Synapse
Energy Economics, Inc.

Reducing Emissions in Connecticut on High Electric Demand Days (HEDD)

A REPORT FOR THE CT Department of Environmental Protection and the US Environmental Protection Agency

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1. Executive Summary

The Connecticut Department of Environmental Protection (DEP) asked Synapse to complete three tasks to analyze electricity demand during peak demand periods:

- project Connecticut electricity demand for the period from 2005 to 2020;
- project generation and transmission from load; and
- project emissions and prepare a report that will be used as part of Connecticut's SIP to demonstrate attainment with the Federal eight-hour ozone standard

DEP's commitment through a Memorandum of Understanding (MOU) to the Ozone Transport Commission is to reduce ozone season NOx emissions 11.7 tons per day from a 2005 baseline by 2009. Synapse's analysis recommends several potential ways by which this commitment can be met, but not even the most aggressive one is capable of meeting the reduction goal within the initial agreed upon timeframe. The potential means by which DEP can reduce NOx emissions are:

- continue energy efficiency measures in accordance with existing (2007 vintage) approved plans;
- ramp up future energy efficiency and demand side measures as anticipated by a 2007 Connecticut statute[1];
- require additional NOx control measures for generators smaller than 15 MW; and
- a combination of the above

There are costs associated with each of these recommended measures. Achieving all cost-effective energy efficiency as required by statute will mean that the state needs to approve additional funding for the Energy Conservation Management Board (ECMB), engage the private sector, or some combination. While the state has plans to implement all cost-effective energy efficiency, funding of these programs at a level needed to procure all such resources is beyond the control of the DEP.

Installing controls on affected sources also will add costs. These costs will be passed along to Connecticut ratepayers through existing cost recovery mechanisms available through the CT Department of Public Utility Control (DPUC), and through higher hourly clearing prices in the ISO-NE electricity market. Energy efficiency continues to be much less expensive than the cost of new generation with costs of 3-3.5c/kWh, compared to 8-11 c/kWh for the cost of new generation.

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[1] PA07-242 requires all cost-effective energy efficiency measures to be procured

- continue energy efficiency measures in accordance with existing (2007 vintage) approved plans;
- ramp up future energy efficiency and demand side measures as anticipated by a 2007 Connecticut statute ;
- require additional NOx control measures for reliability must run (RMR) generating units in two phases, starting in 2012;
- require additional NOx control measures for generators smaller than 15 MW; and
- a combination of the above.

2. Introduction and Problem Description

In 2008, the State of Connecticut continues to experience air quality that exceeds EPA 1-hour and 8-hour ozone standards. The state has adopted many regulations and standards to reduce ozone concentrations over the past thirty years. Consequently, pollution levels and the number of days in which CT exceeded the EPA standard have significantly decreased from over 40-50 days a summer in the 1980s to less than ten days during the last few years. Connecticut participates in regional programs to reduce air pollution transported into the state from upwind areas along the Northeast Corridor (including NY, Philadelphia and Metro DC-Baltimore) and from the Ohio Valley. In the late 1990s, Connecticut joined New England and Mid-Atlantic states to settle several Clean Air Act lawsuits against power plants in the Ohio Valley. Emissions reductions completed by these plants as part of the consent decrees will further reduce transported air pollution into the Northeast[2].

In the mid-1990s, Connecticut began to regulate air emissions for the electric utility sector. When these programs were adopted, the utilities were still regulated as vertically integrated monopolies with generation, transmission and distribution responsibilities. Initial regulatory efforts focused on reducing emissions from electric generating units (EGU) larger than 15 or 25 MW because of the significant contribution of these units to state and EPA emissions inventories. In the late 1990s, the passage of electric restructuring legislation coincided, but was not coordinated, with environmental agency efforts to control NOx emissions from EGUs. Subsequent restructuring of the electricity markets created opportunities for non-utility generators, as well as EGU smaller than 15 or 25 MW. Independent System Operator of New England (ISO-NE) demand response and price response programs helped provide energy, capacity, and reliability in the region, but have also lead to outcomes not anticipated by air regulators. State implementation plans (SIPs) developed in a regulated environment could not anticipate:

- An increase in the number of generating units smaller than 15 MW, with hundreds of units deployed smaller than 1 MW;
- Energy and capacity payments created significant economic incentives for new participants (capacity payments prior to the FCM were as high as $14/kW-month)
- *De minimis* permit thresholds were high enough to enable small units to construct and operate without going through individual New Source Review (NSR) processes, including opportunities for public review and comment

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[2] Lawsuits were pursued and settled with Virginia Electric Power (Dominion); Ohio Edison (First Energy) and American Electric Power (AEP). The lawsuit against Duke Energy (Cinergy) has not been settled as of June 2008.

A. Background

As restructuring of New England's electric markets created many new opportunities for supply side resources, demand increased through the last two decades (Figure 1). With the recent exception of late 2007 into 2008, the previous several years has been a period of significant economic growth, resulting in several factors that lead to increased peak electricity demand. Southwest Connecticut's peak demand growth has been 2-3 times higher than that of base growth (Figure 2). Industrial electric demand has been flat to decreasing over the past decade.

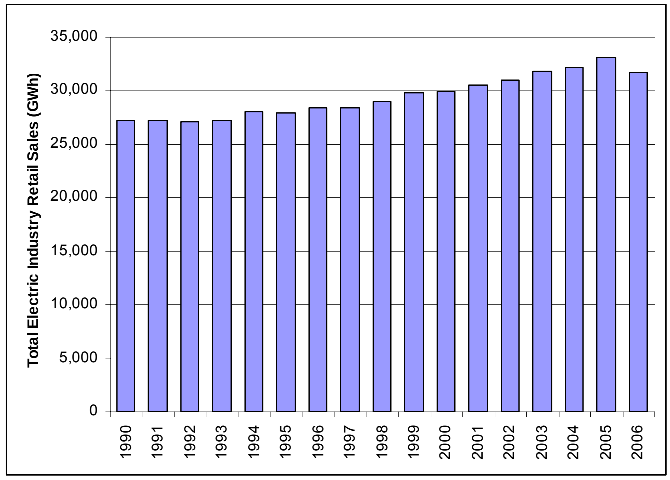

Figure 1 Connecticut electric retail sales, 1990 to 2006. EIA, 2006.

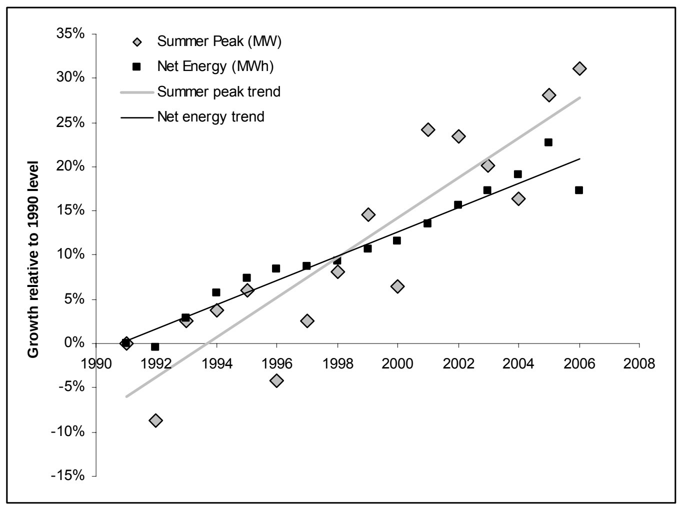

Figure 2 Connecticut load growth (net energy, MWh) relative to peak load growth (summer peak, MW), 1991 to 2006. ISO-NE, 2008.

Transmission constraints and congestion have affected Southwest Connecticut (SW CT) for the past several years. Factors that have caused or contributed to this congestion include:

- Differential rates of electric demand increases between SW CT and the rest of the state;
- Inability to increase generation supplies; and
- Interruption of energy efficiency programs following electric restructuring

B. Demand response in Connecticut: Diesel Generators

As a result of significant congestion in SW CT, both ISO-NE and Connecticut have focused attention on ensuring reliable electric service in this part of the state. Both supply and demand side approaches have been implemented, but, in terms of both MW and dollars, the supply side has received the majority of resources. The DEP has permitted or registered hundreds of diesel generators and several simple cycle gas turbines. The DPUC has helped to finance supply side resources by providing incentives of up to $500 per kW to build new smaller generation. ISO-NE demand and price response programs have also actively signed up resources in SW CT[3].

[3] For example, see www.iso-ne.com June 18, 2008, 11th semi-annual load response program report, which is filed with FERC

Connecticut's energy efficiency program, administered via the Energy Conservation Management Board (ECMB), also focused demand side resources in SW CT, directed at both peak and base load measures.

The significant amount of supply side resources being constructed and operated led the DEP to investigate the degree to which emissions reductions achieved by regulating emissions of larger EGU might be overcome by emissions increases from smaller sources. DEP was unable to conclusively determine the number of small generators that are participating in ISO-NE programs or whom might be registered as an emergency engine, but is operating on non-emergency days to take advantage of price response programs.

The causes of SW CT congestion have also been experienced in other parts of the Northeast, particularly around New York City and Boston. Through the Ozone Transport Commission (OTC), Connecticut participated in a regional process to assess potential stationary source contributors to ozone formation. One of the primary contributors were emissions units that operate during period of peak electricity demand, described as high electric demand days (HEDD). As a result of these processes, Connecticut and several other states, committed, through an Memorandum of Understanding (MOU)[4], to reduce emissions from sources operating on HEDD by 25-35%.

C. Reliability in Connecticut: Reliability-Must-Run (RMR) Units

As a general rule, Connecticut's EGU are dispatched by ISO-NE on an economic basis, with the lowest cost baseload nuclear and coal plants dispatched first. The high natural gas fuel costs mean that these units are dispatched last, and set the hourly marginal clearing price. Connecticut's electricity congestion in the southwestern part of the state (defined as 15 towns in the Stamford-Norwalk area or 52 towns mainly in Fairfield and New Haven Counties) causes the general dispatch rule to be broken frequently during the year. In order to service demand from this area, which accounts for over half of Connecticut's peak load, several older oil-fired units must run out of economic merit order to assure continued reliability. If normal ISO-NE rules were followed, these units, referred to as RMR (for reliability must-run), would operate infrequently and displace several natural gas units to set the marginal clearing price. However, the strategic location of the RMR units, in relation to demand, requires them to operate even though their hourly costs are higher than other units.

The combination of ISO-NE economic dispatch coupled with the out of merit operation of the RMR units means that Connecticut EGU emissions profiles do not align with DEP's environmental preferences. Base loaded nuclear units are dispatched first, providing about 2000 MW of generation without NOx emissions. Above nuclear though are baseloaded coal and then a variety of EGU including the RMR units. With the exception of the Bridgeport Energy facility, the natural gas combined cycle EGU installed since 1998 have limited operating hours and generation, mostly used as load following or peaking units. From a criteria and greenhouse gas pollutant perspective, increased operation of the natural gas units would reduce Connecticut's emissions.

[4] MOU signed March 2007. See http://www.otcair.org (click on meetings, then "materials" for 2007 meetings)

D. CT Emissions Reductions: 2008 State Implementation Plan

Connecticut's efforts to improve air quality and to ensure reliable electricity delivery require cooperation and collaboration with other New England and Middle Atlantic states. Upwind air pollution from the I-95 corridor and the Ohio Valley contributes to elevated levels of ozone and fine particulates. Connecticut is part of ISO-New England, which dispatches electricity for all six New England states, including imports from and exports to surrounding states and provinces.

As part of the desire to develop policies that can help to solve regional air quality concerns, Connecticut is an active participant in the Ozone Transport Commission (OTC). The OTC was formed pursuant to Section 184(a) of the Clean Air Act Amendments of 1990 to provide a collaborative forum to discuss and resolve interstate air pollutant transport issues, and covers a geographic boundary from Maine to northern Virginia.

Air pollution emissions during high electric demand days (HEDD) were raised through the OTC in meetings beginning in 2006. Connecticut, New Jersey and EPA Region 1 completed initial evaluations that attempted to define the universe of units contributing to air pollution, and the degree of their contribution. Several meetings were held throughout 2006 and 2007[5], including representatives from the three power pools with jurisdiction in OTC, distribution companies and operators of electric generators. These efforts led to the March 2007 OTC MOU that committed the signatory states to reducing NOx emissions on high electric demand days.

One of the challenges Synapse faced in evaluating the emissions associated with high electric demand days was an inability to precisely determine the definition of "high electric demand day". While the term is used frequently in the OTC MOU, and in presentations, it is not defined. For this reason, Synapse defined the high electric demand day (HEDD) period to facilitate analysis for this report. We chose to define the HEDD period as the 12 highest electric demand days during the year, following language in the stakeholder approved OTC MOU. Our reasoning is supported through three mechanisms:

a) These 12 days fall during the ozone season, when air quality is unhealthy;

b) The use of any single day to define the HEDD period could lead to erroneous results in compliance monitoring, where peak generation needs are unlikely to be consistent interannually. The use of a multi-day period ensures that average peak emissions are monitored consistently;

c) Finally, in the final "whereas" paragraph of the MOU, the document makes reference to how, if regulatory policies were applied to HEDD in the same manner as those previously developed for the electric sector, that emissions on the 12 highest electric demand days alone would equal 74% of states' Clean Air Interstate Rule allowances.

At the completion of this analysis this evaluation, we learned that the OTC reduction requirement was based upon emissions from the single highest peak day. Comments received after the completion of this analysis have suggested alternative analysis periods which may have merit, but were outside of the agreed upon scope of this work.

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[5] http://www.otcair.org Click on meetings and then scroll down to view HEDD presentations for 2006 and 2007

Synapse believes it is critical to show that the results of our analysis are replicable and reproducible. Using the 12 highest electric demand days, as opposed to a single peak day, is more optimal in terms of smoothing or removing unique influences that might not be replicated every year. The causes of a single peak day may not be identical every year, and if our analysis on the benefits of policies to reduce emissions were based on a single day, their effectiveness could be much different from year to year. One of the primary goals of this evaluation was to develop policies that could confidently ensure that the anticipated emission reductions would occur. Using 12, as opposed to one, high electric demand days helps to increase certainty in our analysis, and precision in forecasting that implementation of policies to reduce NOx emissions will indeed lead to them being achieved.

The March 2007 OTC MOU makes reference to earlier efforts to regulate emissions from this sector, and how these would be inappropriate for adoption to address emissions from high electric demand days. Earlier efforts applied a two-pronged strategy: 1) states required direct application of emissions control devices to reduce emissions at the smokestack; 2) for EGU that operate during peak electric demand, those sources were required to turn in allowances at a ratio of much greater than 1 allowance per 1 ton of NOx emissions. Connecticut's peak shaving policy, developed in the mid-1990s, required certain EGU to turn in seven allowances for each one ton of emissions that occurred on a peak day. The policy applies to combustion turbines that have entered into enforceable trading agreements with the DEP ,and which are part of Connecticut's ozone SIP.

The same approaches are infeasible to apply today, for both environmental and economic reasons. Requiring controls, such as selective catalytic reduction (SCR), as a sole means to reduce emissions would mean that the costs of those controls would be passed along to ratepayers, in the form of higher electricity rates. EGU that have no abatement costs would enjoy extra profits as a result, since New England's single price electricity market means that all EGU operating in a given hour are paid the marginal clearing price.

