RGGI Inc.

Relative Effects of Various Factors on RGGI Electricity Sector CO_2 Emissions: 2009 Compared to 2005

Draft White Paper – 11/2/10

Prepared By:

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

RGGI, Inc. is a non-profit corporation created to provide technical and administrative services to the CO_2 Budget Trading Programs of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont.

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This analysis attempts to estimate the relative effects of various factors that have contributed to the observed decrease of approximately 60.7 million tons of CO_2 emissions from the RGGI region electricity sector in 2009 compared to 2005. CO_2 emissions in the RGGI region have declined from approximately 184.4 million tons in 2005 to 123.7 million tons in 2009, or 33 percent.

Figures 1 and 2 show the relative contribution of the factors identified to the observed decrease in CO_2 emissions from 2005 to 2009. The analysis concludes that three categories of factors are the primary drivers of the decreased CO_2 emissions over this period: 1) lower electricity load (due to weather; energy efficiency programs and customer-sited generation; and the economy); 2) fuel-switching from petroleum and coal to natural gas (due to relatively low natural gas prices); and 3) changes in available capacity mix (due to increased nuclear capacity availability and uprates; reduced available coal capacity; increased wind capacity; and increased use of hydro capacity). The results suggest that modeling analysis of any existing or potential CO_2 policy should be "bounded" by sensitivity runs which evaluate the policy across a range of assumptions for load growth, relative natural gas prices, and changes in available capacity mix, that are both higher and lower than might be projected in a "Reference Case" comprised of "best estimates."

Figure 1

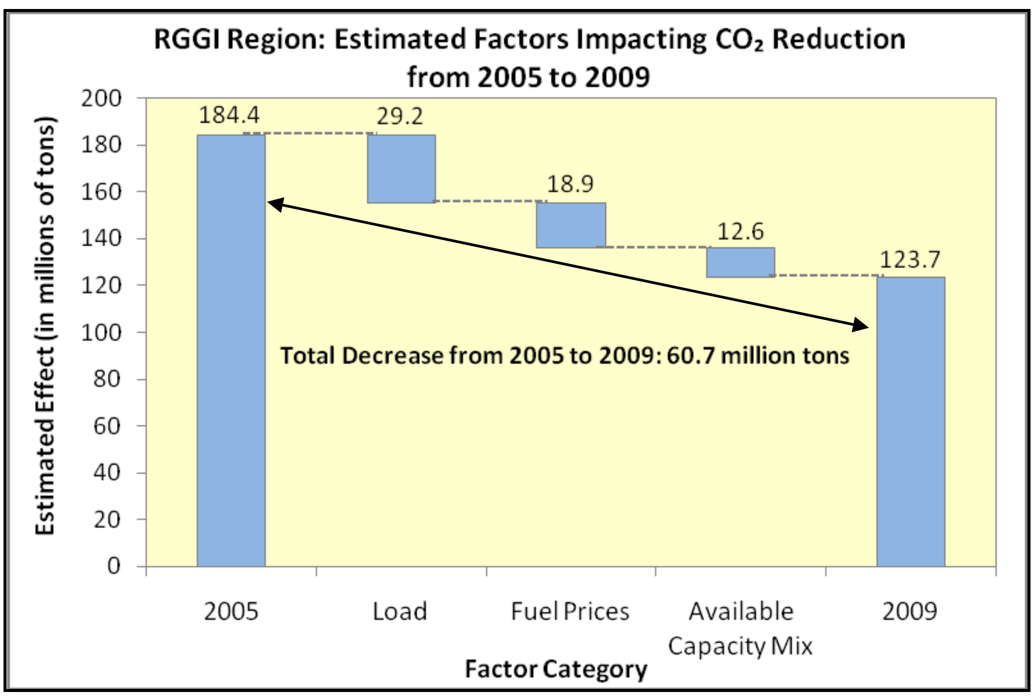
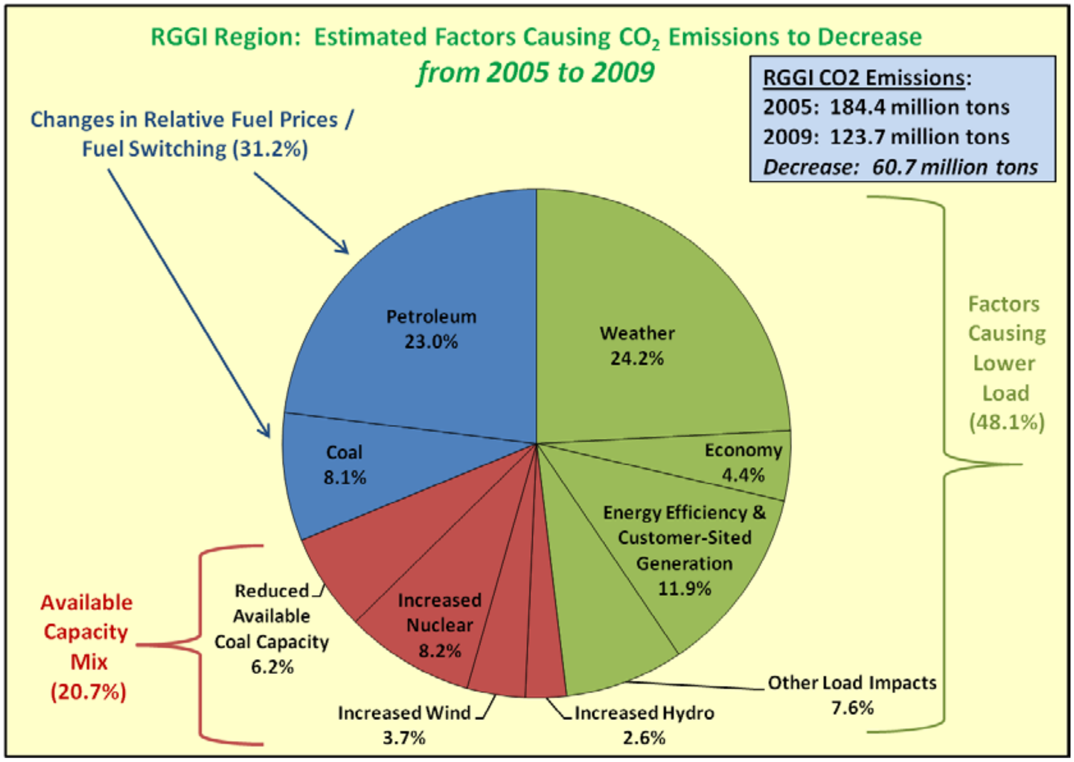


Figure 2



The methodologies, analytical tools, data and assumptions used to estimate the relative impact of each factor identified as affecting CO_2 emissions over the 2005 to 2009 time period are discussed below. [1]

[1] The analysis did not explicitly evaluate the estimated impact on CO_2 emissions of compliance with the RGGI CO_2 cap-and-trade program and did not attempt to estimate the relative contribution of the RGGI program to the reduction in CO_2 emissions from 2005 to 2009. Such an evaluation is beyond the scope of the analysis. Conceptually, it is expected that the impact of RGGI, implemented in 2009, is embedded in some of the factors identified in Figures 1 and 2. For example, lower electricity load may be partially due to the use of RGGI CO_2 allowance auction proceeds to fund state energy efficiency programs. Fuel switching may be partially due to CO_2 allowance costs further narrowing the fuel price differentials between fuels with different carbon content. Coal plant retirements may be partially due to consideration of projected future CO_2 allowance costs in the economic evaluation of the plants that preceded their closure.

The factors analyzed are diverse, complex, and often interactive. The data needed to analyze these factors across ten states over multiple years are often incomplete or inconsistent. Further, there is significant movement over any time period in economic structure, market behavior, consumer attitudes, technology use, energy infrastructure, regulatory structures, and political postures that cannot be fully understood or measured. Given

Methodology Common to Estimating Impacts of All Factors

All of the factors analyzed are related to the observed overall lower use of fossil fuels by electricity generators in the RGGI region in 2009, as compared to 2005. These include decreased electricity requirements in 2009 (caused primarily by weather, the economy, and impacts of energy efficiency programs and customer-sited generation), as well as increased generation from non-emitting sources (*i.e.* nuclear, hydro, and wind units). Fuel switching due to relatively low natural gas prices and retirement of a significant number of coal units between 2005 and 2009 also contributed to increased generation from cleaner sources in 2009 as compared to 2005.

