

Regional Greenhouse Gas Initiative

an Initiative of the Northeast and Mid-Atlantic States of the U.S.

CO₂ Emissions from Electricity Generation and Imports in the Regional Greenhouse Gas Initiative: 2010 Monitoring Report

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The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort of Northeast and Mid-Atlantic states to reduce emissions of carbon dioxide (CO₂), 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.

Executive Summary

This report, the second report in a series of annual monitoring reports, summarizes data for electricity generation, electricity imports, and related carbon dioxide (CO₂) emissions for the ten states¹ that participated in the Regional Greenhouse Gas Initiative (RGGI) first control period for the period from 2005 through 2010. 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 CO₂ Budget Trading Program to result in “emissions leakage²”.³

In the Northeast and Mid-Atlantic states, CO₂ emissions from the regional electric power sector are a function of highly dynamic wholesale electricity markets. The cost of compliance with the RGGI CO₂ Budget Trading Program is only one of several factors that influence the dispatch of electric generation, and resulting CO₂ 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.

The observed trends in electricity demand, net electricity imports, and electricity generation from multiple categories of generation sources (including electricity imports), show there has been no increase in CO₂ emissions or the CO₂ emission rate (pounds of CO₂ per megawatt hour or lb CO₂/MWh) from non-RGGI electric generation serving load in the ten-state RGGI region in the first two years of the RGGI program operation, 2009 and 2010.

Summary of Results

Electric Load (Demand for Electricity) and Generation

- For 2009-2010, the annual average electricity load in the ten-state RGGI region was 14.3 million MWh less than the average 2006 to 2008 electricity load, about a 3% reduction.
- For 2009-2010, the annual average total electric generation in the ten-state RGGI region (fossil and non-fossil) decreased by 17.9 million MWh, or 4.6 percent from the 2006-2008 average.

¹ The “ten-state RGGI region” consists of Delaware, Connecticut, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. New Jersey withdrew its agreement to the RGGI Memorandum of Understanding effective January 1, 2012. See http://www.rggi.org/docs/Documents/NJ-Statement_112911.pdf.

² “Emissions leakage” is the concept that compliance with the RGGI CO₂ Budget Trading Program, and the incorporation of related CO₂ compliance costs by electric generators that are subject to the program, could result in a shift of electricity generation from CO₂-emitting sources that are subject to RGGI to CO₂-emitting sources that are not subject to RGGI.

³ The Memorandum of Understanding called for monitoring electricity imports into the RGGI participating states commencing from the start of the RGGI CO₂ Budget Trading Program and reporting the results of such monitoring on an annual basis beginning in 2010.

- A comparison of the average electricity load in the ten-state RGGI region for 2010 only, to the base period of 2006 to 2008, shows a decrease of 6.6 million MWh, or 1.4 percent.
- A comparison of the average total electric generation in the ten-state RGGI region (fossil and non-fossil) for 2010 only to the base period of 2006 to 2008 shows a decrease of 9.1 million MWh, or 2.4 percent.

Non-RGGI Generation

- The monitoring results indicate that CO₂ emissions from non-RGGI electric generation did not increase in 2009 and 2010 – the first two years of RGGI program implementation - relative to the base period of 2006 to 2008.
- A comparison of the 2009 and 2010 annual average to the base period of 2006 to 2008 annual average shows the total electric generation from all non-RGGI electric generation sources serving load in the 10-state RGGI region increased slightly, by 223 thousand MWh, an increase of 0.1percent.
 - A comparison of the 2009 to 2010 average to the base period of the 2006 to 2008 average shows CO₂ emissions from all non-RGGI electric generation sources serving load in the ten-state RGGI region decreased by 5.8 million short tons of CO₂, or 9.3 percent.
 - A comparison of the 2009 to 2010 average to the base period of the 2006 to 2008 average shows the CO₂ emission rate for this category of electric generation decreased by 44 lb CO₂/MWh, or 9.4 percent.
- The monitoring results do not show an increase of annual CO₂ emissions related to either net electricity imports into the ten-state RGGI region or from small fossil fuel-fired electric generators in the ten-state RGGI region that are not subject to state CO₂ Budget Trading Program regulations in the first two years of the program, 2009 and 2010.

RGGI Generation

- A comparison of the 2009 to 2010 average to the base period of the 2006 to 2008 average shows the electric generation from RGGI-affected electric generation sources decreased by 14 million MWh, or 6.9 percent.
 - A comparison of the 2009 to 2010 average to the base period of the 2006 to 2008 average shows CO₂ emissions from RGGI electric

generation sources decreased by 30 million short tons of CO₂, or 18.9 percent.

- A comparison of the 2009 to 2010 average to the base period of the 2006 to 2008 average shows the CO₂ emissions rate for RGGI electric generation sources decreased by 203 lb CO₂/MWh, or 12.9 percent.
- When 2010 only is compared to the baseline period of 2006 to 2008, the results similarly show a reduction in electric generation and CO₂ emissions from RGGI electric generation sources.

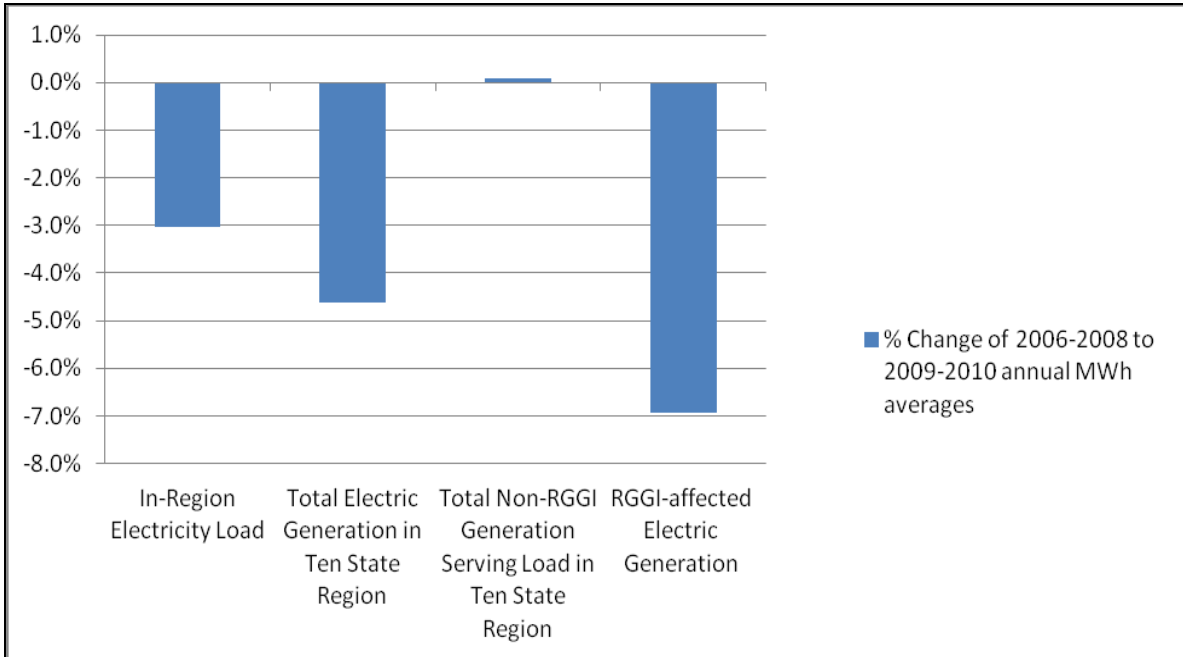


Figure 1. Comparison of percentage changes in electricity load and generation MWhs serving the RGGI Region from 2009 and 2010 to the base period on 2006 to 2008.

Monitoring Approach

The data summarized track electricity generation and imports in each of the three independent system operator (ISO) regions fully or partially subject to the RGGI CO₂ Budget Trading Program (ISO-New England – “ISO-NE”, New York ISO – “NYISO”, and PJM). The data track all MWh of electricity used to serve electric load in each ISO (or portion of an ISO subject to RGGI in the case of PJM) and the actual or estimated related CO₂ emissions. For each ISO, data are tracked for the following categories:

- **RGGI-Affected Generation**: Electric generation and CO₂ emissions for electric generation units subject to a CO₂ allowance compliance obligation under a state CO₂ Budget Trading Program.

- Non-RGGI Generation: Total electricity supplied to serve load in the ten-state RGGI region and related CO₂ emissions. This category is also broken down into the following subcategories:
 - Non-RGGI Generation (Fossil): Fossil fuel-fired electric generators located in the ten-state RGGI region that are not subject to a CO₂ allowance compliance obligation (e.g., fossil generators under 25 megawatts electrical (MWe) capacity)
 - Non-RGGI Generation (Non-Fossil): Non-fossil fuel-fired electric generators located in the ten-state RGGI region (e.g., nuclear, renewable energy, municipal solid waste combustors)
 - Net Imports: Net electricity imports from adjacent control areas (or portion of a control area) outside the ten-state RGGI region and CO₂ emissions related to these net imports

Conclusions

The monitoring results show there has been no increase in CO₂ emissions from non-RGGI electric generation during the first two years of RGGI program operation, 2009 and 2010, compared to an annual average during 2006 to 2008.

Given that the monitoring results presented in this report do not address causality, the results should be evaluated in context with market dynamics. The monitoring results for 2009 and 2010 are consistent with market dynamics given the relatively modest CO₂ allowance prices evident in the first two years of the program. These modest CO₂ allowance prices resulted in CO₂ compliance costs on a per MWh basis that were likely lower than the aggregate price signal of mitigating market factors discussed in this report that would advantageously limit emissions leakage.

I. Background

This annual report summarizes monitoring data for electricity generation and imports in the ten-state RGGI region⁴ and related CO₂ emissions for the period from 2005 through 2010. This monitoring was called for in the 2005 RGGI MOU in response to expressed concerns about the potential for the RGGI CO₂ Budget Trading Program⁵ to result in “emissions leakage”.⁶ 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*.⁷

The report provides data for evaluating CO₂ emissions related to electricity generation and imports in the ten-state RGGI region. The report tracks trends in electricity demand, net electricity imports, electricity generation from multiple categories of generation sources (including electricity imports), and the CO₂ emissions related to these categories of electric generation. The report should not be used to draw definitive conclusions about whether or not CO₂ emissions leakage has occurred, as it does not address the causes of changes in electricity generation and related CO₂ emissions among different categories of electric generation serving load in the ten-state RGGI region.

II. Monitoring Approach

The data summarized in this report track electricity generation and electricity use in each of the three ISO regions fully or partially subject to the RGGI CO₂ Budget Trading Program. The data track all 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 CO₂ emissions (in short tons of CO₂) related to the generation of this electricity, and the associated lb CO₂/MWh emission rate.⁸

⁴ The “ten-state RGGI region” consists of Delaware, Connecticut, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. New Jersey withdrew its agreement to the RGGI Memorandum of Understanding effective January 1, 2012. See http://www.rggi.org/docs/Documents/NJ-Statement_112911.pdf.

⁵ RGGI is comprised of state CO₂ Budget Trading Programs. Under each of these state programs, a regulated power plant must hold CO₂ allowances equal to its emissions to demonstrate compliance at the end of a three-year control period.⁵ CO₂ allowances are issued by participating states in a finite amount, or “budget”, resulting in a regional cap on CO₂ 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, which account for approximately 95 percent of the CO₂ emissions from electric generation in the ten-state RGGI region.

⁶ Specifically, the Memorandum of Understanding called for monitoring electricity imports into the RGGI participating states commencing from the start of the RGGI CO₂ Budget Trading Program and reporting the results of such monitoring on an annual basis beginning in 2010.

⁷ 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 http://www.rggi.org/docs/il_report_final_3_14_07.pdf

⁸ 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 referred to 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 not included in the monitoring results includes the portion of electric generation output used on-site, if an electric generating unit supplies only a portion of its

For each year 2005 through 2010, the following categories of data are presented for the ten-state RGGI region as well as each ISO:

- **RGGI-Affected Generation:** Electric generation (MWh), CO₂ emissions (short tons), and lb CO₂/MWh emission rate for electric generators subject to the RGGI CO₂ Budget Trading Program. This category is limited to electric generating units subject to a CO₂ allowance compliance obligation under state CO₂ Budget Trading Program regulations.⁹
- **Non-RGGI Generation:** Total electricity generation (MWh), CO₂ emissions, and lb CO₂/MWh emission rate for all non-RGGI electric generation serving electric load in the ten-state RGGI region (includes both in-region electric generation and net electricity imports).¹⁰ In addition to total non-RGGI generation, data for the following subcategories of non-RGGI generation are also presented:
 - **Non-RGGI Generation (Fossil):** Electric generation (MWh), CO₂ emissions, and lb CO₂/MWh emission rate for fossil fuel-fired electric generating units in the ten-state RGGI region that are not subject to a CO₂ allowance compliance obligation under state CO₂ Budget Trading Program regulations (e.g., electric generation units under 25 MWe)¹¹
 - **Non-RGGI Generation (Non-Fossil):** Electric generation (MWh), CO₂ emissions, and lb CO₂/MWh emission rate for electric generating units in the ten-state RGGI region that do not meet the definition of fossil fuel-fired in state CO₂ Budget Trading Program regulations (e.g., renewable, nuclear, municipal solid waste combustors)
 - **Net Imports:** Net electricity imports (MWh) from adjacent control areas and CO₂ emissions and lb CO₂/MWh emission rate related to these net imports.¹²

output to the ISO grid, or all electric generation output, if an electric generating unit supplies no electricity to the ISO grid. However, note that behind-the-meter electric generators eligible for credit under state renewable portfolio standards typically voluntarily report electric generation to the PJM Generation Attribute Tracking System (GATS) and NE-ISO Generation Information System (GIS), which are discussed in Section V. Methodology. These behind-the-meter electric generators that report to PJM GATS and ISO-NE GIS are included in the monitoring results.

⁹ For the purposes of this report, this category does not include electric generators that may be subject to a state CO₂ Budget Trading Program regulation, or portion of such regulation, but that are not subject to a CO₂ allowance compliance obligation that requires the generator to submit CO₂ allowances equivalent to its CO₂ emissions. For example, under Maryland's CO₂ Budget Trading Program regulations, certain industrial cogenerators may be subject to alternative CO₂ compliance obligations under certain conditions in lieu of submission of CO₂ allowances.

¹⁰ In practice, this category includes MWh and related CO₂ emissions from all electric generation serving load in the RGGI region, after subtracting out electric generation and related CO₂ emissions from electric generation units subject to a RGGI CO₂ allowance compliance obligation. For ISO-NE and NYISO, the "RGGI region" represents the full ISO footprint. For PJM, the "RGGI region" represents the three-state portion of PJM subject to the RGGI CO₂ Budget Trading Program in 2010 (New Jersey, Delaware, and Maryland).

¹¹ This category also includes electric generation units at industrial facilities that are exempted from a CO₂ allowance compliance obligation under state CO₂ Budget Trading Programs.

¹² 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.

III. Summary of Monitoring Results

Monitoring results are summarized below for the ten-state RGGI region. Results are presented in detail for the ten-state RGGI region, as well as for each individual ISO, under Section VI – Monitoring Results.

Electric Load (Demand for Electricity) and Generation

- For 2009-2010, the annual average electricity load in the ten-state RGGI region was 14.3 million MWh less than the average 2006 to 2008 electricity load, or 3 percent.
- For 2009-2010, the annual average total electric generation in the ten-state RGGI region (fossil and non-fossil) decreased by 17.9 million MWh, or 4.6 percent from the 2006-2008 average.
- A comparison of the average electricity load in the ten-state RGGI region for 2010 only, to the base period of 2006 to 2008, shows a decrease of 6.6 million MWh, or 1.4 percent.
- A comparison of the average total electric generation in the ten-state RGGI region (fossil and non-fossil) for 2010 only to the base period of 2006 to 2008 shows a decrease of 9.1 million MWh, or 2.4 percent.

Non-RGGI Generation

- The monitoring results indicate that CO₂ emissions from non-RGGI electric generation did not increase in 2009 and 2010 – the first two years of RGGI program implementation - relative to the base period of 2006 to 2008.
- A comparison of the 2009 to 2010 average to the base period of 2006 to 2008 average shows the total electric generation from all non-RGGI electric generation sources serving load in the 10-state RGGI region increased slightly, by 223 thousand MWh, an increase of 0.1 percent.
 - A comparison of the 2009 to 2010 average to the base period of the 2006 to 2008 average shows CO₂ emissions from all non-RGGI electric generation sources serving load in the ten-state RGGI region decreased by 5.8 million short tons of CO₂, or 9.3 percent.
 - A comparison of the 2009 to 2010 average to the base period of the 2006 to 2008 average shows the CO₂ emission rate for this category of electric generation decreased by 44 lb CO₂/MWh, or 9.4 percent.
- The monitoring results do not show an increase of annual CO₂ emissions related to either net electricity imports into the ten-state RGGI region or

from small fossil fuel-fired electric generators in the ten-state RGGI region that are not subject to state CO₂ Budget Trading Program regulations in the first two years of the program, 2009 and 2010.

RGGI Generation

- A comparison of the 2009 to 2010 average to the base period of the 2006 to 2008 average shows the electric generation from RGGI-affected electric generation sources decreased by 14 million MWh, or 6.9 percent.
 - A comparison of the 2009 to 2010 average to the base period of the 2006 to 2008 average shows CO₂ emissions from RGGI electric generation sources decreased by 30 million short tons of CO₂, or 18.9 percent.
 - A comparison of the 2009 to 2010 average to the base period of the 2006 to 2008 average shows the CO₂ emissions rate for RGGI electric generation sources decreased by 203 lb CO₂/MWh, or 12.9 percent.
- When 2010 only is compared to the baseline period of 2006 to 2008, the results similarly show a reduction in electric generation and CO₂ emissions and CO₂ emissions rate from RGGI electric generation sources.

