adjoining ISOs**	**Annual Electric Generation - RGGI-Affected Units**	**Annual Electric Generation - Non-RGGI Fossil Fuel-Fired Units**	**Annual Electric Generation - Non-Fossil Fuel-Fired Units**	**Annual Electric Generation - All Non-RGGI Units**	**Total Annual Electric Generation - All Units**	**Non-RGGI Generation Serving Load in ISO (Non-RGGI Generation within ISO + Net Imports)**
2006	1,160	1,268	1,104	1,273	1,841	1,628	249	255	1,104	785
2007	1,157	1,257	1,109	1,262	1,858	1,580	180	186	1,109	731
2008	1,128	1,245	1,069	1,250	1,787	2,013	232	236	1,069	754
2009	991	1,191	880	1,198	1,752	2,006	62	67	880	640
2010	1,055	1,212	970	1,220	1,740	2,024	100	106	970	688
2011	981	1,193	869	1,202	1,657	1,611	73	80	869	643
2012	1,151	1,082	1,204	1,080	1,794	2,231	166	190	1,204	789
2013	1,133	1,109	1,154	1,108	1,854	2,495	141	152	1,154	794
2014	1,148	1,101	1,184	1,099	1,858	2,311	141	150	1,184	766
2015	1,046	1,008	1,077	1,008	1,737	2,104	151	157	1,077	722
2016	1,043	985	1,087	983	1,688	2,047	191	196	1,087	709
2017	907	953	864	954	1,502	1,869	143	145	864	674
2018	898	925	881	926	1,388	1,887	136	141	881	611
2019	838	940	760	944	1,260	1,778	129	134	760	639
2020	678	912	550	920	1,017	1,192	96	97	550	519
2021	727	1,022	598	1,039	1,023	1,215	105	106	598	545
2022	716	1,009	578	1,025	1,005	1,567	96	98	578	549
2023	663	979	522	1,004	928	999	88	89	522	510

RGGI PJM 2021 to 2023 Annual Average Compared to Baseline

The monitoring results indicate that the annual average electricity load in RGGI PJM for 2021 to 2023 decreased by 4.4 million MWh, or 1.6 percent, compared to the base period of 2006 to 2008. Annual average electric generation from all sources in RGGI PJM for 2021 to 2023 increased by 4.6 million MWh, or 2.5 percent, compared to the base period.

In RGGI PJM, annual average electric generation from RGGI generation for 2021 to 2023 decreased by 244,292 MWh during this period, or 0.2 percent, and annual average CO_2 emissions from this category decreased by 42.6 million short tons of CO_2, or 46.2 percent. The annual average CO_2 emission rate of RGGI electric generation decreased by 844 lb CO_2/MWh, a reduction of 46.1 percent.

Annual average electric generation from non-RGGI electric generation sources located in RGGI PJM increased by 4.8 million MWh, or 5.6 percent, during this period, and annual average CO_2 emissions from this category decreased by 5.2 million short tons of CO_2, a decrease of 54.3 percent. The annual average CO_2 emission rate of non-RGGI electric generation located in RGGI PJM decreased by 128 lb CO_2/MWh, a decrease of 56.7 percent.

The annual average electric generation from all non-RGGI electric generation serving load in RGGI PJM for 2021 to 2023 decreased by 4.2 million MWh, or 2.4 percent, compared to the annual average during the 2006 to 2008 base period. Annual average CO_2 emissions from this category decreased by 20.5 million short tons of CO_2, a decrease of 31.0 percent, and the annual average CO_2 emission rate decreased by 222 lb CO_2/MWh, a decrease of 29.3 percent.

When comparing the annual average during the base period of 2006 to 2008 to the annual average for 2021 to 2023, net electricity imports into RGGI PJM decreased by 9.0 million MWh. Annual average CO_2 emissions related to these net electricity imports decreased by 15.3 million short tons of CO_2, or 27.0 percent, during this period. The annual average CO_2 emission rate of the electric generation supplying these imports decreased by 239 lb CO_2/MWh, a decrease of 18.9 percent.