Requiring EGU to surrender allowances at a high ratio to actual emissions would also be infeasible. First, to equalize the economics for units that are paid hourly electricity prices that approach or equal $1000/MWh, the offset ratio would need to be in the range of 30-50 or more allowances for each ton of emissions[6]. Second, if such a program was implemented anyway, even a few high electric demand days would require surrender of a large portion of Connecticut's emissions budget, leaving little for the remaining days. This would likely lead to temporarily shutting down fossil fuel generation for many days if not weeks, and electricity would have to be imported from elsewhere, at higher costs, into Connecticut. Existing EGU with no abatement requirements would also again receive extra profits during these periods.

These two reasons lead Connecticut to investigate other possible ways to reduce NOx emissions during high electric demand days. The DEP was also cognizant of the potential role that demand side measures could play in reducing both base and peak electricity usage. The DEP is a member of the state's Energy Conservation Management Board, and an active participant in the Regional Greenhouse Gas Initiative (RGGI), where energy efficiency is expected to be an important means to reduce greenhouse gas emissions. Energy efficiency is now considered to be a resource on par to supply side resources by ISO-NE, as part of its forward capacity market.

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[6] see http://www.otcair.org Meeting December 2006, Hartford, CT, EPA presentation on TRUM analysis

DEP's previous positive experience with requiring direct controls, and its more recent knowledge on the potential role that energy efficiency could play, led the agency to request that Synapse evaluate both approaches, and their ability to reduce NOx emissions on high electric demand days.

E. Tasks for Completion

The Clean Air Act requires that states implement plans (referred to as SIPs, for state implementation plans) to attain and maintain compliance with National Ambient Air Quality Standards (NAAQS). Over the past thirty years, Connecticut has adopted regulations to reduce emissions that cause or contribute to ozone formation, and these have steadily reduced both ozone concentrations and the frequency of exceedances of the ozone NAAQS. EPA;s recent promulgation of a lower ozone standard will require additional in-state emissions reductions to occur.

The OTC MOU 2007 commitment was made to reduce emissions to help meet the previous ozone NAAQS. Since the new EPA NAAQS will require additional emissions reductions to occur, the DEP asked Synapse to evaluate a number of strategies that could meet both the OTC MOU commitment and be part of the SIP for the new EPA ozone standard.

The DEP asked that Synapse complete three tasks to analyze electricity demand during peak demand periods:

- project Connecticut electricity demand for the period from 2005 to 2020;
- project generation and transmission from load; and
- project emissions and prepare a report that will be used as part of Connecticut's SIP to demonstrate attainment with the Federal eight-hour ozone standard

The following sections describe our methodological approach to evaluate how various energy efficiency and regulatory scenarios could reduce NOx emissions in two phases through 2020. The first phase considered what policies could be implemented to meet Connecticut's OTC commitment, which is a 11.7 tons/day reduction of NOx emissions from the peak electric demand day. The second phase evaluated how an extension of policy measures implemented in phase one could help Connecticut to satisfy its obligation to meet the newly promulgated EPA ozone standard. Connecticut anticipates developing regulations during 2008 to meet the OTC commitment. EPA will require that states submit SIPs by 2011 to demonstrate how they will meet the new ozone standard. Connecticut's efforts to meet the OTC commitment will be very useful to plan for how the state will meet the new ozone standard. Having a longer planning horizon, out to 2020, also helps to provide certainty to the regulated sources, and for agencies that the DEP will need to coordinate with to ensure that the energy efficiency programs are performing at their anticipated levels, and that the levels persist over time.

3. Tasks and Assumptions

To complete the requested tasks, Synapse needed to evaluate Connecticut's electricity load, expected changes in CT load between 2005 and 2020, and determine how generation would be expected to change over this period, and how regulatory and incentive programs might change emissions from CT generators over this time period. To complete these set of tasks, we divide this paper into three methodological segments:

1. Project load in CT to 2020;
2. Create model to estimate generation required to meet load until 2020; and
3. Modify CT load and generator emissions characteristics to simulate emissions reductions regulatory and incentive mechanisms.

Below, we discuss five critical assumptions in our model.

A. Grow Load from Baseline 2005

For the purposes of this research, Synapse was directed to use load shape from 2005 to drive the analysis. Therefore, although we grow load according to predictions from ISO-NE (as detailed below), the fundamental load shape follows a pattern set in 2005 by that year's demand, weather, fuel prices, and anomalies.

B. Connecticut's EE programs are coordinated with ISO-NE

Connecticut is part of ISO-NE regional transmission organization, making up about 25% of the net electricity demand of ME, NH, VT, MA, RI, and CT. In the ISO-NE market structure, load is met by generators in economic "merit-order"; i.e. those generators which are least expensive (or conform to other criteria) are chosen to meet the lowest load, followed by increasingly expensive generators as demand increases. Except within transmission-constrained regions, generators responding to load are not necessarily within the proximity or even state where that load is required, rather the marginal generator can be anywhere on the grid. It is likely then that CT's hourly load is *not* met exclusively by Connecticut generators, rendering the question of how CT electricity-sector emissions will be impacted by energy efficiency programs in CT quite difficult.

For the purposes of this analysis, we assume that any energy efficiency (EE) programs, or any shifts in Connecticut's load, will be proportionally matched throughout ISO-NE, or at least in bordering states. For example, if CT implemented a rigorous EE program without the cooperation or engagement of the remainder of ISO-NE, we might expect that CT generators would still serve load outside of the state. In fact, since CT's load is wrapped up as 25% of ISO-NE's bulk regional demand, any changes in CT's demand profile are diluted by 75% when reflected in the remainder of ISO-NE. For example, in an absurd case, if CT ceased demanding electricity altogether then the remainder of ISO-NE would see a demand reduction of 25%, and it is likely that some of CT's generators would keep spinning even though the state requires no power. To adequately reflect the strength of a load reduction program on emissions in CT, we assume that all other states in ISO-NE adopt similar EE programs as CT, meaning that the EE program in CT is not diluted throughout the region. This assumption is supported by legislation passed in ME, RI and VT, and passed in July 2008 in Massachusetts that, like Connecticut, would require all cost-effective energy efficiency to be procured first as a resource. The neighboring state of New York has also directed NYSERDA to develop and implement a plan to reduce electric consumption there 15% by 2015.

C. The Connecticut Box Model

The research thrust of this paper is to explore the impact of demand reduction programs and emissions regulations on emissions targets, specifically in CT. As noted above, we assume that CT and the remainder of the region act in parallel. As a corollary to this simplification, we also assume that CT acts in a "box", or as a single entity. Currently, CT can be subdivided into at least two regions: the constrained SW corner of the state, and the remainder of the state. During times of high electricity use, SW CT demands more electricity than can be carried across transmission lines from inexpensive generators and local, expensive generators are dispatched to meet load. This load constraint allows out-of-merit plants to operate, and re-arranges economic dispatch order. Currently, CT is building new transmission systems to alleviate this constraint. We assume that this new system will allow electricity to flow from plants dispatched in merit order, and therefore generators will be loaded in the same order as during non-constrained periods.

D. Nuclear Unit Operation

Connecticut and ISO-NE are served by five nuclear generators in CT, MA, NH, and VT. In CT, the Millstone 2 and Millstone 3 units serve over 2000 MW combined. When these units are out of operation, dispatch throughout the region must shift to make up the difference, thereby changing "typical" behavior. We assume that except for very rare events, the two nuclear units in CT will be in operation though every ozone season. Therefore, we only track dispatch and operations in CT when the Millstone units were operating at 100% in 2005.

E. Energy Efficiency Load Shape

Energy efficiency programs can be applied to a number of sectors, and targeted at either a broad array of energy reductions, or though specific technologies (such as efficient lighting or air conditioning). Some programs are optimized for demand reductions at peak periods (e.g. price response programs), while other programs implement general efficiency measures (i.e. weatherization, lighting technology). Different EE programs may reduce energy consumption at different times of the day, or under different conditions. A peak-shavings program will reduce peak loads only, while a lighting program may reduce use across all hours. In addition, programs may be targeted towards different sectors, such as industrial or residential customers. Each of these categories will have different load-shapes for demand reduction. Since we are not in a position to know which types of EE programs could be implemented in CT, we assume that load is reduced across all hours as a percentage of hourly demand. Therefore, a 2% EE initiative will reduce demand by 2% at all hours (50 MW from a 2,500 MW trough and 150 MW from a 7,500 MW peak).

F. Statewide analysis is based strictly upon 2005 EPA reported data

This task examined statewide emissions from EGU. The performance characteristics for each EGU are directly based upon data reported to the EPA Clean Air Markets program[7] for the year 2005 in the state of Connecticut, as agreed upon in the stakeholder process leading up to this analysis. Comments received after the completion of this analysis indicated that some EGU anticipated emissions changes due to technological upgrades and changes in performance or operations. Misreported data or changes in unit operations after 2005 were not considered. It is feasible, and even likely, that some EGU in Connecticut will change operations during the analysis period (to 2020); however, for consistency with the initial dataset and the agreed upon analysis guidelines, we have not altered any single unit's emissions or runtime characteristics except in specified sensitivity runs.

G. Analysis does not include RGGI or CAIR

Neither the ten-state Regional Greenhouse Gas Initiative (RGGI) governing greenhouse gas emissions, nor the recently overturned Clean Air Interstate Rule (CAIR) were considered in this analysis. RGGI, if implemented, will encourage a shift in dispatch throughout New England to resources with lower emissions, but is unlikely to affect the relative economic merit order of fossil plants operating in CT today. In addition, the trading schema is unlikely to directly effect criteria pollutant emissions in the relatively near-term unless generation is reduced. Similarly, CAIR was not implemented as an operational parameter; if a similar rule is implemented, it would likely change the emissions target rather than the baseline operations or dispatch.

[7] http://www.epa.gov/airmarkets/

4. Methodologies

A. Scenarios

Synapse evaluated several different scenarios and their ability to reduce NOx emissions during the ozone season. Each scenario was based upon knowledge of existing policies or technologies.

Scenario 1: Baseline

In the baseline scenario, CT demand grows in pace with 2008 ISO-NE load predictions, following the load shape of 2005. Maximum load increases from just over 7,000 MW in 2005 to 8,000 MW in 2020; net energy for load also grows by about 12.4% by 2020.

Scenario 2: Energy Efficiency (2% per year)

Connecticut's energy efficiency program is achieving energy savings equal to approximately 1% of annual electricity sales. The ECMB's October 2007 plan anticipated increasing the annual savings goal. Based on conversations with ECMB consultants in May 2008, energy efficiency programs are expected to achieve energy savings equal to 2% of annual electricity sales during 2008 or 2009. The 2% per year level selected for this scenario therefore is representative of how the current EE program is expected to perform

Scenario 3: RMR Units Apply Emissions Controls

The second scenario evaluated the effects of applying a two phase NOx emissions reduction requirement to Connecticut's RMR units. Phase one, a 30% reduction, is approximately equal to the level of reduction that could be achieved if selective non-catalytic reduction (SNCR) controls were installed on each RMR unit. SNCR is considered to be a "reasonably available control technology" (RACT), which means the controls have been demonstrated to be effective during operation, and that they would be cost-effective to consider for application to existing emissions units. Phase two would apply a total of a 50% reduction to the RMR units. The 50% reduction is considered to be equivalent to requiring "best available control technology" (BACT) to the sum of all RMR units. BACT would be selective catalytic reduction (SCR). BACT is typically applied to new sources, and in this case, SCR would be expected to reduce NOX emissions by 90-95%. For existing sources, space considerations may preclude BACT level controls on each and every unit, so the 50% reduction level reflects that not all RMR units would individually install BACT level control technology. Note that the 30% and 50% reduction levels do not require emissions controls to be installed. RMR unit emissions reductions could be achieved by decreasing the number of hours they operate, ceasing operation of one or more units or through installation of controls. Synapse is agnostic with respect to which option may be chosen to reduce emissions from these units.

For the purposes of this sensitivity scenario, Synapse manually reduced emissions from RMR units by 30% and 50%, in 2012 and 2015, respectively. Simulated controls were only applied to RMR units, which have a disproportionately high NO_x emissions rate relative to other units in CT. Additional emissions controls were not considered for combustion turbines or other non-RMR units. Other units do not have the high emissions rate of the RMR units and therefore these reductions would have a relatively small impact if applied to non-RMR units.

Scenario 4: Efficiency and RMR Units Apply Controls

A third scenario evaluated the benefits of a hybrid strategy that includes energy efficiency program achieving energy savings equal to 2% of annual electricity sales *and* reducing NOx emissions from RMR units by 30% in phase one, and by a total of 50% in phase two. This scenario was chosen to determine if the OTC MOU commitment could be met within the desired timeframe, and whether the success of a hybrid approach could be extended to help Connecticut reduce emissions further to meet the new EPA ozone standard.

Scenario 5: Aggressive Efficiency (3%)

The Connecticut's Public Act 07-242 (2007) requires the state to procure all cost-effective energy efficiency as a resource of first choice. A 2004 study of energy efficiency[8] concluded that significant potential exists in Connecticut to substantially increase the amount of energy savings achieved from demand side measures. Synapse chose a 3% savings level as an aggressive, but possible goal that the state could achieve. Based on work Synapse is currently performing[9], energy efficiency programs appear capable of achieving savings equal to as much as 5% of annual electricity sales. So, the 3% is an aggressive, but not extreme goal that Connecticut has the capacity to achieve.

B. Load Growth and Energy Efficiency

ISO-NE Load Predictions

Load growth from a 2005 baseline was extrapolated from 2007 ISO-NE load forecasts[10], predicting peak loads and net energy demand from 2008 to 2016. As part of the long-term forecast, ISO-NE provides a monthly peak load forecast for each state in the control region. Monthly data for Connecticut was extracted for the period of 2008 to

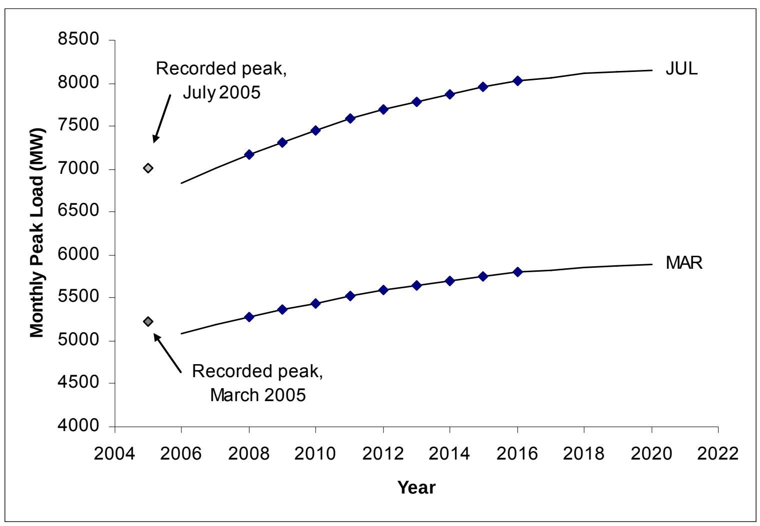

Figure 3: Connecticut monthly peak extrapolation from ISO-NE monthly peak forecasts (2008-2016) for July and March (2006 & 2007, 2017-2020).