IV. 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.

Selection of a Base Period

In this report, 2009 and 2010 monitoring data is compared with data from the base period of the three-year period from 2006 through 2008. Conditions may change significantly during a base period and influence conclusions. This was the case with the electric power sector in the ten-state RGGI region during the period 2005 through 2008, which saw changes in wholesale electricity prices and in underlying market dynamics, such as electricity demand and relative fuel prices. These changes influenced electric generator dispatch and resulted in very significant changes in electric power sector CO₂ emissions in the ten-state RGGI region during the 2005 to 2008 timeframe.

During the period from 2000 through 2010, 2005 had the second highest CO₂ emissions for electric generators that met the applicability criteria of the RGGI CO₂ Budget Trading Program, and the highest CO₂ emissions since 2001.

As a result, this year was dropped as a point of comparison, considering the very significant subsequent drop in CO₂ emissions in subsequent years through 2010. The period of 2006 through 2008 was selected the base period to provide a three-year point of comparison that is comparable to the three-year compliance periods of the RGGI program. For 2009 data comparisons to the base period please see the CO₂ Emissions from Electricity Generation and Imports in the 10-State Regional Greenhouse Gas Initiative: 2009 Monitoring Report.¹³

Key Metrics

A key metric presented in this report that may provide a preliminary indication of *potential* emissions leakage, or a lack thereof, is electric generation and related CO₂ emissions from all non-RGGI affected electric generation that serves electric load in the ten-state RGGI region. This includes electric generation in the ten-state RGGI region from electric generating units that are not subject to a CO₂ allowance compliance obligation under a state CO₂ Budget Trading Program (e.g., small fossil units not subject to RGGI), as well as net imports of electricity into the ten-state RGGI region. If CO₂ emissions leakage were to occur, it would manifest as an increase in CO₂ emissions from this category of non-RGGI electric generation, assuming all other factors that impact electricity system dispatch and CO₂ emissions, such as electricity demand, relative fossil fuel prices, and wholesale electricity prices, did not change. As a result, an increase in CO₂ 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* CO₂ emissions leakage.

General Limitations

It should be emphasized that this report does not provide indicators of CO₂ emissions leakage, but merely tracks electricity generation and imports and related CO₂ emissions in the RGGI region for 2009 and 2010 relative to baseline years prior to implementation of the RGGI program. Changes in these data over time may point to *potential* CO₂ emissions leakage as a result of the RGGI CO₂ Budget Trading Program, or a lack thereof, but may also be the result of wholesale electricity market and fuel market dynamics unrelated to the RGGI program.

The data and analysis in this Monitoring Report do not take into account the full lifecycle of sources of fuel. For example, the direct emissions of CO₂ and the lb CO₂/MWh emission rates from non-RGGI non-fossil fuel units in this report do not reflect the biomass lifecycle carbon reduction of atmospheric CO₂ levels resulting from uptake of CO₂ from the atmosphere as a result of forest and biomass growth. Likewise for municipal solid waste combustors, direct emissions of CO₂ are presented with no analysis of the lifecycle of the

¹³ Report available at http://www.rggi.org/docs/Elec_monitoring_report_11_09_14.pdf.

components of the waste. The analysis of lifecycle reductions and contributions of fuels used in non-RGGI non-fossil fuel units is not within the scope of this report and this report does not provide indicators of total atmospheric reductions or contributions from the fuels used in non-RGGI non-fossil fuel units.

This report cannot draw definitive conclusions about whether or not CO₂ emissions leakage has occurred, as it does not address the causes of shifts in electricity generation and related CO₂ emissions among different categories of electric generation serving load in the ten-state RGGI region. However, the results do demonstrate that there has been no increase in CO₂ emissions or lb CO₂/MWh emission rate from non-RGGI electric generation during the first two years of RGGI program operation, 2009 and 2010, compared to an annual average during 2006 – 2008.

Determining whether CO₂ emissions leakage has occurred requires the evaluation of a hypothetical counterfactual – the amount of CO₂ emissions from non-RGGI electric generation that would occur, assuming there is no shift in electric generation to CO₂-emitting non-RGGI electric generators as a result of the implementation of the RGGI CO₂ Budget Trading Program (i.e., assuming no CO₂ emissions leakage).

In theory, an increase in CO₂ emissions or CO₂ emission rate from non-RGGI electric generation as compared to a historical baseline year could occur in a scenario in which CO₂ emissions leakage does not occur. Conversely, leakage could theoretically occur in a scenario in which CO₂ emissions and CO₂ emission rate for non-RGGI electric generation *decreased* as compared to a historical baseline year, if such emissions would have decreased further under a hypothetical counterfactual where no CO₂ emissions leakage occurs.

Given that the monitoring results presented in this report do not address causality, the results should be evaluated in context with market dynamics. The monitoring results for 2009 and 2010 are consistent with market dynamics given relatively modest CO₂ allowance prices evident in 2009 and 2010 that result in CO₂ compliance costs on a dollar per MWh basis that are likely lower than the aggregate dollar per MWh price signal of mitigating market factors discussed in this report that would be expected to impede emissions leakage. Considering these factors, with modest CO₂ allowance prices, no net market dynamic driving emissions leakage would be expected to occur.

V. 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),¹⁴ supplemented by ISO electricity import/export data, and CO₂ emissions data for RGGI-affected electric generation from the RGGI CO₂ Allowance Tracking System (RGGI COATS) for 2009 and 2010 and emissions statement data reported to state environmental agencies in the RGGI participating states for 2005-2008. For non-RGGI electric generation, CO₂ emissions are based on CO₂ emissions for individual electric generation facilities in the NE 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 were compiled by the New York Department of Public Service from NYISO data (MWh generation data) and PJM and Hydro Quebec data (MWh electricity net import data). This MWh data was supplemented by CO₂ emissions data compiled by the New York Department of Environmental Conservation (NYDEC). 2009 and 2010 CO₂ emissions data for RGGI-affected electric generation units were taken from RGGI COATS and 2005-2008 CO₂ emissions data for these units were compiled from NYDEC emissions statement program data. CO₂ emissions data for fossil fuel-fired electric generation units that are non-RGGI affected were taken or extrapolated from reports compiled by NYDEC. A summary of data sources for NYISO is provided in Appendix A.

For each ISO, CO₂ emissions related to net electricity imports from each adjacent control area¹⁵ are the product of a lb CO₂/MWh emission rate and the reported MWh of net imports. The CO₂ emission rate for electricity imports is based on the system average CO₂ emission rate for the respective exporting adjacent control area.¹⁶ For ISO-NE and NYISO, net electricity imports are based on actual flow data for electricity transfers between adjacent control areas.¹⁷ For PJM, net electricity imports are inferred and represent “transfers” of electricity from the non-RGGI geographic portion of PJM into the RGGI geographic portion of PJM (Delaware, Maryland, and New Jersey). 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

¹⁴ 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 http://www.rggi.org/design/history/import_leakage.) 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).

¹⁵ For PJM, this represents inferred imports from the non-RGGI geographic portion of PJM.

¹⁶ 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.

¹⁷ 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.

to be met through an inferred “import” of electricity from the non-RGGI geographic portion of PJM into the RGGI geographic portion of PJM.¹⁸

When aggregating individual ISO net import data, the reported regional net imports of electricity and related CO₂ emissions from net imports presented in this report represent net imports from adjacent regions not subject to the RGGI CO₂ 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 CO₂ Budget Trading Program. In order to avoid inappropriate double counting of MWh and related CO₂ emissions, the net import subtotals from adjacent ISOs (or portion of ISO) subject to the RGGI CO₂ Budget Trading Program were not included when rolling up the individual ISO data into regional summary totals, as the electricity and CO₂ 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. (See next subsection for further discussion.)

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 the ten-state RGGI region.

For ISO-NE and NYISO, net electricity import data is based on the tracking of actual electricity flows between adjacent control areas.¹⁹ 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 three-state RGGI portion of PJM (Delaware, Maryland, and New Jersey) 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 in order 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

¹⁸ For PJM, this category of data does not technically represent an import of electricity, as PJM is dispatched as a single control area.

¹⁹ The exception is net import data from Hydro Quebec into NYISO, which represents net scheduled electricity imports.

multiplied by this percentage to derive an estimate of net electricity exports from 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.²⁰ 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 (sometimes referred to as “behind-the-meter” generation). Data for this sub-category of electric generation is not captured through the tracking methodology used in this report, as the methodology relies on unit-specific electric generation data provided by the ISOs.²¹

²⁰ This excludes most electric generation and electric load typically referred to 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). However, behind-the-meter electric generators eligible for credit under state renewable portfolio standards typically voluntarily report electric generation to the PJM Generation Attribute Tracking System (GATS) and NE-ISO Generation Information System (GIS). MWh data for these behind-the-meter electric generators that report to PJM GATS and ISO-NE GIS are included in the monitoring results.

²¹ CO₂ emissions data for behind-the-meter electric generation that is RGGI-affected are included in this report. In addition, only electricity output from cogeneration facilities is reported by ISOs, meaning that the average lb CO₂/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.

VI. Monitoring Results

Monitoring results are provided below for the full ten-state RGGI region. These results provide a compilation of data from each ISO fully or partially subject to the RGGI CO₂ Budget Trading Program: ISO-NE, NYISO, and PJM. For PJM, monitoring data is compiled for the three-state portion of PJM affected by RGGI (Delaware, Maryland, and New Jersey). Monitoring data for each ISO is presented in Appendix B.

Monitoring results for the 10-state RGGI region for 2005 through 2010 are summarized below in Table 1 and Figures 2 through 5.²²

Table 1. 2005 – 2010 Monitoring Summary for 10-State RGGI Region

	MWh						Tons CO ₂						Lb CO ₂ /MWh						
	2005	2006	2007	2008	2009	2010	2005	2006	2007	2008	2009	2010	2005	2006	2007	2008	2009	2010	
Electricity Demand																			
Total in RGGI	480,362,389	469,584,885	475,018,102	465,369,918	448,024,418	463,351,429	245,079,303	226,303,741	231,447,633	207,457,063	177,224,403	194,529,170	1,020	964	974	892	791	840	
Net Imports - from Ontario to NYISO	1,898,020	3,672,282	2,637,442	6,162,902	6,463,657	3,872,635	439,364	728,640	581,456	1,154,884	712,496	426,885	463	397	441	375	220	220	
Net Imports - from Quebec to NY & NE	7,375,317	8,982,749	11,912,292	15,141,014	17,065,805	13,549,209	24,390	39,607	157,573	33,380	37,624	29,871	7	9	26	4	4	4	
Net Imports - from New Brunswick to NE	1,620,000	1,047,000	896,000	1,285,000	1,569,000	737,000	785,728	468,573	439,514	767,727	942,592	442,760	970	895	981	1,195	1,202	1,202	
Net Imports - from non-RGGI PJM to NY	6,379,823	8,101,829	8,659,727	9,062,826	7,073,143	10,460,586	4,257,772	5,246,328	5,536,825	5,720,147	4,213,398	6,339,400	1,335	1,295	1,279	1,262	1,191	1,212	
Net Imports - from non-RGGI PJM to RGGI PJM	65,324,576	60,819,367	57,887,856	54,088,276	56,299,698	58,001,518	43,596,369	39,383,494	37,012,128	34,138,677	33,537,149	35,150,499	1,335	1,295	1,279	1,262	1,191	1,212	
Total Net Imports - from All Adjoining ISOs	82,597,736	82,623,227	81,993,317	85,740,018	88,471,303	86,620,948	49,103,621	45,866,641	43,727,496	41,814,815	39,443,259	42,389,415	1,189	1,110	1,067	975	892	979	
Electricity Generation																			
RGGI-Affected Units	211,948,440	199,154,474	207,636,048	197,934,746	180,007,234	195,137,381	180,946,904	159,862,042	167,050,592	149,715,865	122,156,938	135,570,053	1,707	1,605	1,609	1,513	1,357	1,389	
Non-RGGI Fossil Fuel-Fired Units	11,612,120	10,613,142	9,792,096	7,573,527	7,406,408	14,089,816	8,057,483	11,008,127	10,320,462	7,031,243	6,259,108	6,192,482	1,388	2,074	2,108	1,857	1,690	879	
Non-Fossil Fuel-Fired Units	174,335,370	177,430,089	175,813,369	173,972,867	172,599,291	168,292,700	6,971,295	9,566,931	10,349,083	8,895,141	9,365,098	10,377,221	80	108	118	102	109	123	
All Non-RGGI Units	185,947,490	188,043,230	185,605,464	181,546,394	180,005,699	182,382,516	15,028,778	20,575,057	20,669,545	15,926,384	15,624,205	16,569,702	162	219	223	175	174	182	
All Units	397,764,653	386,961,658	393,024,786	379,629,900	359,553,115	376,729,481	195,975,682	180,437,100	187,720,137	165,642,248	137,781,144	152,139,755	985	933	955	873	766	808	
Summary Data																			
Non-RGGI Generation Serving Load in ISO = Non-RGGI Generation within ISO + Net Imports	268,545,226	270,666,457	267,598,781	267,286,412	268,477,002	269,003,464	64,132,399	66,441,699	64,397,041	57,741,199	55,067,464	58,959,117	478	491	481	432	410	438	

²² Note that reported regional net imports of electricity represent net imports from adjacent control areas (or portion of a control area) not subject to the RGGI CO₂ Budget Trading Program. As a result, the net electricity imports and related CO₂ emissions as reported in tabular summaries for each ISO provided in Appendix B do not add up to the reported total regional net imports and related CO₂ 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 CO₂ Budget Trading Program. In order to avoid inappropriate double counting of MWh and related CO₂ emissions, these net import subtotals were not included when rolling up the individual ISO data into regional summary totals, as the electricity and CO₂ emissions represented by these net imports are included in the electric generation subtotals for each ISO.

The monitoring results indicate that during the first two years of the RGGI program, 2009 and 2010, total average annual electric generation from all non-RGGI electric generation serving load in the ten-state RGGI region increased, by 223 thousand MWh, an increase of 0.1 percent, from the average annual generation from the benchmark period of 2006 to 2008. In a comparison of the 2009 and 2010 annual average to the 2006 to 2008 base period annual average, the CO₂ emissions from this category of electric generation decreased by 5.8 million short tons of CO₂, a reduction of 9.3 percent, and the CO₂ emission rate decreased by 44 lb CO₂/MWh, a reduction of 9.4 percent. (See Figures 2, 3, and 4.)

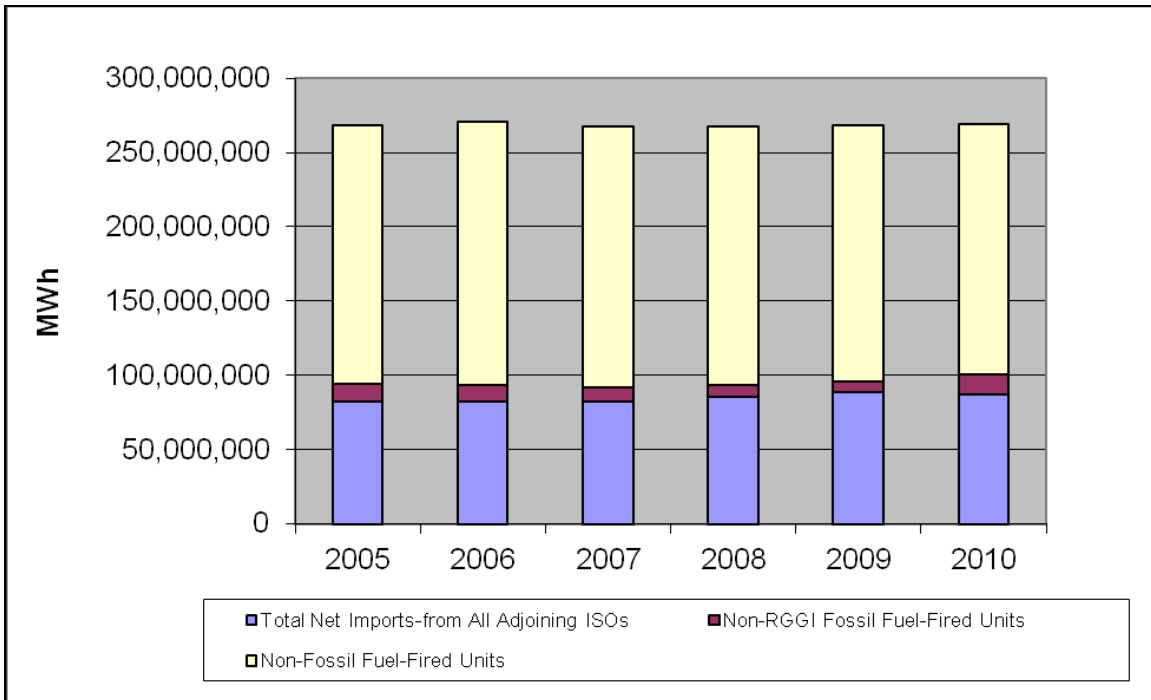


Figure 2. Non-RGGI Generation Serving Load in RGGI Region (MWh)