RGGI PJM 2023 Annual Average Compared to Baseline

The monitoring results indicate the 2023 annual average electricity load in RGGI PJM decreased by 7.6 million MWh, or 2.8 percent, compared to the 2006 to 2008 base period. The annual average 2023 electric generation from all sources in RGGI PJM increased by 3.7 million MWh, or 2.0 percent, compared to the base period.

Compared to the annual average during the 2006 to 2008 base period, 2023 electric generation from RGGI generation in RGGI PJM decreased by 2.9 million MWh, or 2.9 percent, and CO_2 emissions from RGGI generation in RGGI PJM decreased by 46.8 million short tons of CO_2, or 50.7 percent. The CO_2 emission rate of RGGI electric generation decreased by 901 lb CO_2/MWh, a reduction of 49.3 percent.

Compared to the 2006 to 2008 annual average, 2023 electric generation from non-RGGI generation located in RGGI PJM increased by 6.6 million MWh, or 7.8 percent, and CO_2

emissions from this category of electric generation decreased by 5.5 million short tons of CO_2 a decrease of 57.5 percent. The CO_2 emission rate of non-RGGI electric generation located in RGGI PJM decreased by 137 lb CO_2/MWh, a decrease of 60.6 percent.

Compared to the annual average during the 2006 to 2008 base period, electric generation in 2023 from all non-RGGI electric generation sources serving load in RGGI PJM decreased by 4.7 million MWh, a decrease of 2.7 percent. Compared to the base period, 2023 CO_2 emissions from this category of electric generation decreased by 22.8 million short tons of CO_2, a decrease of 34.4 percent, and the CO_2 emission rate decreased by 246 lb CO_2/MWh, a reduction of 32.5 percent. (See Figures 35, 36, and 37).

Compared to the annual average during the 2006 to 2008 base period, 2023 net electricity imports into RGGI PJM decreased by 11.3 million MWh, or 12.6 percent. (See Figure 38). CO_2 emissions related to these net electricity imports decreased by 17.2 million short tons of CO_2, or 30.4 percent, during this period (See Figure 39). The average CO_2 emission rate of the electric generation supplying these imports decreased by 257 lb CO_2/MWh, a reduction of 20.4 percent.

