

APPENDIX E
ENVIRONMENTAL REGULATIONS

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INTRODUCTION

This appendix summarizes the various environmental regulations that may affect the economics of operating electric generating units (EGUs) in New England. For each pollutant or pollution issue, the existing and emerging federal and state regulations are described and analyzed as to whether such regulations are likely to impose specific control requirements or emission allowance obligations on EGUs that should be reflected in the 2014 Integrated Resource Plan (2014 IRP) modeling.

Previous IRPs focused significant attention on projecting emission allowance prices that would affect future EGU operating costs in New England. These included allowance prices for sulfur dioxide (SO₂) and nitrogen oxides (NO_x), a regional carbon dioxide (CO₂) emission allowance program, and potential U.S. nationwide CO₂ cap-and-trade policies to address global climate change issues. In recent years, emissions of SO₂, NO_x, and CO₂ have declined primarily because low natural gas prices enabled gas-fired generation to displace dirtier coal and oil-fired generation. Low emissions have sharply reduced the market price for SO₂ and NO_x allowances, so the 2014 IRP projects prices to remain at negligible levels through 2024. However, CO₂ allowance prices are expected to increase because the New England states have tightened emissions limits under the Regional Greenhouse Gas Initiative (RGGI). Although a similar federal program is unlikely in the IRP study horizon, the recently proposed Clean Power Plan may result in more states participating in RGGI or expand the market in which CO₂ credits are exchanged.

This assessment finds that expected increases in regional CO₂ emissions allowance prices and requirements to limit hazardous air pollutants (HAPs) from coal-fired EGUs should be analyzed in 2014 IRP modeling. Some other *future* environmental regulations are too uncertain to project in the 2014 IRP, including pending federal regulations to limit CO₂ emissions and EGU water usage. Since it is not known at this time what steps Connecticut and other Northeast states will take to implement these future requirements nor how EGU owners will respond, these issues bear close watching in subsequent IRPs.

The results of the 2014 IRP modeling demonstrate that expected regional CO₂ emissions allowance prices will have only a modest impact on energy prices, and will not significantly alter the region's supply mix. With regards to meeting HAP regulations, five coal-fired EGUs in the region, totaling about 930 MW, potentially face future retrofit costs. In the 2014 IRP Base Case, 96 MW of coal-fired capacity retires in New Hampshire due to insufficient revenues to cover assumed retrofit costs. In the Abundant Supply Market Scenario, which has lower power prices than the Base Case, an additional 143 MW of coal-fired capacity retires in Massachusetts due to poor economics. These projected economic retirements are discussed in further detail in Appendix B (Resource Adequacy).

OVERVIEW OF RELEVANT ENVIRONMENTAL REGULATIONS

Based on the experience of prior IRPs, federal and state environmental regulations that have the greatest potential impact on resource adequacy and electricity rates are promulgated under or mandated by the federal Clean Air Act (CAA) and the Clean Water Act (CWA). This appendix summarizes those regulations and the pollutants of concern that are most likely to significantly affect the operations of electric generating units (EGUs) in Connecticut and the rest of New England. A recent poll of the New England states confirms that there are no additional environmental requirements that are likely to significantly affect New England EGUs at this time.

The federal CAA, which was last amended in 1990, requires EPA to set national ambient air quality standards (NAAQS) for six criteria air pollutants. These pollutants include ground-level ozone, sulfur dioxide (SO₂), nitrogen dioxide (NO₂), particulate matter, lead, and carbon monoxide. The CAA charges EPA with promulgating rules for states to assess the concentrations of these criteria pollutants in the ambient air in those states, and determine whether or not there is attainment with the NAAQS. EPA also promulgates rules to ensure attainment and maintenance of ambient air quality that is at or below the NAAQS in each state. EPA may delegate to states the authority to implement these rules and/or more stringent, state specific rules, if necessary, to achieve and maintain attainment with the NAAQS.

The 1990 CAA amendments also require EPA to promulgate federal rules to reduce emissions of 187 hazardous air pollutants from various emissions sources. EPA may delegate the authority to implement these rules to states, and states may also promulgate additional rules to reduce hazardous air pollutant emissions in accordance with state-specific goals. Often, the specific emissions limits and operating requirements needed to protect air quality are set forth in operating permits for sources of air pollutants. These permits dictate the type of emissions controls that must be installed at sources of air pollution and the level of emissions reduction and performance that must be achieved.

The CWA establishes criteria to protect the quality and quantity of nationwide water resources. In a manner very similar to the CAA, EPA requires states to assess the quantity and quality of groundwater sources, lakes, streams, rivers and coastal water bodies within their jurisdictions. EPA also promulgates rules to improve and maintain water quality and quantity by limiting withdrawals from and effluent discharges to various water bodies. With delegated authority from EPA, states may establish their own rules to protect water quality and quantity within their jurisdictions. States, with delegated authority from EPA, limit effluent discharges and water withdrawals through a variety of regulations and permits issued under those regulations, including: diversion permits, National Pollutant Discharge Elimination System (NPDES) permits, and stormwater discharge permits.

EGUs emit all of the six criteria air pollutants. Additionally, EGUs emit a variety of hazardous air pollutants, often require large withdrawals from local water bodies, and discharge effluent with physical and chemical properties that can impair water quality. Consequently, state and federal regulations promulgated to protect air and water quality can impose pollution control requirements that impact the economics and/or the viability of EGU operations.

AIR QUALITY REGULATIONS

Ground-Level Ozone

Ground-level ozone, commonly known as smog, is a secondary air pollutant formed when precursor air pollutants of NO_x and non-methane organic compounds oxidize in the presence of sunlight. Smog is thus a late spring and summer phenomenon in Connecticut and the ISO-NE region.