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[8] Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region; Final Report, GDS Associates, April 2004, prepared for the Connecticut Energy Conservation Management Board

[9] Draft work to be published summer 2008

[10] ISO-NE, September 2007. CELT Forecast Data, 2007. Available online at http://www.iso-ne.com/trans/celt/fsct_detail/2007/isone_2007_forecast_data.xls. An updated forecast (2008-2018) was made available since the inception of this research on April 30th, 2008. The updated report is available at http://www.iso-ne.com/trans/celt/fsct_detail/index.html.

2016.

In each month, the annual forecast 2008 to 2016 in Connecticut conforms to a 2nd order polynomial of the form

$$L_{m,y} = a_m x_y^2 + b_m x_y + c_m \qquad \text{(Equation 1)}$$

where $L_{m,y}$ is the peak load of month *m* in year *y*; and a_m, b_m, and c_m are coefficients of the polynomial specific to month *m*. In the polynomial fit, 2008 is year one (1). Values of the coefficients are presented below in Table 1. These best fit polynomials were used to estimate monthly peaks in 2017 through 2020 in a business-as-usual scenario (see Figure 3). This assumes that ISO-NE is using the best possible information about current demand growth rates and not including energy efficiency or demand reduction programs which are not currently deployed.

Month (m)	a	b	c	r^2	Month (m)	a	b	c	r^2
Jan	-3.38	105.24	5807	0.9994	**Jul**	-6.03	166.45	7006	0.9996
Feb	-3.18	100.85	5615	0.9994	**Aug**	-5.98	165.35	6945	0.9995
Mar	-3.14	95.22	5188	0.9994	**Sep**	-5.04	138.96	5836	0.9995
Apr	-2.49	80.73	4546	0.9995	**Oct**	-2.84	86.16	4711	0.9995
May	-4.40	124.55	5308	0.9998	**Nov**	-2.99	94.54	5257	0.9992
Jun	-5.49	152.54	6446	0.9996	**Dec**	-3.18	101.98	5741	0.9996

Table 1: Coefficients of monthly peak growth from 2008 to 2016 from ISO-NE forecast for equation 1. Year 2008 is portrayed as x=1 in this polynomial (i.e. 2016 is year 9). Goodness-of-fit (r^2) values exceed 0.999 in all cases.

We also use the same polynomials to extrapolate backwards to 2006 and 2007, even though actual energy use and monthly peaks are known for these two years. Using actual monthly peak data for 2006 and 2007 would suggest that we had also used real hourly data for those two years, which was not requested. Therefore, we assume that these two years conform to the growth rates predicted by the ISO for 2008 to 2016. We use real hourly load and monthly peaks for 2005.

Extrapolating hourly load from 2005 to 2020

The peak extrapolation is adequate for explaining peak periods only, but not the remainder of hours in the hourly load profile. To extrapolate the hourly load profile of 2005 out to 2020 using the monthly peak data, we examine the relationship between monthly peak loads in 2005 and every other year, and apply the same relationship to every hour. Simply, we gather the coefficient for each year with a zero-intercept linear regression between monthly load in 2005 and estimated monthly load in every other year. The form of the equation for this regression is $L_y = a_y x_{2005}$, where L are monthly peak loads in year *y*, x are the monthly peak loads of 2005, and *a* is the slope between 2005 and year *y*. The slopes (to be used as a multiplier) are presented in Table 2.

Year	Slope	Year	Slope	Year	Slope	Year	Slope
2005	1.000	2009	1.058	2013	1.120	2017	1.159
2006	0.997	2010	1.075	2014	1.131	2018	1.165
2007	1.019	2011	1.094	2015	1.142	2019	1.169
2008	1.040	2012	1.108	2016	1.152	2020	1.172

Table 2: Slope relationships between monthly peaks in 2005 and every other year (including 2005). To obtain an estimated monthly peak in another year, multiply the peak by the slope factor.

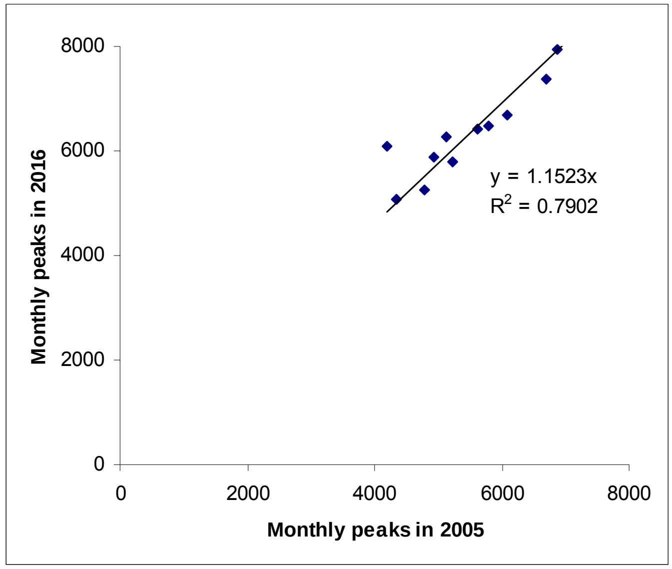

Figure 4: Obtaining the slope factor for 2016 relative to 2005. The slope is forced through the origin (0,0) and represents a simplified growth rate of the monthly peak relative to 2005.

We assume that the same relationship seen between years in the monthly peaks can also be applied to all other hours. For example, if in 2016, all monthly peaks are expected to see a load increase of approximately 15.2% (a slope of 1.152) relative to 2005, then we assume that hours would expect to see a similar growth. More complicated factors could be used, including non-linear (polynomial) relationships, but these are prone to providing anomalous data during trough periods. For example, a 2nd order polynomial fit between monthly peaks in 2005 and 2016 never falls below 5,500 MW, and yet there are estimated monthly peaks in 2016 as low as 5075 MW (in April), indicating that we would be likely to overestimate load during trough periods. Therefore, we have chosen to use a simplified metric of a single slope factor which goes through the origin (see Figure 4).

All 8760 points in the 2005 hourly load profile (365 days x 24 hours per day = 8760 hours) are multiplied by each years' slope factor to obtain an estimate of the hourly load profile in 2006 to 2020. These hourly load profiles become the business-as-usual (BAU) load growth scenario.

Applying Energy Efficiency

In three of the scenarios presented in §4.A above, we explore the impact of energy efficiency programs on emissions reductions in Connecticut. The application of energy efficiency in this analysis is applied to the load growth assumptions, after hourly loads in each year have been calculated. We make several simplifying assumptions about EE:

- EE measures are comprehensive and are applied across all hours,
- EE programs reduce loads by a constant percentage (see §3.E),
- EE programs do not expire, and
- EE measures are cumulative and compounded

EE is applied in this analysis in the following way. In each hour, the BAU rate increase from the previous year's same hour is calculated; the EE rate is subtracted from this growth rate to obtain an apparent growth rate. This new apparent growth rate is used to calculate the growth since the same hour in the previous year, and the result is load growth after EE. The form of the equation is:

$$L_{EE}(h,y)=\left[\frac{L_{BAU}(h,y)-L_{BAU}(h,y-1)}{L_{BAU}(h,y-1)}-EE\right]*L_{EE}(h,y-1)+L_{EE}(h,y-1)$$

where L_{EE} and L_{BAU} are the loads (in MW) at hour *h* in year *y* after the EE measure and in the business-as-usual (BAU) scenarios, respectively. The term *y-1* indicates the previous year, in the same hour *h*.

C. The Load-Based Probabilistic Emissions Model (LBPEM): Core Program

The Load-Based Probabilistic Emissions Model, LBPEM, is designed to estimate regional or state generation from hourly demand. The model uses hourly load to estimate hourly fossil generation, and hourly generation to estimate hourly emissions of NO_x and SO_x. This model is based on the simple precept that EGUs are dispatched to meet loads, but may not do so in a linear or easily interpretable reason. In addition, although EGUs have a measurable average emissions rate (measured in lbs or tons per MWh), it is rarely the case that the emissions rate is constant over all levels of generation. A warming or cooling generator will often be less efficient (per unit of generation) than a unit running at full rated capacity. To overcome these barriers, LBPEM is a statistical model using historical data to estimate potential emissions from hourly load. The following sections describe LBPEM and its operation, as well as some of the assumptions which go into the model in practice.

To determine the relationship between load and emissions, we first determine the relationships between load and expected generation. EGUs are dispatched economically, or in merit order. Least expensive units are dispatched first to meet the lowest loads, and as more electricity is required, more expensive generators are dispatched in order of their increasing costs per unit. If all external variables remained constant, generators never required maintenance or other outages, and a system was fully constrained such that all load inside a region were met by generators in the same area, the system would be simple to simulate. In the simple case, if load were known, we would add the least expensive generators together until load were met. However, in the more common circumstance, non-fossil units such as nuclear, hydro, wind, and solar contribute to the grid with their own patterns of generation, electricity is imported into the region at rates determined by the cost of electricity in neighboring areas and the strain on the transmission system; forced and planned outages cause generators to cease operating for maintenance and inspections. Thus, building a model which relies on each EGU being continuously available is unlikely to reflect the range of possibilities which occur in reality.

LBPEM gathers statistics about the operating behavior of a generator based on historical hourly generation and emissions information, as well as concurrent hourly regional load. The model structure recognizes that the electricity sector has significant underlying patterns and internal consistencies, and yet is filled with stochastic behaviors. We can divide dispatch models into first principles and statistical models. First-principles models build an electrical system from the 'ground up', using information on capital costs, fuel and operating & maintenance (O&M) costs, economic dispatch assumptions, transmission constraints, and known outage frequencies. The LBPEM statistical model (with no other known analog) is backwards looking, building a statistical database which portrays the system behavior at a period of time. Manipulating some of the assumptions of this statistical model, we can predict how simple, short-term changes will impact dispatch operations.

In LBPEM, increasing load must be met with new generation resources. Unlike dispatch or planning models, the operator of LBPEM must choose particular new resources and the year in which these resources become operational. Because resources all have specific probabilistic operational parameters in LBPEM, we simplify the addition of new resources by adding EGU statistically analogous to existing EGU until peak requirements are met. In this implementation of the model in Connecticut, acceptable new generators are analogous to the cleanest new combined cycle (CC) and combustion turbines (CT) units built in the state (Devon units 11-14, Bridgeport Energy 1&2, and Milford Power 1&2). For additional statistical breadth, we also included four South Meadow Stations (13A-14B) as potential new resources, although the emissions characteristics from these units are unfavorable and similar resources are unlikely to be built.

Datasets and Exclusions

LBPEM is built with three data sets. The fundamental dataset is from the 2005 EPA Clean Air Markets Dataset (CAMD) program[11], designed track national NO_x and SO_x emissions for regional trading programs and acid rain controls. Every fossil power plant greater than 15 MW in Connecticut is required to report hourly generation (in MWh), emissions of CO_2 (tons), NO_x (lbs), and SO_x (lbs). The data were extracted for the State of Connecticut for the year of 2005 and compiled into a large database.

The second dataset is comprised of hourly load for the State of Connecticut for 2005, obtained from New England Independent System Operator (ISO-NE). This dataset records loads ending on the hour. The data was shifted from local daylight savings time to a continuous hourly dataset.

Finally, the last dataset identifies the days of the year in which the nuclear units in Connecticut were not operating at full capacity. On these days, fossil units in the State operate at higher than expected generation levels to make up the difference, and may not reflect a standard merit order of operation. The nuclear outage data was obtained from the Nuclear Regulatory Commission[12].

Southwest Connecticut (SW CT) is currently transmission constrained, a situation in which during high demand periods, dispatch becomes non-meritorious as expensive EGUs within the constrained region come online to meet local demand. Because of this dramatic shift in dispatch during periods of transmission constraint, this condition provides a poor baseline for future conditions. Currently, new transmission capacity is being added to CT's infrastructure intended on relieving this congestion and since it is unlikely that these transmission constrained periods will be maintained in the future, and the hours in which these conditions exist are unlikely to persist. We remove these hours from our analysis by targeting hours in which congestion prices exceed $20.

Dates falling between January 18th and 30th of 2005 were excluded from this analysis. During a cold snap, natural gas shortages drove a switch from natural gas burning EGU to RMR units in CT. This fuel availability and price fluctuation caused units to run out of economic merit order, a

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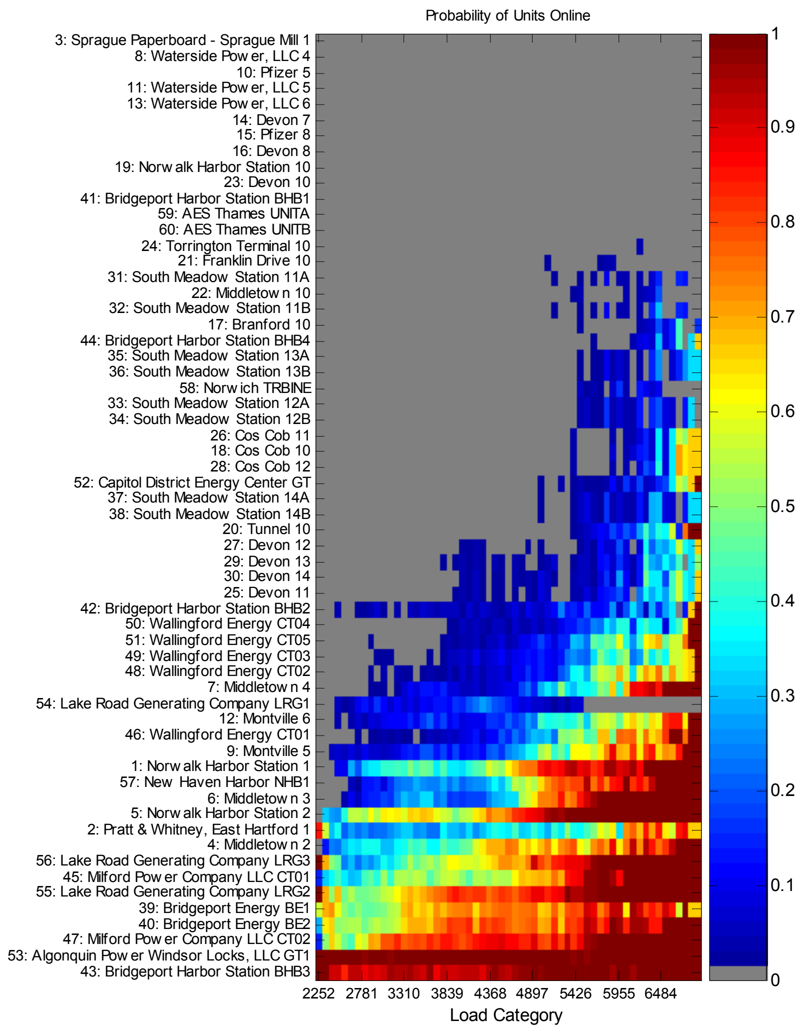
[11] Available at http://camddataandmaps.epa.gov/gdm/
[12] Nuclear outage data for 2005 available at http://www.nrc.gov/reading-rm/doc-collections/event-status/reactor-status/2005/

situation which is unlikely to be repeated as dramatically in the future. Because of this switch, we have excluded this time period

Generation statistics from load: Operational probability and generation probability distribution

We gather statistics from the generation dataset by examining discrete "load bins", the hours in which load fell between an upper and lower bounding demand. There are 100 such load bins,



each indexing a number of hours. In each load bin, we collect two statistics:

- the probability that each unit is operational, and
- if at all operational, the probability distribution function of the unit's generation within the load bin

The probability that the unit is operational is one function of the type of generator. For example, a baseload unit will be operational even when very little load is demanded (off-peak hour), and thus generate in most of the load bins. A peaking unit, however, is unlikely to ever operate at low load bins, but might occasionally operate at high loads. The probability that a unit is operational at low loads is relatively well predicted by the unit's capacity factor (Figure 5). In low load categories, only the baseload units operate. In the mid-load categories, intermediate units begin operating, and at peak loads, all units which run during the year are fully operational.