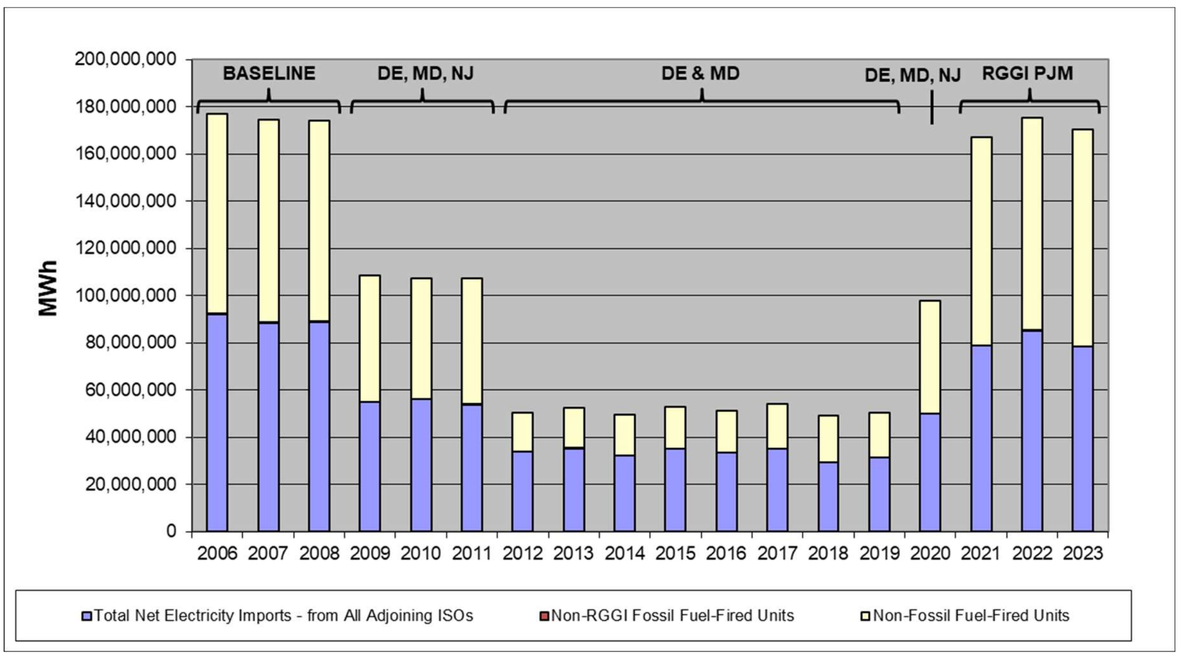

Figure 35. Non-RGGI Generation Serving Load in RGGI PJM (MWh). Annual averages for baseline years and 2021 to 2023 represent RGGI PJM; 2009 to 2011 and 2020 include Delaware, Maryland, and New Jersey (RGGI PJM-2); 2012 to 2019 include Delaware and Maryland only.

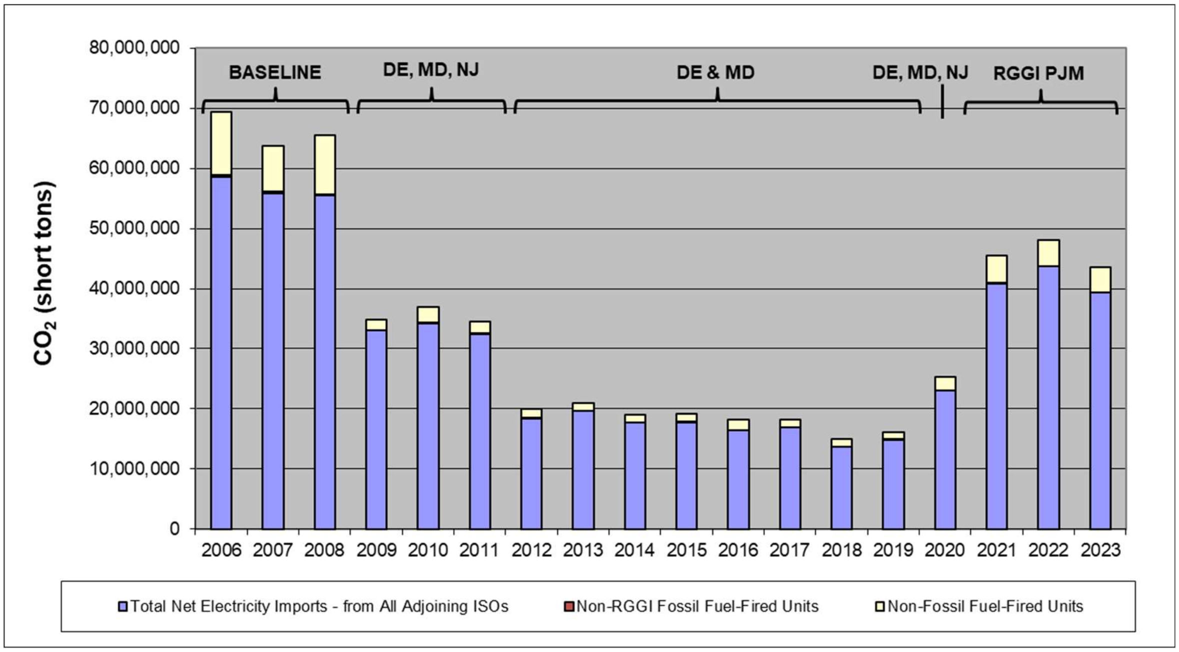

Figure 36. CO_2 Emissions from Non-RGGI Generation Serving Load in RGGI PJM (short tons CO2). Annual averages for baseline years and 2021 to 2023 represent RGGI PJM; 2009 to 2011 and 2020 include Delaware, Maryland, and New Jersey (RGGI PJM-2); 2012 to 2019 include Delaware and Maryland only.