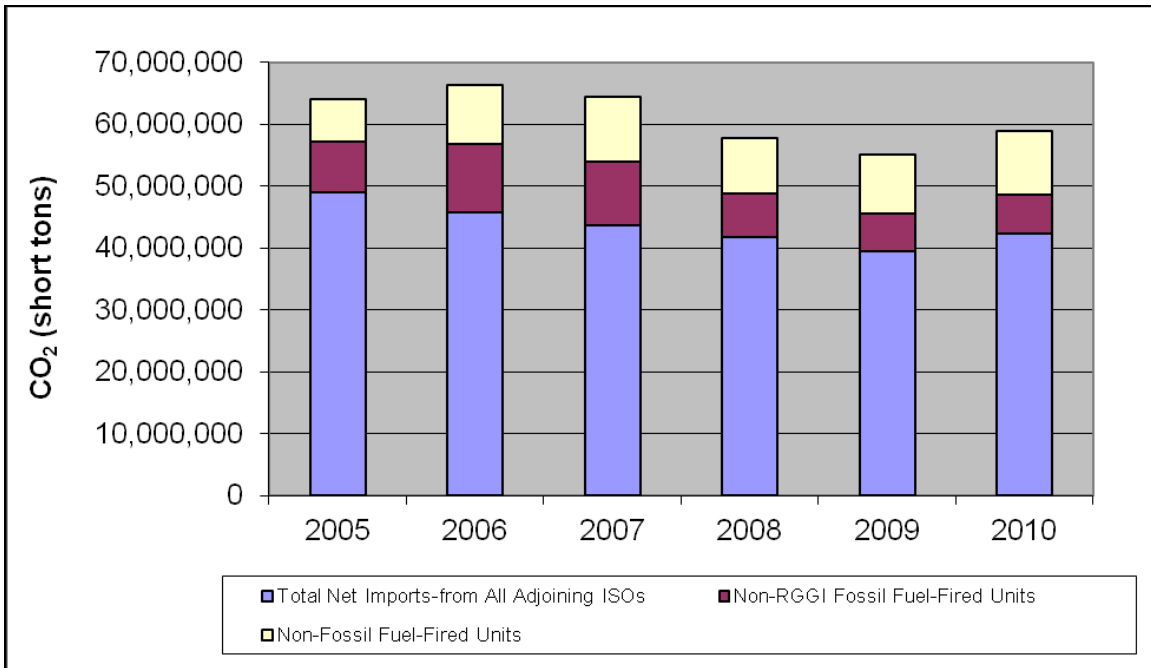


Figure 3. CO₂ Emissions from Non-RGGI Generation Serving Load in RGGI Region (short tons CO₂)

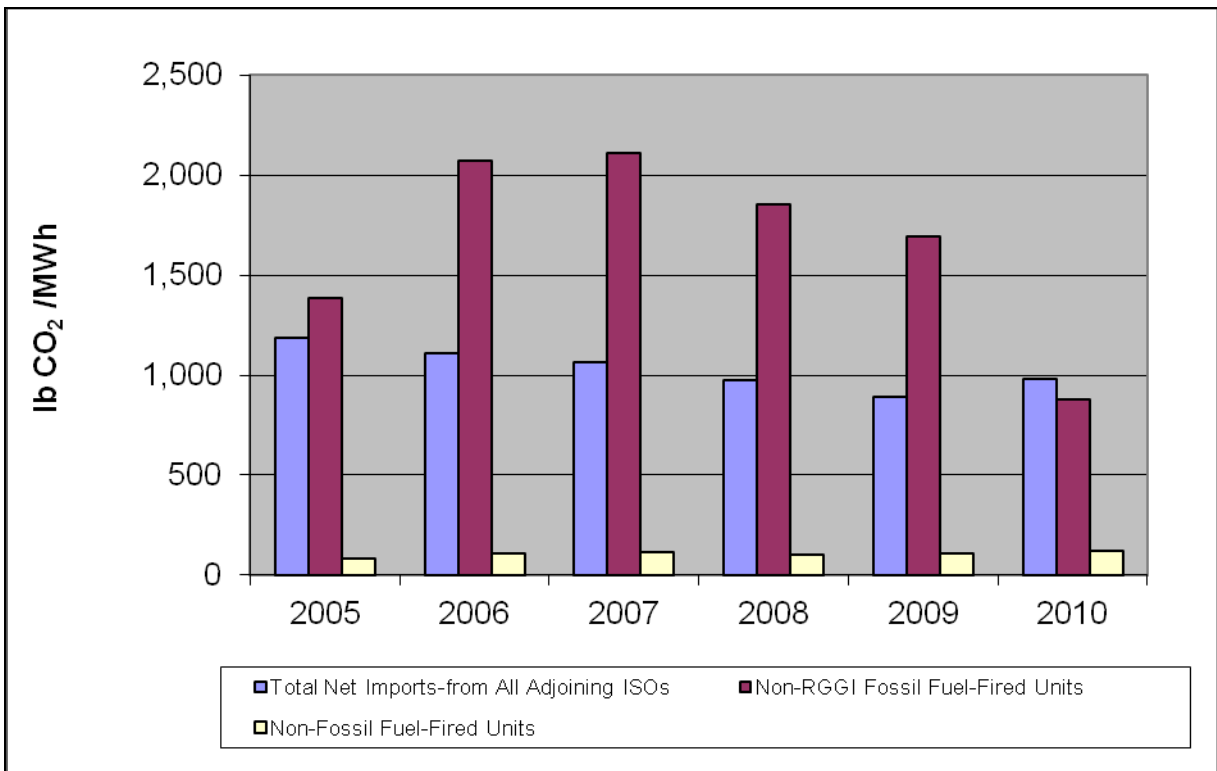


Figure 4. CO₂ Emission Rate for Non-RGGI Generation Serving Load in RGGI Region (lb CO₂/MWh)

The 2009 and 2010 annual average electricity load in the 10-state RGGI region decreased by 14.3 million MWh, or 3 percent, from the 2006 to 2008 base period annual average. In total, electric generation in the ten-state RGGI region (fossil and non-fossil) decreased by 17.9 million MWh, or 4.6 percent, from the base period annual average.

Electric generation from RGGI-affected generation decreased by 14 million MWh during this period, or 6.9 percent, and CO₂ emissions from RGGI-affected generation decreased by 30 million short tons, or 18.9 percent. The CO₂ emission rate of RGGI-affected electric generation decreased by 203 lb CO₂/MWh, a decrease of 12.9 percent. Electric generation from non-RGGI generation sources located in the 10-state RGGI region decreased by 3.9 million MWh, or 2.1 percent, during this period, and CO₂ emissions from this category of electric generation decreased by 3.0 million short tons, a reduction of 15.5 percent. The CO₂ emission rate of non-RGGI electric generation located in the ten-state RGGI region decreased by 28 lb CO₂/MWh, a reduction of 13.7 percent.

Average annual net electricity imports into the 10-state RGGI region increased by 4.1 million MWh, or 4.9 percent, from the 2009 and 2010 average compared to the 2006 to 2008 base period annual average. CO₂ emissions related to these net electricity imports decreased by 2.9 million short tons, or 6.6 percent, during this period, indicating a reduction in the average CO₂ emission rate of the electric generation supplying these imports of 115 lb CO₂/MWh, a reduction of 10.9 percent. (See Figures 5 and 6.)

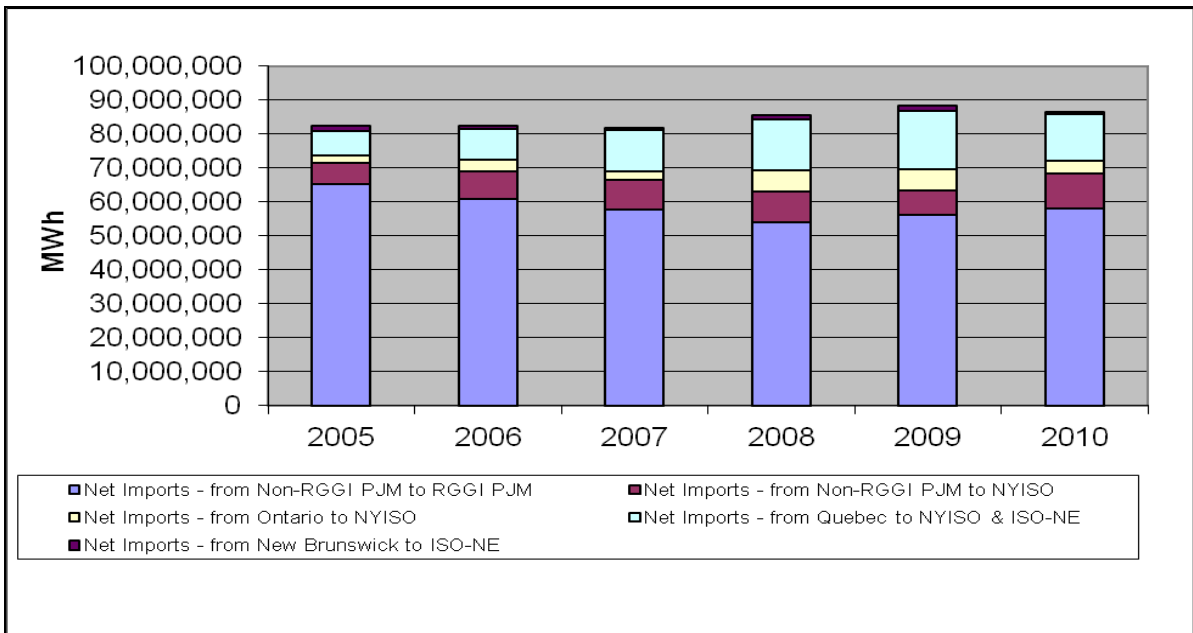


Figure 5. Net Electricity Imports to 10-State RGGI Region (MWh)

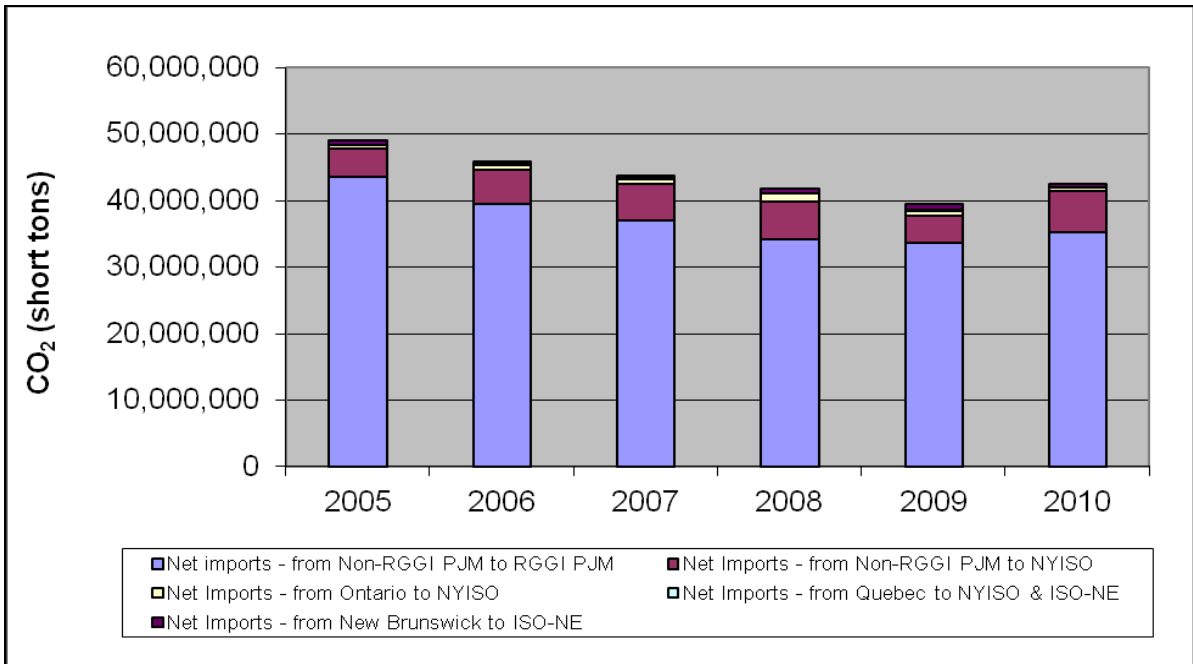


Figure 6. CO₂ Emissions Related to Net Electricity Imports to 10-State RGGI Region (short tons CO₂)

Compared to the annual average during a multi-year 2006 – 2008 base period, 2010 total electricity load in the ten-state RGGI region decreased by 6.6 million MWh, or 1.4 percent. Compared to the 2006 – 2008 annual average, total electric generation in 2010 in the ten-state RGGI region decreased by 9.1 million MWh, or 2.4 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2010 electric generation from RGGI-affected generation decreased by 6.4 million MWh, or 3.2 percent, and CO₂ emissions from RGGI-affected generation decreased by 23.3 million short tons of CO₂, or 14.7 percent. The CO₂ emission rate of RGGI-affected electric generation decreased by 187 lb CO₂/MWh, a reduction of 11.9 percent. Compared to the 2006 – 2008 annual average, 2010 electric generation from non-RGGI generation sources located in the ten-state RGGI region decreased by 2.7 million MWh, or 1.4 percent, and CO₂ emissions from this category of electric generation decreased by 2.5 million short tons, a reduction of 13.1 percent. The CO₂ emission rate of non-RGGI electric generation located in the ten-state RGGI region decreased by 24 lb CO₂/MWh, a reduction of 11.8 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2010 net electricity imports into the ten-state RGGI region increased by 3.2 million MWh, or 3.8 percent. CO₂ emissions related to these net electricity imports decreased by 1.4 million short tons of CO₂, or 3.2 percent, during this period, indicating a decrease in the average CO₂ emission rate of the electric generation supplying these imports of 71 lb CO₂/MWh, a reduction of 6.8 percent.

VII. Discussion

In the context of the multiple market factors outlined below that influence dispatch of electric generation, CO₂ allowance costs in 2009 and 2010, the first two years of RGGI operation, were relatively modest compared to other electric generation cost components that impact wholesale electricity prices. This modest carbon price signal is consistent with monitoring data in this report that indicate no net increase in CO₂ emissions for non-RGGI electric generation in the annual average of 2009 and 2010 compared to the annual average during 2006 – 2008.

Across the three ISOs subject to RGGI, CO₂ allowance costs accounted for 0.06 percent to 1.5 percent of the average all-in wholesale electricity price in 2010.²² While CO₂ allowance costs represented a modest component of wholesale electricity prices, wholesale prices dropped significantly from 2008 to 2009 in each of the three ISOs subject to RGGI. The wholesale electricity price reduction was primarily due to a reduction in natural gas prices and a reduction in electricity demand. Higher fuel prices in 2010, coupled with increased economic activity and hot weather led to an increase in wholesale prices in 2010 relative to 2009.²³

A number of market drivers have changed dramatically during the 2005 through 2010 monitoring timeframe. This includes changes in relative fossil fuel prices (prices for natural gas, coal, and oil), electricity demand, and the availability of different types of electric generation capacity with differing CO₂ emissions profiles. An analysis of these changes, and their estimated impact on

²² For 2010, the average all-in wholesale electricity price was \$66.72/MWh for PJM, \$58.82/MWh for ISO-NE, and \$59.00/MWh for NYISO (energy only) (See ISO-NE Monthly Wholesale Load Cost Report, December 2010; NYISO, *Power Trends 2011*, p. 21; Monitoring Analytics, *2010 State of the Market Report for PJM*, Section 1, Introduction, p. 11). The CO₂ allowance component is based on a 2010 average CO₂ allowance spot price of \$1.93 per CO₂ allowance (See Potomac Economics, *Annual Report on the Market for RGGI CO₂ Allowances: 2010* p. 13). For PJM, the CO₂ allowance component of the Locational Marginal Price (LMP) for 2010 was \$0.40 per MWh (See Monitoring Analytics, *2010 State of the Market Report for PJM*, Section 2, Energy Market, Part 1, p. 79). ISO-NE and NYISO do not report the CO₂ allowance component of wholesale electricity prices. Both the New England and New York analyses used a 2010 average CO₂ allowance spot price of \$1.93 as a starting point for deriving a CO₂ allowance wholesale price component. The ISO-NE CO₂ allowance wholesale price component was calculated by assuming an aggregate oil/natural gas unit is the marginal unit, with a CO₂ emission rate of 0.482 short tons of CO₂ per MWh (see *2008 New England Electric Generator Air Emissions Report, August 2010, Table 5.10*). The NYISO CO₂ allowance wholesale price component was calculated by assuming that a natural gas plant is the marginal unit, with a 2009 fleet average heat rate of 8,978 Btu per kWh and a CO₂ emission rate of 117 pounds per MMBtu. For both ISO-NE and NYISO, the CO₂ emission rate of the assumed marginal unit was used to translate the annual average spot price for CO₂ allowances (\$1.93) into a dollar per MWh value. For ISO-NE, this resulted in an average CO₂ allowance wholesale price component of approximately \$0.93 per MWh. For NYISO, this resulted in an initial average CO₂ allowance wholesale price component of \$1.03 per MWh. Since ISO-NE imports from Canada are not subject to RGGI and associated with a wholesale CO₂ allowance price component, the ISO-NE initial \$0.93 per MWh wholesale CO₂ allowance price component is reduced to \$0.86 to account for the electricity imported from these areas, about 7.5% of the load. Since Canada and Pennsylvania are not RGGI participating jurisdictions, electricity imported into NYISO from these areas is not assumed to be associated with a CO₂ allowance wholesale price component in NYISO. Therefore, the initial \$1.03 per MWh CO₂ allowance wholesale price component for NYISO was reduced to \$0.76 to account for the amount of marginal electricity imported from these areas.

²³ See, for example, Monitoring Analytics, *2010 State of the Market Report for PJM*, Section 1, Introduction; Potomac Economics, *2010 State of the Market Report New York ISO*, pp. ii-iv; ISO New England Internal Market Monitor, *2010 Annual Markets Report*, May 2010, pp. 1-2.

CO₂ emissions in the 10-state RGGI region from 2005 to 2009, was completed by the New York State Energy Research and Development Authority (NYSERDA).²⁴

The dynamics of a competitive wholesale electricity market could drive emissions leakage if they provide a sufficient net financial incentive to shift electric generation to units not subject to CO₂ regulation. The extent of this impact is likely to depend, at least in part, on the market value of CO₂ allowances (and the related \$/MWh CO₂ costs incorporated into bids by generators subject to the RGGI CO₂ Budget Trading Program) in relation to other economic factors associated with the generation and delivery of electricity. These factors include locational marginal pricing (LMP), which includes both transmission congestion charges and line loss costs, standard transmission pricing, relative fuel prices, and relative heat rates of generation units.²⁵ 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.

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 CO₂ 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, given the dynamic operation of the electric power system.