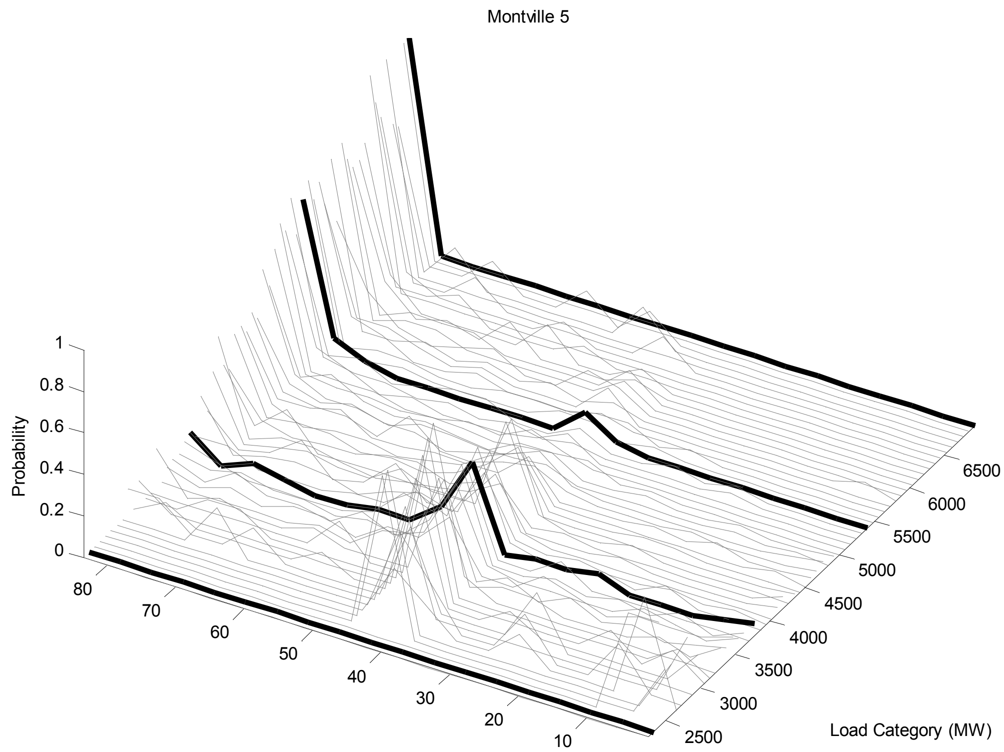


Figure 5: Color histogram indicating the probability of operation for 60 EGUs in CT in 2005. In each of 60 load categories across the X-axis, each power plant (in the Y-axis) displays a color indicating

Figure 6: Montville 5 generation behavior. When in operation, this unit (and all others) is dispatched to meet load according to a variety of factors. We can see in this graph that Montville 5 generates approximately 42 MW during most hours of operation when load is below 5000 MW. Above 5000 MW, the unit is increasingly likely to generate 82 MW.

When units do run, their generation is often also a function of the total demand. We collect statistics for each generator on how much energy the unit is producing in each load category. The information is translated into a discrete probability distribution function with 20 different generation options. In essence, this process creates a histogram of potential power outputs for a generator when a particular load is demanded. We illustrate an example in Figure 6. Montville 5, an oil-burning unit from 1954, runs as an intermediate generator, turning on when loads exceed 2400 MW. This unit maintains a minimum generation of about 45 MW as spinning reserve. As loads climb above 4500 MW, the generator is dispatched more often towards its capacity (~86 MW). At peak loads (>6500 MW), the unit runs almost exclusively at capacity. These behaviors are aggregated in the load probability distribution function. We see that at the lowest load categories (first black line), the unit does not operate at all, and therefore this load bin is empty. At a load bin from 3785 to 3866 MW (the second black line), the unit runs, generating mostly at spinning reserve, indicated by the steep peak at about 45 MW. At a load bin closer to 5500 MW (the third black line), the unit runs about 20% of the time at spinning reserve and 70% of the time at capacity[13]. As peak loads are demanded (the last black line), the unit is dispatched at full capacity (indicated by steep peak at 86 MW).

The operational probability and generation probability distribution functions are recorded for each generating unit and each load category. These data will be used later to re-construct the probabilistic generation of LBPEM.

Emissions statistics from generation (probabilistic emissions rate)

Unit emissions statistics relative to unit generation are gathered from the database similarly to the way in which generation statistics were gathered relative to load. For many types of units, emissions are a reasonably straightforward function of generation (higher emissions when more power is generated). In other datasets[14], emissions are calculated as a rate relative to generation

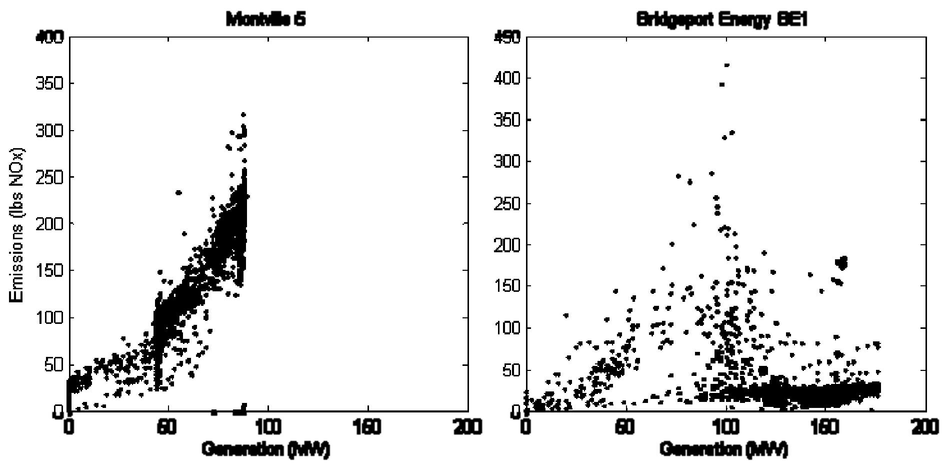


Figure 7: NOx emissions versus generation for two CT EGUs. (A) Montville 5 (RMR) unit emissions rise at approximately 2.02 lbs per MWh. (B) Bridgeport Energy BE1 has a non-linear emissions path, which is simulated in the Monte Carlo model. The average emissions rate for this unit is 0.19 lbs per MWh.

(Lbs NO_x / MWh, or T CO_2 / MWh), assuming a linear increase with generation. However, emissions (particularly NO_x and SO_x) are not always tightly correlated with generation (see Figure 7), and can vary depending on running conditions, operating temperatures, and whether emissions controls are in operation.

We use 20 generation bins, or categories, for each unit, bounded by zero and the highest possible generation capacity for that unit. We find all hours in which the unit generated the amount in each bin, and record the emissions during these running hours for the ozone and non-ozone season separately. Within each generation bin, we create a histogram, or PDF, of likely emissions. For some units, this is a very tightly bounded constraint, while for other units, this

[13] About 10% of the time, this unit is transitioning between 45 MW and 86 MW when the load is near 5500 MW.
[14] For example, see the US Environmental Protection Agency's eGRID dataset (http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html), one of the most comprehensive resources for plant-level, state and regional emissions reporting data, based on the CAMD dataset.

distribution can be quite wide. For example, Bridgeport Energy BE1 in Connecticut is a new, low emissions natural gas combined cycle generator with best available emissions control technology. The unit tends to run as a baseload unit in continuous operation (Figure 8). However, during the times that the unit is ramping up, the emissions controls are not as effective, and the unit's operation during these periods has high emissions. However, as the unit is ramping down, the emissions controls are very effective, and emissions are very low. We capture this behavior in the very wide PDF at low generation categories, even thought the unit is very predictable and well constrained at high generation categories.

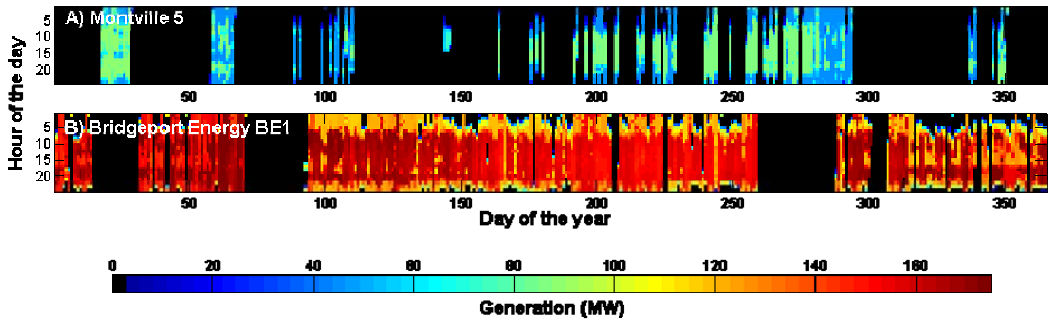


Figure 8: Generation of two CT EGUs. Generation in MW is portrayed as colors ranging from 0 (blue) to 175 MW (red). The y-axis are hours of the day and the x-axis are days of the year. Every vertical line is a daily cycle. (A) Montville 5 operates about 25% of the time, and cycles from zero to 80 MW, holding at 40 MW during evening hours. (B) Bridgeport Energy BE1 operates 69% of the time and also cycles, but generally provides more of a baseload operation between 140 and 175 MW.

Monte Carlo Simulation

To estimate generation and emissions when a particular load is demanded, we run a Monte Carlo simulation. A Monte Carlo simulation is a method of obtaining both likely average system behavior and error bounds when there are a large number of uncertain variables. It creates hundreds or thousands of manifestations of a model run by drawing randomly from within probability distribution functions, rather than just using the expected value (the mean). The average behavior of the system is the average of all of these manifestations, and the standard deviation of the behavior can also be obtained from these multiple runs. In our system, there is uncertainty on:

1. the number of units operating when a particular demand is required,
2. the generation level of those units which are operating when a particular demand is required, and
3. the emissions level of those units at a particular generation.

We solve for expected generation and load by running 100 manifestations of the model in the Monte Carlo simulation. We can divide this process into three distinct steps:

1. choosing which units operate,
2. choosing the generation of each of these units, and

3. choosing the emissions level of each of these units.

Each manifestation of the Monte Carlo approach runs as follows. First, given a particular load, we determine which load bin it falls into. Within this load bin, each plant has a certain probability of operating. For the 60 units in Connecticut, we roll a random die (actually choosing a randomly generated number) and determine if it is higher or lower than the probability that the unit is in operation. If it is higher or equal to the unit probability, than the unit is operational, if it is lower than the unit is offline. This gives us a list of all of the units running in this particular manifestation. Second, we determine how much each unit is generating. For each unit, we choose a random number (0-1) and determine where within the unit's generation PDF this random roll falls[15]. The nearest generation value (in MW) below the random roll is taken as the unit generation. Finally, to determine the unit's emissions, we reference the unit's chosen generation bin and pull a random number (0-1), which chooses an emissions level given the amount of energy the particular unit is generating. We sum all of these emissions together to obtain net system emissions in this particular manifestation and record the value.

The Monte Carlo simulation runs 100 times for each load category. At the end of these 100 runs, the average and standard deviation of the generation and emissions are recorded and reported.

D. LBPEM Extension: Load Growth, Interpolation, and System Changes

The core of LBPEM, described above, is able to generate an assessment of emissions in Connecticut in the base year, simply by recalculating average behavior from statistics gathered from the same base year. While this system provides a useful check on the reference case, it does not help to identify how changes in the system would result in changes in emissions or system generation. However, because of the nature of this system, it is able to dynamically adapt to changes in the base case. For example, simply shifting around load within the dynamic range of the reference year (2005) is simple: since the emissions in each hour are calculated independently, the order in which loads occur through the year is relatively insignificant. Therefore, from just the LBPEM core program alone, we can determine how different loads will result in emissions differences. How can we determine emissions in the case that load grows or shrinks outside of the dynamic range seen in the reference year, or a new plant is added or old plants retired? The extension of LBPEM allows this functionality.

The basic concept in the following sections are that (a) the amount of generation expected at any given load category remains constant in all circumstances[16], and (b) units respond to load at a given level of generation (or are dispatched to respond to load) based on a "perceived load" requirement. Using the first precept, if we interpolate up the system load vs. generation curve, we can determine how much generation would be expected at any given level of load (even if the load wasn't demanded in the reference year). Using the second assumption, we can add and

[15] This is accomplished by transforming the PDF into a cumulative distribution function (CDF), with values from zero to one. When the random variable is drawn, it is compared to the CDF and chooses the generation with a cumulative probability less than or equal to the random variable. If we repeat this operation multiple times, the histogram of all chosen generation values converges on the shape of the PDF.

[16] The constancy of the generation vs. load relationship is critical to this statistical approach. We assume that the amount of energy generated by fossil units is a relatively constant ratio, and other types of generators and transmission remain relatively constant as well.

subtract generators by shifting the perceived load of all other units as generators are built or taken offline.

Statistics Extrapolation: Load growth and shrinkage

The statistics which are gathered for the core version of LBPEM have a critical shortfall, in that they are only able to portray a world in which the load falls in the dynamic range of the base year (in this case, 2005). If projected loads extend above or below the base year dynamic range (in the case of Connecticut, approximately 2,200 to 7,000 MW), then the non-extended version of LBPEM is unable to identify a load category and is unable to use the available statistics. The first expansion module extrapolates available statistics out to load categories that did not exist in the base year to estimate how existing generators would operate in these unknown conditions. The following four steps are taken:

4. Create new load categories above and below the reference dynamic range,
5. Extrapolate unit probabilities of operation into new load categories, and
6. Extrapolate generation level PDFs into new load categories.

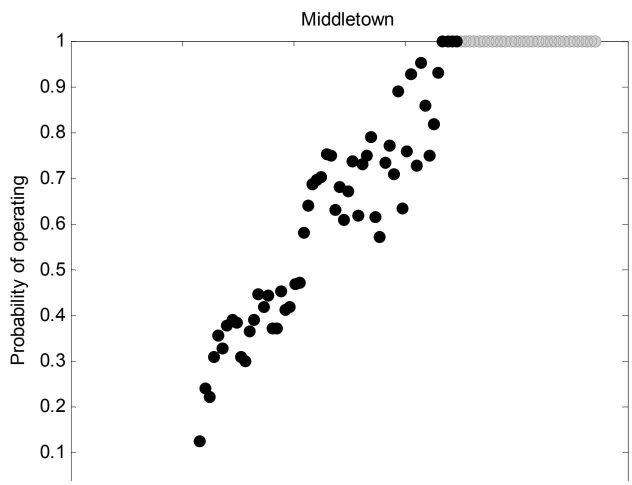


Figure 9: Extrapolating run-time probability for a Middletown (RMR) unit. The EGU always runs at the highest loads (>7000 MW), and therefore maintains this behavior if even higher loads are demanded.