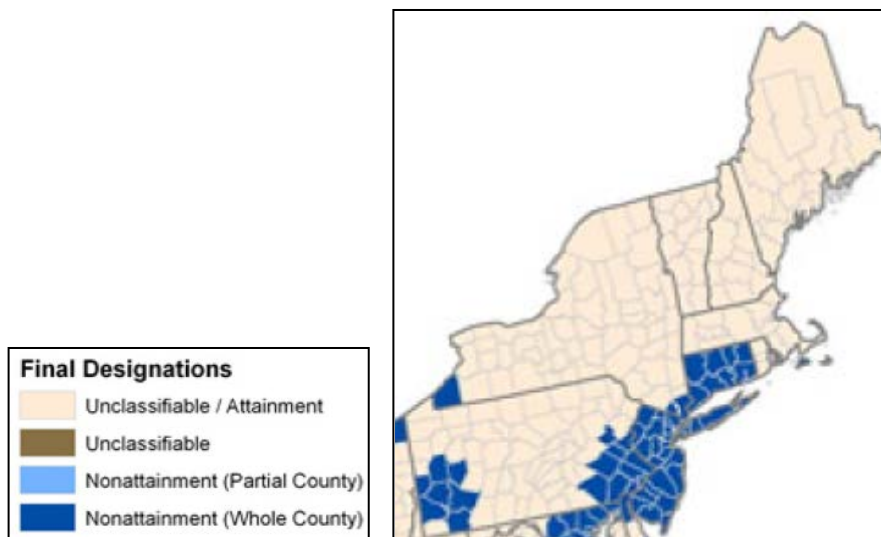
Periodically, EPA promulgates attainment designations for each state or groups of states. Among other factors, attainment designations take into account whether or not monitored air quality in a given area complies with the NAAQS. If air quality does not comply with the standard, then EPA must designate the area as *nonattainment*. There are various degrees of nonattainment which depend on how closely monitored air quality exceeds the NAAQS concentration level. A minor exceedance would result in a designation of *marginal* nonattainment. Progressively more significant designations of *moderate*, *serious*, *severe*, or *extreme* nonattainment result from air quality that fails to meet the NAAQS by ever-increasing margins.

The 1997 ozone NAAQS of 85 parts per billion (ppb) averaged over 8 hours was lowered in 2008 to 75 ppb averaged over 8 hours.¹ On April 30, 2012, EPA designated Connecticut and Dukes County, Massachusetts as marginal non-attainment for the 2008 8-hour ozone NAAQS of 75 ppb. Since Connecticut and portions of Massachusetts are classified by EPA as marginal nonattainment, these states must take appropriate steps to ensure compliance with the standard within three years (*i.e.*, by the fall of 2015). As part of their nonattainment requirements, Connecticut and Massachusetts are also required to perform a review of their regulatory requirements for major sources of nitrogen oxides (NO_x) and volatile organic compounds (VOC) to ensure that the limitations represent a level of pollution control that is reasonably available control technology or RACT. Under this review for the 2008 ozone NAAQS, NO_x emissions limitations for EGUs will become more stringent. Figure 1 shows the final nonattainment areas under the 2008 Ozone NAAQS for the Northeast and neighboring states.

Figure 1 Final Nonattainment Areas under the 2008 Ground Level Ozone NAAQS²

¹ Although commonly referred to as an 85 ppb standard (which we adopt in this discussion) the 1997 NAAQS is expressed as 0.8 parts per million (ppm). Under EPA rounding conventions, the actual effective standard was set at 84 ppb.

² <http://www.epa.gov/glo/designations/2008standards/final/finalmap.htm>

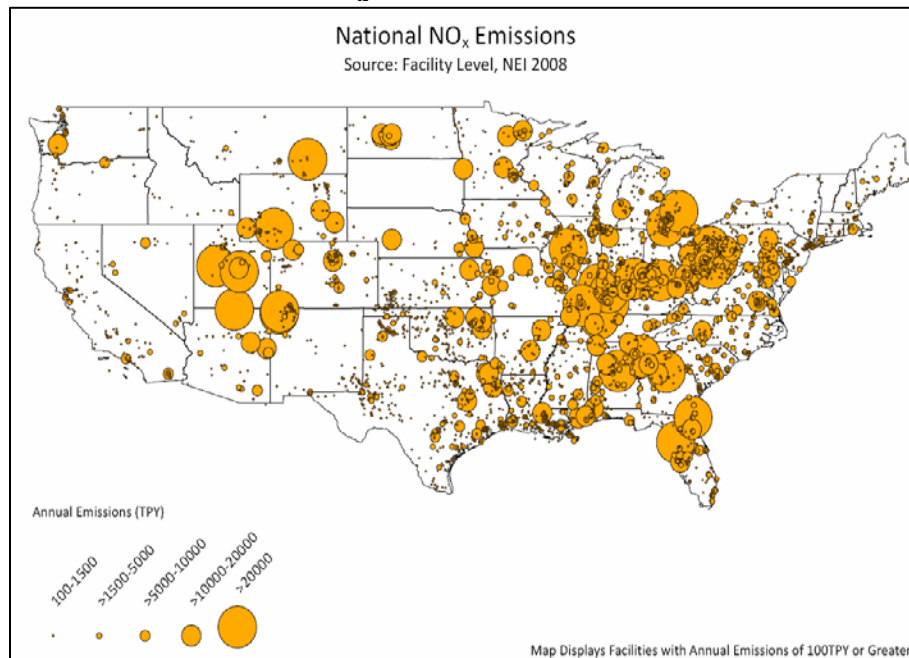


The CAA also requires EPA to review each NAAQS every five years and to update it if current science indicates that the existing standard does not protect public health with an adequate margin of safety. EPA has been reviewing the ground-level ozone NAAQS throughout 2013 and has indicated that the best science justifies a more protective standard in the range of 60-70 ppb averaged over an 8-hour period. A new 8-hr ground level ozone NAAQS is scheduled to be promulgated in 2015. If EPA adopts a standard in this range, then Connecticut and portions of Massachusetts would likely be designated by EPA as moderate or serious nonattainment. These states would then be required to take steps to meet the standard within six to nine years (*i.e.*, by 2021 or 2024, depending on the severity of the classification). These steps would likely include significant EGU NO_x emissions reductions towards the middle and latter years of the 2014 IRP planning horizon.

Ground-level ozone formation in the Northeast is heavily influenced by emissions from upwind sources. Figure 2 shows ground-level ozone contributions to Connecticut from upwind states. Emissions from New York, New Jersey, and Pennsylvania contribute over half of the ground-level ozone concentrations (about 41 ppb) of the 75 ppb standard. These states are home to large NO_x sources that have cost-effective opportunities to reduce emissions. The contribution of upwind states to downwind air quality has led to ongoing regional discussions and policy approaches seeking additional emission controls to ensure upwind states comply with the good neighbor provisions of the CAA. The most recent EPA effort to address interstate ground-level ozone pollution, the Cross State Air Pollution Rule (CSAPR), is intended to bring about compliance with the 1997 8-hour ground-level ozone NAAQS of 85 ppb but will be insufficient for states to meet the more stringent 2008 8-hour ground level ozone NAAQS of 75 ppb. CSAPR is scheduled to take effect on January 1, 2015.