Locational marginal pricing (LMP) can be expected to affect the market response to the imposition of a CO₂ allowance cost adder to generation in the RGGI region. LMP is based on the principle that the generation of power has different values at different points in the electric power network. 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 local generation units. Market participants utilize finite transmission resources, and transfers of power in a region can impact the local generation economics in that area, due to the physics of the electric transmission network. 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 transmission-constrained area, higher cost units in this

²⁴ New York State Energy Research and Development Authority (NYSERDA), Relative Effects of Various Factors on RGGI Electricity Sector CO₂ Emissions: 2009 Compared to 2005, November 2010; available at http://www.rggi.org/docs/Retrospective_Analysis_Draft_White_Paper.pdf.

²⁵ Heat rate is a measure of electric generator energy efficiency, represented as Btu of fuel input per kWh of electricity output.

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 due to a combination of electricity demand, transmission limitations, and the marginal cost of local generation.

If the cost of RGGI CO₂ 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. This net market signal would be a function of the relationship between the generation cost differential due to RGGI CO₂ compliance and the all-in market cost of transferring incremental power into the RGGI region or shifting generation to other unregulated smaller fossil fuel-fired generation sources within the RGGI region. Market factors that may impact the economics of importing incremental power in response to a CO₂ allowance price signal include²⁶:

- *Existing Generator Economics* – Including a CO₂ compliance cost into the generation costs of an individual electric generator may make that generator uneconomic relative to a competitor. However, whether this occurs depends on the operating costs of each electric generator, both with and without CO₂ 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 allowance costs for air pollutants (nitrogen oxides (NO_x), sulfur dioxide (SO₂), and CO₂). As a result, inclusion of a CO₂ 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* – Differential LMPs between regions represent the presence of transmission constraints that require the dispatch of higher priced electric generation in a certain region. Electricity demand, in particular, can have a large impact on LMPs in a specific region. For example, in 2010 the average day-ahead, load-weighted zonal LMP in eastern PJM (NJ, DE, MD) was \$7.38 per MWh above the average PJM LMP, indicating the presence of existing transmission congestion.²⁷
- *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 CO₂ 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,

²⁶ Some of these factors may also impact the economics of shifting dispatch to smaller in-region fossil fuel-fired electric generation in the ten-state RGGI region that is not subject to regulation of CO₂.

²⁷ Monitoring Analytics, *2010 State of the Market for PJM*, 2010; Section 2, Energy Market, Part 1, pp. 91.

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.²⁸

- *Line loss charges* – The greater the distance that electricity is transmitted, and as more power is 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. For example, 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.²⁹
- *Long-Term Contracts* – Other factors, such as existing long-term power purchase agreements, can be expected to mitigate emissions leakage, especially in the near-term, since units that are subject to such agreements will continue to dispatch subject to the terms of the agreements. With existing contracts in place, LSEs are constrained from seeking alternative sources of generation supply.^{30, 31} It is estimated that long-term contracts account for approximately 12% of electric generation in the ten-state RGGI region.³²

VIII. Conclusions

This report presents data and trends for electricity generation, imports and related CO₂ emissions without assigning causality to any one of the factors

²⁸ As an example, the congestion component of the 2010 average day-ahead, load weighted LMP in the Delmarva Power & Light zone (Delaware and Maryland) zone of PJM was \$3.73 per MWh. For the Baltimore Gas & Electric zone (Maryland), the congestion component was \$6.83 per MWh, and for the PSEG zone (New Jersey), the congestion component was \$3.47 per MWh. See, Monitoring Analytics, 2010 *State of the Market for PJM*, 2011; Section 2, Energy Market, Part 1, p. 91.

²⁹ As an example, the line loss component of the 2010 average day-ahead, load weighted LMP in the Delmarva Power & Light (Delaware and Maryland) zone of PJM was \$3.02 per MWh. Similarly, for the Baltimore Gas & Electric zone (Maryland), the line loss component of LMP was \$2.88 per MWh, and for the PSEG zone (New Jersey) the line loss component of LMP was \$3.24 per MWh. See, Monitoring Analytics, 2010 *State of the Market for PJM*, 2011; Section 2, Energy Market, Part 1, Table 2-55, p. 90.

³⁰ For example, some coal- and gas-fired units in New Jersey are subject to long-term power contracts. Similarly, two thirds of Vermont’s load is served under long-term contracts.

³¹ The power purchase agreements (PPAs) referenced here are plant-specific. It should be noted that this is not the case for all long-term PPAs. With the advent of electricity restructuring, many PPAs with non-utility generators (NUGs) were renegotiated. These renegotiated contracts often granted generators the flexibility to dispatch on a merchant basis in exchange for reducing the price paid by the purchaser for delivered firm energy and capacity. The PPA seller retained the responsibility for providing energy and capacity to the purchaser from either the generation facility or other generation resources within the ISO. These types of PPAs would not be expected to mitigate emissions leakage.

³² See Wilson et al., *The Impact of Long-Term Generation Contracts on Valuation of Electricity Generating Assets under the Regional Greenhouse Gas Initiative*, Resources for the Future Discussion Paper, RFF DP 05-37, August 2005.

influencing observed trends in electricity generation and related CO₂ emissions among different categories of electric generation serving load in the 10-state RGGI region. The results do demonstrate that there has been no increase in CO₂ emissions or CO₂ emission rate (lb CO₂/MWh) from non-RGGI electric generation serving load in the ten-state RGGI region during the first two years of RGGI program operation, 2009 and 2010. If emissions leakage were to occur, it would manifest through an increase in CO₂ emissions from this aggregate category of non-RGGI electric generation, assuming all other factors that impact electric generator dispatch and CO₂ emissions, such as electricity demand, relative fossil fuel prices, and wholesale electricity prices, did not change.

Given that the monitoring results presented in this report do not address causality, the results should be evaluated in context with market dynamics. The monitoring data for 2009 and 2010, which show no increase from the base period of 2006 to 2008 in CO₂ emissions from non-RGGI electric generation serving electricity load in the ten-state RGGI region, are consistent with expectations, given the relatively modest CO₂ allowance prices evident in 2009 and 2010. The average CO₂ allowance price in 2009 and 2010 represented approximately 1.5 percent or less of the average wholesale electricity price in the three ISOs fully or partially subject to RGGI. The monitoring results are consistent with market dynamics given the modest CO₂ allowance prices that result in CO₂ compliance costs on a per MWh basis that are likely lower than the aggregate per MWh price signal of mitigating market factors discussed in this report that would counter emissions leakage. Considering these factors, with modest CO₂ allowance prices, no net market dynamic driving emissions leakage would be expected to occur.

This report is the second in a series of annual monitoring reports, as called for in the 2005 RGGI MOU. This continued monitoring is warranted, especially considering the fact that both electricity market drivers and non-market drivers that impact CO₂ emissions have shifted dramatically from year to year during the 2005 to 2010 time period evaluated in this report. Ongoing monitoring will further evaluate changes in market and non-market drivers that impact CO₂ emissions related to electricity generation and imports in the RGGI region.

Appendix A. ISO Monitoring Sources

Table 2. Summary of Data Sources for ISO-NE

Code	Monitoring Category Associated with Data Elements at Right	MWh	CO ₂ lb/MWh	CO ₂ Tons
Electricity Demand (Annual)				
A-1	Total Electricity Use in ISO-NE	ISO-NE ¹	CO ₂ tons divided by MWh	Sum of A-3 and B-5
A-2	Net Electricity Imports - from New York	ISO-NE ¹	B-5	MWh multiplied by CO ₂ /MWh
A-2	Net Electricity Imports - from Quebec	ISO-NE ¹	Environment Canada ³	MWh multiplied by CO ₂ /MWh
A-2	Net Electricity Imports - from New Brunswick	ISO-NE ¹	Environment Canada ³	MWh multiplied by CO ₂ /MWh
A-3	Total Net Electricity Imports - from All Adjoining ISOs	ISO-NE ¹	CO ₂ tons divided by MWh	Sum of A-2s
Electricity Generation (Annual)				
B-1	RGGI-Affected Units	NEPOOL-GIS ²	CO ₂ tons divided by MWh	State reported data for 2005-2008; RGGI COATS for 2009 & 2010. 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.
B-2	Non-RGGI Units (Fossil Fuel-Fired; <25MW)	NEPOOL-GIS ²	CO ₂ tons divided by MWh	NEPOOL-GIS ²
B-3	Non-RGGI Units (Non-Fossil Fuel-Fired)	NEPOOL-GIS ²	CO ₂ tons divided by MWh	NEPOOL-GIS ²
B-4	All Non-RGGI Units (Fossil and Non-Fossil)	Sum of B-2 and B-3	CO ₂ tons divided by MWh	Sum of B-2 and B-3
B-5	All Units	ISO-NE ¹	CO ₂ tons divided by MWh	Sum of B-1 and B-4

Table Notes:

1. ISO-NE, Historical Data Reports, "Net Energy and Peak Load by Source" (Annual Summary). Available at <http://www.iso-ne.com/markets/hstdata/rpts/net_eng_peak_load_sorc/index.html>.
2. NEPOOL Generation Information System. Available at <<http://www.nepoolgis.com>>.
3. Environment Canada, *National Inventory Report 1990–2009: Greenhouse Gas Sources and Sinks in Canada*, Environment Canada, May 16, 2011. In Part 3, see Table A13-5 "Electricity Generation and GHG Emission Details for New Brunswick"; Table A13-6 "Electricity Generation and GHG Emission Details for Quebec". Available at <http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php>. Note that New Brunswick emission factors were updated for 2005-2009, as compared to the previous year's report.
4. Historical 2005 – 2008 CO₂ emissions data reported by RGGI participating states compiled from CO₂ emissions data reported to U.S. EPA pursuant 40 CFR Part 75 and from CO₂ emissions and fuel use data reported to state emissions statement programs. Historical 2005 – 2008 CO₂ emissions data is available at <http://www.rggi.org/historical_emissions>. 2009 and 2010 CO₂ emissions data is from data reported to the RGGI CO₂ Allowance Tracking System (RGGI COATS), available at <<http://www.rggi-coats.org>>.

Table 3. Summary of Data Sources for NYISO

Code	Monitoring Category Associated with Data Elements at Right	MWh	CO ₂ lb/MWh	CO ₂ Tons
Electricity Demand (Annual)				
A-1	Total Electricity Use in NYISO	Sum of A-3 and B-5	CO ₂ tons divided by MWh	Sum of A-3 and B-5
A-2	Net Electricity Imports - from Hydro Quebec	Hydro Quebec ¹	Environment Canada ⁶	MWh multiplied by CO ₂ /MWh
A-2	Net Electricity Imports - from ISO-NE	ISO-NE ²	ISO-NE system average ⁷	MWh multiplied by CO ₂ /MWh
A-2	Net Electricity Imports - from Ontario	Ontario Independent Electricity System Operator ³	Environment Canada ⁶	MWh multiplied by CO ₂ /MWh
A-2	Net Electricity Imports - from PJM	PJM Annual State of the Market Report ⁴	PJM GATS ⁸	MWh multiplied by CO ₂ /MWh
A-3	Total Net Electricity Imports - from All Adjoining ISOs	Sum of A-2s	CO ₂ tons divided by MWh	Sum of A-2s
Electricity Generation (Annual)				
B-1	RGGI-Affected Units	NYDPS Calculation ⁵	CO ₂ tons divided by MWh	State reported data for 2005-2008; RGGI COATS for 2009 & 2010 ^{9,10} . Includes only sources subject to a state CO ₂ Budget Trading Program CO ₂ allowance compliance obligation.
B-2	Non-RGGI Units (Fossil Fuel-Fired; < 25 MW)	NYDPS Calculation ⁵	CO ₂ tons divided by MWh	NYSDEC Emissions Report ¹¹
B-3	Non-RGGI Units (Non-Fossil Fuel-Fired)	NYDPS Calculation ⁵	CO ₂ tons divided by MWh	NYSDEC Emissions Report ¹¹
B-4	All Non-RGGI Units (Fossil and Non-Fossil)	Sum of B-2 and B-3	CO ₂ tons divided by MWh	Sum of B-2 and B-3
B-5	All Units	Sum of B-1 and B-4	CO ₂ tons divided by MWh	Sum of B-1 and B-4

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 <http://www.iso-ne.com/markets/hstdata/rpts/net_eng_peak_load_sorc/index.html>.
3. Ontario IESO response to information request.
4. Monitoring Analytics, *State of the Market for PJM* (2005 through 2009 reports).

5. NYDPS calculation based on MWh for each generator reported by NYISO and assignment of each generator to appropriate monitoring classification.
6. Environment Canada, *National Inventory Report 1990–2009: Greenhouse Gas Sources and Sinks in Canada*, Environment Canada, May 16, 2011. In Part 3, see Table A13-6 “Electricity Generation and GHG Emission Details for Quebec”; Table A13-7 “Electricity Generation and GHG Emission Details for Ontario”. Available at <http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php> Note that Ontario emission factors were updated for 2008 and 2009, as compared to the previous year’s report.
7. Calculated average, based on Row B-5 in Table 2 above.
8. PJM Generation Attribute Tracking System, accessible at <http://www.pjm-eis.com>.
9. MWh and CO₂ emissions data include Linden Cogeneration, units 005001 – 009001, as these units are physically located in New Jersey, but dispatch electricity into NYISO.
10. Historical 2005 – 2008 CO₂ emissions data reported by RGGI participating states compiled from CO₂ emissions data reported to U.S. EPA pursuant 40 CFR Part 75 and from CO₂ emissions and fuel use data reported to state emissions statement programs. Historical 2005 – 2008 CO₂ emissions data is available at <http://www.rggi.org/historical_emissions>. 2009 and 2010 CO₂ emissions data is from data reported to the RGGI CO₂ Allowance Tracking System (RGGI COATS), available at <<http://www.rggi-coats.org>>.
11. NYDPS calculation based on NYSDEC emissions data and other state data.

Table 4. Summary of Data Sources for RGGI PJM

Code	Monitoring Category Associated with Data Elements at Right	MWh	CO ₂ lb/MWh	CO ₂ Tons
	Electricity Demand (Annual)			
A-1	Total Electricity Use in RGGI PJM	Sum of A-3 and B-5	CO ₂ tons divided by MWh	Sum of A-3 and B-5
A-2	Net Electricity Imports - from Non-RGGI PJM	PJM GATS ¹	PJM GATS ¹	MWh multiplied by CO ₂ /MWh
A-2	Net Electricity Imports - from NYISO	PJM Annual State of the Market Report ²	B-5	MWh multiplied by CO ₂ /MWh
A-3	Total Net Electricity Imports - from All Adjoining ISOs	Sum of A-2s	CO ₂ tons divided by MWh	Sum of A-2s
	Electricity Generation (Annual)			
B-1	RGGI-Affected Units	PJM GATS ¹	CO ₂ tons divided by MWh	State reported data for 2005-2008; RGGI COATS for 2009 & 2010. 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. ^{3,4}
B-2	Non-RGGI Units (Fossil Fuel-Fired; < 25 MW)	PJM GATS ¹	CO ₂ tons divided by MWh	PJM GATS ¹
B-3	Non-RGGI Units (Non-Fossil Fuel-Fired)	PJM GATS ¹	CO ₂ tons divided by MWh	PJM GATS ¹
B-4	All Non-RGGI Units (Fossil and Non-Fossil)	Sum of B-2 and B-3	CO ₂ tons divided by MWh	Sum of B-2 and B-3
B-5	All Units	Sum of B-1 and B-4	CO ₂ tons divided by MWh	Sum of B-1 and B-4

Table Notes:

1. PJM Generation Attribute Tracking System, accessible at <<http://www.pjm-eis.com>>.
2. Monitoring Analytics, *State of the Market for PJM* (2005 through 2010 reports) at <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010.shtml>.
3. Historical 2005 – 2008 CO₂ emissions data reported by RGGI participating states compiled from CO₂ emissions data reported to U.S. EPA pursuant 40 CFR Part 75 and from CO₂ emissions and fuel use data reported to state emissions statement programs. Historical 2005 – 2008 CO₂ emissions data is available at <http://www.rggi.org/historical_emissions>. 2009 and 2010 CO₂ emissions data is from data reported to the RGGI CO₂ Allowance Tracking System (RGGI COATS), available at <<http://www.rggi-coats.org>>.
4. MWh and CO₂ emissions data do not include Maryland Limited Industrial Exemption Set-aside (LIESA) sources. LIESA sources for 2009 and 2010 include Severstal Sparrows Point LLC and Luke Paper Company. LIESA sources refer to certain industrial cogenerators under Maryland’s CO₂ Budget Trading Program regulations that are subject to alternative CO₂ compliance obligations under certain conditions in lieu of submission of CO₂ allowances. MWh and CO₂ emissions data do not include Linden Cogeneration, units 005001 – 009001, as these units are physically located in New Jersey but dispatch electricity into NYISO; MWh and CO₂ emissions data for these units are included in NYISO data.

Appendix B. ISO-Specific Monitoring Results

Detailed monitoring results for ISO-NE, NYISO, and the RGGI portion of PJM are presented below.³³

ISO-NE

Monitoring results for ISO-NE for 2005 through 2010 are summarized below in Table 5 and Figures 6 through 10.