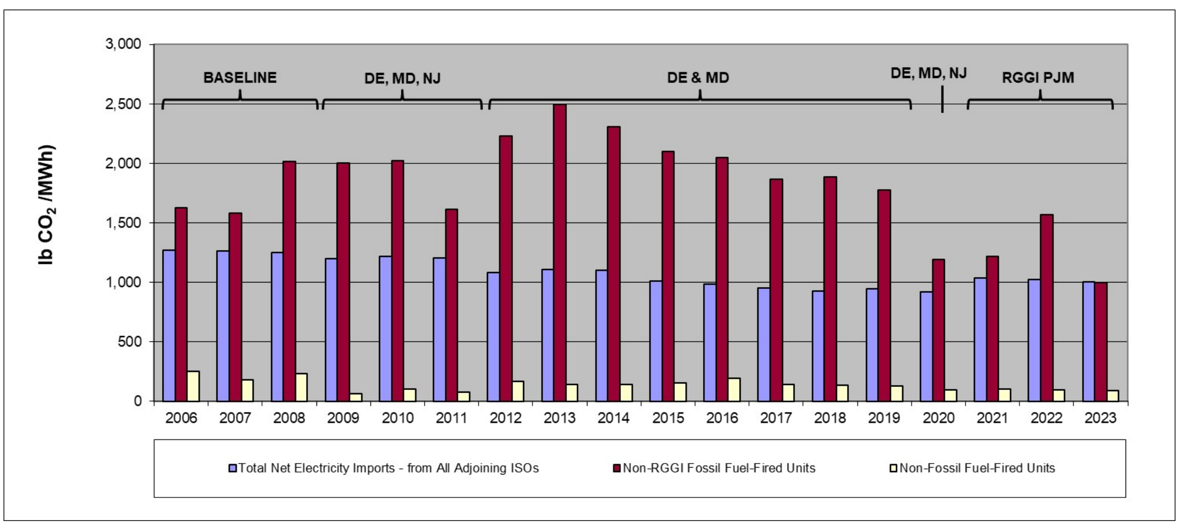

Figure 37. CO_2 Emission Rate for Non-RGGI Generation Serving Load in RGGI PJM (lb CO_2/MWh). Annual averages for baseline years and 2021 to 2023 represent RGGI PJM; 2009 to 2011 and 2020 include Delaware, Maryland, and New Jersey (RGGI PJM-2); 2012 to 2019 include Delaware and Maryland only.