To estimate the impact of any specific factor on CO_2 emissions, it is necessary to net the actual emissions in 2009 against a proxy estimate of what emissions might have been in the absence of the factors that actually existed in 2009. For analytical purposes, it was assumed that if each contributing factor were returned to 2005 conditions (*e.g.* electricity requirements were higher or wind generation was lower), the increase in generation needed to meet load would come from regional units burning natural gas, coal, and petroleum fuels proportional to the actual regional fossil fuel generation mix in 2009. Figure 3 shows the average RGGI region 2009 fossil fuel mix, and Table 1 shows the assumed heat rates and emission factors.

For factors related to decreased electricity requirements and increased nuclear, wind, and hydro generation, "marginal" heat rates were used to estimate proxy emissions. The natural gas heat rate is assumed to be higher than the fleet average, because the bulk of efficient combined cycle plants were likely to be already dispatched. Had more generation been needed from within the region, it is likely that more natural gas steam units and combustion turbines would have been dispatched, as opposed to dispatching more natural gas combined-cycle units. Heat rates for natural gas steam units and combustion turbines typically range from 11,000 to 13,000 Btu per kWh. "Marginal" petroleum and coal unit heat rates are assumed to mirror the fleet averages, because there is a much smaller efficiency disparity among these types of units. For coal retirements, fleet average heat rates were used.

The analysis followed a "bottom-up" approach, and estimated each identified factor independently from the others, using assumptions for marginal generation mix and heat rates that are based on objectivity and defensibility (*i.e.* assumed values can be referenced to actual data in specific years or are reported in published sources). Assumptions for various parameters are needed because, for example, it cannot be known exactly which generation sources would have operated over each of the 8,760 hours in 2009 in the absence of the actual market and economic conditions that existed in that year. The assumed values for marginal generation mix and heat rates enabled the quantification of about 88 percent of the actual observed change in tons of regional CO_2 emissions from 2005 through 2009. The estimated tons of CO_2 attributed to each factor were scaled upward so that the sum of the impacts of individual factors was equal to the total change in CO_2 emissions.

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these types of uncertainties, the conclusions of this analysis should be regarded as indicative of direction and relative order of magnitude, rather than as precise measurements.

Figure 3

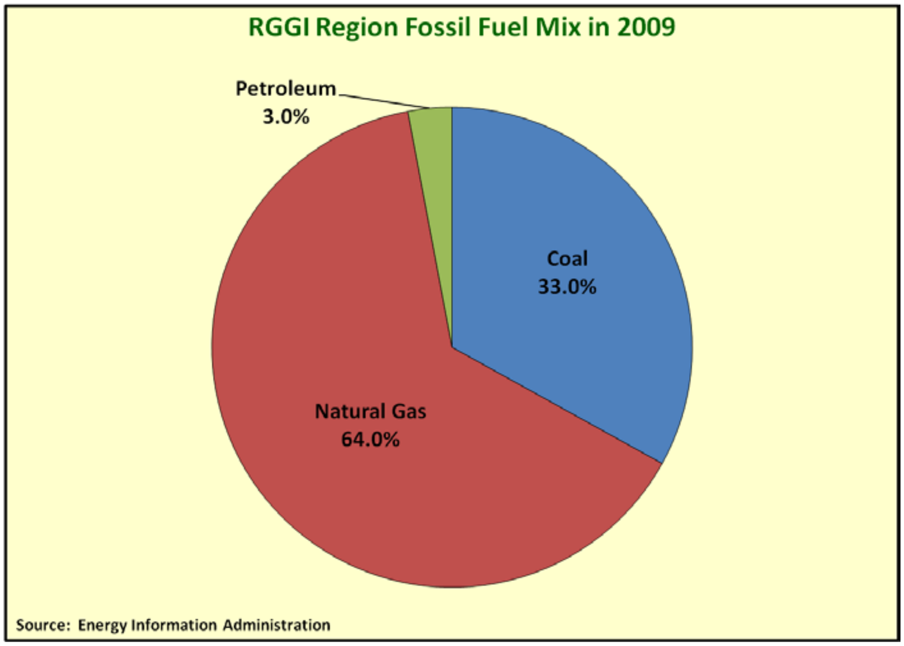


Table 1

RGGI Region	Coal	Natural Gas	Petroleum
Average 2009 Fleet Heat Rates (Btu per kWh)	10,284	7,998	10,195
"Marginal" Heat Rates Assumed (Btu per kWh)	10,284	11,000	10,195
Emission Factors (pounds per MMBtu)	208	117	170
Source for Average Heat Rates: Energy Information Administration			

Impact of Changes in Imports on RGGI CO_2 Emissions

Annual net imports were estimated by calculating the difference between regional end-use electricity sales (adjusted by a factor of 0.928 to account for line losses at the transmission and distribution level) and the electricity generated within the region. Electricity requirements not met by generation within the region were assumed to be met with imports.

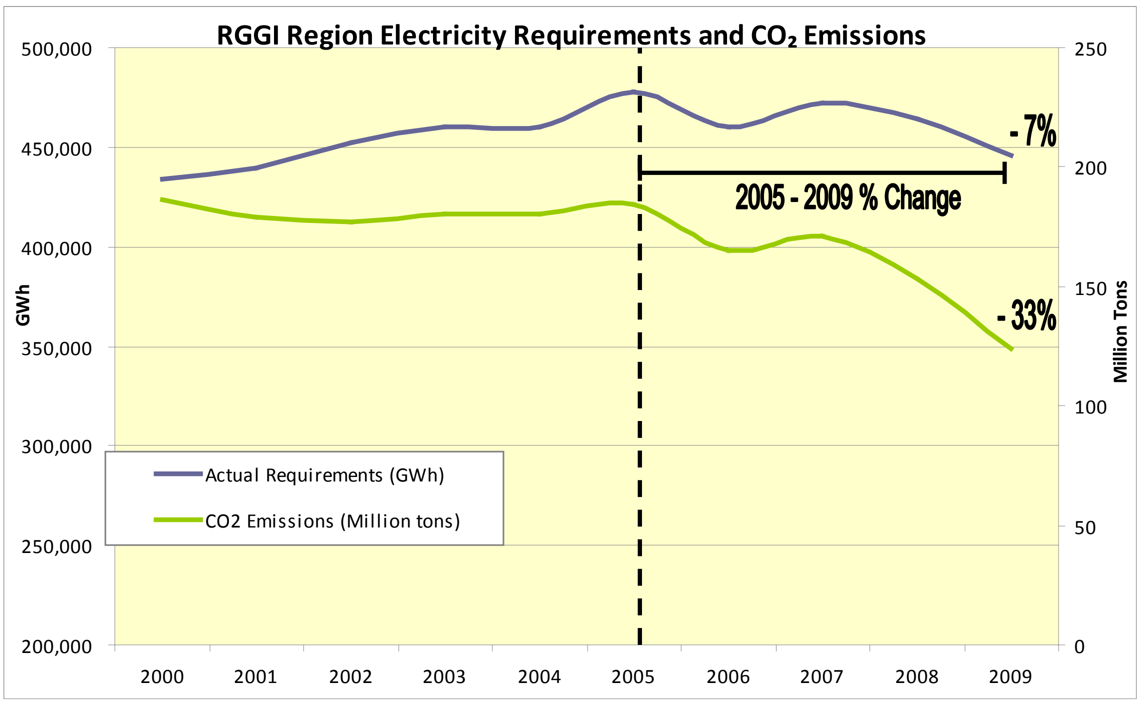
Net imports of electricity into the RGGI region were estimated to be virtually the same in 2009 as in 2005, though there is significant year-to-year fluctuation in net imports. Therefore, the analysis results indicate that changes in net imports do not appear to have contributed to the decrease in CO_2 emissions from 2005 to 2009.

1. Lower Electricity Load (i.e. Decreased Electricity Requirements)

Electricity requirements for the RGGI region decreased by approximately 32,137 GWh (at the generation level) between 2005 and 2009. If RGGI region electricity requirements had been at 2005 levels in 2009, it was assumed that the additional electricity requirements would have been met by an in-region mix of units burning natural gas, coal, and petroleum fuels (see Figure 3). Given this assumption, the reduction in electricity requirements accounted for approximately 29.2 million tons of the total decrease in CO_2 emissions from 2005 to 2009, or 48.1 percent of the total decrease.