Table 5. 2005 – 2010 Monitoring Summary for ISO-NE

	MWh						Tons CO ₂					Lb CO ₂ /MWh						
	2005	2006	2007	2008	2009	2010	2005	2006	2007	2008	2009	2010	2005	2006	2007	2008	2009	2010
Electricity Demand																		
Total in ISO	138,174,000	134,243,000	136,869,000	134,000,000	128,801,000	131,956,000	64,141,043	58,295,663	58,466,292	53,299,329	48,176,890	50,462,691	928	869	854	796	748	765
Net Imports - from NYISO	-115,000	-877,000	-2,477,000	-1,529,000	-3,031,000	-4,412,000	-55,282	-398,599	-1,118,781	-651,589	-1,229,274	-1,808,124	961	909	903	852	811	820
Net Imports - from Quebec	4,792,000	6,023,000	7,727,000	9,495,000	10,826,000	9,214,000	15,847	26,557	102,211	20,933	23,867	20,313	7	9	26	4	4	4
Net Imports - from New Brunswick	1,620,000	1,047,000	896,000	1,285,000	1,569,000	737,000	785,728	468,573	439,514	767,727	942,592	442,760	970	895	981	1,195	1,202	1,202
Total Net Imports - from All Adjoining ISOs	6,297,000	6,193,000	6,146,000	9,251,000	9,363,000	5,539,000	746,293	96,530	-577,056	137,071	-262,814	-1,345,050	237	31	-188	30	-56	-486
Electricity Generation																		
RGGI-Affected Units	77,439,814	70,911,131	75,345,502	70,591,734	65,426,926	71,314,622	54,223,939	47,783,423	49,434,978	44,508,400	38,815,561	41,682,045	1,400	1,348	1,312	1,261	1,187	1,169
Non-RGGI Fossil Fuel-Fired Units <25MW	94,304	75,137	64,598	152,110	627,311	908,731	37,197	42,415	47,105	98,880	374,282	875,835	789	1,129	1,458	1,300	1,193	1,928
Non-RGGI Fossil Fuel-Fired Units >=25MW	5,953,312	5,212,883	4,419,405	2,484,119	2,095,712	2,195,189	4,054,743	3,565,819	2,744,219	1,734,332	1,810,538	1,810,538	1,362	1,368	1,242	1,396	1,728	1,650
Non-Fossil Fuel-Fired Units	48,520,847	52,086,895	51,110,222	51,372,277	51,746,869	52,787,874	5,078,871	6,807,476	6,817,046	6,820,646	7,439,324	7,439,324	209	261	267	266	288	282
All Non-RGGI Units	54,568,463	57,374,915	55,594,225	54,008,506	54,469,892	55,891,794	9,170,811	10,415,709	9,608,370	8,653,859	9,624,143	10,125,696	336	363	346	320	353	362
All Units	131,877,000	128,050,000	130,723,000	124,749,000	119,437,000	126,416,000	63,394,750	58,199,133	59,043,348	53,162,258	48,439,704	51,807,741	961	909	903	852	811	820
Summary Data	6,047,616	5,288,020	4,484,003	2,636,229	2,723,023	3,103,920	4,091,940	3,608,234	2,791,324	1,833,213	2,184,820	2,686,373	1,353	1,365	1,245	1,391	1,605	1,731
Non-RGGI Generation Serving Load in ISO = Non-RGGI Generation within ISO + Net Imports	60,865,463	63,567,915	61,740,225	63,259,506	63,832,892	61,430,794	9,917,104	10,512,240	9,031,314	8,790,929	9,361,329	8,780,646	326	331	293	278	293	286

The monitoring results indicate that the 2009 and 2010 annual average compared to the 2006 to 2008 base period annual average, total electric generation from all non-RGGI electric generation serving load in ISO-NE decreased by 224 thousand MWh, a decrease of 0.4 percent. From the 2006 to 2008 base period annual average to the 2009 and 2010 annual average, CO₂ emissions from this category of electric generation decreased by 374 thousand short tons of CO₂, an decrease of 4 percent, and the CO₂ emission rate decreased by 11 lb CO₂/MWh, an increase of 3.6 percent. (See Figures 7, 8, and 9.)

³³ The tons of CO₂ emitted and the lb of CO₂/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.

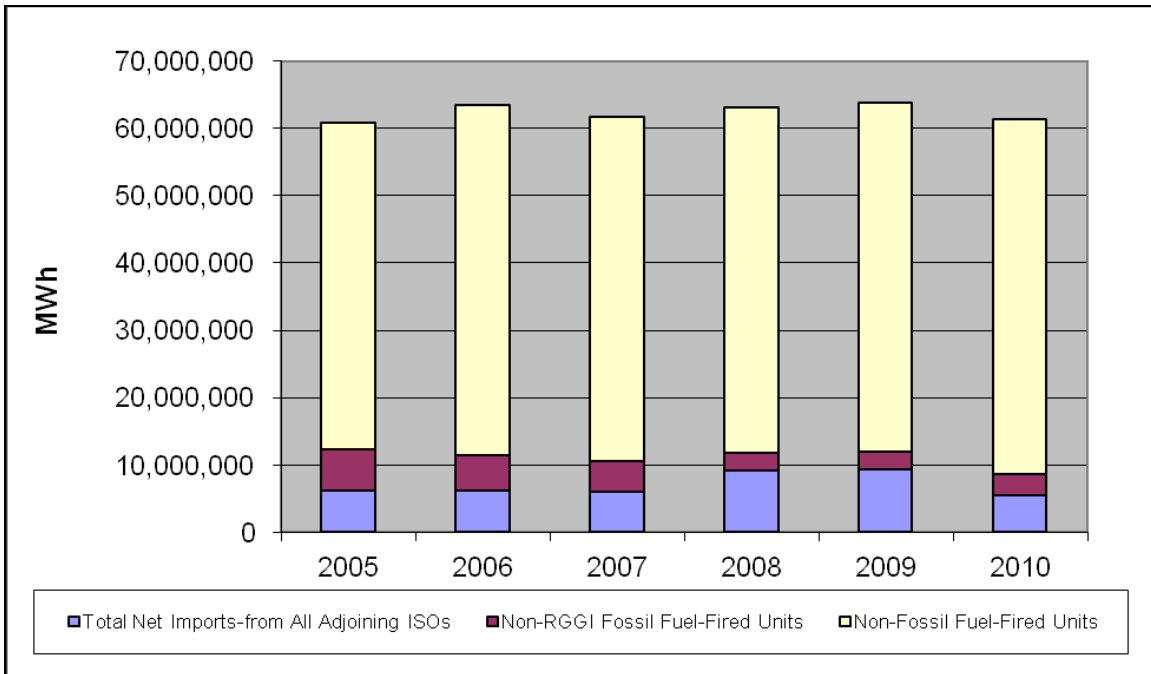


Figure 7. Non-RGGI Generation Serving Load in ISO-NE (MWh)

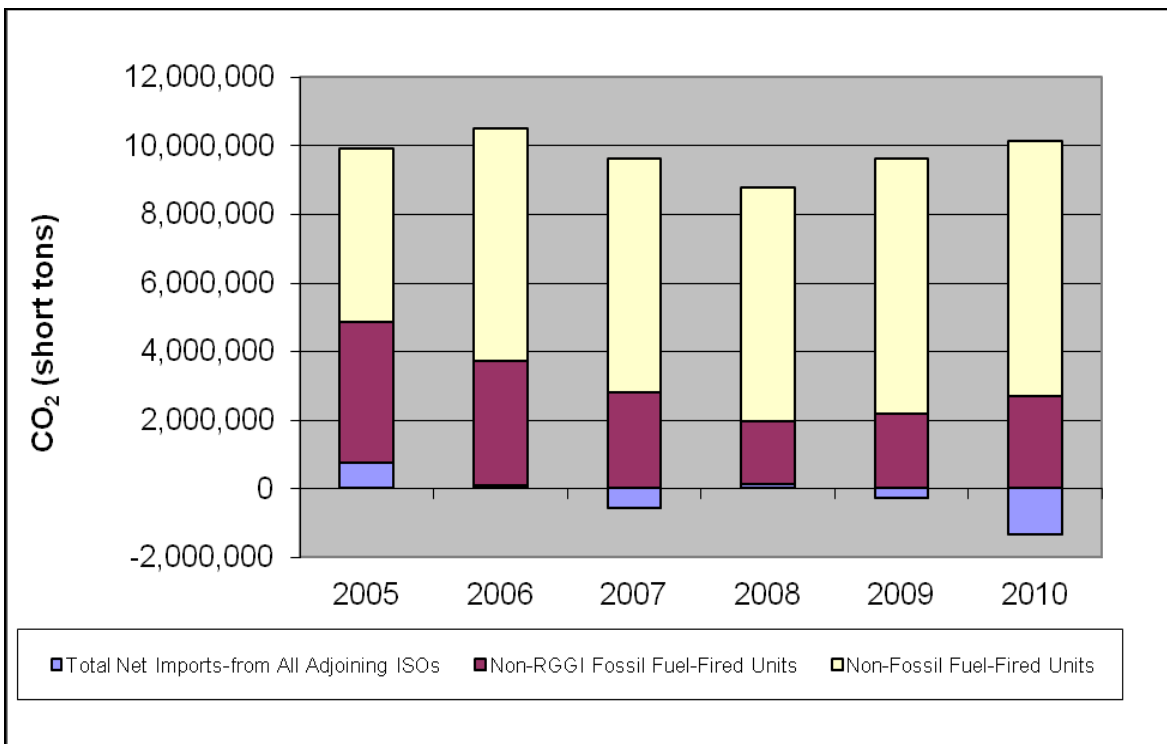


Figure 8. CO₂ Emissions from Non-RGGI Generation Serving Load in ISO-NE (short tons CO₂)

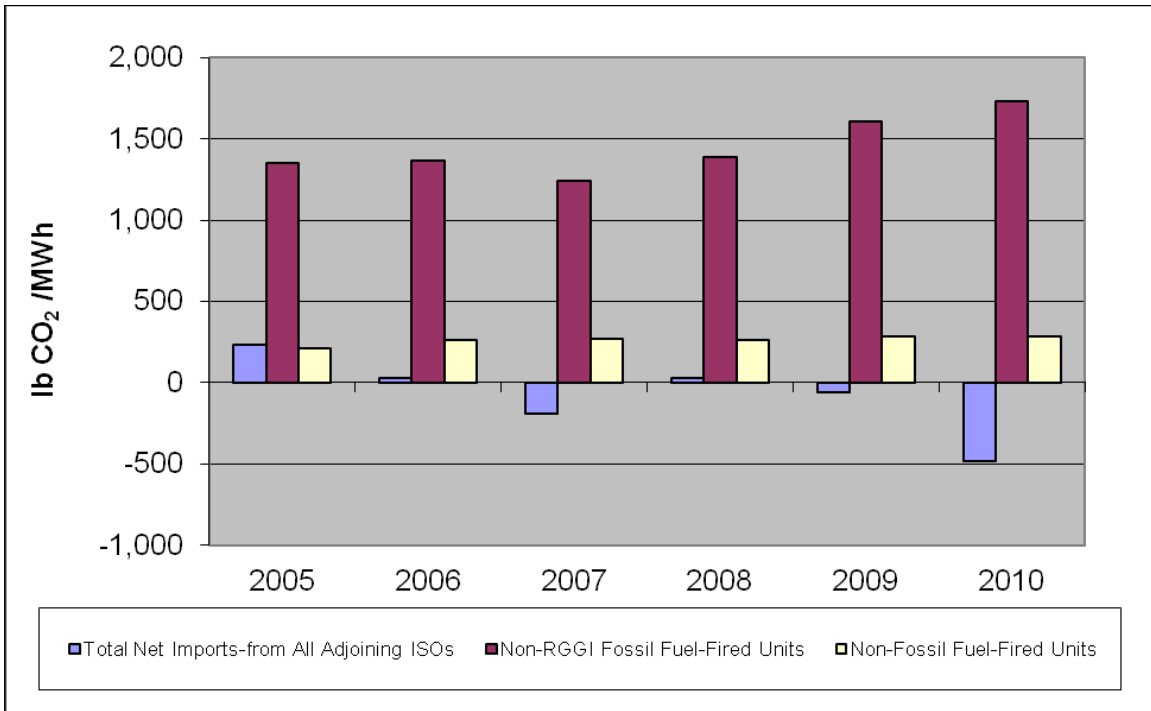


Figure 9. CO₂ Emission Rate for Non-RGGI Generation Serving Load in ISO-NE (lb CO₂/MWh)

The annual average electricity load in ISO-NE decreased by 4.7 million MWh, or 3.5 percent for 2009 and 2010 as compared to the annual average from the baseline period of 2006 to 2008. In total, electric generation (fossil and non-fossil) in ISO-NE decreased by 4.4 million MWh, or 3.4 percent, when comparing the 2006 to 2008 annual average to the 2009 and 2010 annual average.

Electric generation from RGGI-affected generation in ISO-NE decreased by 3.9 million MWh during this period, or 5.4 percent, and CO₂ emissions from RGGI-affected electric generation in ISO-NE decreased by 7 million short tons of CO₂, or 14.8 percent. The CO₂ emission rate of RGGI-affected electric generation decreased by 129 lb CO₂/MWh, a reduction of 9.9 percent. Electric generation from non-RGGI electric generation sources located in ISO-NE decreased by 478 thousand MWh, or 0.9 percent, during this period, and CO₂ emissions from this category of electric generation increased by 316 thousand short tons of CO₂, an increase of 3.3 percent. The CO₂ emission rate of non-RGGI electric generation located in ISO-NE increased by 14 lb CO₂/MWh, an increase of 4.2 percent.

Net electricity imports into ISO-NE increased by 254 thousand MWh, or 3.5 percent, when comparing the base period annual average from 2006 to 2008 to the annual average from 2009 and 2010. CO₂ emissions related to these net electricity imports decreased by 689 thousand short tons of CO₂, or 602 percent,

during this period.³⁴ The CO₂ emission rate of the electric generation supplying these imports decreased by 239 lb CO₂/MWh, a decrease of 751.5 percent.

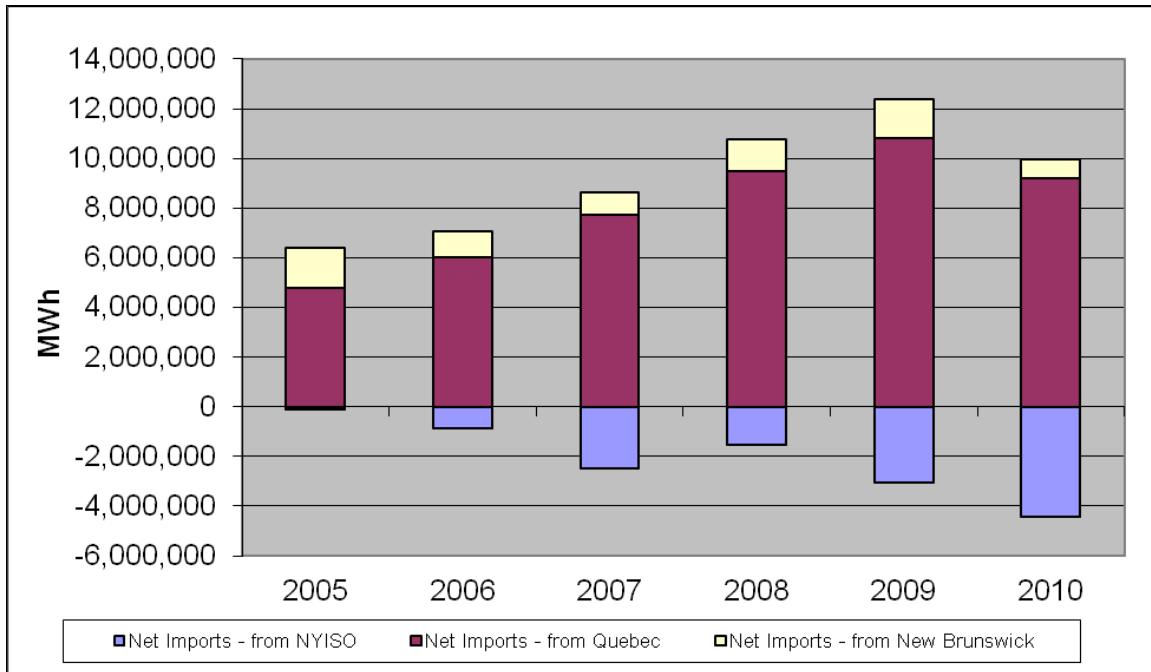


Figure 10. Net Electricity Imports to ISO-NE (MWh)

³⁴ This significant percentage change is due to the fact that ISO-NE net exports to NYISO doubled from 2008 to 2009, and increased again in 2010. Negative values for MWh and CO₂ tons indicate that more MWh were exported than imported. As a result, the increase in net exports to NYISO in 2009 and 2010 increased the amount of CO₂ emissions debited from the ISO-NE net import total, resulting in a negative CO₂ emissions value for total CO₂ emissions related to total net electricity imports in 2009 and 2010 for ISO-NE. In 2008, CO₂ emissions related to net imports of electricity to ISO-NE were 137,071 short tons of CO₂; in 2009 and 2010, CO₂ emissions related to net imports of electricity to ISO-NE were -262,814 and -1,345,050 short tons of CO₂, representing the assignment of an increased amount of CO₂ emissions to NYISO for tracking purposes.