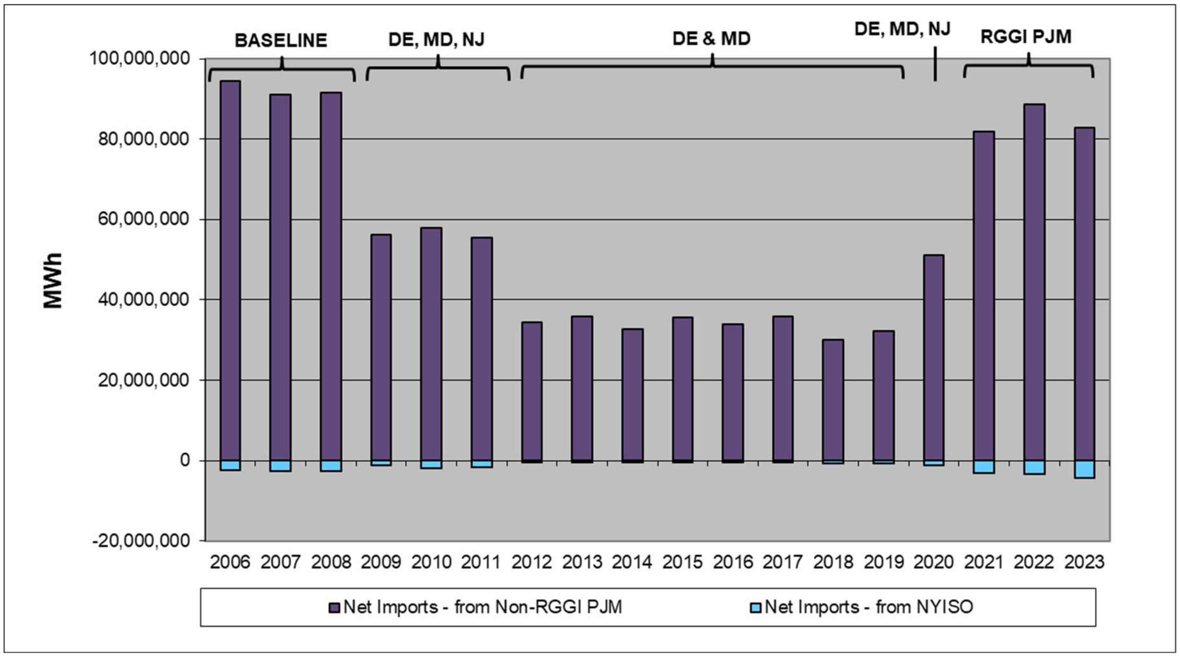

Figure 38. Net Electricity Imports to RGGI PJM (MWh). Annual averages for baseline years and 2021 to 2023 represent RGGI PJM; 2009 to 2011 and 2020 include Delaware, Maryland, and New Jersey (RGGI PJM-2); 2012 to 2019 include Delaware and Maryland only.

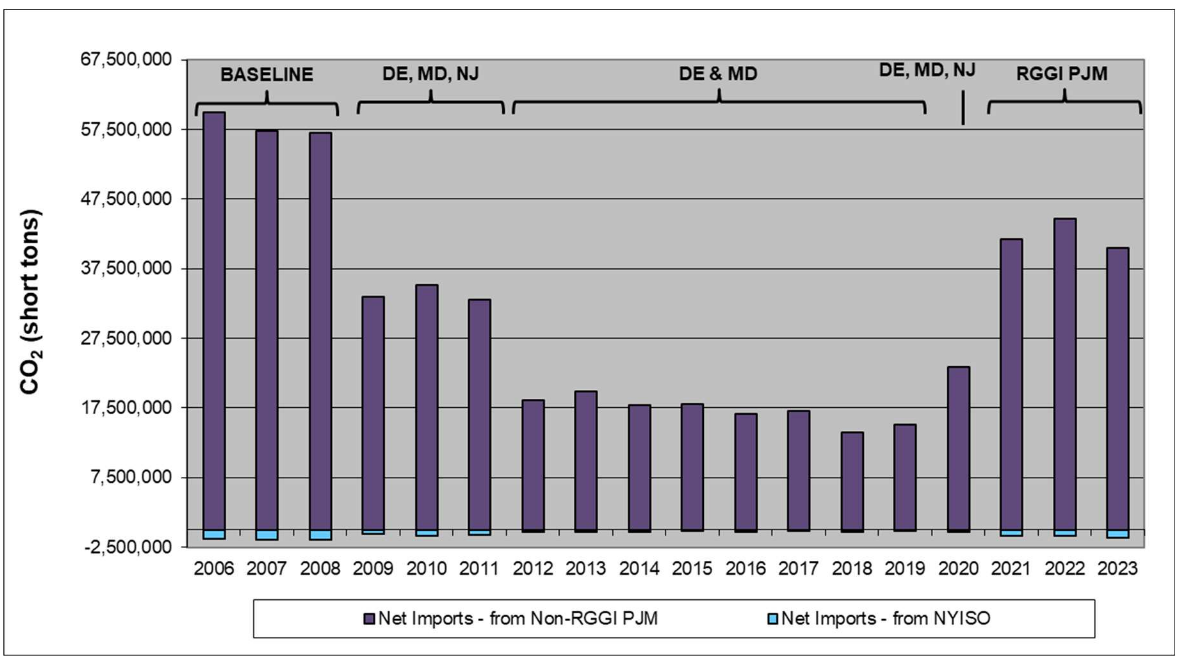

Figure 39. CO_2 Emissions Related to Net Electricity Imports to RGGI PJM (short tons CO2). Annual averages for baseline years and 2021 to 2023 represent RGGI PJM; 2009 to 2011 and 2020 include Delaware, Maryland, and New Jersey (RGGI PJM-2); 2012 to 2019 include Delaware and Maryland only.

Appendix C. Monitoring Trends

Detailed monitoring trends for the RGGI Region, ISO-NE, NYISO, and the RGGI portion of PJM are presented in Tables 8 through 11. The tables summarize the comparison between the 2006 to 2008 base period with the three-year average of RGGI operation (2021 to 2023) and the 2023 annual average.