New load categories are defined for loads up to 50% above and 30% below the existing dynamic range. For each generator, we extrapolate (both up and down) the probability that the unit is in operation using the first third and last third of the probability at a load category as a basis for the extrapolation. If a unit always operates at the historical peak load, then it will also always operate at any higher loads (see Figure 9). If a unit never operates at minimum loads, then at any loads below it will also never operate. If an extrapolated line goes above a probability of 1, the line stays level at 1; the same rule applies if an extrapolated line goes below a probability of zero.

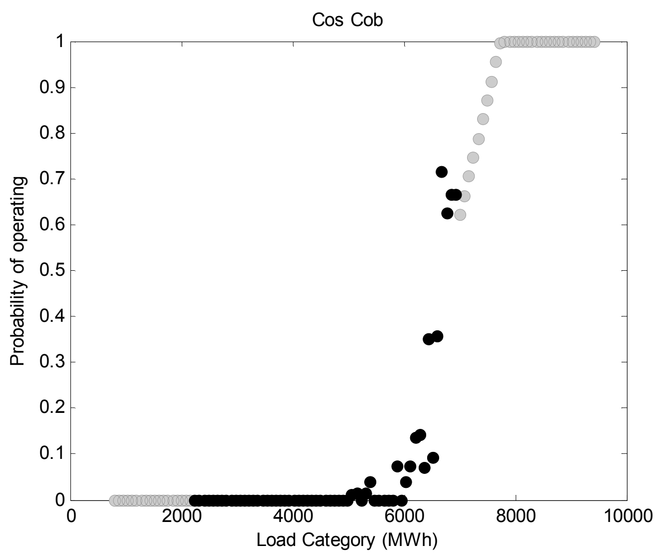


Figure 10: Extrapolating run-time probability for a Cos Cob (peaker) station. At low loads, the unit never runs (zero probability of operation); at high loads, the unit becomes increasingly likely to run. This high probability is extrapolated up to loads not seen in the 2005 dataset.

When a unit is actually in operation, it may follow a probability of generating some amount of electricity with a pattern similar to that seen in Figure 10. But what happens to its expected generation as loads increase beyond those seen in the base year? Do the generators all operate all the time at peak capacity? In some cases, it is likely that this will be the case, but in others, even at peak loads, the plant may have sometimes operated in spinning reserve. When this is the case, we must extrapolate out the PDF functions of generation in each load category. We do so by comparing the probability that a unit will generate at each probability and extrapolating this pattern up and down into new load categories (see Figure 11). In only a few cases does the plant have a probability of operating in multiple modes at higher load categories, and most of the plants cease operation at load categories below the base. Once these statistics are gathered, the Monte Carlo approach can be run at higher and lower loads than are otherwise available in the reference year.

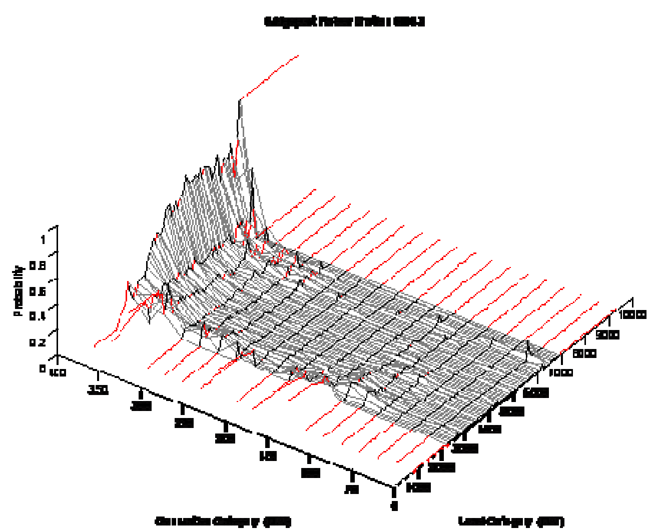


Figure 11: Extrapolation of generation behavior in Bridgeport Harbor Station for higher and lower load categories. Probabilities are extrapolated out by load category.

Retiring and adding generators

The process of retiring a generator is relatively simple. When a generator is taken offline, the units remaining must make up the difference that this unit otherwise would have generated. The demanded load plus the generation which is no longer offered by the retired unit becomes the *perceived load*. The perceived load is the load which all operating units "see". When a 150 MW unit is retired, all other units must make up this difference. An example serves for illustrative purposes: in year one at a given hour, the system-wide demand is 5500 MW, which will be served by many of the generators, including unit R, which will be retired in the next year. Forty-five out of 60 generators respond to the load and together generate about 2200 MW. The following year, unit R is retired, and when 5500 MW are demanded, 45 of 60 generators respond. However, together these units still need to make up for the generation which has been lost with unit R. Together, they perceive a *higher* load than is actually demanded and thus are more likely to be dispatched at a higher generation level to answer that load. In fact, the load that they perceive is the total system demand plus whatever unit R would have otherwise generated. In this extension of the Monte Carlo simulation, first we run unit R to determine how much it could have generated when demand was 5500 MW. We find that it would could generated 100 MW (based on a random draw), and add this to the 5500 MW system-wide load. The remaining 45 active generators (not including R) now perceive a load of 5600 MW and respond accordingly, generating 2200 MW.

To add a generator, we copy the statistics from an existing generator, and add it into the cohort of plants. Similarly to the process of removing a generator, by adding a generator we reduce the perceived load of all other plants. Again, the new generator is run independently to determine how much electricity it could have generated, and then this generation is subtracted from the system-wide load to yield the perceived load. In this way, a new power plant does not change the relationship between system-wide load and expected system-wide generation; it only changes the dispatch order of the plants responding to this load.

Changing Emissions Profiles

To simulate the effect of RMR units adopting increasingly rigorous air quality (NO_x) controls, we manually set reduction by 30% in 2012 and 50% (total) in 2015 for the RMR units. The Monte Carlo analysis is still run in completion, but the RMR unit emissions are simply multiplied by 70% or 50% to simulate the effect of sprayed water controls and later SCM-type controls in 2012 and 2015, respectively. The reductions are applied to:

- Norwalk Harbor Station 1, 2
- Middletown 2, 3, & 4
- Montville 5 and 6
- New Haven Harbor NHB1
- Bridgeport Harbor 2

Simulated controls were only applied to RMR units, which have a disproportionately high NO_x emissions rate relative to other units in CT. Additional emissions controls were not considered for combustion turbines.

Reporting Results

Results are reported as statistics on unit operations, as well as in tons of emissions (NO_X and SO_X) during the HEDD period, and pounds of emissions per MWh for every load category.

5. Results

A. EGU operations and RMR statistics

In 2005, there were a wide variety of plant operational types in CT, including peakers, intermediate units, baseload units, and EGUs which did not operate at all, but were reporting to the EPA Clean Air Markets Database (CAMD). The operational characteristics are well matched by capacity factor, as seen in Figure 5. As explained in the methods section, this figure shows the probability that any given EGU was dispatched when a particular load was called. One of the interesting features of this figure is that the RMR units appear to have been dispatched in 2005 as intermediate units. With the exception of one Norwalk Harbor EGU which did not operate in 2005, the remainder of the RMR units (Montville, Middletown, New Haven Harbor, and Norwalk Harbor) all ran at even very low loads. Most of these units had a 20-30% probability of running at loads under 5000 MW, well under peaking conditions (>6500 to 7000 MW). While this statistic yields no information on the congestion, reliability, or pricing conditions under which these units operated, it is interesting to note that these units ran frequently under non-peaking conditions and aside from two Montville and one Middletown unit, ran almost without exception when loads exceeded 5000 MW.

B. Ozone season load and generation

Forecasted loads rose according to the extrapolation of the ISO-NE forecast. In the baseline load growth scenario, ozone season load rose from just over 15 TWh in 2005 to 17 TWh in 2020, rising at over 1.3% in 2010, but slowing to just over 0.5% in 2020 (see Figure 12). In the 2% EE scenario, load is reduced by 1% in 2008, and 2% (compounded) starting in 2009. The departure from the baseline scenario can be seen immediately in 2008, as growth slows to zero and then begins dropping to 13.5 TWh in 2020. The more ambitious 3% scenario drops to 12.3 TWh in 2020.

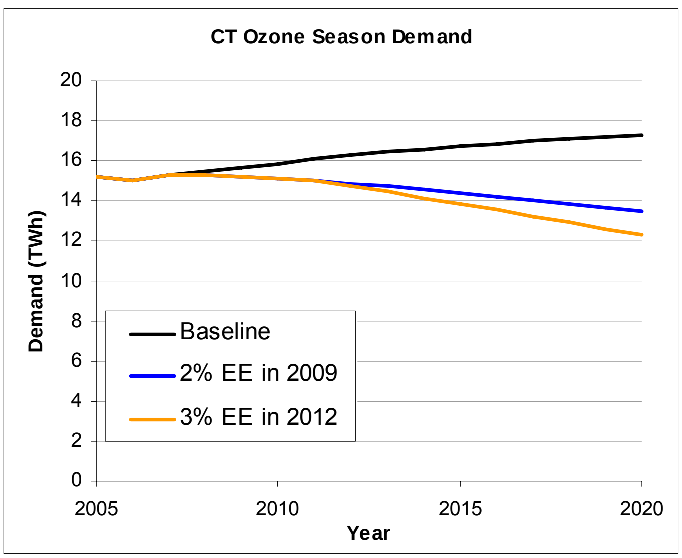


Figure 12: Ozone season generation in CT in terawatt hours.

Fossil generation on high electricity demand days (HEDD) follows a similar pattern, rising in step with demand. Figure 13 shows expected average generation on the twelve HEDD days (cumulative over a 24 period). The error bars indicate the potential spread (1st standard deviation) of generation which could be called to answer the load. The standard deviations are derived from the Monte Carlo model, in which there a large number of probable ways for each EGU to respond to load. Averaging all of the possibilities yields the mean probable behavior, but the spread of options is captured in the standard deviation.

C. Emissions behavior in scenarios

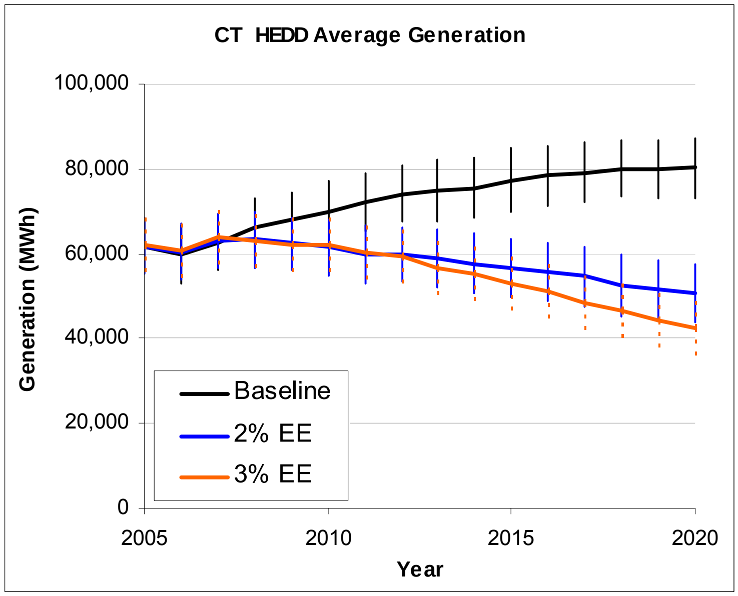


Figure 13: CT HEDD average daily generation in megawatt hours. Average expected generation in solid lines; error bars indicate 1st standard deviation of generation according to Monte Carlo model.

Core results are available in the comparison between load and generation, and load and expected emissions (see Figure 19 through Figure 22 in the Appendix). In the baseline scenario (Scenario 1, Figure 16) as load demand increases, fossil generation rises; the slope of this line becomes steeper towards higher loads as CT has fewer options for importing electricity and generates more in-state. In the baseline scenario, higher loads require more generation along a similar slope. This model inserts new, natural gas power plants to make up the generation deficit. In the right-hand graph, as load increases, the slope of the emissions line becomes increasingly steep after 5000 MW as RMR units are dispatched. Over the years until 2020, clean new generators are built and dispatched as intermediate units. Because of the collectively lower emissions, the system can handle higher loads with lower emissions. Therefore, we would expect that although loads continue to increase, emissions do not increase markedly.

In Appendix Figure 19 (Scenario 2), energy efficiency reduces the number of hours in which peak loads (and thus peak emissions) are experienced and thus overall emissions drop. Fewer hours are spent above 5000 MW in the steep part of the emissions curve implying, in this case, that the RMR units operate less frequently and thus overall emissions are reduced.

In Appendix Figure 21 (Scenario 3), RMR units adopt cleaner emissions technologies in 2012 (reducing emissions by 30%) and 2015 (reducing emissions by 50% from 2005 levels). Therefore, even though load rises towards 2020 (as in the baseline scenario), the emissions slope past 5000 MW becomes significantly less steep, and emissions during peak periods are lower than in 2005. While in 2005, peak emissions could exceed 8000 lbs NOx (4 tons) per hour, emissions controls in the RMR units (as well as dilution with new clean plants) reduce peak emissions to about 5000 lbs NOx (2.5 tons) per hour.

Appendix Figure 22 (Scenario 4) indicates what occurs if both energy efficiency and RMR reductions occur simultaneously. No new generators come online in this scenario because load falls, and thus all reductions are due to efficiency and RMR reductions alone. In this case, the steep part of the emissions curve falls due to implementation of RMR control technologies, and less time is spent in the steep portion of the curve because of energy efficiency.

D. Meeting the OTC MOU Commitment

Figure 14 below illustrates the reference case which assumes that as Connecticut's electricity demand grows, new generation is installed with emissions characteristics equal to those

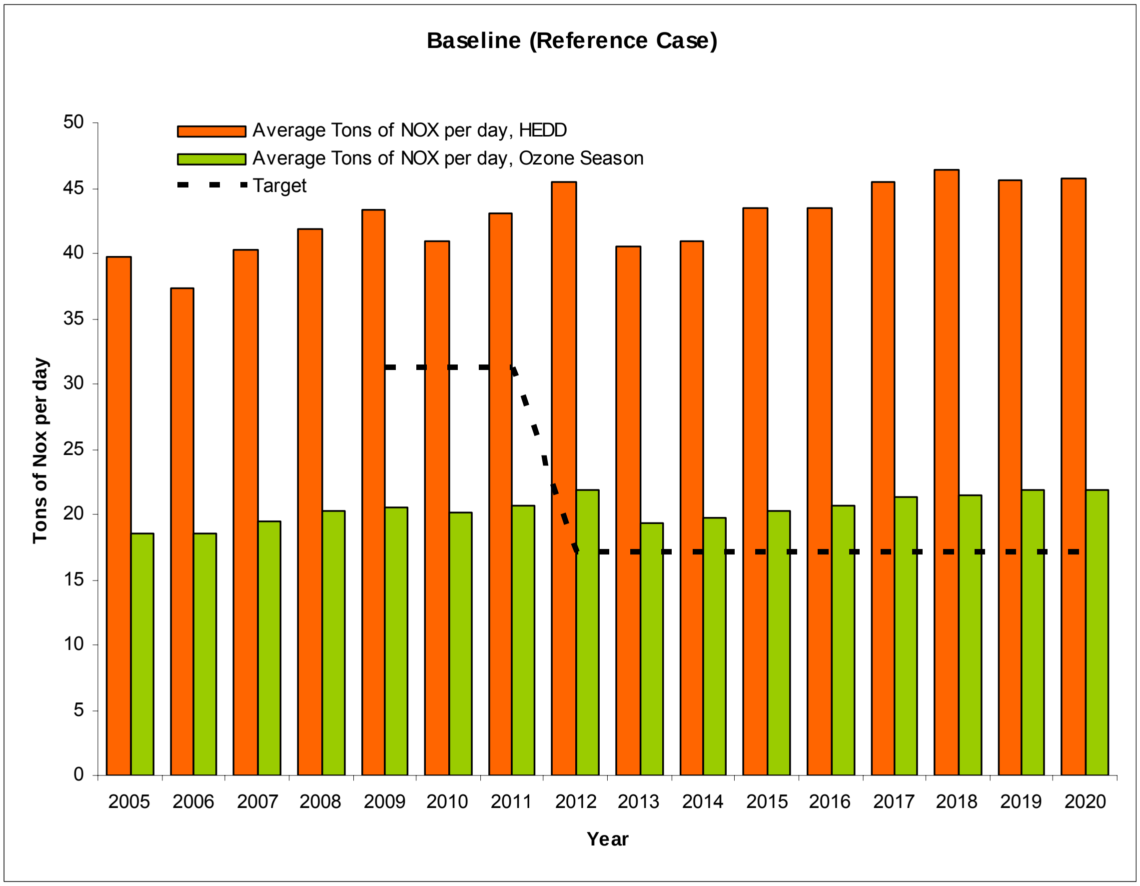


Figure 14: Scenario 1: Baseline reference case average NOx emissions on HEDD (orange) and during the ozone season (green). Target line represents OTC MOU for HEDD days.

associated with natural gas fired turbines (i.e. like the Milford power station). The reference case shows that NOx emissions on the peak and average days are essentially flat after 2011, showing neither significant increases or decreases. Peak day emissions remain well above that anticipated to be met via the OTC MOU.