As shown in Figure 4, from 2005 to 2009, RGGI region electricity requirements in GWh decreased by 7 percent, while CO_2 emissions decreased by 33 percent. The impact of lower electricity requirements is quantified by three factors: (1) weather; (2) energy efficiency programs and customer-sited generation; and (3) the economy. The fourth factor is residual and accounts for the changes in load that are unexplained by these three factors.

Figure 4



1.1 Lower Electricity Load Due to Weather (2005 to 2009)

Weather affects electricity sales (*i.e.* end-use) and requirements (*i.e*. at the generator). According to NYISO, ISO-NE, and PJM, the RGGI region experiences peak electricity requirements during the summer months due to the increase in air conditioning load.[2] A summer with above-average temperatures increases air conditioning load and requires additional electricity to be provided. On a smaller scale, a winter with below-average temperatures increases electric heat and furnace fan loads and therefore increases electricity requirements.

The NYISO, ISO-NE and PJM[3] estimate the effect that weather has on annual electricity requirements by a calculation known as weather-normalization. Weather-normalization is a mathematical adjustment of actual energy use to represent the energy that would be expected to be used in a "normal" or average-weather year. The weather-normalization calculation accounts for year-to-year fluctuations in weather that may result in abnormally high or low energy use, but do not contribute to the long-term trend in energy use.

As shown in Table 2, the electricity requirements in 2005 were 9,862 GWh, or about 2 percent, higher than if the weather had been "normal" or average. Conversely, the electricity requirements for 2009 were 6,298 GWh lower than if the weather had been "normal." Combining the effects of a hot summer (above normal cooling degree days[4]) in 2005 and a cool summer (below normal cooling degree days) in 2009, weather accounted for 16,160 GWh of the reduction in electricity requirements between 2005 and 2009 for the RGGI region. Using the assumed fuel mix shown in Figure 3, it is estimated that weather accounted for approximately 24.2 percent of the total decrease in CO_2 emissions. For perspective over a longer time period, Figure 5 shows the RGGI region weather-normalized and actual electricity requirements between 2000 and 2009.

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[2] New York Independent System Operator (NYISO) is a not-for-profit corporation responsible for operating New York State's bulk electricity grid. The Independent System Operator New England (ISO-NE) is a not-for-profit corporation responsible for ensuring reliable operation of New England's bulk power generation and transmission system. PJM Interconnection (PJM) is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states plus the District of Columbia.

[3] PJM does not post actual or weather-normalized load requirements for the individual states in its territory. Actual electricity requirements for Delaware, New Jersey and Maryland were deduced from EIA data. It was assumed that seasonal weather conditions in DE, NJ and MD are similar to NY and therefore the percent difference between New York's actual and weather-normalized requirement was applied to DE, NJ, and MD's actual requirements to determine weather-normalized requirements for those three states.

[4] A cooling degree day (CDD) is a unit that relates the day's temperature to the energy demands of air conditioning. CDDs are calculated by subtracting 65 from the day's mean temperature. The hotter the day's mean temperature, the higher the CDD number.

Table 2

RGGI Region Electricity Requirements (GWh)					
Year	**Actual**		**Weather Normalized**		**Difference due to Weather**
2005	477,655	-	467,793	=	**9,862**
2009	445,518	-	451,816	=	**(6,298)**
Absolute Difference	**32,137**	-	**15,977**	=	**16,160**

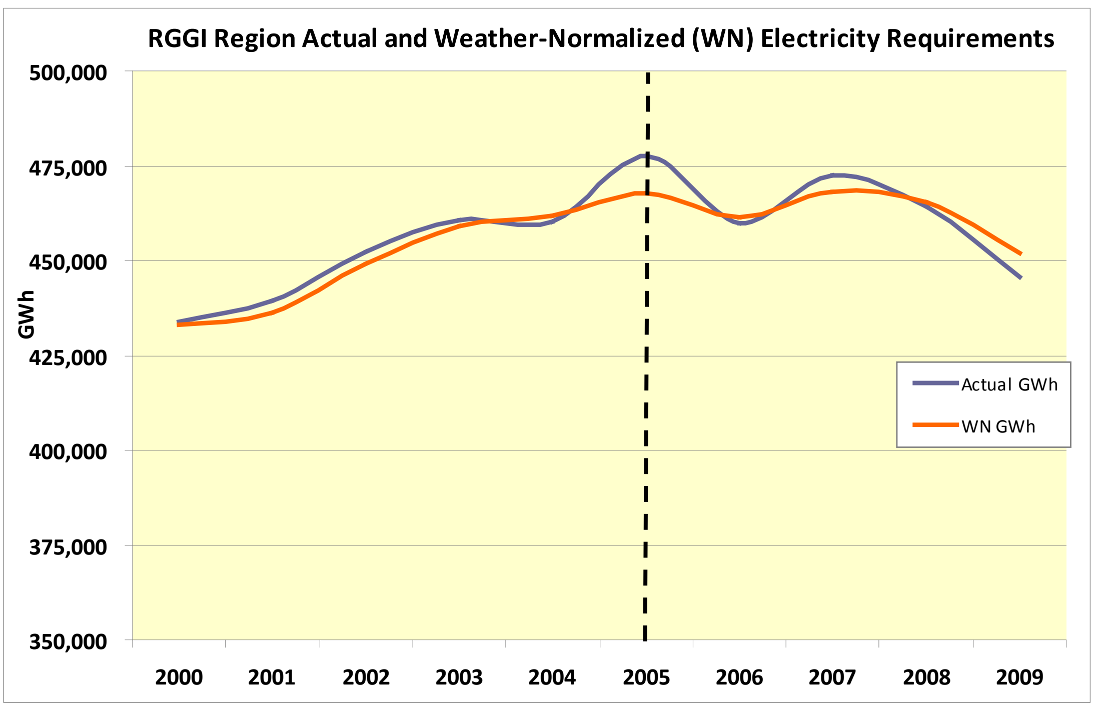
Note: Data are from the NYISO, ISO-NE and EIA.

Table 3

Northeast Region Cooling Degree Days (CDD)				
Year	**CDD**	**30-year Normal CDD**	**Difference from Normal**	**Absolute % Difference from Normal**
2005	1,548	1,164	384	33%
2006	1,294	1,164	130	11%
2007	1,223	1,164	59	5%
2008	1,228	1,164	64	5%
2009	932	1,164	-232	20%

Note: Data are from the National Climatic Data Center.

Figure 5



1.2 Lower Electricity Load Due to Energy Efficiency Programs and Customer-Sited Generation (2005 to 2009)

Energy efficiency programs and customer-sited generation are responsible for reducing electricity use by 7,393 GWh between 2005 and 2009, based on program evaluation data provided on request by individual RGGI states. Taking into consideration an average transmission and distribution line loss of 7.2 percent, the amount of electricity that would have been generated in order for 7,393 GWh of electricity to be used is 7,967 GWh (see Table 4 below). Therefore, energy efficiency programs and customer-sited generation are estimated to have reduced the electricity requirements (at the generator level) in 2009 by 7,967 GWh relative to 2005. Using the assumed fuel mix shown in Figure 3, this accounts for 11.9 percent of the total decrease in CO_2 emissions.

Table 4

RGGI Region Energy Efficiency and Customer-Sited Generation Impacts: Annualized GWh					
State	2006	2007	2008	2009	Total Impacts
Connecticut	328	355	368	237	1,288
Delaware*	n/a	n/a	n/a	n/a	n/a
Massachusetts	417	490	391	528	1,826
Maryland	0	0	0	131	131
Maine	75	87	108	77	347
New Hampshire	97	100	81	78	356
New Jersey	127	224	335	462	1,148
New York	400	720	150	600	1,870
Rhode Island*	n/a	n/a	n/a	n/a	n/a
Vermont	62	112	152	101	428
TOTAL	1,506	2,088	1,584	2,215	7,393
TOTAL w/est. Line Losses	1,623	2,250	1,707	2,387	7,967
*Data from Delaware and Rhode Island were not available					

1.3 Lower Electricity Load Due to Reduced Economic Activity (2005 to 2009)—See full discussion of analysis of economic activity in Appendix

Electricity requirements have historically been closely tied to economic activity, and more specifically, to the standard of living (as measured by variables related to consumer spending). Gross domestic product (GDP) is a reasonably good indicator of the general level of electricity requirements as it reflects overall economic activity. There is a strong correlation between changes in GDP and changes in electricity requirements due to the fact that a significant portion of economic growth (or economic decline) is tied to the level of consumption of goods and services. The components of GDP are Personal Consumption, Investment, Government Spending, and Net Imports (*i.e*. Imports minus Exports). The U.S. Bureau of Economic Analysis (BEA) uses Personal Consumption Expenditures (PCE) as the primary measure of consumer spending on goods and services in the U.S. economy. PCE can be further disaggregated into

Retail and Food Services Sales (RFS). Retail sales provide a good representation of the primary consumption of goods. Moreover, the food services component represents an aspect of consumption that is more strongly correlated with electricity use as it represents the economic activity of businesses in the food industry.