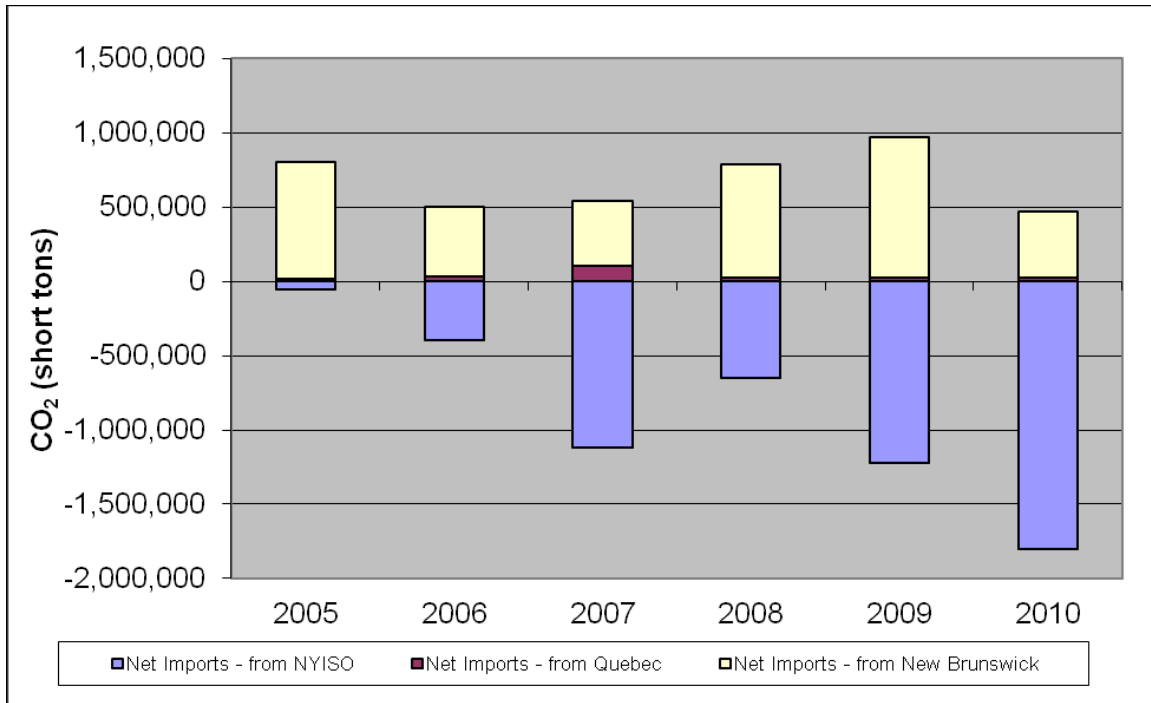


Figure 11. CO₂ Emissions Related to Net Electricity Imports to ISO-NE (short tons CO₂)

Compared to the annual average during a multi-year base period of 2006 – 2008, electric generation in 2010 from all non-RGGI electric generation sources serving load in ISO-NE decreased by 1.4 million MWh, a decrease of 2.3 percent. Compared to the 2006 – 2008 annual average, 2010 CO₂ emissions from this category of electric generation decreased by 664 thousand short tons of CO₂, a reduction of 7.0 percent, and the CO₂ emission rate decreased by 15 lb CO₂/MWh, a reduction of 4.9 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2010 total electricity load in ISO-NE decreased by 3.1 million MWh, or 2.3 percent. Compared to the 2006 – 2008 annual average, 2010 total electric generation in ISO-NE decreased by 736 thousand MWh, or 0.6 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2010 electric generation from RGGI-affected generation in ISO-NE decreased by 968 thousand MWh, or 1.3 percent, and CO₂ emissions from RGGI-affected generation in ISO-NE decreased by 5.6 million short tons of CO₂, or 11.8 percent. The CO₂ emission rate of RGGI-affected electric generation decreased by 138 lb CO₂/MWh, a reduction of 10.6 percent. Compared to the 2006 – 2008 annual average, 2010 electric generation from non-RGGI generation located in ISO-NE increased by 233 thousand MWh, or 0.4 percent, and CO₂ emissions from this category of electric generation increased by 566 thousand short tons of CO₂, an increase of 5.9 percent. The CO₂ emission rate of non-RGGI electric generation located in ISO-NE increased by 19 lb CO₂/MWh, an increase of 5.5 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2010 net electricity imports into ISO-NE decreased by 1.7 million MWh, or 23 percent. CO₂ emissions related to these net electricity imports declined by 1.2 million short tons of CO₂, or 1074.9 percent during this period. The CO₂ emission rate of the electric generation supplying these imports declined by 454 lb CO₂/MWh, a reduction of 1426.5 percent.

NYISO

Monitoring results for NYISO for 2005 through 2010 are summarized below in Table 6 and Figures 12 through 15.

Table 6. 2005 – 2010 Monitoring Summary for NYISO

	MWh						Tons CO ₂						Lb CO ₂ /MWh					
	2005	2006	2007	2008	2009	2010	2005	2006	2007	2008	2009	2010	2005	2006	2007	2008	2009	2010
Electricity Demand																		
Total Annual Electricity Load in NYISO	164,783,642	166,654,412	167,859,706	167,769,588	160,565,962	166,347,895	74,735,892	71,241,698	74,713,725	63,958,937	50,423,270	56,924,786	907	855	890	762	628	684
Net Imports - from Quebec	2,583,317	2,959,749	4,185,292	5,646,014	6,239,805	4,335,209	8,543	13,050	55,362	12,447	13,756	9,557	7	9	26	4	4	4
Net Imports - from ISO-NE	115,000	877,000	2,477,000	1,529,000	3,031,000	4,412,000	55,282	398,599	1,118,781	651,589	1,229,274	1,808,124	961	909	903	852	811	820
Net Imports - from Ontario	1,898,020	3,672,282	2,637,442	6,162,902	6,463,657	3,872,635	439,364	728,640	581,456	1,154,884	712,496	426,885	463	397	441	375	220	220
Net Imports - from PJM	7,604,000	9,559,000	10,225,000	10,690,000	8,331,000	12,305,000	4,912,184	5,983,934	6,349,725	6,520,900	4,736,174	7,179,968	1,292	1,252	1,242	1,220	1,137	1,167
Total Net Electricity Imports	12,200,337	17,068,031	19,524,734	24,027,916	24,065,462	24,924,844	5,415,373	7,124,223	8,105,324	8,339,821	6,691,700	9,424,534	888	835	830	694	556	756
Electricity Generation																		
RGGI-Affected Units (1)	71,936,054	70,523,142	69,933,159	68,000,465	64,574,854	66,197,587	65,041,240	55,637,919	57,693,658	50,239,607	39,536,767	43,762,015	1,808	1,578	1,650	1,478	1,225	1,322
Non-RGGI Fossil Fuel-Fired Units	5,085,066	4,985,189	4,943,484	4,771,887	4,531,497	10,841,936	3,595,557	7,124,735	7,243,229	5,029,613	3,921,963	3,360,405	1,414	2,858	2,930	2,108	1,731	620
Non-Fossil Fuel-Fired Units	75,562,185	74,078,051	73,458,329	70,969,320	67,394,149	64,383,528	683,722	1,354,821	1,671,514	349,896	272,840	377,833	18	37	46	10	8	12
All Non-RGGI Units	80,647,251	79,063,239	78,401,812	75,741,207	71,925,646	75,225,464	4,279,279	8,479,556	8,914,743	5,379,509	4,194,803	3,738,238	106	215	227	142	117	99
All Units	152,583,305	149,586,381	148,334,972	143,741,672	136,500,500	141,423,051	69,320,519	64,117,475	66,608,401	55,619,116	43,731,570	47,500,253	909	857	898	774	641	672
Summary CO₂ Emissions and MWh Data																		
Annual CO ₂ Emissions from Non-RGGI Generation Serving Load in ISO = Non-RGGI Generation within ISO + Net Imports	92,847,588	96,131,270	97,926,546	99,769,123	95,991,108	100,150,308	9,694,652	15,603,779	17,020,067	13,719,330	10,886,503	13,162,772	209	325	348	275	227	263

The monitoring results indicate that the 2009 and 2010 annual average compared to the 2006 to 2008 base period annual average, total electric generation from all non-RGGI electric generation serving load in NYISO increased by 128 thousand MWh, an increase of 0.1 percent. From the 2006 to 2008 base period annual average to the 2009 and 2010 annual average, CO₂ emissions from this category of electric generation decreased by 3.4 million short tons of CO₂, a decrease of 22.2 percent, and the CO₂ emission rate decreased by 70 lb CO₂/MWh, an decrease of 22.3 percent. (See Figures 12, 13, and 14.)

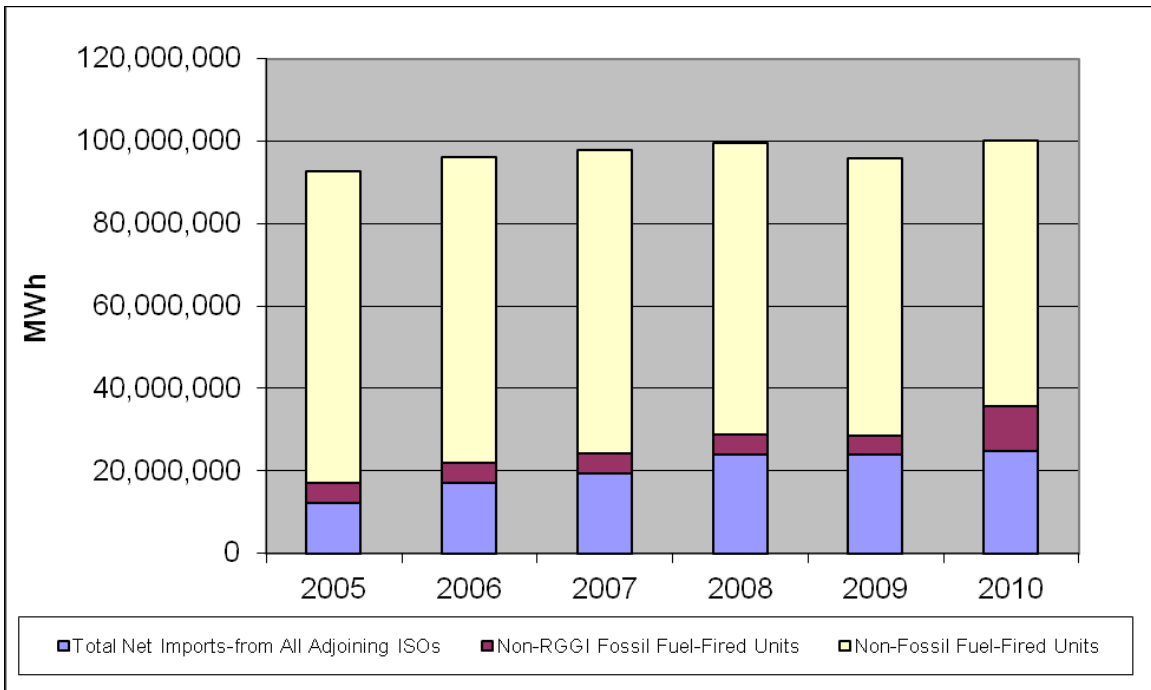


Figure 12. Non-RGGI Generation Serving Load in NYISO (MWh)

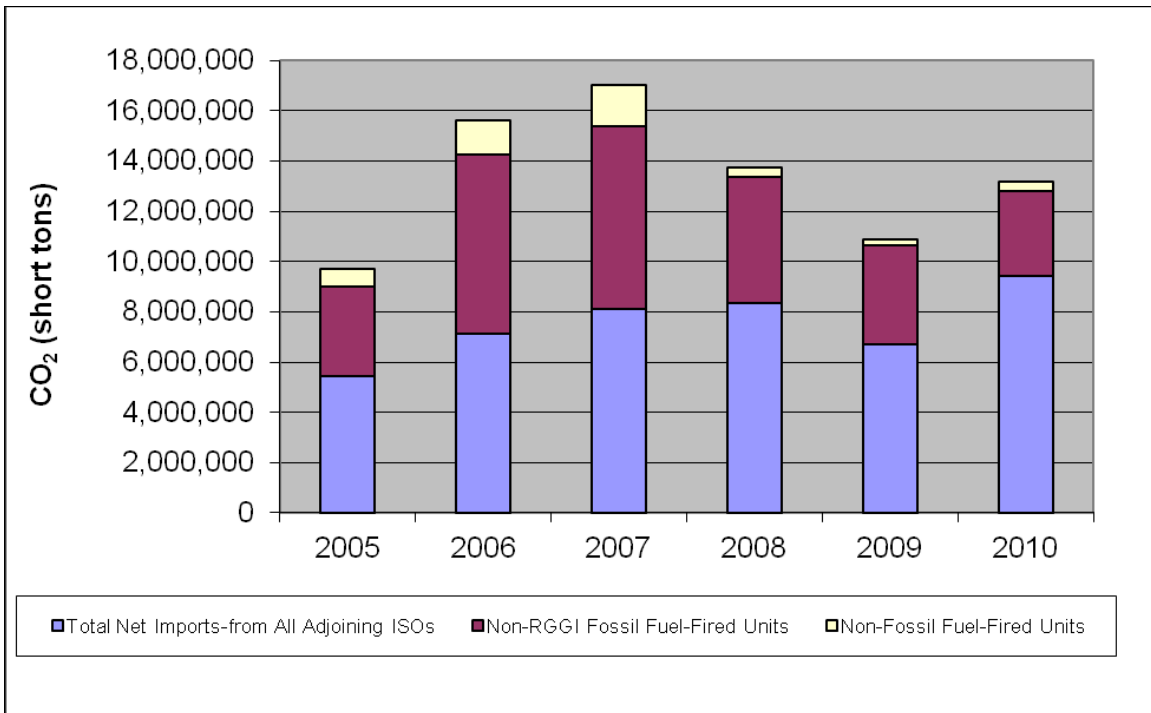


Figure 13. CO₂ Emissions from Non-RGGI Generation Serving Load in NYISO (short tons CO₂)

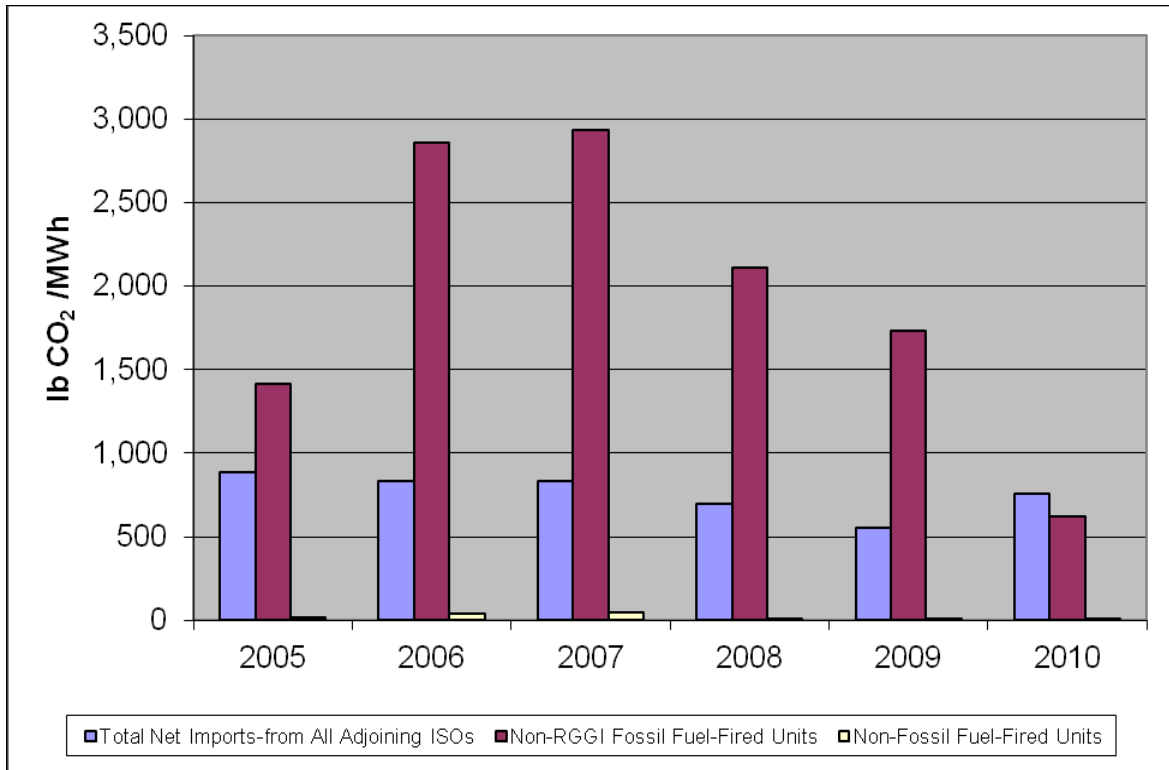


Figure 14. CO₂ Emission Rate for Non-RGGI Generation Serving Load in NYISO (lb CO₂/MWh)

The annual average electricity load in NYISO decreased by 4 million MWh, or 2.4 percent for 2009 and 2010 as compared to the annual average from the baseline period of 2006 to 2008. In total, electric generation (fossil and non-fossil) in NYISO decreased by 8.3 million MWh, or 5.6 percent, when comparing the 2006 to 2008 annual average to the 2009 and 2010 annual average.

Electric generation from RGGI-affected generation in NYISO decreased by 4.1 million MWh during this period, or 5.9 percent, and CO₂ emissions from RGGI-affected electric generation in NYISO decreased by 12.9 million short tons of CO₂, or 23.6 percent. The CO₂ emission rate of RGGI-affected electric generation decreased by 296 lb CO₂/MWh, a reduction of 18.9 percent. Electric generation from non-RGGI electric generation sources located in NYISO decreased by 4.2 million MWh, or 5.4 percent, during this period, and CO₂ emissions from this category of electric generation increased by 3.6 million short tons of CO₂, a decrease of 47.7 percent. The CO₂ emission rate of non-RGGI electric generation located in NYISO decreased by 87 lb CO₂/MWh, a decrease of 44.7 percent.

Net electricity imports into NYISO increased by 4.3 million MWh, or 21.2 percent, when comparing the base period annual average from 2006 to 2008 to the annual average from 2009 and 2010. CO₂ emissions related to these net electricity imports increased by 202 thousand short tons of CO₂, or 2.6 percent, during this period. The CO₂ emission rate of the electric generation supplying

these imports decreased by 121 lb CO₂/MWh, a decrease of 15.6 percent. (See figures 15 and 16).