RGGI Region

Table 8. Monitoring Trends for the RGGI Region

	Non-RGGI Generation (In-Region)			RGGI Generation			Net Imports		
	MWh	CO_2 Emissions	lb CO_2/MWh	MWh	CO_2 Emissions	lb CO_2/MWh	MWh	CO_2 Emissions	lb CO_2/MWh
Annual average for 2006-2008 (base period)	220,791,512	24,035,294	218	241,542,264	196,379,023	1,625	117,176,851	64,268,492	1,098
Annual average for 2021-2023	212,321,635	19,092,810	180	214,136,525	102,746,038	959	123,156,927	48,907,211	795
Difference from base period	-8,469,877	-4,942,484	-37.8	-27,405,739	-93,632,984	-666	5,980,076	-15,361,281	-303
% change from base period	-3.8%	-20.6%	-17.4%	-11.3%	-47.7%	-41.0%	5.1%	-23.9%	-27.6%
2023	212,806,538	17,613,355	166	212,155,901	98,087,209	925	115,837,564	47,912,607	827
Difference from base period	-7,984,974	-6,421,939	-52.1	-29,386,362	-98,291,814	-700.6	-1,339,287	-16,355,885	-270.7
% change from base period	-3.6%	-26.7%	-24.0%	-12.2%	-50.1%	-43.1%	-1.1%	-25.4%	-24.7%

	Non-RGGI Generation (Non-RGGI In-Region + Net Imports)			In-Region Generation	In-Region Load
	MWh	CO_2 Emissions	lb CO_2/MWh	MWh	MWh
Annual average for 2006-2008 (base period)	337,968,363	88,303,786	523	462,333,776	579,409,289
Annual average for 2021-2023	335,478,562	68,000,021	405	426,458,160	539,393,225
Difference from base period	-2,489,801	-20,303,765	-117	-35,875,616	-40,016,064
% change from base period	-0.7%	-23.0%	-22.4%	-7.8%	-6.9%
2023	328,644,101	65,525,962	399	424,962,439	529,976,163
Difference from base period	-9,324,262	-22,777,824	-124	-37,371,337	-49,433,126
% change from base period	-2.8%	-25.8%	-23.7%	-8.1%	-8.5%

ISO-NE

Table 9. Monitoring Trends for ISO-NE

	Non-RGGI Generation (In-Region)			RGGI Generation			Net Imports		
	MWh	CO_2 Emissions	lb CO_2/MWh	MWh	CO_2 Emissions	lb CO_2/MWh	MWh	CO_2 Emissions	lb CO_2/MWh
Annual average for 2006-2008 (base period)	60,527,897	11,046,433	365	67,414,107	47,242,267	1,401	7,196,667	-138,167	-48
Annual average for 2021-2023	59,193,477	12,404,258	418	51,623,917	24,257,626	940	16,885,001	1,449,132	172
Difference from base period	-1,334,420	1,357,826	53.7	-15,790,191	-22,984,640	-461.2	9,688,335	1,587,299	221
% change from base period	-2.2%	12.3%	14.7%	-23.4%	-48.7%	-32.9%	134.6%	1148.8%	455.3%
2023	57,628,278	11,026,698	383	52,819,362	24,094,406	912	15,102,000	1,486,971	197
Difference from base period	-2,899,619	-19,735	17.9	-14,594,745	-23,147,861	-489.0	7,905,333	1,625,139	245
% change from base period	-4.8%	-0.2%	4.9%	-21.6%	-49.0%	-34.9%	109.8%	1176.2%	506.6%

	Non-RGGI Generation (Non-RGGI In-Region + Net Imports)			In-Region Generation	In-Region Load
	MWh	CO_2 Emissions	lb CO_2/MWh	MWh	MWh
Annual average for 2006-2008 (base period)	67,724,564	10,908,266	322	127,942,004	135,037,333
Annual average for 2021-2023	76,078,478	13,853,390	364	110,817,394	117,480,667
Difference from base period	8,353,914	2,945,125	41.7	-17,124,611	-17,556,667
% change from base period	12.3%	27.0%	12.9%	-13.4%	-13.0%
2023	72,730,278	12,513,669	344	110,447,640	114,726,000
Difference from base period	5,005,714	1,605,403	22.0	-17,494,364	-20,311,333
% change from base period	7.4%	14.7%	6.8%	-13.7%	-15.0%