Figure 2
States Contributing to Connecticut's 75 ppb Ground-Level Ozone

Figure 3
NO_x Emissions Sources



Federal NO_x Regulations

EGUs have been subject to federal rules limiting NO_x emissions for decades, initially through New Source Performance Standards (NSPS) that apply to new units. In the early 1990s, the CAA also required NO_x emission limits on existing EGUs to address the problem of acid deposition. Despite these federal efforts, ground-level ozone levels in the eastern U.S. remained high, and ground-level ozone transport concerns (*i.e.*, Midwestern emissions contributing to smog in the Eastern U.S.) motivated proposals in the late 1990s to adopt a regional approach to reduce NO_x emissions from existing EGUs in the eastern part of the U.S. The Ozone Transport Region adopted a NO_x emission allowance trading system in the late 1990s for large sources located on the East Coast, with caps that applied to the five-month “ozone season” (May through September).

The federal NO_x Budget Program successfully built upon this regional framework by limiting NO_x emissions over a 20-state area beginning in 2003. EPA subsequently expanded federal NO_x requirements with the promulgation of the Clean Air Interstate Rule (CAIR) in 2005, which lowered the ozone season emission caps, added an annual emission cap and trade component beginning in 2009, and expanded the geographic scope of the program to 28 states and the District of Columbia. EGUs in Connecticut and Massachusetts were subject to CAIR ozone season NO_x requirements, but in 2008 a Federal Court vacated CAIR and remanded the rule to EPA on the basis that it did not conform to certain CAA requirements. The Federal Court authorized CAIR to continue while EPA proposed, analyzed, and finalized a new approach, the Cross State Air Pollution Rule (CSAPR), which was stayed by the D.C. Circuit Court of Appeals on December 30, 2011 (it was scheduled to go into effect on January 1, 2012). While EGUs in

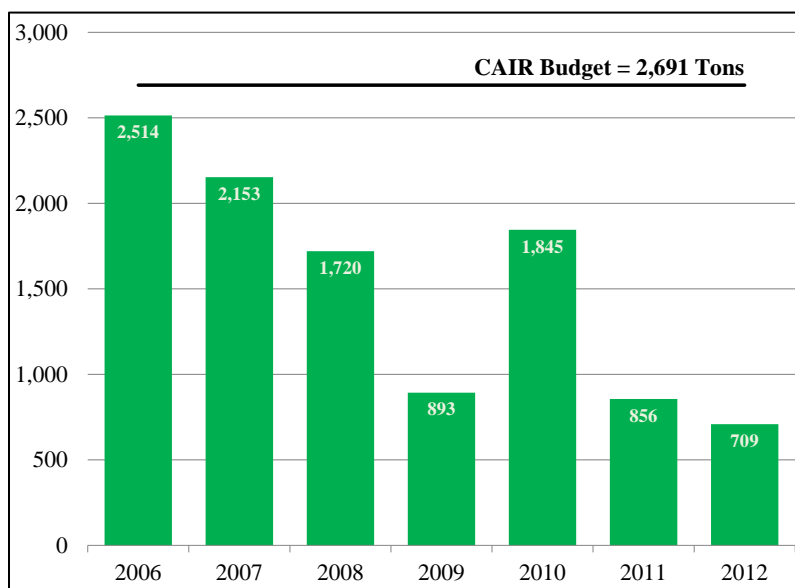
Connecticut and Massachusetts were subject to CAIR, these EGUs were *not* subject to CSAPR because emissions from EGUs located in Connecticut and Massachusetts no longer significantly contributed to ozone pollution (with respect to the 1997 8-hour standard) in other states. EPA proposed several significant revisions to CSAPR in 2012; however, the D.C. Circuit Court vacated the rule in August 2012. In August 2013, the Supreme Court granted EPA's petition to have the Supreme Court review the D.C. Circuit Court decision. In April 2014, the U.S Supreme Court issued a decision reversing the D.C. Circuit decision and remanded the case to the D.C. Circuit. On June 26, 2014, EPA filed a motion requesting the D.C. Circuit to lift the stay of CSAPR and move compliance deadlines by three years so CSAPR implementation would begin January 1, 2015. On October 24, 2014, the D.C. Circuit granted the motion to lift the stay.

While the fate of CSAPR was decided, the seasonal NO_x budgets and allowance allocations established under CAIR have remained in place. This has had limited effect on Connecticut EGUs because their recent emissions levels have remained well below the CAIR budget cap, as shown in Figure 4, as a result of earlier compliance-related investment decisions.

During 2012, for example, emissions were 74% below the cap, primarily due to a combination of factors: the displacement of coal- and oil-fired generation by relatively low-cost, natural gas-fired generation; the introduction of new generation and peaking capacity utilizing natural gas along with advanced emission controls; reductions in peak demand achieved through investments in energy efficiency and demand response, and the effects of the economic recession. Similar results were observed for the state of Massachusetts.

Under market conditions analyzed in the 2014 IRP, seasonal NO_x emissions from EGUs in Connecticut are projected to remain at similarly low levels over the 10-year study horizon, as shown in the main report.

Figure 4
Connecticut Ozone Season NO_x Emissions Relative to CAIR Emission Budget³
(NO_x Tons per Year)



State NO_x Regulations

Connecticut continues to rely on the emission reductions associated with CAIR in the State Implementation Plans (SIPs) filed with EPA directed at attaining the 1997 8-hour ozone standard and meeting Regional Haze⁴ Program requirements. Because of these federally enforceable and pre-existing commitments, Connecticut must take steps to maintain the NO_x emissions reductions associated with CAIR. Upon CSAPR's implementation, EPA has stated that DEEP will need to adopt another federally enforceable means of continuing the reductions relied on in its SIPs for the 1997 ozone standard and the Regional Haze Program requirements.