Econometric modeling performed in the context of this analysis (See Appendix) showed a significant correlation between Retail and Food Service Sales and weather-normalized electricity requirements. Based on econometric modeling (*i.e*. "predicted" annual electricity requirements based solely on the historical mathematical relationship between economic conditions and electricity use), the "predicted" electricity requirements in 2005 and 2009, given actual economic conditions in those years, were 461,670 GWh and 458,714 GWh, respectively (see Table 5 below). It is therefore estimated that the economy reduced the electricity requirements by 2,957 GWh between 2005 and 2009. Using the assumed fuel mix in Figure 3, the economy accounted for approximately 4.4 percent of the total decrease in CO_2 emissions.

Table 5

Comparison of Predicted (Econometric) and Actual RGGI Region Weather-Normalized Electricity Requirements (GWh)

Year	Predicted	Actual	Difference
2005	461,670	477,655	1.33%
2009	458,714	445,518	1.50%
Difference due to Economy	**-2,957**	**-32,137**	

Note: Data are from the NYISO, ISO-NE, EIA and Bureau of Economic Analysis.

1.4 Combined Results from Analyzing the Decrease in Electricity Load (2005 to 2009)

Figure 6 shows the estimated percentage impact each factor had on electricity requirements, while Table 6 shows the breakdown of the estimated values for the impacts according to the individual factors. The combined effects of weather (-16,160 GWh), energy efficiency programs and customer-sited generation (-7,967 GWh), and the economy (-2,957 GWh), account for 27,083 GWh, or 84 percent of the actual 32,137 GWh reduction that occurred between years 2005 and 2009. The remaining 5,054 GWh load reduction labeled "Other Load Impacts" cannot be accounted for by known factors. These unexplained load impacts could include, for example, adoption of more energy-efficient products that were not directly associated with state-funded energy efficiency programs. Another example could be that the economic downturn resulted in energy conservation that is not fully reflected in the standard measures of consumer spending (*e.g*. people scale back use of air conditioners in summer, electric space heaters in winter, and lighting and rechargers year-round). There could be numerous other types of changes in general patterns of customer behavior and technology use over this period that have not been documented or measured.

Figure 6

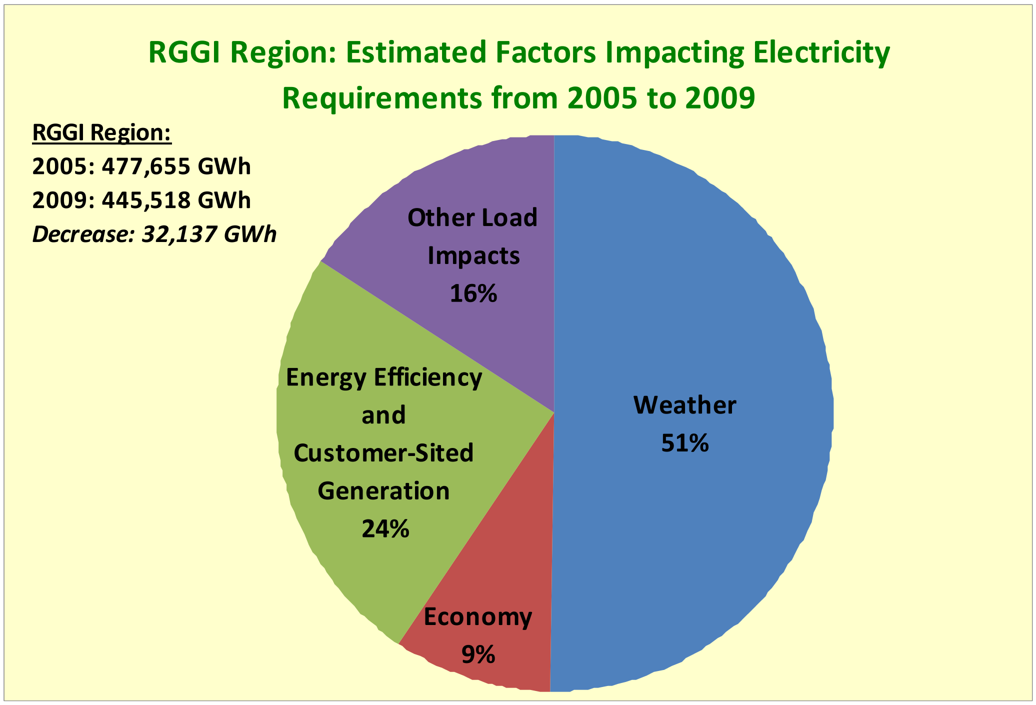


Table 6

Breakdown of the Estimated Components for the Change in Electricity Requirements Bewteen 2005 and 2009 (GWh)	
Estimated Change from Weather	-16,160
Estimated Change from Energy Efficiency and Customer-Sited Generation	-7,967
Estimated Change from the Economy	-2,957
Estimated Change from Other Load Impacts	-5,054
Total Estimated Change from Impacts	**-32,137**

It should be recognized that the estimated impact of the economy on electricity load (both proportion and absolute amount) would be far more substantial if the analysis had been framed to compare 2009 to 2007, rather than 2005. This is true, first, because most of the decrease in electricity load occurred between 2007 and 2009 (84 percent). Second, the effects of the economic downturn became evident in 2008 and 2009, while 2005 to 2007 were years of economic growth. Economic activity, as measured by Gross Domestic Product, was actually higher in 2009 than in 2005, though there was a large decrease from 2008 to 2009. Retail and Food Service Sales, the measure of economic activity used in this analysis, increased from 2005 to 2007, then decreased in 2008 and 2009 to a point that was lower than 2005.

To illustrate, Figure 7 shows the relative impacts of the various factors on electricity load if the analysis period is 2007 to 2009, rather than 2005 to 2009. Table 7 shows the breakdown of the estimated values for the impacts according to the individual factors. From this alternative perspective, 43 percent of the load decrease is attributed to the economy, compared to 9 percent in the 2005 to 2009 analysis period on which this analysis is focused.

Figure 7

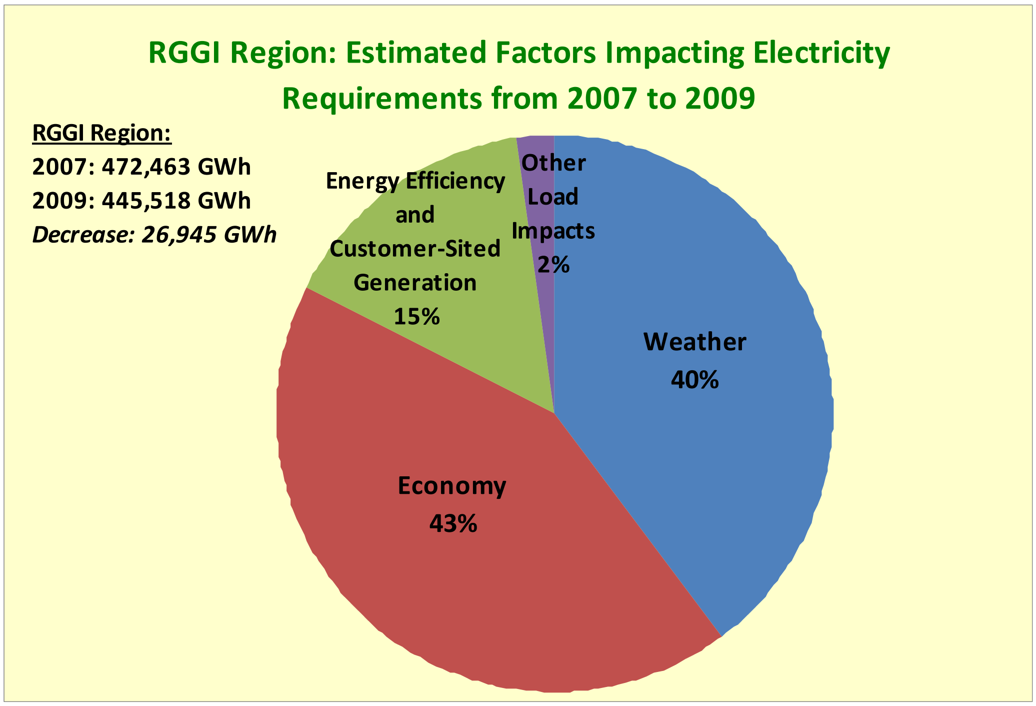


Table 7

Breakdown of the Estimated Components for the Change in Electricity Requirements Bewteen 2007 and 2009 (GWh)	
Estimated Change from Weather	-10,715
Estimated Change from Energy Efficiency and Customer-Sited Generation	-4,094
Estimated Change from the Economy	-11,538
Estimated Change from Other Load Impacts	-598
Total Estimated Change from Impacts	**-26,945**