NYISO

Table 10. Monitoring Trends for the NYCA

	Non-RGGI Generation (In-Region)			RGGI Generation			Net Imports		
	MWh	CO_2 Emissions	lb CO_2/MWh	MWh	CO_2 Emissions	lb CO_2/MWh	MWh	CO_2 Emissions	lb CO_2/MWh
Annual average for 2006-2008 (base period)	74,907,441	3,366,481	90	73,296,785	56,897,266	1,550	20,206,894	7,885,769	790
Annual average for 2021-2023	62,964,022	2,292,323	73	61,925,528	28,886,439	992	25,457,585	6,229,802	498
Difference from base period	-11,943,419	-1,074,158	-16.8	-11,371,257	-28,010,827	-558.1	5,250,691	-1,655,967	-292
% change from base period	-15.9%	-31.9%	-18.7%	-15.5%	-49.2%	-36.0%	26.0%	-21.0%	-37.0%
2023	63,202,200	2,493,311	79	61,418,600	28,554,226	1,036	22,266,000	6,961,725	625
Difference from base period	-11,705,241	-873,170	-10.7	-11,878,185	-28,343,040	-514.5	2,059,106	-924,044	-164.2
% change from base period	-15.6%	-25.9%	-11.9%	-16.2%	-49.8%	-33.2%	10.2%	-11.7%	-20.8%

	Non-RGGI Generation (Non-RGGI In-Region + Net Imports)			In-Region Generation	In-Region Load
	MWh	CO_2 Emissions	lb CO_2/MWh	MWh	MWh
Annual average for 2006-2008 (base period)	95,114,334	11,252,250	236	148,204,225	168,411,119
Annual average for 2021-2023	88,421,607	8,522,124	194	124,889,550	150,347,002
Difference from base period	-6,692,727	-2,730,125	-42.7	-23,314,675	-18,064,117
% change from base period	-7.0%	-24.3%	-18.1%	-15.7%	-10.7%
2023	85,468,200	9,455,036	221	124,620,800	146,886,600
Difference from base period	-9,646,134	-1,797,214	-15.0	-23,583,426	-21,524,519
% change from base period	-10.1%	-16.0%	-6.3%	-15.9%	-12.8%

RGGI PJM

Table 11. Monitoring Trends for RGGI PJM

	Non-RGGI Generation (In-Region)			RGGI Generation			Net Imports		
	MWh	CO_2 Emissions	lb CO_2/MWh	MWh	CO_2 Emissions	lb CO_2/MWh	MWh	CO_2 Emissions	lb CO_2/MWh
RGGI PJM annual average for 2006-2008 (base period)	85,356,174	9,622,380	226	100,831,371	92,239,490	1,829	89,773,291	56,635,007	1,262
Annual average for 2021-2023	90,164,136	4,396,229	98	100,587,080	49,601,973	985	80,814,341	41,328,685	1,023
Difference from base period	4,807,962	-5,226,151	-128.0	-244,292	-42,637,517	-843.5	-8,958,950	-15,306,322	-238.9
% change from base period	5.6%	-54.3%	-56.7%	-0.2%	-46.2%	-46.1%	-10.0%	-27.0%	-18.9%
2023	91,976,060	4,093,347	89	97,917,939	45,438,577	928	78,469,564	39,402,864	1,004
Difference from base period	6,619,886	-5,529,033	-136.6	-2,913,432	-46,800,913	-900.8	-11,303,727	-17,232,143	-257.3
% change from base period	7.8%	-57.5%	-60.6%	-2.9%	-50.7%	-49.3%	-12.6%	-30.4%	-20.4%