Figure 15 below shows the effects of a 2% energy efficiency program in Connecticut's on HEDD and average ozone season NOx emissions. The results in the figure assume that Connecticut's current energy efficiency program, which is achieving energy savings levels equivalent to about 1% of total annual electrical sales will ramp up to achieve savings levels equivalent to 2% of annual electrical sales starting from 2009. This level of savings is consistent with the October 2007 plan submitted by the Connecticut Energy Conservation Management Board to the DPUC.

Increasing the level of savings from energy efficiency reduces both peak and average ozone season NOx emissions such that the level of the OTC reduction commitment is reached in 2017.

Effect of Strategies on High Electricity Demand Day (HEDD) Emissions

Results from scenarios 1 and 2 indicate that the DEP's goal to achieve the OTC MOU reduction commitment by 2009 cannot be met through a business as usual approach (even when all new generation is as clean as possible) or through a program that relies solely on existing levels of energy efficiency. Figure 16 shows results from several different scenarios that were evaluated

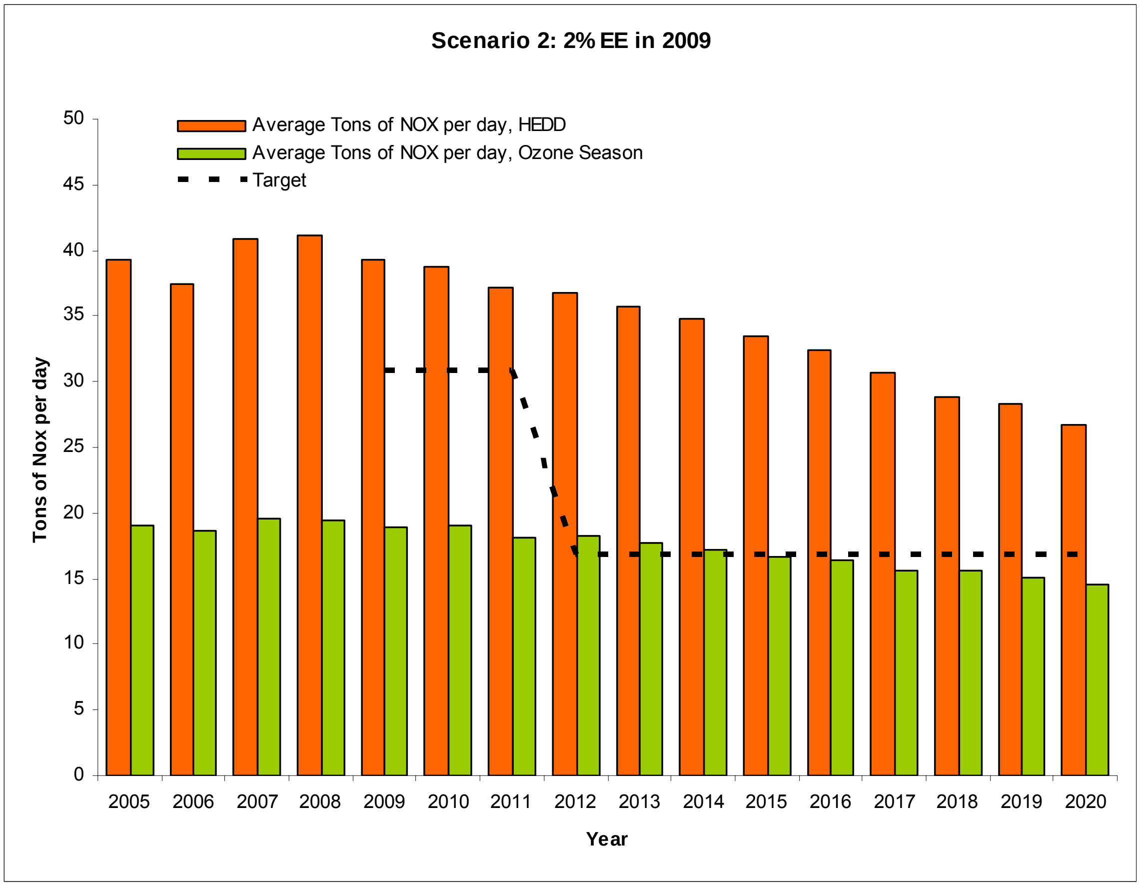


Figure 15: Scenario 2: Energy efficiency case average NOx emissions on HEDD (orange) and during the ozone season (green). Target line represents OTC MOU for HEDD days.

to determine their ability to reduce NOx emissions during peak electric demand periods.

Five scenarios are included in Figure 16:

1. the reference case, reflecting business as usual with growth in electric demand met through the installation of new natural gas fired turbines;
2. an assumption that the RMR units reduce NOx emissions by 30% starting in 2012 and by a total of 50% by 2015;
3. increasing the trajectory of savings achieved from Connecticut's energy efficiency program from 1% to 2%, as contained in the ECMB 2007 filing to the DPUC
4. a combination of RMR units reducing their NOx emissions 25% and Connecticut's EE

program achieving 2% savings as a percent of sales; and

5. Connecticut's EE program achieving 3% savings as a percent of sales

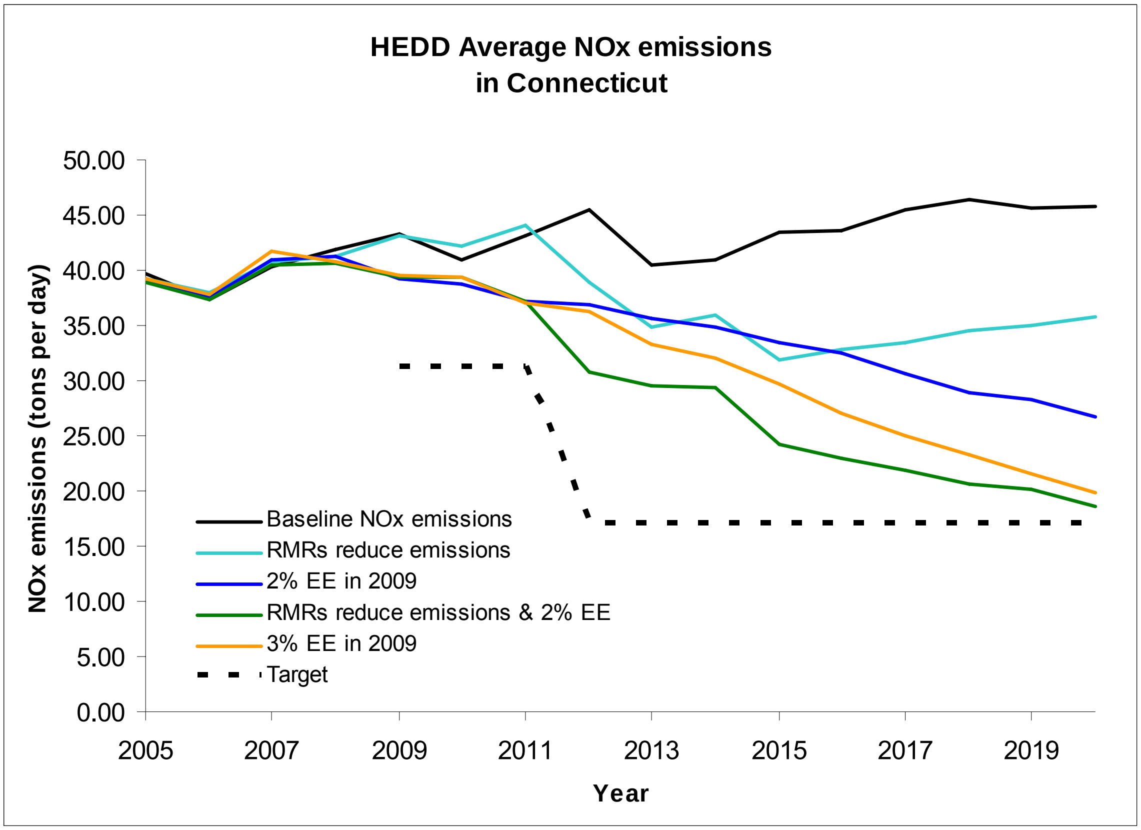


Figure 16: NOx emissions during HEDD in each of the five scenarios. The target line represents OTC MOU for HEDD days. The combination of RMR unit reductions and efficiency, as well as aggressive efficiency, are the most effective scenarios for meeting future targets by 2020.

Scenario 1 was discussed earlier. The reference case meets Connecticut's electricity demand, but does not result in any NOx emissions decrease.

Reducing emissions from RMR units by 30% in 2012, as shown in Scenario 2, decreases peak day NOx emissions by 2012, but not enough to meet the commitment of the OTC MOU, and after 2012, statewide emissions decrease no further.

Scenario 3 was also discussed earlier. Connecticut's existing energy efficiency program does reduce peak ozone emissions such that the OTC commitment can be met, but in the year 2017, rather than 2009. Peak NOx emissions continue to decline at a relatively shallow rate after this year.

Scenario 4, the combination of reducing RMR unit NOx emissions by 30% in 2012 as well as a 2% savings from EE has the effect of meeting the OTC commitment in 2012. NOx emissions continue to decline in subsequent years.

Scenario 5, a scenario where Connecticut's energy efficiency program achieves savings equal to 3% of annual electricity sales produces about the same effect as Case 4, with the OTC commitment met in 2012, and a continued decline in peak NOx emissions in subsequent years.

Effect of Strategies on Average Ozone Season Day Emissions

The previous section discussed the effects of various strategies that could reduce NOx emissions, and their benefits on peak ozone season days. Figure 17 below shows the results of the same strategies when evaluated for their benefits across the entire ozone season.

Applying the same five cases as were evaluated for their benefits on the peak ozone season day, the same approximate benefits also occur across the entire ozone season, with one difference. Observing only HEDD days, emissions from Case 2 (reducing RMR emissions 30% to 50%) mostly remain above the levels of Case 3 (2% energy efficiency), however, in the average ozone season day, Case 2 emissions decrease initially to lower than the levels from Case 3 in 2012 and remain essentially flat through 2020. Case 3 NOx emissions continue to decline, reflecting the cumulative benefits of energy efficiency, and drop to below the levels of Case 2 after 2018.

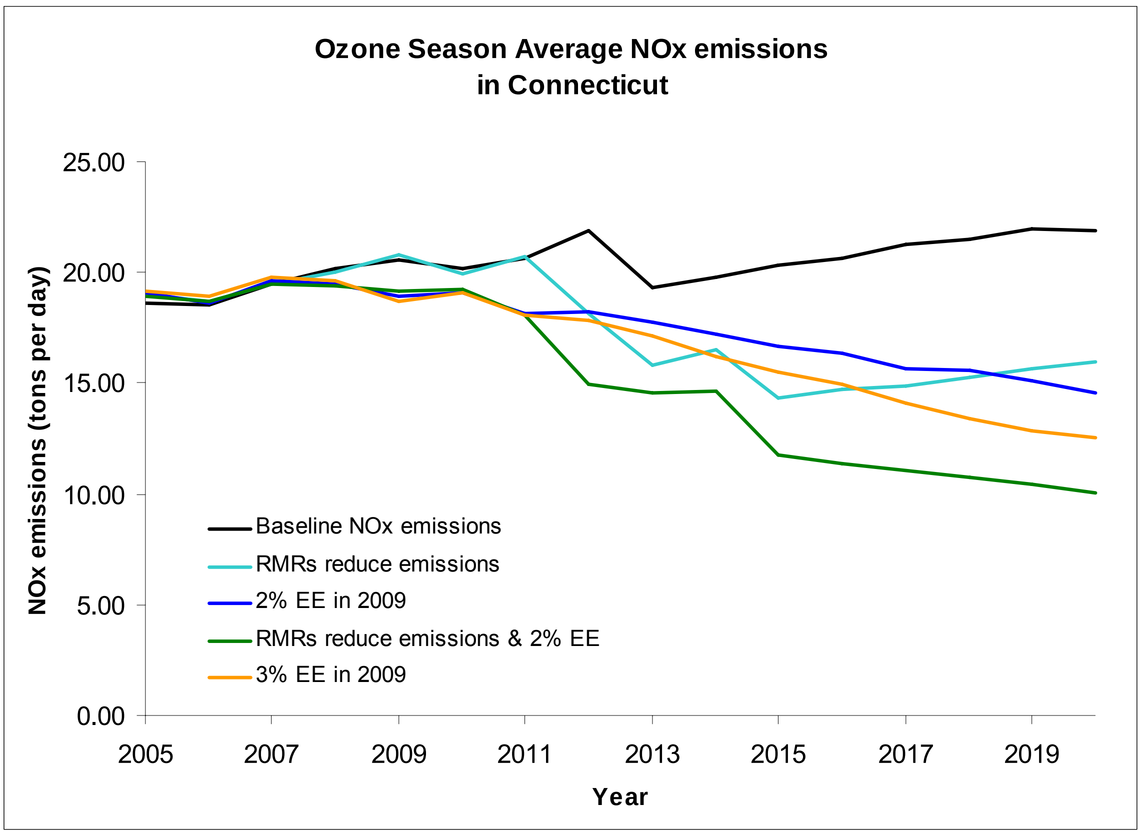


Figure 17: Average daily NOx emissions during the ozone season in each of the five scenarios.

E. Post-2009 Emission Reduction Strategies

The US EPA recently promulgated an eight-hour ozone standard at 75 parts per billion, an effective reduction of 9 ppb from the previous 0.08 parts per million level[17]. Connecticut's commitment through the March 2007 OTC MOU addresses emissions reductions that are needed to comply with the previous 0.08 ppm ozone standard. Additional emissions reductions will be

[17] March 27, 2008, Federal Register, vol 73, no 60, pp 16436-16513. Previous ozone standard of 0.08 ppm effectively permitted ozone concentrations of up to 84 ppb due to rounding and number of significant figures.

needed to comply with the new 75 ppb ozone standard. Per Section 110(a)(1) of the Clean Air Act, states are required to submit plans within three years of the date that new air quality standards are promulgated. The plans are due to EPA by March 12, 2011, and must describe measures that the state will implement to ensure compliance with the air quality standard.