Connecticut also continues to monitor NO_x emissions from peaking units used to meet electric demand on hot summer days when air quality is impaired. These "High Electric Demand Days" (HEDD) are of particular concern because surging air conditioning loads increase the need to dispatch peaking units with historically high NO_x emissions rates during ambient atmospheric

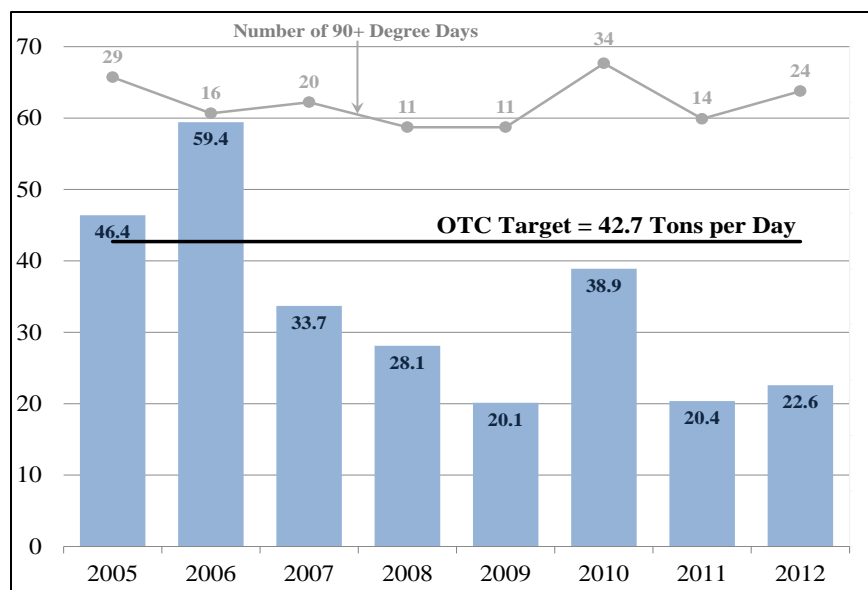
³ Connecticut CAIR Sources are EGUs located in Connecticut with nameplate capacity greater than 15MW and industrial boilers located in Connecticut with heat input greater than 250MMBtu.

⁴ One of the most basic forms of air pollution - haze - degrades visibility in many American cities and scenic areas. Haze is caused when sunlight encounters tiny pollution particles in the air, which reduce the clarity and color of what we see, and particularly during humid conditions. Particle pollution is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles. The Regional Haze Rule calls for state and federal agencies to work together to improve visibility in [156 national parks and wilderness areas](#). The rule requires the states, in coordination with federal agencies and other interested parties, to develop and implement air quality protection plans to reduce the pollution that causes visibility impairment.

conditions ideal for ozone formation. Connecticut has committed to the Ozone Transport Commission (OTC) to limit Connecticut HEDD NO_x emissions to below a target level of 42.7 tons per day (TPD). Average HEDD NO_x emissions in Connecticut between 2007 and 2012 were roughly 27 TPD, as shown on Figure 5.

Even though Connecticut is meeting the HEDD reduction targets agreed to in 2007, in 2014 Connecticut measured ozone levels exceeding the 2008 as well as the 1997 8-hour ozone standards. Ozone standard exceedances were recorded on High Electric Demand Days (HEDD) when peaking units (HEDD units) are relied upon to meet electrical demand. HEDD units accounted for at least 57% of the NO_x emissions while supplying only 17% of the MWHs. To address these exceedances and plan for a new tighter ozone standard a renewed focus and control strategy is necessary for HEDD units.

Figure 5
Actual NO_x Emissions on Connecticut High Electric Demand Days (HEDDs)
and Ozone Transport Commission (OTC) Target⁵
 (Average NO_x Tons per Day)



⁵ These data were derived from the average of the four highest demand days in each year. Data includes emissions from all CAIR units, including electric generating units and load-following boilers.

DEEP is currently revising its NO_x emissions limits for fuel burning sources to satisfy RACT under the 2008 ozone NAAQS. The revised RACT rules would likely require EGUs to meet more stringent, federally enforceable NO_x limits and will include provisions to ensure that Connecticut continues to meet its HEDD targets. The new emissions limits would first apply in 2017 with full implementation required in 2021 or 2022. In addition, DEEP will be required to perform a new RACT analysis under the 2015 ozone NAAQS, likely in or near 2022.

Modeling the Impacts of NO_x Allowance Prices on New England EGUs

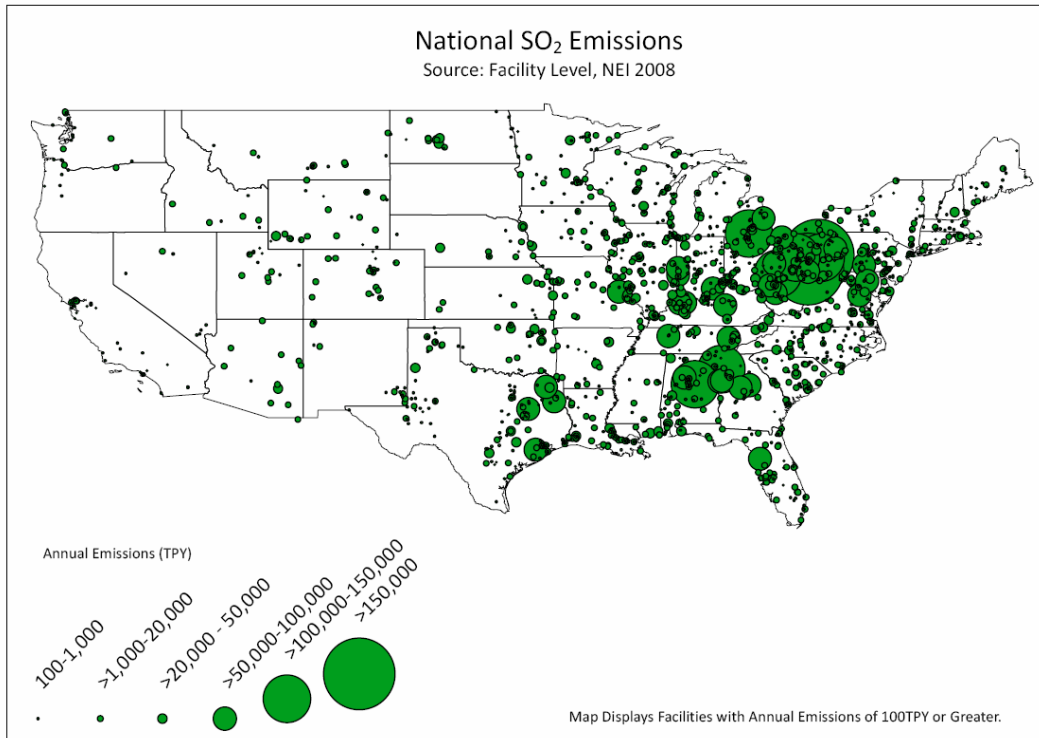
Because New England is exempt from CSAPR and ozone season EGU emissions in Connecticut and Massachusetts remain below the CAIR allowance budgets, both ozone season and annual allowance prices were assumed to be negligible for all EGUs. Therefore, the 2014 IRP modeling system does not include any policy mechanisms for additional NO_x controls, and generating units are assumed to emit NO_x at their current rates.