2. Changes in Relative Fuel Prices / Fuel Switching

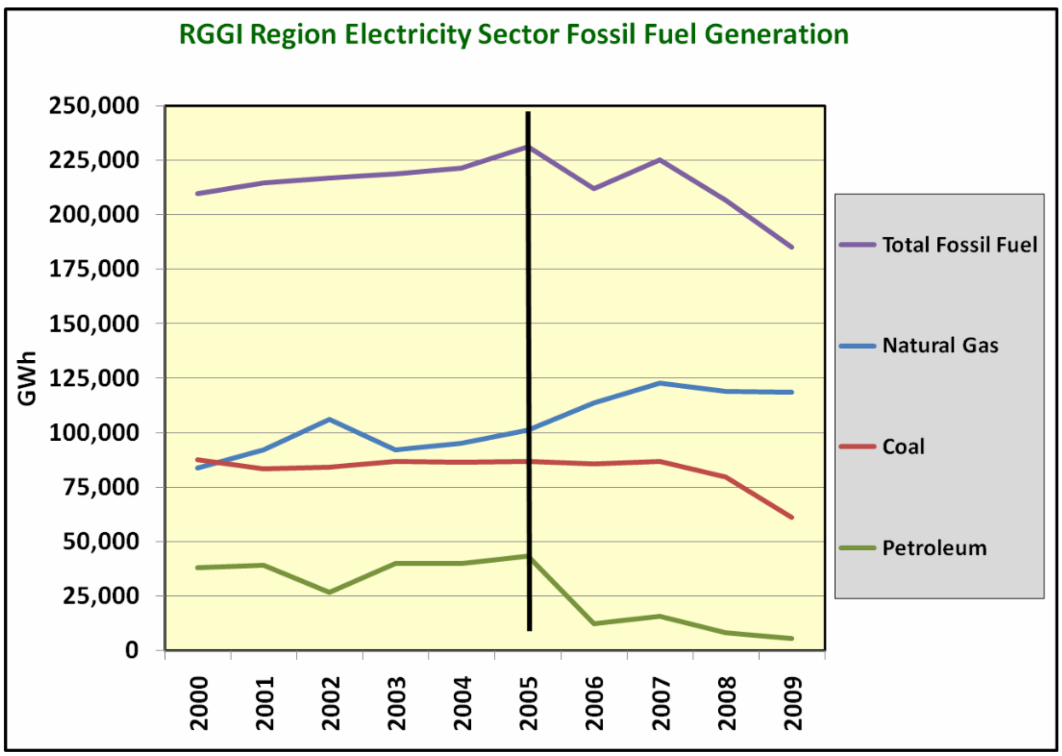
Table 8 shows the GWh of electricity generation by fossil fuels in 2005 and 2009 within the RGGI region. The relative contribution of coal and petroleum generation decreased substantially in 2009 compared to 2005, while the contribution of natural gas generation increased substantially.

Table 8

RGGI Region	Coal	Natural Gas	Petroleum	Total
	GWh	GWh	GWh	GWh
2005	86,782	101,125	43,207	231,114
% of fossil fuel generation	37.5%	43.8%	18.7%	100.0%
2009	61,131	118,410	5,462	185,003
% of fossil fuel generation	33.0%	64.0%	3.0%	100.0%
Note: Data are from the Energy Information Administration				

Figure 8 illustrates the year-by-year trend (since 2005) of decreasing petroleum and coal generation, accompanied by increasing natural gas generation. From 2005 to 2009, petroleum and coal generation decreased by 37,700 and 25,600 GWh, respectively, while natural gas generation increased by 17,300 GWh. Total generation from fossil fuels decreased by 46,100 GWh.

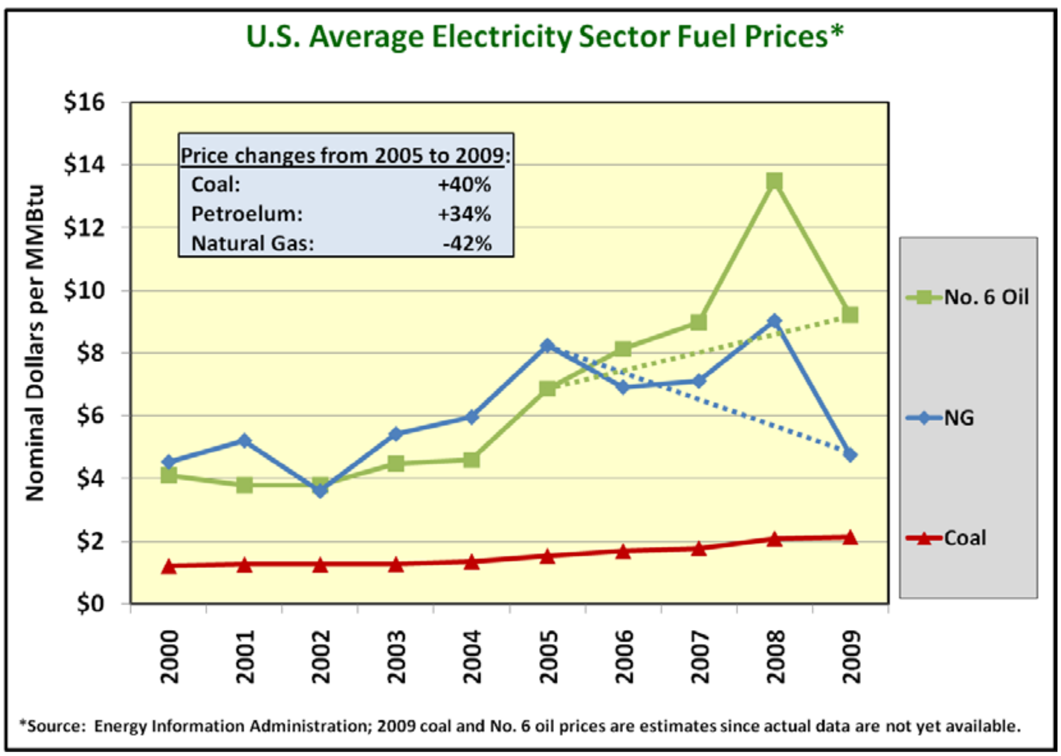
Figure 8



The trend of moving away from petroleum and coal generation to natural gas was caused in large part by the decrease in natural gas prices relative to petroleum and coal prices. Figure 9 shows average annual delivered fuel prices for the U.S. electricity sector from 2000 to 2009. Natural gas prices decreased by 42 percent from 2005 to 2009, while both petroleum and coal prices increased. Through 2005, natural gas prices were generally higher than No. 6 oil prices (dollars per MMBtu); beginning in 2006, natural gas prices have been lower than No. 6 oil prices.

The price gap between U.S. natural gas and coal decreased by 61 percent, from $6.72 per MMBtu in 2005 to $2.62 per MMBtu in 2009. The effective price gap between natural gas and coal prices decreased slightly more within the RGGI region, due to the requirement to purchase CO_2 allowances and the fact that a unit of electricity generated by coal requires nearly twice the CO_2 allowances compared to natural gas. To illustrate: Based on an average spot price for RGGI CO_2 allowances during 2009 of $3.06 per allowance, RGGI compliance further narrowed the effective price of natural gas relative to coal by $0.14 per MMBtu. This amount accounts for about 3.4 percent of the change in the price gap between natural gas and coal in the RGGI region over the 2005 to 2009 period.[5]

Figure 9



[5] By this accounting, in 2009, RGGI compliance decreased the price gap between natural gas and coal from $2.62 per MMBtu to $2.48 per MMBtu.