	Non-RGGI Generation (Non-RGGI In-Region + Net Imports)			In-Region Generation	In-Region Load
	MWh	CO_2 Emissions	lb CO_2/MWh	MWh	MWh
RGGI PJM annual average for 2006-2008 (base period)	175,129,465	66,257,387	757	186,187,546	275,960,837
Annual average for 2021-2023	170,978,477	45,724,914	535	190,751,216	271,565,557
Difference from base period	-4,150,988	-20,532,474	-221.7	4,563,670	-4,395,280
% change from base period	-2.4%	-31.0%	-29.3%	2.5%	-1.6%
2023	170,445,624	43,496,211	510	189,893,999	268,363,563
Difference from base period	-4,683,841	-22,761,177	-246.2	3,706,453	-7,597,274
% change from base period	-2.7%	-34.4%	-32.5%	2.0%	-2.8%

Appendix D. Concept of "Emissions Leakage"

"Emissions leakage" is the concept that the RGGI CO_2 compliance obligation and related CO_2 compliance costs for electric generators could result in a shift of electricity generation from CO_2-emitting sources subject to the RGGI CO_2 Budget Trading Program to higher emitting CO_2 sources not subject to RGGI. Key to this concept is that the cause of such a shift would be due to the RGGI CO_2 Budget Trading Program rather than other factors that influence electric power sector CO_2 emissions. The concept of emissions leakage presumes that an increase in electricity production costs for certain electric generators due to RGGI CO_2 compliance costs would be the driver of changes in the operation of the electric power system that result in an increase in CO_2 emissions from electric generation that is not subject to the RGGI CO_2 Budget Trading Program.

Factors that Influence Electric Generator Dispatch and CO_2 Emissions

In New England and the Mid-Atlantic, electric generation is deregulated and subject to competitive wholesale electricity markets. In the simplest terms, wholesale electricity markets are used to determine which power plants run to meet electricity demand and determine the wholesale price of electricity. Electric generators bid into day-ahead and real-time auctions for generation supply, in which the lowest priced plants are selected one by one until electricity demand is met. The last plant selected, or "dispatched," to meet demand is referred to as the marginal unit and sets the wholesale clearing price. A number of elements factor into the bid offers made by individual electric generators, including fuel prices, operation and maintenance costs, and environmental compliance costs. For this latter category, certain environmental compliance costs are represented by the market value of emissions allowances, such as CO_2, NO_X, and SO_2 allowances. The market value of these emission allowances influences the production costs of individual electric generators in a similar manner as fuel costs and therefore play a role in influencing the dispatch of electric generators and the wholesale market clearing price of electricity.

In addition to the production costs of electric generators, such as natural gas supply and costs which can be influenced by pipeline constraints, the dispatch of electric generators and wholesale electricity prices are also influenced by electricity demand and electricity transmission constraints. Since electricity cannot be stored, it must be delivered instantaneously to where it is needed. In locations where electric demand is high, transmission capability may be constrained, meaning that electric generation has different values in different areas because the lowest cost electric generation cannot always be delivered to where it is needed based on transmission limitations. As a result, wholesale electricity prices also differ by location, a concept referred to as locational marginal pricing.

All of the above, including production costs, market factors, and physical limitations, impact the dispatch of electric generation, and related CO_2 emissions, through a highly dynamic wholesale electricity market.

The concept of emissions leakage assumes a scenario in which only a subset of CO_2-emitting electric generators are subject to a CO_2 allowance requirement.[58] As a result, certain electric generators are subject to an additional production cost – the cost of CO_2 allowances – that is not faced by other CO_2-emitting electric generators. In theory, this could result in a shift in electric generation to emitting units that do not face a CO_2 compliance cost. If such a shift results in an increase in CO_2 emissions from electric generation as a whole, such an increase is referred to as emissions leakage.

[58] The RGGI region does not completely align with the geographic footprint of wholesale electricity markets in the greater New England and Mid-Atlantic region, and electric power can flow across multiple wholesale markets in North America.

If emissions leakage were to occur, it would result from an increase in dispatch (and related CO_2 emissions) from: (a) in-region non-RGGI units (i.e., fossil fuel-fired units in the RGGI Region with a capacity less than 25 MWe, which are not subject to RGGI); (b) electric generation outside the RGGI Region (represented as electricity imports); or (c) a combination of the two, both of which are referred to in this report as “non-RGGI generation.”