Sulfur Dioxide (SO₂)

SO₂ emissions are a concern as both a criteria pollutant and because SO₂ is a precursor pollutant to the secondary formation of fine particulate matter, defined under the CAA as particles smaller than 2.5 microns (PM_{2.5}).⁶ Coal-fired EGUs are the predominant source of nationwide SO₂ emissions, and similar to NO_x emissions, originate primarily in the Midwest and Southeast regions of the U.S., as shown in Figure 6. Although New England has relatively low SO₂ emissions, SO₂ emissions from upwind states contribute to PM levels and regional haze in New England, and interfere with progress on addressing fine particulate and visibility standards.

⁶ There is also a 24-hour NAAQS for PM_{2.5}, under which Fairfield and New Haven Counties were designated non-attainment areas in 2009 (the only non-attainment areas in New England). Those counties were redesignated to attainment on October 24, 2013.

Figure 6
SO₂ Emissions Sources



Federal SO₂ Regulations

Title IV of the CAA established a nationwide SO₂ allowance cap-and-trade system, designed to combat acid deposition that significantly damaged water bodies throughout the Northeast. While the acid deposition program remains in effect, the emission reductions attributed to CAIR and those expected under CSAPR will likely exceed the reduction requirements associated with the acid deposition program. This has reduced the economic value of Title IV SO₂ allowances to the point they have negligible impact on EGU compliance costs.

EGUs in Connecticut and Massachusetts were not subject to the SO₂ provisions of CAIR and are not subject to the SO₂ provisions of CSAPR because the New England EGUs do not significantly contribute to particulate pollution in other states.

EPA revised the 1-hour SO₂ NAAQS in 2010, and, on August 5, 2013, EPA published nonattainment designations for 29 areas based on air quality monitoring data. EPA intends to address designations for the rest of the country, including Connecticut, in the near future. The attainment status designation in Connecticut and in most of New England depends on the results of a hybrid modeling and monitoring process that was completed in mid-2012. Since completing its modeling, Connecticut has submitted a request to be designated in attainment of the 2010 1-hour SO₂ NAAQS statewide and is awaiting EPA's response. If EPA disagrees with that request and applies a nonattainment designation, the impacts of that nonattainment designation on sources of emissions in Connecticut could range from minor (*e.g.*, permit modifications to limit operating hours) to significant (*e.g.*, required SO₂ controls, operational limits, or fuel sulfur limits). EPA is expected to issue a determination on Connecticut's request as soon as resources allow. Since EPA hasn't made a determination on Connecticut's request for designation in attainment of the 2010 1-hour SO₂ NAAQS, the impact on EGU operations associated with implementing the standard cannot be predicted at this time. This bears closer watching in subsequent IRPs.

State SO₂ Regulations

Connecticut continues to implement state-specific SO₂ requirements on EGUs pursuant to Section 22a-174-19a of the Regulations of Connecticut State Agencies (RCSA), which DEEP revised in April 2014 in conjunction with the adoption of RCSA section 22a-174-19b, RCSA section 22a-174-19b limits the sulfur content of fuel oil used in power generation. Compliance with the requirements of RCSA section 22a-174-19b was required as of July 1, 2014, and the requirements and timing for distillate fuel oil are the same as those of section 16a-21a of the general statutes, as revised by Public Act 13-298. Section 16a-21 regulates the sulfur content of distillate oil sold as home heating oil. RCSA section 22a-174-19b may impose minimal compliance costs on owners of EGUs. .

Modeling the Impacts of SO₂ Allowance Prices on New England EGUs

Because New England is exempt from CSAPR, and CAA Title IV SO₂ allowances are assumed to have near-zero cost due to emission reductions associated with other programs, SO₂ allowance

prices were assumed to be negligible for all EGUs. Additionally, Connecticut's fuel sulfur content regulations are not expected to significantly impact EGU operations. Therefore, the 2014 IRP modeling system does not include any policy mechanisms for additional SO₂ controls, and generating units are assumed to emit SO₂ at their current rates.

Carbon Dioxide (CO₂)

In June 2013, President Obama introduced his Climate Action Plan (the Plan). The Plan sets forth a goal of reducing U.S. GHG emissions to 17% below 2005 levels by 2020. A cornerstone of the Plan is the President's direction to EPA to promulgate new source performance standards and emissions guidelines to reduce CO₂ emissions from new and existing fossil fuel EGUs.

Federal CO₂ Regulations

In accordance with its authority under Section 111(b) of the CAA, EPA proposed New Source Performance Standards (NSPS) for CO₂ emissions from new fossil fuel EGUs with an output rating of at least twenty-five megawatts on September 20, 2013. The proposal contains separate standards depending on generating technology, fuel, and heat input rating. The proposed standards applicable to new natural gas combustion turbines and new natural gas combined cycle plants can be met by conventional technologies. The proposed standards applicable to fossil fuel-fired utility boilers and integrated gasification combined cycle (IGCC) plants are based on the demonstrated performance of an IGCC plant using carbon capture and sequestration to achieve reductions in CO₂ emissions. EPA will accept comment on the proposal through the end of 2013 and will promulgate a final rule as soon as possible thereafter.

In June of 2014, EPA proposed emission guidelines to limit CO₂ emissions from existing fossil fuel EGUs under its authority pursuant to Section 111(d) of the CAA, in the Clean Power Plan ("CPP"). The draft Clean Power Plan targets a 30% reduction below 2005 levels of CO₂ from the power sector. The proposal contains four areas or "building blocks" for CO₂ reductions at existing EGUs: 1. Increase efficiency at coal plants; 2. Redistribution from coal to oil EGUs; 3. Increase low and zero carbon generation; and 4. Increase in energy efficiency. The CPP sets a CO₂ emissions rate for each state based upon application of the four building blocks. States are allowed to convert the rate to a CO₂ mass cap. RGGI is specifically referenced as an appropriate compliance mechanism. The final rule is expected to be released in the summer of 2015. States would be required to file plans to implement the final emissions guidelines by June 2016 if submitting a single state plan and June 2017 if submitted a multi-state plan. Emission reductions will begin in 2020.