The changing fuel price landscape has resulted in dual fuel units burning natural gas rather than oil. Similarly, natural gas units have become more economically competitive with units that burn coal or oil exclusively.

To estimate the contribution of fuel switching to the overall CO_2 reduction, the actual CO_2 emissions in 2009 are netted against estimated emissions from a proxy fuel mix that assumes the same total amount of fossil generation (185,003 GWh), using the proportions from the actual fuel mix burned in 2005 (see Table 8). This methodology approximates the ability to isolate the impacts of fuel switching, while stripping out the impacts of lower overall electricity sales, higher generation levels from renewable and nuclear generation, and coal plant retirements.

Table 9

RGGI Region	Coal	NG	Petroleum	Total	Estimated CO_2
	GWh	GWh	GWh	GWh	Million Tons
2009 Actual Generation	61,131	118,410	5,462	185,003	125.5
2009 Gen Assuming 2005 Proportions	69,468	80,949	34,587	185,003	142.1
Difference due to Fuel Switching					**-16.6**
Source for actual proportions: Energy Information Administration					

As shown in Table 9, 18.9 million tons of the decrease in CO_2 emissions from 2005 to 2009 can be attributed to fuel switching, or 31.2 percent of the total observed decrease (See Table 1 for heat rate and emission factor assumptions). Fleet average heat rates were assumed.

The bulk of the decrease in natural gas prices is due to the recent sharp increase in the supply of natural gas from sources such as the Marcellus Shale formation. While it is recognized that economic conditions may have played a role in causing natural gas prices to decrease, estimating the extent of this role is beyond the scope of this analysis. Therefore, any economic impacts that may have resulted in lower natural gas prices are accounted for in the “Fuel Switching” factor, not the “Economy” factor. It should also be understood that the key driver of fuel switching is the relationship of natural gas prices to coal and petroleum prices, not the absolute price of natural gas.

3. Changes in Available Capacity Mix

Changes in the availability of generation capacity from nuclear, coal, wind, and hydro units occurred between 2005 and 2009 due to plant retirements, re-rates of existing plants, addition of new generation units, conversion to alternative fuel capability, and increased hours of operation of existing capacity. Changes in the availability of capacity are discussed below for each fuel type.

3.1 Increased Nuclear Generation

In 2009, the RGGI region generated 5,491 more GWh from nuclear as compared to 2005, due to both capacity uprates of existing units and improved operation and maintenance procedures. If the lower 2005 output levels from these sources had occurred in 2009, it is assumed that the gap would have been filled with in-region fossil fuel units proportional to the actual mix in 2009 (see Figure 3). Given this assumption, it is estimated that the 2009 increase in nuclear generation accounted for approximately 5.0 million tons of the overall decrease in CO_2 emissions from 2005 to 2009, or about 8.2 percent of the total decrease.

3.2 Reduced Available Coal Capacity

Between December 31, 2004 and December 31, 2009, approximately 1,582 MW of coal capacity within the RGGI region became unavailable for dispatch due to retirement, re-rating, or facility conversion (see Table 10 below).[6] In lieu of firm and final 2009 data for the entire region, the firm aggregate New York State coal capacity factor for 2009 (55 percent) was applied to these coal units throughout RGGI region to estimate the likely output from the plants in 2009 had they been available. This equates to approximately 7,619 GWh of generation from coal units that was not dispatched in 2009 that was available for dispatch in 2005.

Table 10

RGGI Region	2005 Coal Capacity	2009 Coal Capacity*	Net Change
	Summer MW	Summer MW	Summer MW
	as of 12/31/2004	as of 12/31/2009	as of 12/31/2009
Connecticut	553	553	0
Delaware	1,070	1,074	4
Massachusetts	1,723	1,662	-61
Maryland	4,958	4,944	-14
Maine	85	85	0
New Hampshire	575	528	-47
New Jersey	2,124	2,054	-70
New York	4,201	2,807	-1,394
Rhode Island	0	0	0
Vermont	0	0	0
Total	15,289	13,707	-1,582
Source: EIA Electric Power Annual Reports & EIA Form 860 Database			
***Assumes units scheduled to retire in 2009 as of 12/31/08 did in fact retire**			

This additional 7,619 GWh of coal generation would have caused approximately 8.15 million tons of CO_2 emissions in 2009. This reduction in output is assumed to be replaced by units burning the average RGGI fossil fuel mix in 2009 (see Figure 3), with the exception of a 47 MW converted unit in New Hampshire which was assumed to burn biomass with zero associated emissions of CO_2. After netting out the CO_2 impact of generation from the 2009 fossil fuel mix, it was estimated that the coal plant retirements accounted for approximately 3.7 million tons of the overall decrease in CO_2 emissions from 2005 to 2009, or approximately 6.2 percent of the total decrease.

[6] Retirements for 2009 are based on the EIA Form 860 database of planned retirements, as of 12/31/2008.

3.3 Increased Wind Generation

In 2009, the RGGI region generated 2,468 more GWh from wind as compared to 2005, primarily the result of new units installed over that period in response to Renewable Portfolio Standard requirements. If the lower 2005 output levels from this type of sources had occurred in 2009, it is assumed that the gap would have been filled with in-region fossil fuel units proportional to the actual mix in 2009 (see Figure 3). Given this assumption, the 2009 increase in wind generation is estimated to account for approximately 2.2 million tons of the overall decrease in CO_2 emissions from 2005 to 2009, or about 3.7 percent of the total decrease.

3.4 Increased Hydro Generation

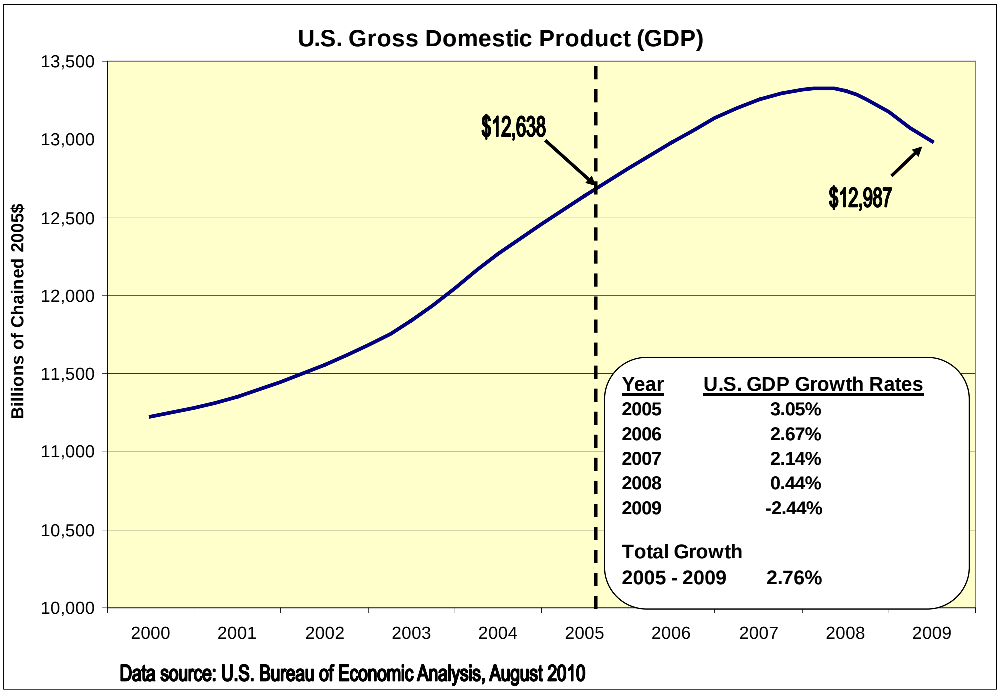
In 2009, the RGGI region generated 1,739 more GWh from hydro as compared to 2005.[7] If the lower 2005 output levels from these sources had occurred in 2009, it is assumed that the gap would have been filled with in-region fossil fuel units proportional to the actual mix in 2009 (see Figure 3). Given this assumption, the 2009 increase in hydro generation is estimated to account for approximately 1.6 million tons of the overall decrease in CO_2 emissions from 2005 to 2009, or about 2.6 percent of the total decrease.

[7] The gigawatt-hours associated with hydro have subtracted the energy needed for water pumping.