The same five cases analyzed for their ability to meet the OTC commitment were also evaluated to assess the degree to which these same policies could also be effective in helping to meet the new ozone standard. Figure 14 through Figure 16 show a dotted line going from left to right, with a downward step in the year 2012. The timing of this decrease and the level approximate what the DEP believes will be necessary to achieve from this sector in order to demonstrate progress to meet the 75 ppb ozone standard. This second step is equivalent to applying BACT level emissions controls to the RMR units, effective in 2012.

Using the policies evaluated as shown in Figure 16, only two of the scenarios reach the 2012 to 2020 target and none reach the more immediate 2009-2012 target. Scenario 1, business as usual, achieves neither of the two emissions reductions goals. NOx emissions continue at the same level for the entire period evaluated. Reducing emissions from RMR units in a two-step process, as shown in Scenario 2, by 30% in 2012 and by a total of 50% by 2015, also does not meet the post-2009 emission reduction requirement. Existing levels of energy efficiency (Scenario 3) reflect a trend of decreasing NOx emissions over time, but the needed reductions do not occur by 2020 using this policy measure by itself. Scenario 4, the combination of reducing emissions from RMR in a two-step process plus continued energy efficiency savings equal to 2% of annual electricity sales, reduces NOx emissions sufficiently to nearly achieve the lower emissions goal by 2020. Scenario 5, energy efficiency program savings equal to 3% of annual electricity sales, has the same approximate trajectory as emissions from Case 4, and also nearly achieves the lower NOx emissions goal by 2020.

6. Recommendations

Policies to reduce emissions from the electric sector should consider the benefits and impacts from environmental, energy and economic perspectives. Evaluating these effects is especially important in a restructured electric market, where any costs incurred to meet standards will be built into the hourly market clearing price and passed along to all ratepayers. Additional costs can also have the effect of increasing the profits of generators whom are unaffected by the environmental decisions made. Connecticut's base loaded nuclear and coal plants will see additional revenue from any policies that result in increasing the marginal price of electricity. Any differential increases in hourly electricity prices also increases the likelihood for electricity to be imported into Connecticut from other New England states, from NY, and wheeled from PJM through NY into Connecticut.

These additional potential economic impacts can be balanced with the economic costs to Connecticut ratepayers from the continued operation of the RMR units. The recent Integrated Resource Plan for Connecticut, completed pursuant to Section 51 of Public Act 07-242, reported that the annual fixed operating and maintenance costs for Connecticut's RMR units is greater than $140 million per year[18].

The recommendations in this section reflect upon the complex intersection of environmental, energy and economic elements, each of which is important alone, but which also has direct and indirect effects to the other elements:

- Connecticut's ozone attainment status precludes construction of new large central electricity generating plants unless older plants shut down or otherwise enforceably limit their operation;
- Connecticut's energy efficiency program is ranked in the top of all such programs nationally. Implementation of section 51 of Public Act 07-242 would substantially increase the amount of EE savings, potentially to levels even higher than those evaluated as part of this report;
- Funding of energy efficiency programs needs to be sustained over the long-term (i.e. decades) to ensure that program savings accumulate and that all cost-effective measures are implemented. While the state has plans to implement all cost-effective energy efficiency, funding of these programs at a level needed to procure all such resources is beyond the control of the DEP;
- Past EE funding swings create uncertainty as to the ability of Connecticut to achieve its full potential; and
- Requiring emissions controls to be installed on EGUs will enable NOx reductions to be achieved and directly measured, but the costs of these controls will likely be passed along to ratepayers, who already are paying some of the highest electricity rates in the United States

[18] Integrated Resource Plan for Connecticut; January 1, 2008; The Brattle Group (at appendix A, page A-6)

Recommendation 1: Implement a combination of increased energy efficiency and reductions from units that contribute to peak day NOx emissions

Case 4 evaluated a scenario where energy efficiency programs achieved a level of 2% savings as a percent of annual electricity sales, and where emissions from RMR units were reduced in two phases: by 30% in 2012, and by a total of 50% by 2015. Energy efficiency programs are currently avoiding about 50 MW of demand each year, and this amount accumulates. This amount of EE alone is insufficient to achieve the level of savings needed to offset all demand growth. Additional EE savings will likely be identified by October 2008, per the required updated maximum achievable potential study that is to be completed by Public Act 07-242. Funding for such increased level of savings is uncertain. This is discussed further in a later section related to Recommendation 2

Reducing NOx emissions from RMR units can be achieved via:

- Installing controls to directly reduce emissions;
- Reducing the number of hours that the units are needed; and/or
- Reducing the number of RMR units that are running

For the RMR reductions, installing emissions controls or reducing the number of RMR units that are operating will ensure that the anticipated level of NOx reductions from this sector is achieved. Reducing the number of operating hours could also be made to be enforceable through permit restrictions and other administrative means, but this might also result in increased regulatory burdens, along with additional permit fees to process the revisions, for affected sources, and additional permitting resources for the DEP.

Recommendation 2: Ensure sustained funding for EE programs

Connecticut's energy efficiency program is nationally recognized[19] and has the potential to achieve substantially greater savings. Energy efficiency programs are funded via a 3 mil surcharge on Connecticut ratepayers. Funds collected are adminstered by the Energy Conservation Management Board (ECMB), which reviews and comments upon plans submitted by the two main distribution companies, CL&P and UI and those who service a much smaller municipal service territory. The level of funding needed to achieve the 3% level suggested to reduce NOx emissions will likely exceed the amount administered by the ECMB , even with the additional RGGI revenue. While the state has plans to implement all cost-effective energy efficiency, funding of these programs at a level needed to procure all such resources is beyond the control of the DEP. Higher savings levels would require the following elements to be met:

- Revenue from the auction of RGGI allowances directed to the ECMB and re-invested in additional EE measures;
- Private sector interest in the business case for EE to direct investments that could achieve additional savings without requiring public funding;
- Innovative financing schemes that would use a mix of public and private funding. Public funding could buy down interest rates, serve as first loss to permit a focus on sectors that

[19] ACEEE Scorecard of State Energy Efficiency Programs, 2007 (for the year 2006). CT tied for first with Vermont and California.

have higher risks, such as low-income and small businesses, and help to guarantee or insure that the anticipated savings persists over time. Private capital would be directed towards the measures themselves.

- Continued updating of building codes and appliance standards, and enforcement of them, to maintain and increase the baseline level of savings that can occur without requiring incentives

Recommendation 3: Increase transparency of generation data

Since ISO-NE began demand response programs in 2000, the RTO has maintained that operation of inefficient generating units has environmental as well as energy benefits. Conclusively determining the degree of benefit, or not, has been hampered by an inability to obtain data from ISO-NE related to generating units that are called upon to operate during peak electric demand periods. The RTO has claimed confidentiality concerns, but the same type of information is publicly available from the NY ISO. Increasing data transparency would improve trust between the environmental agencies and ISO-NE, and would help to ensure that decisions considered by these respective parties took into account potential impacts and avoided unintended consequences. The following information would be beneficial to environmental agencies:

- Event type, date and hours (already available through ISO's semi-annual filing to FERC on demand response programs)
- Generator name, location and amount of load provided or load shed (not available and claimed confidential)

The lack of transparency means that air regulatory agencies may again be designing control programs that do not include all affected sources.

B. Next Steps: Enforceability of Recommended Policy Measures

Connecticut's state implementation plan submittal to EPA will require a demonstration that any of the policies adopted are enforceable, and that the anticipated emissions reductions are permanent. Traditional regulatory programs have relatively straight forward enforceability, since the emissions controls and their effectiveness, can be directly and precisely measured at the stack. Demand side programs have equally precise methods to account for their benefits. Determining their effectiveness however requires attention and coordination with the DPUC and ECMB, rather than directly at the smokestack.

Bundled EE Measures

For energy efficiency, the establishment of the ISO-NE forward capacity market creates a vehicle by which the benefits of demand side measures can be reported, measured and verified using internationally accepted protocols. The bundle of existing EE measures achieved to date has already been submitted and qualified by ISO-NE as a resource in their capacity market. To assure continued performance, and that the benefits of EE persist, Connecticut should continue to participate in the FCM, and also enroll all new qualified resources to ensure continued monitoring and verification of the program's benefits.

The emissions avoided from energy efficiency measures can be calculated from the ISO-NE Marginal Emissions Analysis report (published annually). Avoided NOx emissions would be the product of the number of MW of qualified energy efficiency measures and the Connecticut specific marginal emissions rate. Measure life, or persistence, also needs to be factored into the calculation. The benefits of energy efficiency assume a certain measure life, and that these benefits persist at or close to the same level of performance for their entire life. The DEP, through its statutory role on the ECMB, continue to coordinate closely in the planning and implementation of the state's EE programs to ascertain and confirm assumptions about the types of EE measures that are included in the bundle of resources that qualify for the ISO FCM. For example, a series of lighting measures may have an expected performance of 7-8 years, while those for motors, chillers and other equipment may have an expected life of 15 years or more. Alternatively, all measures may be combined into one bundle that uses an expected life of 10 years.

The second important factor to accurately account for energy efficiency measures is to recognize their cumulative nature. Consider the following example to illustrate this characteristic. In year one, a bundle of 50 MW qualifies for a resource in the FCM. In year two, another 50 MW bundle of EE qualifies. Year two's measures are in addition to those from year one, so the total benefits at the end of year two are 100 MW, and the avoided emissions are calculated on this basis. In year three, another 50 MW qualifies, making the avoided emissions benefit equal to 150 MW and so forth, until the end of the expected measure life.

ECMB Measures Not Submitted to the FCM

Implementation of the "all cost-effective energy efficiency procurement" requirement of PA 07-242 could result in a doubling or more of energy efficiency savings as a percent of electricity sales. Not all of these measures may be submitted for qualification in the ISO FCM. The ECMB program also includes a programs that are directed at reducing natural gas consumption. Quantifying the electric benefits of these additional programs can be calculated using the same methodology as is used for those which qualify for the FCM. Natural gas efficiency program benefits can also be determined, but methodology is less consistent that that now used for the FCM, as highlighted in the January 2006 NEEP report on common protocols to measure the benefits of energy efficiency programs[20]. Connecticut has recently begun a program to improve end-use efficiency for oil consumption (also required by PA 07-242). The oil program and the ECMB are supposed to collaborate on policy measures that could complement both programs, and work towards achieving an "all fuels" or "fuel blind" approach to energy efficiency. Since the oil program has just

[20] International Performance and Measurement Verification Protocols. See also http://www.neep.org/files/Protocols_report.pdf The Need for and Approaches to Developing Common Protocols to Measure, Verify and Report

Energy Efficiency Savings in the Northeast Final Report ,January 2006 , Northeast Energy Efficiency Partnerships, Inc.

begun, its programs and potential benefits are not yet known, but this could also be an important component to reducing air emissions in future years.

Building Codes and Standards, Appliance Standards

All energy efficiency programs will not be operated or administered through the ECMB, or overseen by the DPUC. Providing incentives to either reduce differential costs, or to help pay for the installation of more efficient appliances and measures is only part of a comprehensive energy efficiency program. Adopting and revising building codes and standards, and updating appliance standards substantially improve energy performance while requiring minimal levels of incentives. Enforcing these codes and standards is equally important, as is training for building operators and staff to ensure that the efficient level of performance is sustained. Building life is also decades longer than that of appliances or other EE measures, so having the most efficient buildings possible helps to assure that substantial energy performance occurs and is maintained. Calculating energy use from buildings is facilitated by use of the EPA Energy Star tool called Portfolio Manager[21]. This tool is used to benchmark building performance, based on existing or designed electricity demand. Performance after commissioning or on a year to year basis is calculated using the same tool, and results can be compared to determine how the building's energy use has changed.

Public-Private Partnerships

An emerging area that appears to offer promise to substantially increase the level of energy efficiency savings is one involving private capital and/or public-private partnerships. Private capital has been invested in energy efficiency measures for several years in Central and Eastern Europe, where it has been used to improve industrial and process efficiency. The decrease in energy demand is calculated and those benefits have been quantified, and then monetized, after qualifying under the Clean Development Mechanism (CDM), implemented as part of the Kyoto Protocol[22]. While the US is not yet a signatory to the Kyoto Protocol, the idea of private sector, or public-private sector, capital investing in American energy efficiency projects has gained a foothold. Pennsylvania Governor Rendell launched an Energy Independence Fund initiative in March 2007. This is a combined public benefits fund, like that of the CT ECMB, that would also provide access to venture capital and for clean energy economic development[23]. Implementing legislation has not yet been passed. Connecticut could take advantage of venture capital offered through the Connecticut Development Authority, whose mission focuses on local economic development and growth. Since this is a still emerging area, enforcing and committing to a plan that would include private sector resources is premature. But, Connecticut's electricity costs, at 20c/kWh retail, coupled with underlying market dynamics that favor continued high fuel prices, should encourage efforts to implement substantial energy efficiency programs. As shown in Figure 19, energy efficiency programs are achieving savings levels at costs of 2 - 5 c/kWh [24], with

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[21] See https://www.energystar.gov/istar/pmpam/
[22] The FE Clean Energy Group, based in Darien, CT, was formed in 2000 to provide capital for energy efficiency projects in former Soviet bloc countries in Eastern Europe. It has since branched out to Mexico and Asia. http://www.fecleanenergy.com
[23] http://www.depweb.state.pa.us/energindependent/site/default.asp
[24] Synapse Energy Economics. CERES Conference April 2008. "Prudent Planning and New Coal Fired Power Generation". Bruce Biewald.

an average of approximately 3 c/kWh. The costs of energy efficiency savings compare favorably to the cost of new generation, which has been at 8 - 11c/kWh [25].

The table below describes what steps DEP will need to make in order to ensure that the energy efficiency measures perform and persist as anticipated.