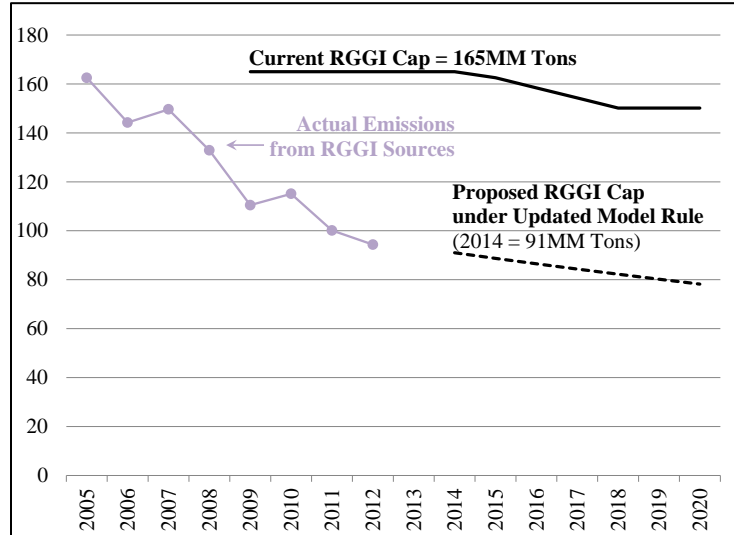
The NSPS and states' implementation of the emission guidelines are anticipated to take effect towards the mid and latter years of the 2014 IRP planning horizon. The final limits applicable to new and existing EGUs have yet to be finalized but are expected to have significant impacts on coal- and oil-fired EGUs. EPA's promulgation of these standards bears close watching in subsequent IRPs.

State CO₂ Regulations

Connecticut, the other New England States, New York, Delaware and Maryland continue to implement the Regional Greenhouse Gas Initiative (RGGI), the first multi-state cap-and-trade program where CO₂ allowances are auctioned to an open market, rather than allocated to regulated sources at no cost. The auction proceeds are intended for investments in sources of renewable energy and to fund energy efficiency initiatives designed to reduce energy consumption across all classes of electricity rate payers. The states adopted rules to implement RGGI in 2008.

Under the RGGI Memorandum of Understanding (MOU), the RGGI program recently underwent an extensive review to evaluate its effectiveness and is now preparing for the next extensive program review. The states observed that a significant surplus of allowances existed due to the fact that recent CO₂ emissions were significantly lower than promulgated allowance budgets (See Figure 7). In order to preserve the reduction in current emissions and reduce future CO₂ emissions, the RGGI states committed to lowering the regional CO₂ allowance cap and reducing states' individual CO₂ allowance budgets to align with recent actual emissions and adjust for the surplus of CO₂ allowances in the marketplace. The proposed 2014 regional cap of 91 million CO₂ allowances is just slightly less than 2012 and projected 2013 emissions. Each year that regional cap declines by 2.5%. States also committed to retire any surplus allowances that were not sold in prior auctions to protect the integrity of the new regional cap. Finally, states included cost containment mechanisms to mitigate CO₂ allowance price spikes from abhorrent circumstances (e.g. an unforeseen, drastic decrease in the supply of pipeline natural gas). All nine RGGI states have implemented the necessary statutory and regulatory changes to satisfy the commitments made during the program review, all of the changes were effective as of January 1, 2014.

Figure 7
Current and Revised CO₂ Emissions Caps under RGGI
10-State RGGI Region
(Million CO₂ Tons per Year)

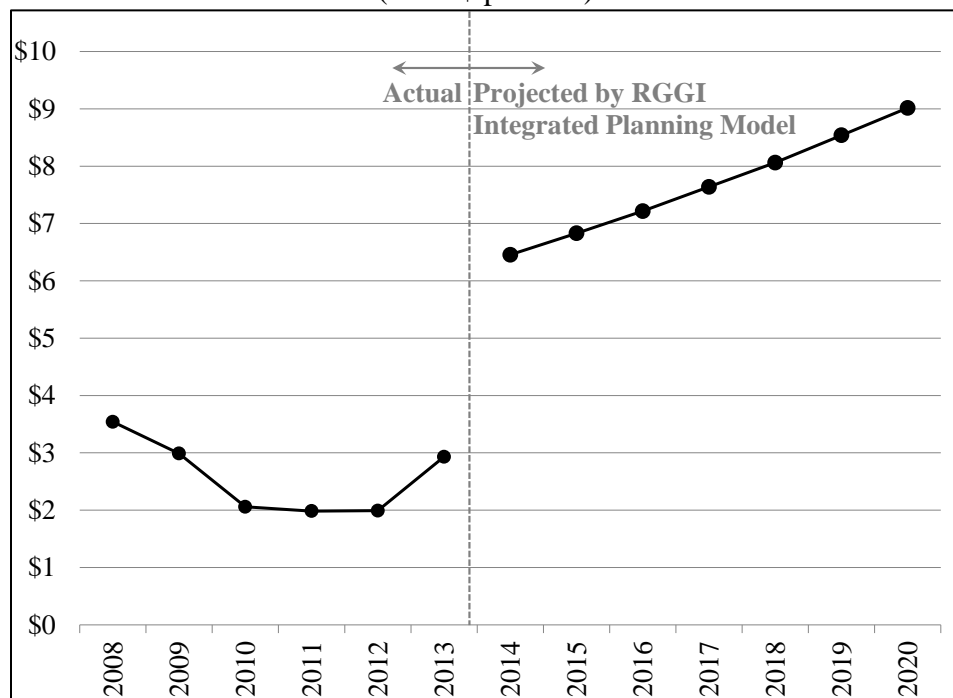


CO₂ allowance prices in prior auctions and subsequent trading in secondary markets through 2012 remained at the price floor (currently \$1.90 per ton in nominal dollars), CO₂ allowance prices at auction in 2013 averaged \$2.89 per ton (in nominal dollars) and \$4.78 in 2014. Additionally, all the allowances offered at auction in 2013 and 2014 were purchased. The rise in prices and the sale of all allowances offered signal the fact that the market is reacting to the announcement of the proposed, lower, regional cap., As the program cap declines overtime, allowance prices in future auctions and subsequent trades are expected to rise, as shown in Figure 8. CO₂ allowance price forecasts, developed using the Integrated Planning Model (IPM), to rise to \$9.02 per ton by 2020 (prices indicated in 2014 dollars).

Modeling the Impacts of CO₂ Allowance Prices on New England EGUs

The IPM forecast allowance prices for each of the 2014 IRP planning years were applied to EGUs located in participating states. No additional CO₂ prices were added in the latter years.

Figure 8
Actual and Projected Average RGGI Allowance Auction Clearing Prices
2008 Through 2020
(2010 \$ per Ton)



HAZARDOUS AIR POLLUTANTS (HAPS)

Toxic air pollutants from coal and oil-fired power plants cause serious health and environmental impacts. In December 2011, EPA finalized rules to reduce mercury and other heavy metals such as arsenic, chromium, and nickel, as well as acid gases, from coal- and oil-fired EGUs.