Appendix: Methodology for Analyzing the Decrease in Electricity Requirements Associated with Economic Activity (2005 to 2009)

U.S. Gross State Product provides the starting point for deriving an econometric model based on the components of GDP that best fits the actual electricity requirement data. Figure 10 shows the U.S. GDP from 2000 to 2009. Notice that although GDP decreased between 2008 and 2009, the overall level of GDP in 2009 is still larger than that in 2005.

Figure 10: U.S. Gross Domestic Product in Billions of Constant 2005 Dollars



The RGGI region annual electricity requirements were regressed against U.S. GDP using standard ordinary least squares econometric analysis. Figure 11 shows the predicted electricity requirements graphed against the actual electricity requirements for 2000 through 2009 when U.S. GDP is used as the independent, or predictor, variable. The figure also shows the U.S. GDP time series so that its behavior can be compared to movements in the RGGI region electricity requirements. The Mean Absolute Percent Error (MAPE) is the average of all the absolute percent differences. The MAPE, r-squared value, t-stat, and P-value are standard diagnostic tools used in statistical analysis. All of these tools are used together when developing a regression model rather than relying on a single statistical measure, such as the r-squared value. The objective in developing a best-fit regression model is to minimize the amount of error or difference between the actual data and predicted data series. Figure 12 shows the absolute percent difference between the actual and predicted electricity requirements for each year. Typically a MAPE of less than 5% is desirable. If the MAPE is higher than 5%, there may be reason to include another variable in the model, or replace the current independent variable with another that may better explain the actual data series being examined. A bottom-up approach is typically used where independent variables, such as the U.S. GDP, are tested individually and compared to models using a different independent variable. Depending on the statistical results and guided by industry knowledge, models may then be combined and built up one variable at a time to derive a multivariate econometric model. However, any variables included in the model should be consistent with some rational expectation of interaction between the independent and dependent variables.

Figure 11: Comparison of the Predicted RGGI Region Weather-Normalized Electricity Requirements using U.S. GDP to the Actual RGGI Region Weather-Normalized Electricity Requirements

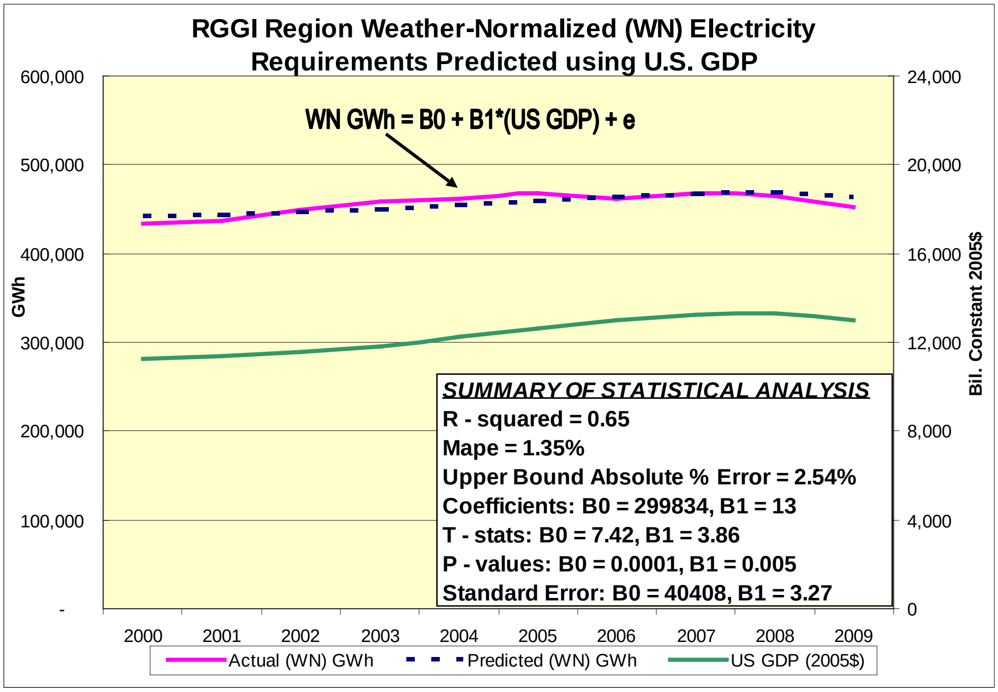
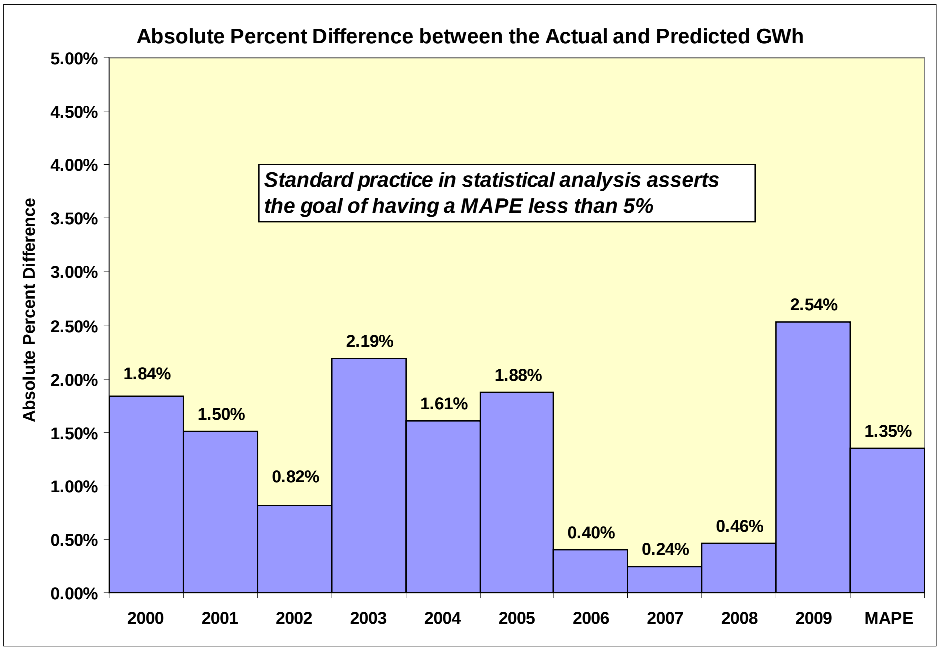
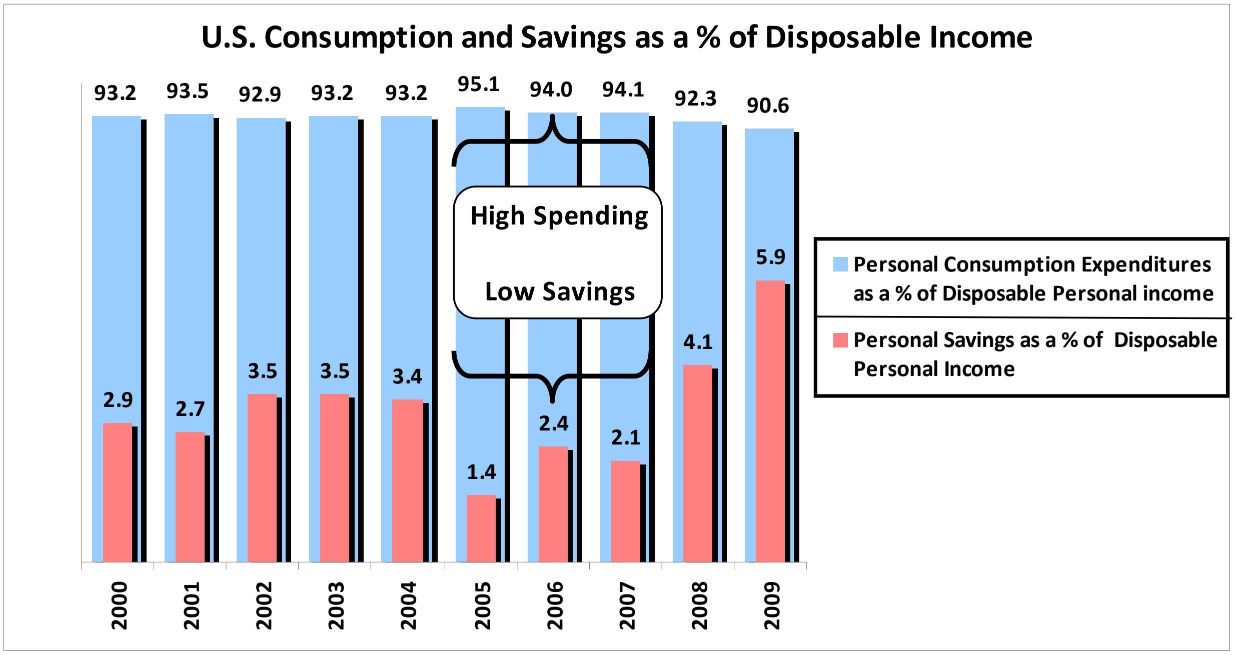