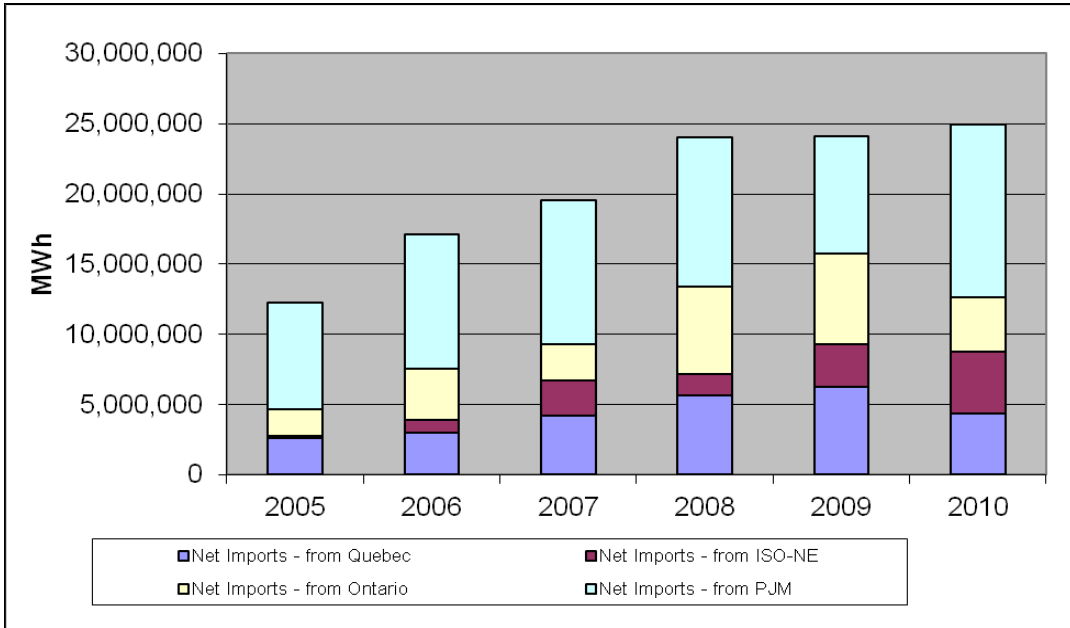


Figure 15. Net Electricity Imports to NYISO (MWh)

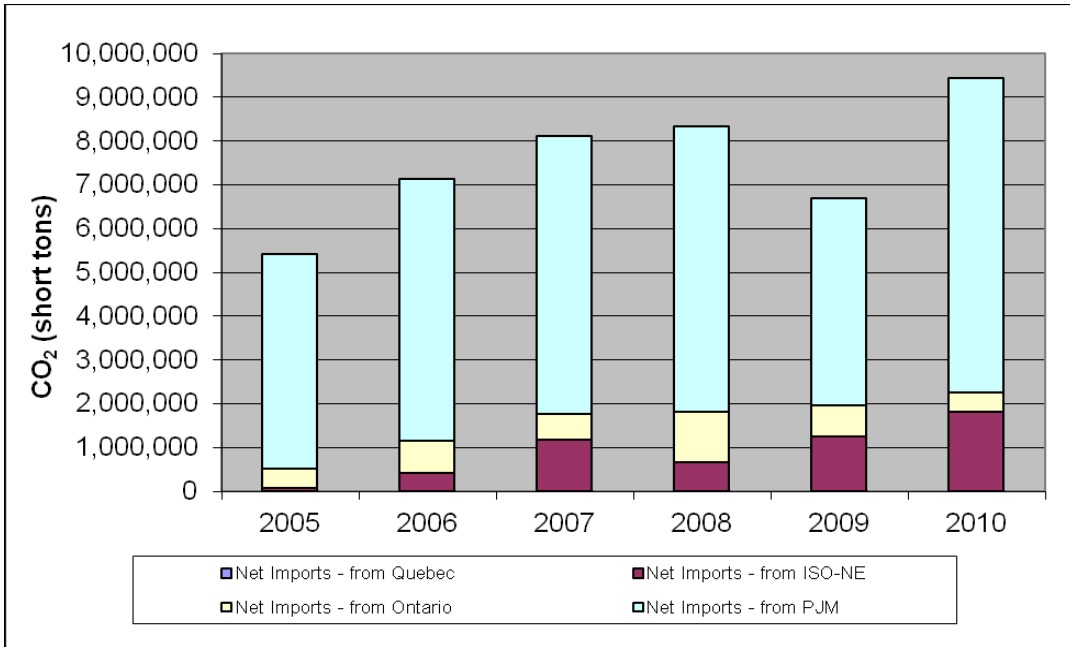


Figure 16. CO₂ Emissions Related to Net Electricity Imports to NYISO (short tons CO₂)

Compared to the annual average during a multi-year base period of 2006 – 2008, electric generation in 2010 from all non-RGGI electric generation sources serving load in NYISO increased by 2.2 million MWh, an increase of 2.3 percent. Compared to the 2006 – 2008 annual average, 2010 CO₂ emissions from this category of electric generation decreased by 2.3 million short tons of CO₂, a

reduction of 14.8 percent, and the CO₂ emission rate decreased by 53 lb CO₂/MWh, a reduction of 16.7 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2010 total electricity load in NYISO decreased by 1.1 million MWh, or 0.6 percent. Compared to the 2006 – 2008 annual average, total electric generation in 2010 in NYISO decreased by 5.8 million MWh, or 3.9 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2010 electric generation from RGGI-affected generation in NYISO decreased by 3.3 million MWh, or 4.7 percent, and CO₂ emissions from RGGI-affected generation in NYISO decreased by 10.8 million short tons of CO₂, a reduction of 19.7 percent. The CO₂ emission rate of RGGI-affected electric generation decreased by 247 lb CO₂/MWh, a reduction of 15.8 percent. Compared to the 2006 – 2008 annual average, 2010 electric generation from non-RGGI generation located in NYISO decreased by 2.5 million MWh, or 3.2 percent, and CO₂ emissions from this category of electric generation decreased by 3.9 million short tons of CO₂, a reduction of 50.8 percent. The CO₂ emission rate of non-RGGI electric generation located in NYISO decreased by 96 lb CO₂/MWh, a reduction of 49.1 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2010 net electricity imports into NYISO increased by 4.7 million MWh, or 23.3 percent. CO₂ emissions related to these net electricity imports increased by 1.6 million short tons of CO₂, or 20 percent. The CO₂ emission rate of the electric generation supplying these imports decreased by 21 lb CO₂/MWh, a reduction of 2.7 percent.

PJM (RGGI Portion)

Monitoring results for PJM for 2005 through 2010 are summarized below in Table 7 and Figures 17 through 20. Note that for PJM, the data presented below is for the RGGI geographic portion of PJM (Delaware, Maryland, and New Jersey referred to below as “RGGI PJM”). Net “imports” represent inferred flows of electricity from the non-RGGI geographic portion of PJM (Non-RGGI PJM) to the RGGI geographic portion of PJM (RGGI PJM) to make up for shortfalls in electric generation relative to total electricity load for this subset of PJM.³⁵

Table 7. 2005 – 2010 Monitoring Summary for RGGI PJM

	MWh						Tons CO ₂						Lb CO ₂ /MWh					
	2005	2006	2007	2008	2009	2010	2005	2006	2007	2008	2009	2010	2005	2006	2007	2008	2009	2010
Electricity Demand																		
Total Annual Electricity Load in ISO	177,404,747	168,687,473	170,289,397	163,600,330	158,657,456	165,047,534	106,173,296	96,729,311	98,228,040	90,167,059	78,593,331	87,087,382	1,197	1,147	1,154	1,102	991	1,055
Net Imports - from Non-RGGI PJM	65,324,576	60,819,367	57,887,856	54,088,276	56,299,698	58,001,518	43,596,369	39,383,494	37,012,128	34,138,677	33,537,149	35,150,499	1,335	1,295	1,279	1,262	1,191	1,212
Net Imports - from NYISO	-1,224,177	-1,457,171	-1,565,273	-1,627,174	-1,257,857	-1,844,414	-683,486	-774,675	-852,476	-832,492	-553,688	-894,878	1,117	1,063	1,089	1,023	880	970
Total Net Electricity Imports - from All Adjoining ISOs	64,100,399	59,362,196	56,322,583	52,461,102	55,041,841	56,157,104	42,912,883	38,608,819	36,159,652	33,306,185	32,983,461	34,255,621	1,339	1,301	1,284	1,270	1,198	1,220
Electricity Generation																		
RGGI-Affected Units	62,572,572	57,720,201	62,357,387	59,342,547	50,005,454	57,625,172	61,681,725	56,440,700	59,921,956	54,967,858	43,804,611	50,125,993	1,972	1,956	1,922	1,853	1,752	1,740
Non-RGGI Fossil Fuel-Fired Units	479,438	339,933	364,609	165,411	151,888	143,960	369,986	275,158	285,909	168,417	152,325	145,704	1,543	1,619	1,568	2,036	2,006	2,024
Non-Fossil Fuel-Fired Units	50,252,338	51,265,143	51,244,818	51,631,270	53,458,273	51,121,298	1,208,702	1,404,634	1,860,523	1,724,599	1,652,934	2,560,064	48	55	73	67	62	100
All Non-RGGI Units	50,731,776	51,605,076	51,609,427	51,796,681	53,610,161	51,265,258	1,578,688	1,679,792	2,146,432	1,893,016	1,805,259	2,705,768	62	65	83	73	67	106
All Units	113,304,348	109,325,277	113,966,814	111,139,228	103,615,615	108,890,430	63,260,413	58,120,492	62,068,388	56,860,874	45,609,870	52,831,761	1,117	1,063	1,089	1,023	880	970
Summary CO₂, Emissions and MWh Data																		
Annual CO ₂ Emissions from Non-RGGI Generation Serving Load in ISO = Non-RGGI Generation within ISO + Net Imports	114,832,175	110,967,272	107,932,010	104,257,783	108,652,002	107,422,362	44,491,571	40,288,611	38,306,084	35,199,201	34,788,720	36,961,389	775	726	710	675	640	688

The monitoring results indicate that the 2009 and 2010 annual average compared to the 2006 to 2008 base period annual average, total electric generation from all non-RGGI electric generation serving load in PJM increased by 318 thousand MWh, an increase of 0.3 percent. From the 2006 to 2008 base period annual average to the 2009 and 2010 annual average, CO₂ emissions from this category of electric generation decreased by 2 million short tons of CO₂, a

³⁵ 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.

decrease of 5.4 percent, and the CO₂ emission rate decreased by 40 lb CO₂/MWh, an decrease of 5.7 percent. (See Figures 17, 18, and 19.)

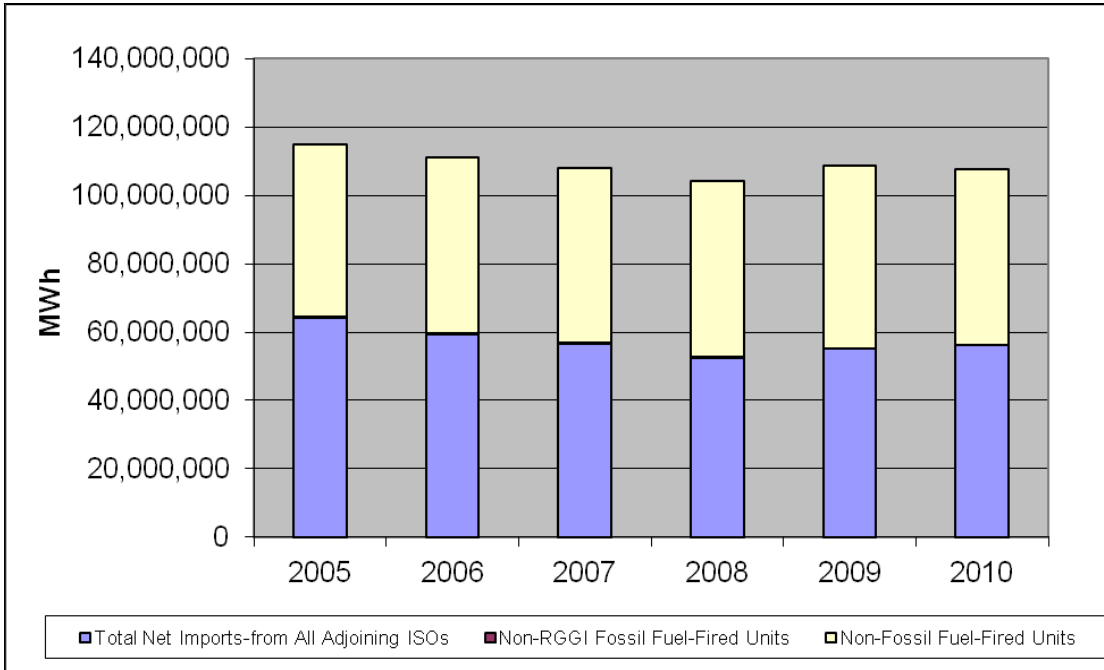


Figure 17. Non-RGGI Generation Serving Load in RGGI PJM (MWh)

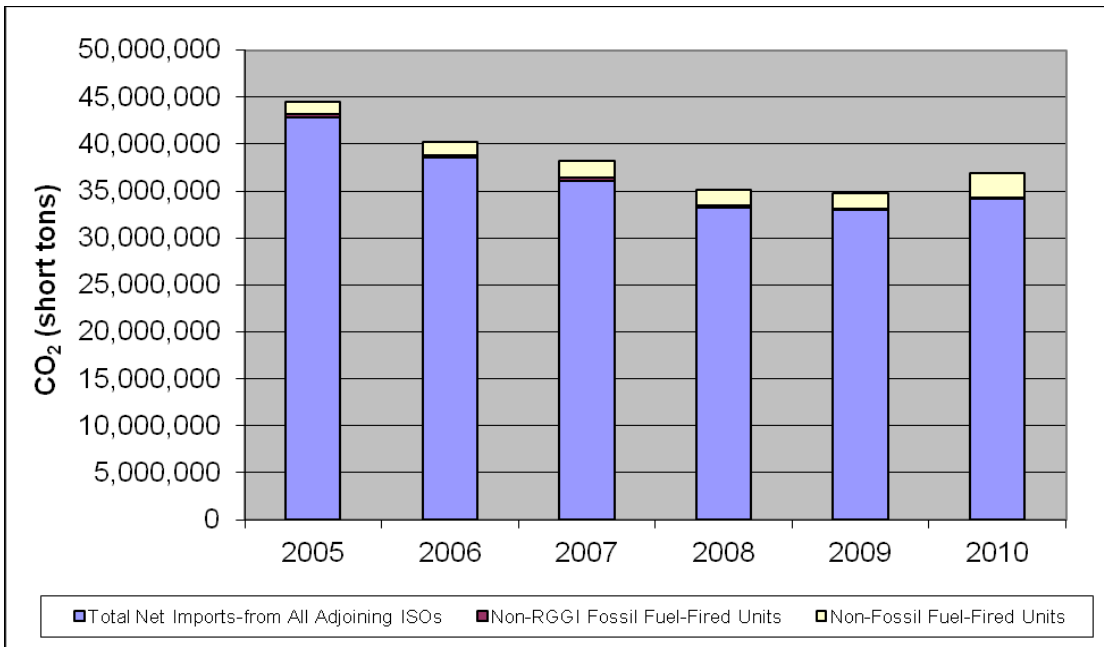


Figure 18. CO₂ Emissions from Non-RGGI Generation Serving Load in RGGI PJM (short tons CO₂)

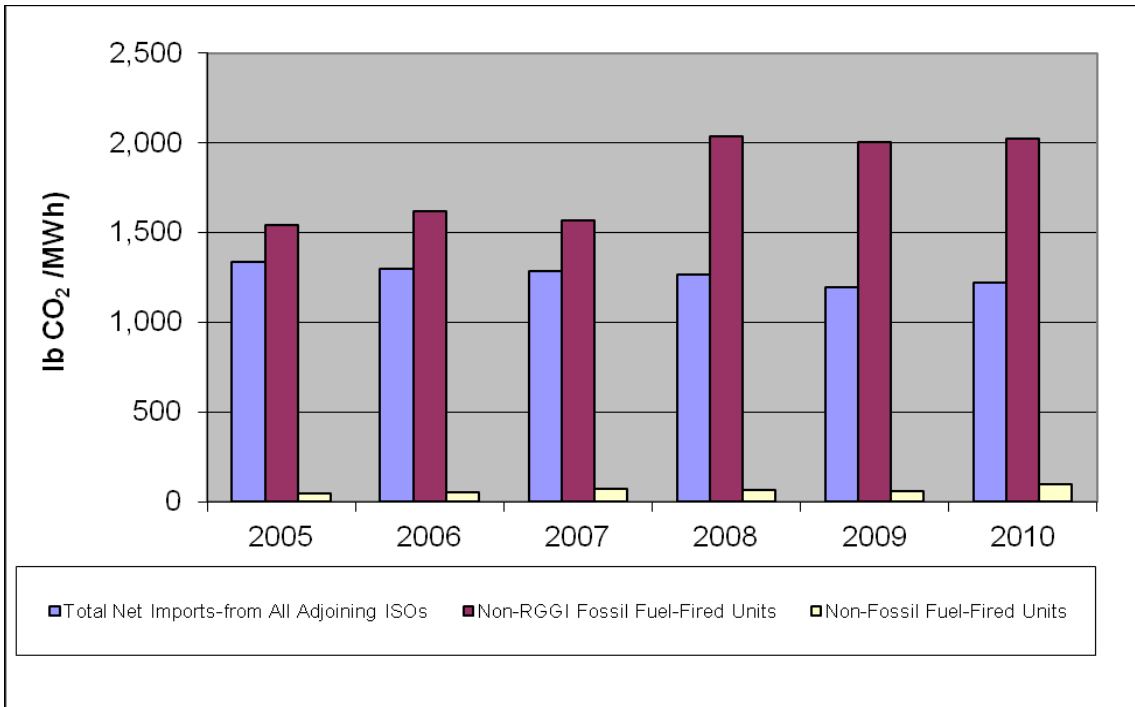


Figure 19. CO₂ Emission Rate for Non-RGGI Generation Serving Load in RGGI PJM (lb CO₂/MWh)

The annual average electricity load in PJM decreased by 5.7 million MWh, or 3.4 percent for 2009 and 2010 as compared to the annual average from the baseline period of 2006 to 2008. In total, electric generation (fossil and non-fossil) in PJM decreased by 5.2 million MWh, or 4.7 percent, when comparing the 2006 to 2008 annual average to the 2009 and 2010 annual average.

Electric generation from RGGI-affected generation in PJM decreased by 6.0 million MWh during this period, or 10.0 percent, and CO₂ emissions from RGGI-affected electric generation in PJM decreased by 10.1 million short tons of CO₂, or 17.8 percent. The CO₂ emission rate of RGGI-affected electric generation decreased by 164 lb CO₂/MWh, a reduction of 8.6 percent. Electric generation from non-RGGI electric generation sources located in PJM increased by 767 thousand MWh, or 1.5 percent, during this period, and CO₂ emissions from this category of electric generation increased by 349 thousand short tons of CO₂, an increase of 18.3 percent. The CO₂ emission rate of non-RGGI electric generation located in PJM increased by 13 lb CO₂/MWh, an increase of 17.2 percent.