Federal HAP Regulations

EPA proposed the Mercury and Air Toxics Standards (MATS) for power plants on May 3, 2011. EPA issued the final rule on December 21, 2011. The rule, promulgated at 40 CFR 63, Subpart UUUUU, replaced the court-vacated Clean Air Mercury Rule (CAMR).

The rule limits mercury, acid gases, and other toxic pollution from coal- and oil-fired power plants across the U.S. However, the vast majority of oil-fired units in Connecticut and the New England region are not likely to be subject to emissions limits because they may qualify for the “limited-use, liquid fuel oil subcategory.” Analyses by the Independent System Operator of New

England indicate that all the oil-fired units in the New England Region are currently operating at reduced levels that qualify for the “limited-use, liquid fuel oil subcategory.”⁷

In the 2012 IRP analysis, the “limited-use, liquid fuel oil subcategory” had not yet been established, so these oil-fired units were assumed to be subject to extensive emissions controls requirements that would possibly drive some retirements or increase rates. However; for the 2014 IRP, the oil-fired units are assumed not to be subject to emissions control requirements as a result of MATS.

Coal-fired units in Connecticut and the New England region remain subject to requirements to limit emissions of metals, acid gases, and Particulate Matter (PM). These requirements will likely drive the installation of extensive emissions controls for coal-fired EGUs without technologies such as activated carbon injection (ACI), equipment to reduce acid gases, and state-of-the-art particulate (PM) controls.

State HAP Regulations

Connecticut continues to implement state-specific HAP requirements on EGUs pursuant to Section 22a-174-29 of the Regulations of Connecticut State Agencies and pursuant to Section 22a-198 of the Connecticut General Statutes. The latter statute established state-level mercury (Hg) standards for coal-fired EGUs, namely Bridgeport Harbor Unit 3 (BH3) and AES Thames. On July 1, 2008, BH3 and AES Thames were subject to a standard of 0.6 pounds Hg per trillion Btu or 90% reduction of Hg from measured inlet conditions. AES Thames ceased operation in 2011; however, BH3 continues to operate. This unit could face an additional requirement for implementation of Hg continuous emissions monitoring systems (CEMS) based on the DEEP’s Commissioner finding that CEMS for Hg in flue gases are commercially available and can perform in accordance with National Institute of Standards and Technology (NIST) or other EPA-approved methodology. Mercury CEMS are projected to cost \$150,000 to \$300,000 per facility.

Modeling the Impacts of MATS on New England EGUs

Based on an analysis of the MATS rule, five New England coal-fired EGUs will be required to add additional controls to comply with MATS. These units will have until 2014/15 to achieve compliance.⁸ The control requirements could induce some EGUs to retire rather than incur significant retrofit costs.

For these coal-fired units, the MATS rule will enforce emissions limits for mercury, particulate matter (PM) as a surrogate for toxic non-mercury metals, and hydrogen chloride (HCl) as a surrogate for all toxic acid gases. For the purposes of the 2014 IRP, the MATS compliance

⁷ The persistence and duration of constraints on the availability of natural gas during the winter months could cause an increase in use of some oil fired units, triggering the need to comply fully with MATS.

⁸ The exact date that most generators will be required to comply with the MATS rule has some flexibility. The final rule gives generators three years to comply, but encourages state permitting authorities to grant an additional year extension for compliance if needed to install controls.

strategy for coal-fired units relies on a combination of existing controls and already-announced planned controls, when possible.⁹ Based on EPA analysis regarding the combination of controls needed for compliance, each coal unit is assumed to need: (1) activated carbon injection (ACI) for mercury control; (2) either a fabric filter (FF or “baghouse”) or a cold ESP for mercury and PM control; and (3) either dry flue gas desulfurization (FGD), wet FGD, or dry sorbent injection (DSI) for HCl.¹⁰ For units that do not currently have a cold ESP or baghouse, a baghouse is assumed to be the preferred upgrade option consistent with the EPA’s analysis.¹¹ For units without existing or planned wet FGD, dry FGD, or DSI, the preference is assumed to include an upgrade to DSI due to the lower capital costs.¹²

In the 2014 IRP, all coal-fired units larger than 25 MW are assumed to need activated carbon injection (ACI) combined with a fabric filter or cold ESP to control mercury emissions, and wet flue gas desulfurization (FGD), dry FGD, or dry sorbent injection (DSI) to control acid gas emissions. Retrofit costs for these technologies were estimated based on EPA documentation, and vary based on unit size, as shown in Figure 9. Note that PSEG was issued a NSR permit for the installation of DSI at Bridgeport Harbor 3 in September 2014.

Figure 9
Unit-Level Retrofit & Cost Requirements, Coal-Fired Units

Unit Information				MATS Control Strategy		Total Controls Costs in 2015			Notes on Needed Controls
Name	2013 CELT Summer (MW)	Fuel	State	Existing and Announced Controls	Additional Assumed Controls	Capital Cost (2014\$/kW)	Incremental FOM (2014\$/kW)	Incremental VOM (2014\$/kW)	
BRIDGEPORT HARBOR 3	383	Coal	CT	ACI+FF	DSI	\$54	\$1	\$7	Needs acid gas control (assume DSI).
MT TOM	143	Coal	MA	ACI+FF+DSI		-	-	-	In compliance.
MERRIMACK 1	113	Coal	NH	ACI+Cold ESP+Wet FGD	Level 2 ESP upgrade	\$87	-	-	Needs level 2 ESP upgrade.
MERRIMACK 2	338	Coal	NH	Cold ESP+Wet FGD	ACI+level 2 ESP upgrade	\$100	\$0	\$3	Needs ACI and level 2 ESP upgrade.
SCHILLER 4	48	Coal	NH	Cold ESP	ACI+level 3 ESP upgrade+DSI	\$306	\$3	\$19	Needs ACI, level 3 ESP upgrade, and acid gas control (assume DSI).
SCHILLER 6	48	Coal	NH	Cold ESP	ACI+level 3 ESP upgrade+DSI	\$306	\$3	\$19	Needs ACI, level 3 ESP upgrade, and acid gas control (assume DSI).

⁹ Existing and planned controls data from Ventyx (2011), detail on hot and cold ESP from EPA (2011d).

¹⁰ See EPA (2011e), pp. 76-82 regarding mercury and PM controls, and pp. 87-89 regarding HCl controls.

¹¹ See EPA (2011e), pp. 76-82.

¹² See EPA (2011e), Table 5-23, EPA (2011f), Table 5-4.