Figure 12: Percent Difference between the Actual and Predicted RGGI Region Electricity Requirements using U.S. GDP



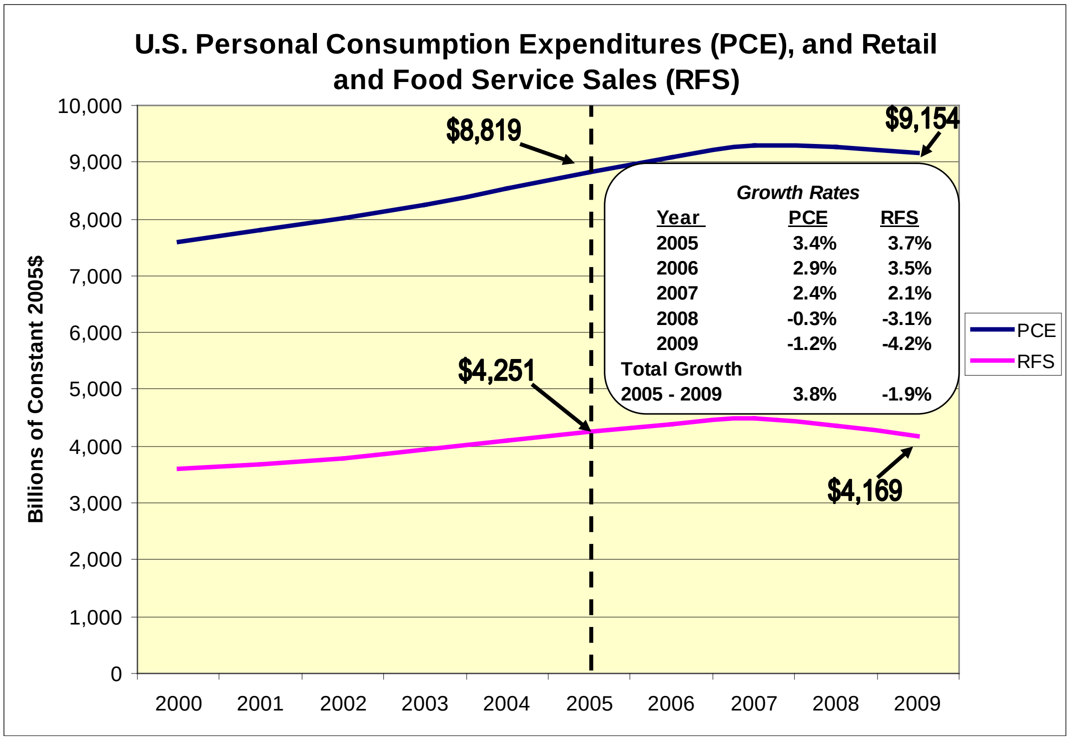
The results in Figures 11 and 12 demonstrate that U.S. GDP is a reasonably good indicator of the general level and direction of RGGI region electricity requirements over the 10-year analysis period. However, further analysis shows that the consumption component of GDP is a better predictor for analyzing the year-to-year changes in electricity requirements. Figure 13 shows the U.S. consumption and savings as a percentage of disposable income. Economic data indicate that 2005 through 2007 were years of high economic activity characterized by high amounts of consumption and low amounts of personal savings. Conversely, 2008 and 2009 were years of low economic activity characterized by low amounts of consumption and high amounts of personal savings. It is particularly noteworthy that 2009 exhibited the lowest amount of consumption compared to the previous eight years.

Figure 13: U.S. Consumption and Savings as a Percentage of Disposable Income



U.S. Personal Consumption Expenditures (PCE) can be further disaggregated into U.S. Retail and Food Services Sales (RFS). Retail sales are considered by economists to provide a good representation of the primary consumption of goods; Food Services measure an aspect of consumption that is highly correlated with electricity requirements as it represents the economic activity of restaurants. Figure 14 shows the time series of both U.S. Personal Consumption Expenditures and Retail and Food Service Sales for 2000 through 2009. Similar to GDP (shown in Figure 10), the PCE decreased between 2008 and 2009; but the overall level in 2009 is still larger than that in 2005. The total growth in PCE between 2005 and 2009 is 3.8 percent. While the PCE provides a good indicator of the overall level of electricity requirements, analysis of the changes in electricity requirements from year to year requires further disaggregation of the independent variable into its components. Regression results indicate that Retail and Food Service Sales more aptly capture the changes in economic activity, especially the activity that is correlated with electricity requirements. The RFS growth rate declined more severely in 2008 and 2009 compared to GDP or PCE. Moreover, the overall growth rate is negative, meaning that the level of RFS was lower in 2009 than it was in 2005. In other words, the overall trend of RFS between 2005 and 2009 is decreasing while the overall trend in GDP and PCE for the same years is increasing.

Figure 14: U.S. Personal Consumption Expenditures, and Retail and Food Service Sales



The regression analysis using the Retail and Food Service Sales as a predictor of weather-normalized electricity requirements for 2000 through 2009 is shown in Figure 15. Both the r-squared and MAPE improved compared to using only PCE as a predictor. The figure also shows the U.S. RFS time series so that its behavior can be compared to movements in the RGGI region electricity requirements. Figure 16 shows the absolute percent difference between the actual and predicted electricity requirements for each year.

Figure 15: Comparison of the Predicted RGGI Region Weather-Normalized Electricity Requirements using U.S. Retail and Food Service Sales to the Actual RGGI Region Weather-Normalized Electricity Requirements

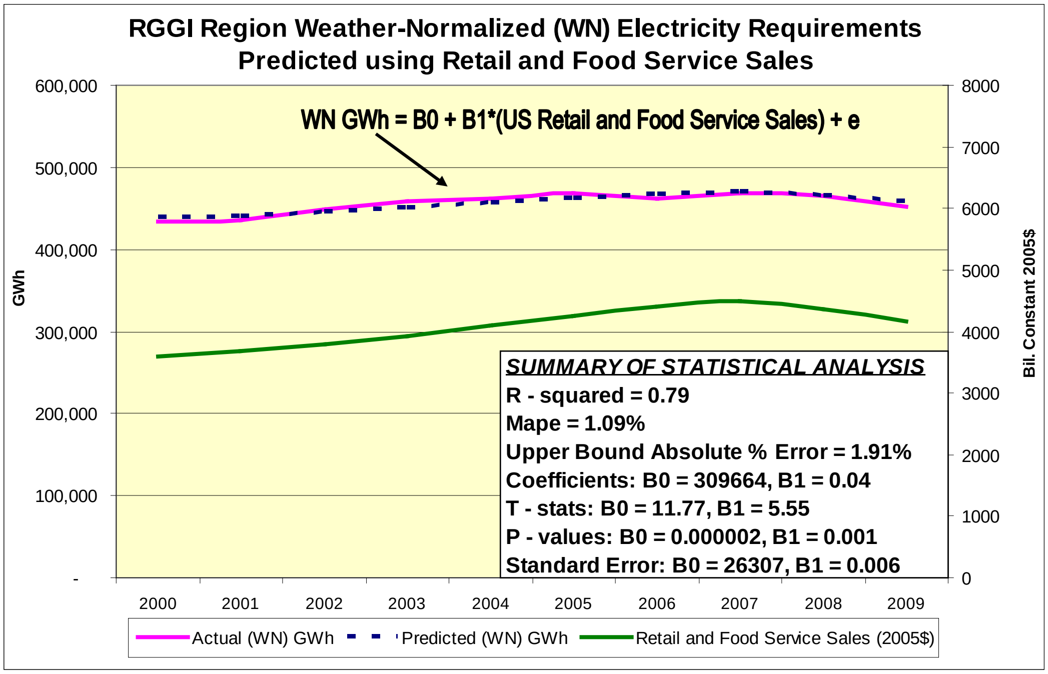


Figure 16: Percent Difference between the Actual and Predicted RGGI Region Electricity Requirements using U.S. Retail and Food Services Sales