Net electricity imports into PJM decreased by 449 thousand MWh, or 0.8 percent, when comparing the base period annual average from 2006 to 2008 to the annual average from 2009 and 2010. CO₂ emissions related to these net electricity imports decreased by 2.4 million short tons of CO₂, or 6.7 percent, during this period. The CO₂ emission rate of the electric generation supplying

these imports decreased by 76 lb CO₂/MWh, a decrease of 5.9 percent. (See Figures 20 and 21.)

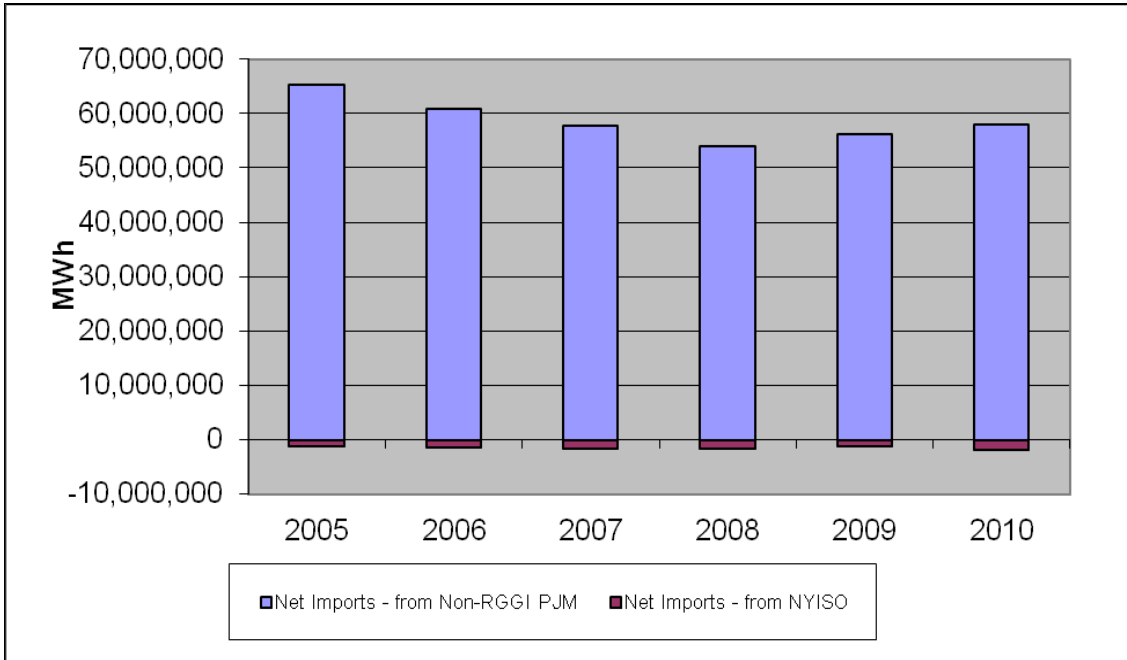


Figure 20. Net Electricity Imports to RGGI PJM (MWh)

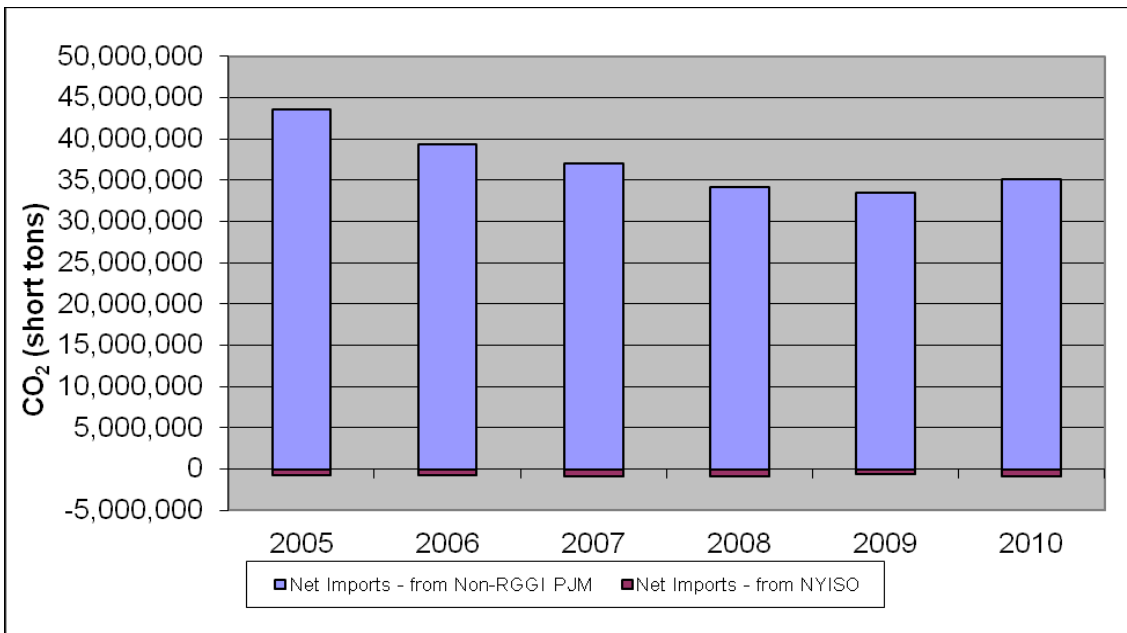


Figure 21. CO₂ Emissions Related to Net Electricity Imports to RGGI PJM (short tons CO₂)

Compared to the annual average during a multi-year base period of 2006 – 2008, electric generation in 2010 from all non-RGGI electric generation sources serving load in RGGI PJM decreased by 297 thousand MWh, a decrease of 0.3 percent. Compared to the 2006 – 2008 annual average, 2010 CO₂ emissions

from this category of electric generation decreased by 970 thousand short tons of CO₂, a reduction of 2.6 percent, and the CO₂ emission rate decreased by 16 lb CO₂/MWh, a reduction of 2.3 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2010 total electricity load in RGGI PJM decreased by 2.5 million MWh, or 1.5 percent. Compared to the 2006 – 2008 annual average, total electric generation in RGGI PJM decreased by 2.6 million MWh, or 2.3 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2010 electric generation from RGGI-affected generation in RGGI PJM decreased by 2.2 million MWh, or 3.6 percent, and CO₂ emissions from RGGI-affected generation in RGGI PJM decreased by 7 million short tons of CO₂, or 12.2 percent. The CO₂ emission rate of RGGI-affected electric generation decreased by 170 lb CO₂/MWh, a reduction of 8.9 percent. Compared to the 2006 – 2008 annual average, 2010 electric generation from non-RGGI generation located in RGGI PJM decreased by 405 thousand MWh, or 0.8 percent, and CO₂ emissions from this category of electric generation increased by 799 thousand short tons of CO₂, an increase of 41.9 percent. The CO₂ emission rate of non-RGGI electric generation located in RGGI PJM increased by 32 lb CO₂/MWh, an increase of 43.1 percent.

Compared to the annual average during a multi-year 2006 – 2008 base period, 2010 net electricity imports into RGGI PJM increased by 108 thousand MWh, or 0.2 percent. CO₂ emissions related to these net electricity imports declined by 1.8 million short tons of CO₂, or 4.9 percent, during this period, indicating a reduction in the average CO₂ emission rate of the electric generation supplying these imports of 65 lb CO₂/MWh, a reduction of 5.1 percent.

Appendix C. Monitoring Trends

Detailed monitoring trends for the 10-State 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 and the first two years of program operation, 2009 and 2010.

10-State RGGI Region

Table 8. Monitoring Trends for 10-State RGGI Region

	Non-RGGI Generation			RGGI Generation			Imports			Total Non-RGGI Generation (ISO + Net Imports)		
	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh
2006-2008	185,065,030	19,056,995	206	201,575,089	158,876,166	1,576	83,452,187	43,802,984	1,050	268,517,217	62,859,979	468
2009-2010	181,194,108	16,096,954	178	187,572,308	128,863,495	1,373	87,546,126	40,916,337	935	268,740,233	57,013,291	424
Difference	-3,870,922	-2,960,042	-28	-14,002,782	-30,012,671	-203	4,093,938	-2,886,647	-115	223,016	-5,846,689	-44
% change	-2.1%	-15.5%	-13.7%	-6.9%	-18.9%	-12.9%	4.9%	-6.6%	-10.9%	0.1%	-9.3%	-9.4%
	In-Region Generation (MWh)		Total In-Region Load (MWh)									
2006-2008	386,640,119		469,990,969									
2009-2010	368,766,415		455,687,924									
Difference	-17,873,704		-14,303,045									
% change	-4.6%		-3.0%									

	Non-RGGI Generation			RGGI Generation			Imports			Total Non-RGGI Generation (ISO + Net Imports)		
	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh
2006-2008	185,065,030	19,056,995	206	201,575,089	158,876,166	1,576	83,452,187	43,802,984	1,050	268,517,217	62,859,979	468
2010	182,382,516	16,569,702	182	195,137,381	135,570,053	1,389	86,620,948	42,389,415	979	269,003,464	58,959,117	438
Difference	-2,682,514	-2,487,293	-24	-6,437,708	-23,306,114	-187	3,168,761	-1,413,569	-71	486,247	-3,900,862	-30
% change	-1.4%	-13.1%	-11.8%	-3.2%	-14.7%	-11.9%	3.8%	-3.2%	-6.8%	0.2%	-6.2%	-6.4%
	In-Region Generation (MWh)		Total In-Region Load (MWh)									
2006-2008	386,640,119		469,990,969									
2010	377,519,897		463,351,429									
Difference	-9,120,222		-6,639,539									
% change	-2.4%		-1.4%									

ISO-NE

Table 9. Monitoring Trends for ISO-NE

	Non-RGGI Generation			RGGI Generation			Imports			Total Non-RGGI Generation (ISO + Net Imports)		
	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh
2006-2008	55,659,215	9,559,313	343	72,282,789	47,242,267	1,307	7,196,667	-114,485	-32	62,855,882	9,444,828	301
2009-2010	55,180,843	9,874,920	358	68,370,774	40,248,803	1,178	7,451,000	-803,932	-271	62,631,843	9,070,988	290
Difference	-478,372	315,607	14	-3,912,015	-6,993,464	-129	254,333	-689,447	-239	-224,039	-373,840	-11
% change	-0.9%	3.3%	4.2%	-5.4%	-14.8%	-9.9%	3.5%	602.2%	751.5%	-0.4%	-4.0%	-3.6%

	In-Region Generation (MWh)	Total In-Region Load (MWh)
2006-2008	127,942,004	135,037,333
2009-2010	123,551,617	130,378,500
Difference	-4,390,387	-4,658,833
% change	-3.4%	-3.5%

	Non-RGGI Generation			RGGI Generation			Imports			Total Non-RGGI Generation (ISO + Net Imports)		
	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh
2006-2008	55,659,215	9,559,313	343	72,282,789	47,242,267	1,307	7,196,667	-114,485	-32	62,855,882	9,444,828	301
2010	55,891,794	10,125,696	362	71,314,622	41,682,045	1,169	5,539,000	-1,345,050	-486	61,430,794	8,780,646	286
Difference	232,579	566,384	19	-968,167	-5,560,222	-138	-1,657,667	-1,230,565	-454	-1,425,088	-664,182	-15
% change	0.4%	5.9%	5.5%	-1.3%	-11.8%	-10.6%	-23.0%	1074.9%	1426.5%	-2.3%	-7.0%	-4.9%

	In-Region Generation (MWh)	Total In-Region Load (MWh)
2006-2008	127,942,004	135,037,333
2010	127,206,416	131,956,000
Difference	-735,588	-3,081,333
% change	-0.6%	-2.3%

NYISO

Table 10. Monitoring Trends for NYISO

	Non-RGGI Generation			RGGI Generation			Imports			Total Non-RGGI Generation (ISO + Net Imports)		
	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh
2006-2008	77,735,420	7,591,269	195	69,485,589	54,523,728	1,569	20,206,894	7,856,456	778	97,942,313	15,447,725	315
2009-2010	73,575,555	3,966,521	108	65,386,221	41,649,391	1,273	24,495,153	8,058,117	656	98,070,708	12,024,637	245
Difference	-4,159,865	-3,624,749	-87	-4,099,368	-12,874,337	-296	4,288,259	201,661	-121	128,395	-3,423,088	-70
% change	-5.4%	-47.7%	-44.7%	-5.9%	-23.6%	-18.9%	21.2%	2.6%	-15.6%	0.1%	-22.2%	-22.3%
	In-Region Generation (MWh)		Total In-Region Load (MWh)									
2006-2008	147,221,008		167,427,902									
2009-2010	138,961,776		163,456,929									
Difference	-8,259,233		-3,970,973									
% change	-5.6%		-2.4%									

	Non-RGGI Generation			RGGI Generation			Imports			Total Non-RGGI Generation (ISO + Net Imports)		
	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh
2006-2008	77,735,420	7,591,269	195	69,485,589	54,523,728	1,569	20,206,894	7,856,456	778	97,942,313	15,447,725	315
2010	75,225,464	3,738,238	99	66,197,587	43,762,015	1,322	24,924,844	9,424,534	756	100,150,308	13,162,772	263
Difference	-2,509,956	-3,853,031	-96	-3,288,002	-10,761,713	-247	4,717,950	1,568,078	-21	2,207,995	-2,284,954	-53
% change	-3.2%	-50.8%	-49.1%	-4.7%	-19.7%	-15.8%	23.3%	20.0%	-2.7%	2.3%	-14.8%	-16.7%
	In-Region Generation (MWh)		Total In-Region Load (MWh)									
2006-2008	147,221,008		167,427,902									
2010	141,423,051		166,347,895									
Difference	-5,797,957		-1,080,007									
% change	-3.9%		-0.6%									

RGGI-PJM

Table 11. Monitoring Trends for RGGI-PJM

	Non-RGGI Generation			RGGI Generation			Imports			Total Non-RGGI Generation (ISO + Net Imports)		
	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh
2006-2008	51,670,395	1,906,413	74	59,806,712	57,110,171	1,910	56,048,627	36,024,885	1,285	107,719,022	37,931,299	704
2009-2010	52,437,710	2,255,514	86	53,815,313	46,965,302	1,746	55,599,473	33,619,541	1,209	108,037,182	35,875,055	664
Difference	767,315	349,100	13	-5,991,399	-10,144,870	-164	-449,154	-2,405,344	-76	318,161	-2,056,244	-40
% change	1.5%	18.3%	17.2%	-10.0%	-17.8%	-8.6%	-0.8%	-6.7%	-5.9%	0.3%	-5.4%	-5.7%
	In-Region Generation (MWh)		Total In-Region Load (MWh)									
2006-2008	111,477,106		167,525,733									
2009-2010	106,253,023		161,852,495									
Difference	-5,224,084		-5,673,238									
% change	-4.7%		-3.4%									

	Non-RGGI Generation			RGGI Generation			Imports			Total Non-RGGI Generation (ISO + Net Imports)		
	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh	MWh	CO2 Emissions	lb CO2/MWh
2006-2008	51,670,395	1,906,413	74	59,806,712	57,110,171	1,910	56,048,627	36,024,885	1,285	107,719,022	37,931,299	704
2010	51,265,258	2,705,768	106	57,625,172	50,125,993	1,740	56,157,104	34,255,621	1,220	107,422,362	36,961,389	688
Difference	-405,137	799,355	32	-2,181,540	-6,984,178	-170	108,477	-1,769,264	-65	-296,659	-969,909	-16
% change	-0.8%	41.9%	43.1%	-3.6%	-12.2%	-8.9%	0.2%	-4.9%	-5.1%	-0.3%	-2.6%	-2.3%
	In-Region Generation (MWh)		Total In-Region Load (MWh)									
2006-2008	111,477,106		167,525,733									
2010	108,890,430		165,047,534									
Difference	-2,586,676		-2,478,199									
% change	-2.3%		-1.5%									

Appendix D. Concept of “Emissions Leakage”

“Emissions leakage” is the concept that the RGGI CO₂ compliance obligation and related CO₂ compliance costs for electric generators could result in a shift of electricity generation from CO₂-emitting sources subject to the RGGI CO₂ Budget Trading Program to CO₂-emitting sources not subject to RGGI. Key to this concept is that the cause of such a shift would be due to the RGGI CO₂ Budget Trading Program, rather than other factors that influence electric power sector CO₂ emissions. The concept of emissions leakage presumes that an increase in electricity production costs for certain electric generators due to RGGI CO₂ compliance costs would be the driver of changes in the operation of the electric power system that result in an increase in CO₂ emissions from electric generation that is not subject to the RGGI CO₂ Budget Trading Program.

Factors that Influence Electric Generator Dispatch and CO₂ Emissions

In the Northeast and 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 in to 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 CO₂, NO_x, and SO₂ 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, 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 CO₂ emissions, through a highly dynamic wholesale electricity market.

The concept of emissions leakage assumes a scenario in which only a subset of CO₂-emitting electric generators are subject to a CO₂ allowance requirement.³⁶ As a result, certain electric generators are subject to an additional production cost – the cost of CO₂ allowances – that is not faced by other CO₂-emitting electric generators. In theory, this could result in a shift in electric generation to emitting units that do not face a CO₂ compliance cost. If such a shift results in an increase in CO₂ emissions from electric generation as a whole, such an increase is referred to as emissions leakage.

If emissions leakage were to occur, it would result from an increase in dispatch (and related CO₂ emissions) from: (a) in-region non-RGGI units (i.e., small fossil fuel-fired units in the ten-state RGGI region with a capacity less than 25 MWe, which are not subject to RGGI); (b) electric generation outside the ten-state 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”.

³⁶ The ten-state RGGI region does not completely align with the geographic footprint of wholesale electricity markets in the greater Northeast and Mid-Atlantic region, and electric power can flow across multiple wholesale markets in North America.