WATER QUALITY REGULATIONS

EGUs that use steam turbines require a significant amount of water in the condensing cycle, and are subject to regulations designed to minimize impacts on surface water quality and aquatic organisms. Water quality impacts include thermal discharges, discharge of effluents containing chemical pollutants, and damage to aquatic life as a result of interaction with water intake structures. EPA and the states, using authority found in the Clean Water Act (CWA), issue and periodically renew permits under the National Pollutant Discharge Elimination System (NPDES) that require sources to employ technologies to reduce impacts on surface water resources.

Existing EPA rules could impact future limitations on the thermal discharges from EGUs operating in Connecticut and the ISO New England region that have or require a NPDES permit. Forthcoming EPA rules could require costly retrofits to limit impacts associated with cooling water intake. The timing of these requirements is such that they may impact some EGUs as early as 2016; however the impacts are too uncertain to model at this time.

Water Discharge Regulations

Regulations promulgated under Section 316(a) of the CWA require that the thermal component of effluent discharges must ensure the protection and propagation of a balanced, indigenous population of shellfish, fish and wildlife in the receiving body of water. These regulations are implemented through limitations in NPDES permits. These may include effluent temperature limitations or a limitation on the allowable temperature of the receiving water at the edge of an allocated mixing zone.

On April 20, 2011, EPA proposed a rule regulating cooling water intake structures at existing facilities. The final rule regarding this matter was published on August 15, 2014 and took effect on October 14, 2014. The requirements of the final rule impact EGUs operating in Connecticut that have or require a NPDES permit, use a cooling water intake structure with a design of greater than 2 million gallons per day to withdraw cooling water from a water of the United States, and use at least 25% of the water actually withdrawn exclusively for cooling purposes.¹³ The final rule establishes regulations under Section 316(b)¹⁴ of the Clean Water Act which require that the location, design, construction, and capacity of cooling water intake structures reflect the Best Available Technology for minimizing adverse environmental impact. Cooling water intake structures can harm aquatic life via impingement (organisms trapped against intake screens) and entrainment (organisms passing through the screens and entering the plants' cooling water system). The objective of the final rule is to reduce fish mortality from either cause. The final rule establishes seven alternatives that can be used to address impingement mortality. Measures taken to address entrainment are not prescribed by the rule and must be made on a site-specific basis. The timing of these requirements may impact EGUs towards the end of the 2014 IRP planning horizon in 2017/2018.

¹³ Affected sources according to 76 FR 22174.

¹⁴ More information at <http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/>.

Connecticut is an authorized state and implements federal and state water discharge regulations and cooling water intake requirements through state-issued NPDES permits. If necessary, compliance schedules can be incorporated into NPDES permits should a permittee need time to come into compliance with a new or revised requirement. Requirements under Section 316(a) of the CWA are implemented as permit limitations in NPDES permits. These requirements must be re-evaluated when these permits are modified or renewed. The new regulations established for cooling water intake structures for existing facilities will now be incorporated into re-issued NPDES permits. It is likely that several permits will require compliance schedules so that the permittees can have time to install and optimize the technologies or operational measures necessary to bring them into compliance with the new regulations. As set forth in the final rule, these projects must be completed as soon as practicable.

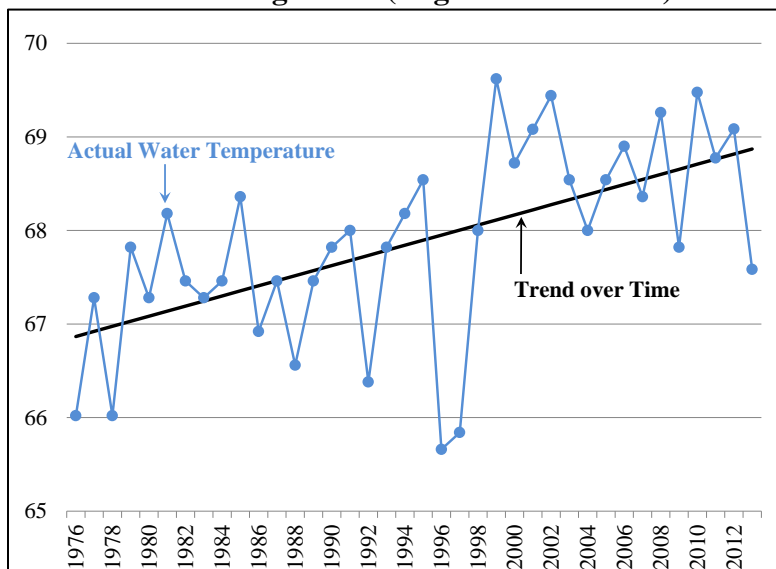
Impacts of Section 316(a) of the Clean Water Act

Large EGUs may face significant challenges in meeting their thermal discharge effluent limits due to rising ambient temperatures in rivers, tributaries, and Long Island Sound. These temperature changes may result in modifications to thermal discharge limits or thermal mixing zone allocations in NPDES permits. Millstone Station was required to suspend operations at least twice in 2012 due to high ambient temperatures in Long Island Sound (See Figure 10 for Summer Near Surface water temperature trend data for Niantic Bay, Long Island Sound). Accordingly, new water quality standards and their impacts on NPDES permits, particularly with respect to thermal discharges for EGUs, should be closely monitored in future IRPs.

Impacts of Section 316(b) of the Clean Water Act

Four 316(b) NPDES permits are projected to be re-issued in mid-2015. The remaining backlogged applications will be processed by early to mid-2016. It is anticipated that at least two of the mid-2015 re-issuances will require installation of some sort of technology to address impingement and entrainment. Technology installation will need to be performed during an outage. Since the projects have yet to be finalized, the length of the outage necessary to complete the work is unclear.

Figure 10
Average Summer Near-Surface Water Temperature in Niantic Bay and Long Island Sound
1976 through 2013 (Degrees Fahrenheit)



Impacts of CWA Section 316(b) Rules on New England EGUs

The North American Electric Reliability Council (NERC) issued the 2011 Long-Term Reliability Assessment (LTRA), which contained an analysis of the impact of impending environmental controls on capacity shutdowns across the country. In that analysis, NERC found that the vast bulk of retirements would be due to the CWA Section 316(b) rules, and in New England specifically these rules would effectively cause the entire oil/gas steam fleet to retire by 2018, imperiling reserve margins in ISO-NE. This analysis appears to take a conservative view of the technology options allowed by the proposed rule and the degree of discretion that states might exercise in applying the requirements.

It is difficult at this time to predict how the final rule might differ from the proposed rule, and how states will approach implementation. Lacking precise data on potential EGU-specific costs, the potential impacts of CWA rules concerning water intake structures were not modeled as part of the 2014 IRP. These requirements do bear monitoring and should be included in subsequent IRPs.