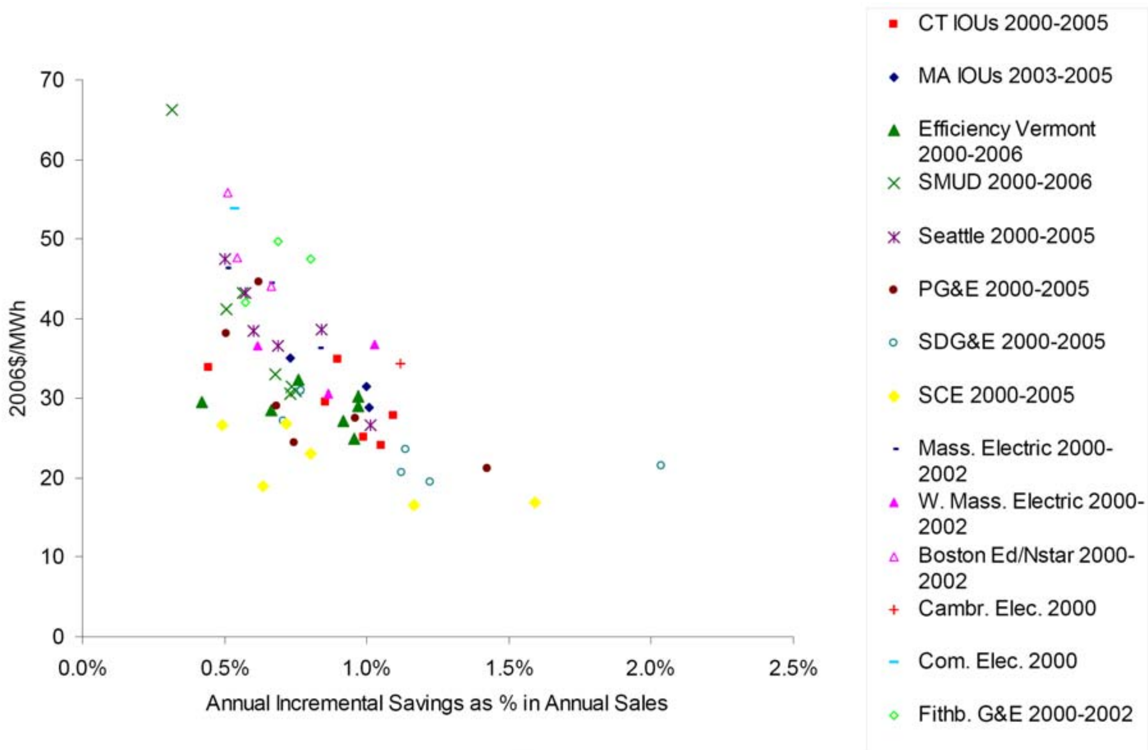


Figure 18: Utility costs of saved energy (over expected efficiency measure lifetime) versus incremental savings (MWh) as a percentage of annual sales (MWh). Data as publicly available in 2007.

[25] The Keystone Center, Nuclear Power Joint Fact Finding, June 2007 (for nuclear) and "Paying to Warm the Globe: Climate Crises and Opportunities", Presentation to Chicago Area Mensa, January 19, 2008, Sean Casten (for coal and natural gas)

Description	Responsible Agency(ies)	How to Calculate EE Benefits	Measurement Protocols	Comment
EE bundled into FCM	ECMB- program administration; ISO-NE- qualifying resources; CT DPUC- program review and approval	ISO Marginal Emissions Analysis (published annually); Avoided emissions data based on EPA ETS	ISO requires protocols consistent with those from IPMVP[26]	Coordinate with ECMB to determine measure life of qualified bundle of measures
EE not part of FCM	ECMB-program adminstration, CT DPUC-program review and approval	ISO Marginal Emissions Analysis; avoided emissions data	IPMVP	Coordinate with ECMB on measure life
Natural Gas efficiency programs	ECMB-program administration; DPUC-program review and approval	EPA avoided emissions data	Requires collaboration with ECMB and NEEP	Coordinate with ECMB on measure life
Building Codes and Standards, Appliance Standards	Office of Policy and Management-regulations; ECMB-training programs for building operators	EnergyStar Portfolio Manager (for retro-commissioning and modifications to existing buildings); ISO marginal emissions and EPA avoided emissions data	Building inspectors and code enforcers; manufacturer's certification	Requires coordination with Federal standards, to ensure reductions are not already included in EPA baseline. May only get to account for codes and standards that are more stringent than their Federal counterparts
Public-Private Partnerships	Emerging area, potentially: Connecticut Development Authority, Treasurer and other state agencies working with banks, insurers, venture capital firms	For electric savings, same as above	Use IPMPV protocols, including those used to qualify CDM projects	Requires coordination between state agencies, may require regulations or changes in policies

7. Conclusion

Connecticut DEP can meet the OTC MOU commitment to reduce NOx emissions through a combination of reducing emissions from the RMR units and continuing to have sustained performance from the state's energy efficiency programs. Achieving the second phase, with NOx emissions decreasing a total of 50% from 2005 levels, will require additional reductions from the RMR units and ramping up energy efficiency programs to levels higher than 2008 in order to achieve these levels by 2020.

[26] International Performance and Measurement Verification Protocols. See also NEEP January 2006 report accessed via http://www.neep.org/files/Protocols_report.pdf

8. Appendix: Figures

A. Load vs. Ozone Season NOx Emissions

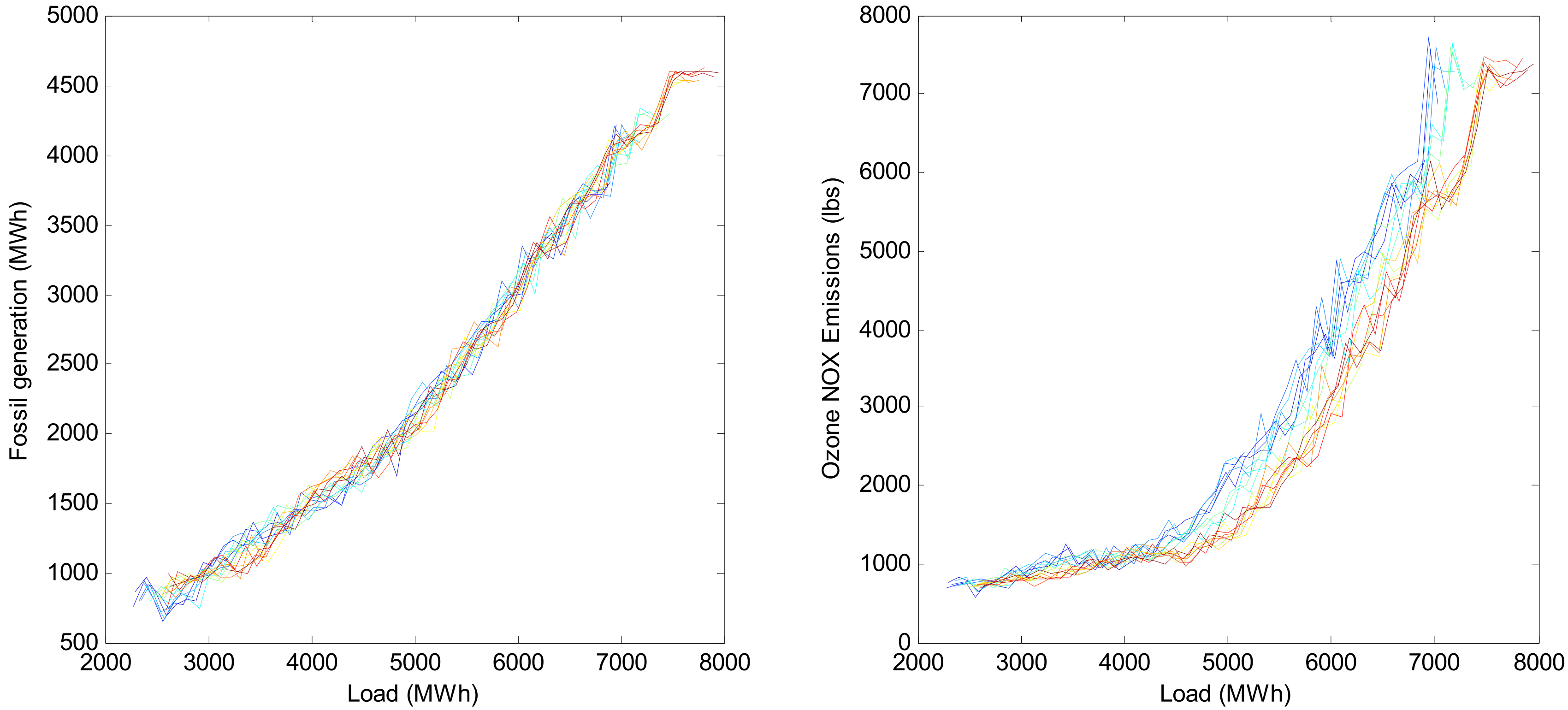


Figure 19: Scenario 1: Baseline. Load versus average fossil generation (A, left) and ozone season NOx emissions (B, right) for 2005 (blue line) to 2020 (red line). (A) As load demand increases, fossil generation rises; the slope of this line becomes steeper towards higher loads as CT has fewer options for importing electricity and generates more in-state. In the baseline scenario, higher loads require more generation along a similar slope. This model inserts new, natural gas power plants to make up the generation deficit. (B) As load increases over time, new (clean) generators are available to help answer the load, and because of the collectively lower emissions, the system can handle higher loads with lower emissions.

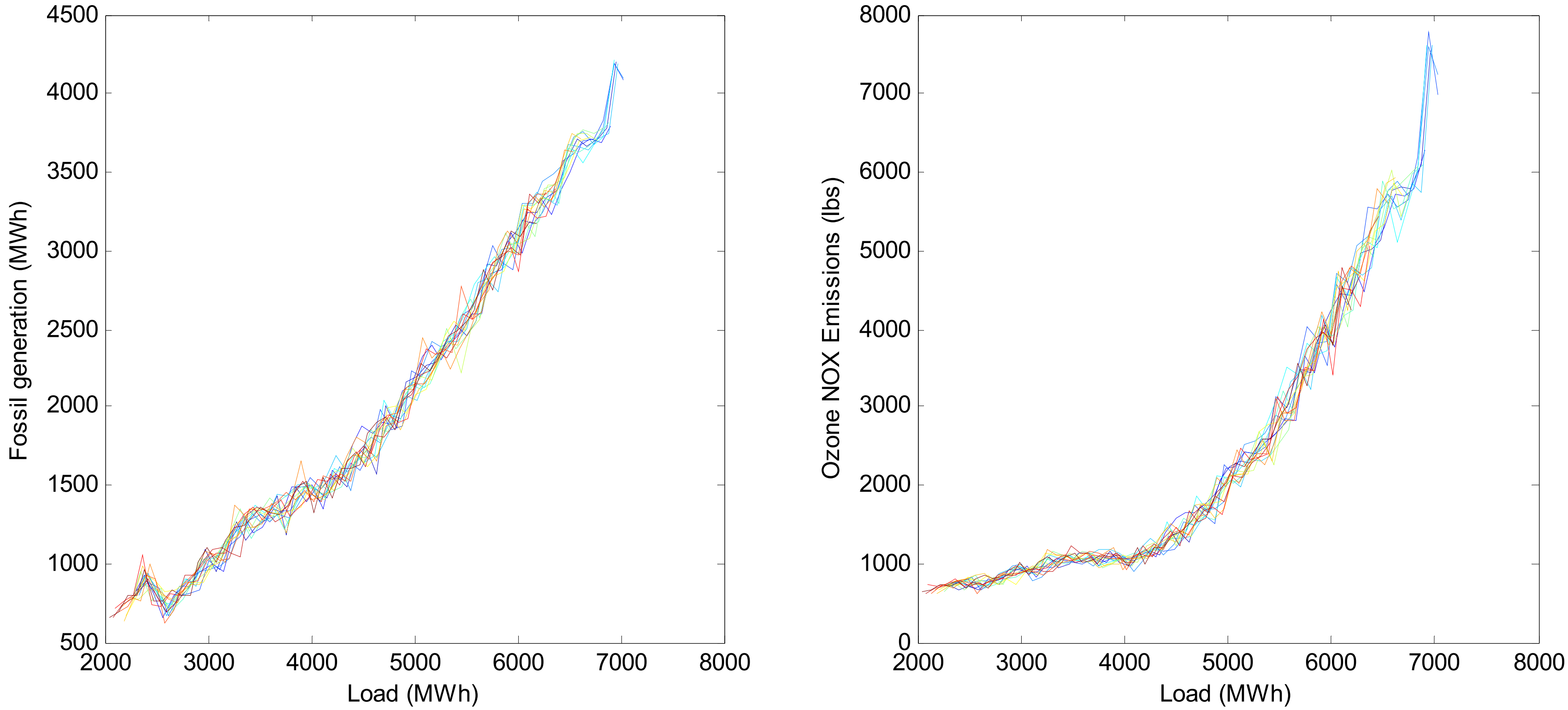


Figure 20: Scenario 2: Energy efficiency at 2% after 2009. (A) Load vs. fossil generation. Generation falls with load as less energy is demanded. The shape of the load vs. generation curve remains the same. (B) Load vs. ozone season NOx emissions. The shape of the curve remains the same (fundamental dynamics of the system remain intact), but less time is spent at higher loads and thus higher emissions.

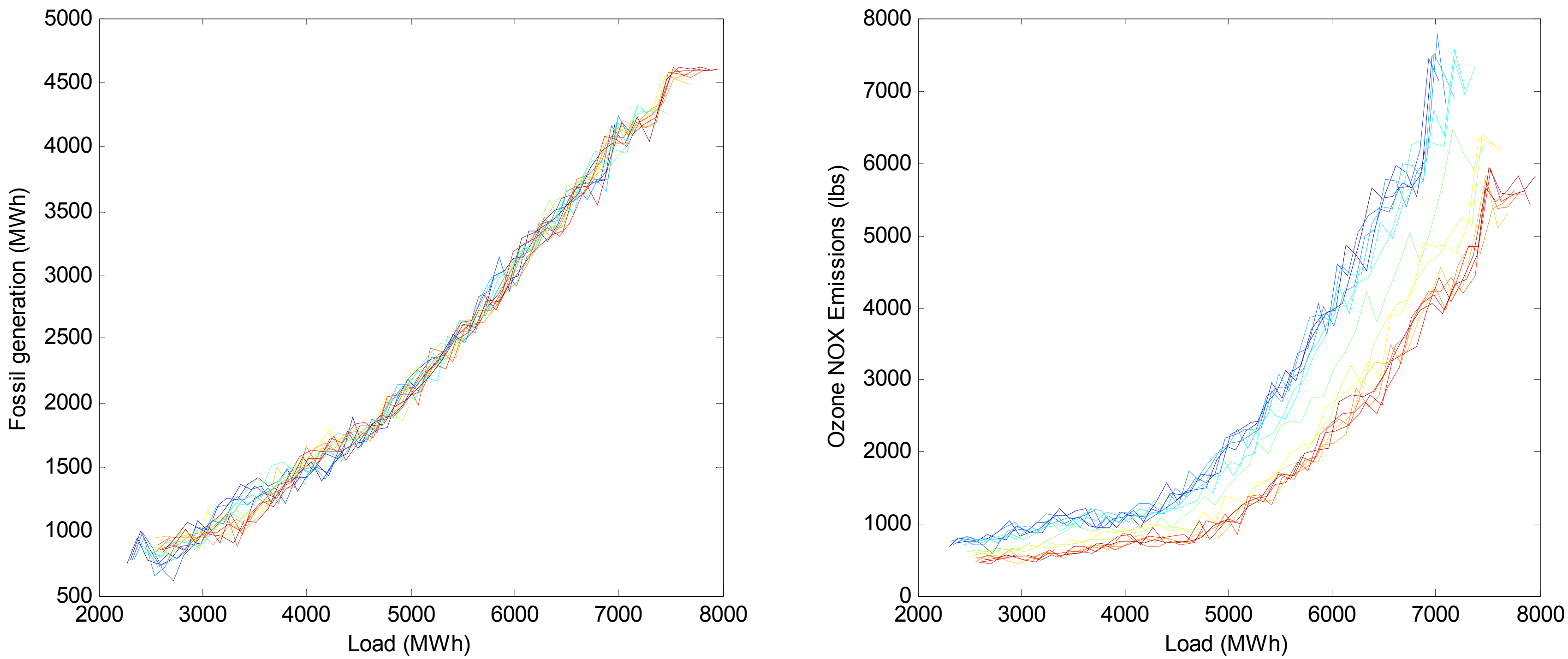
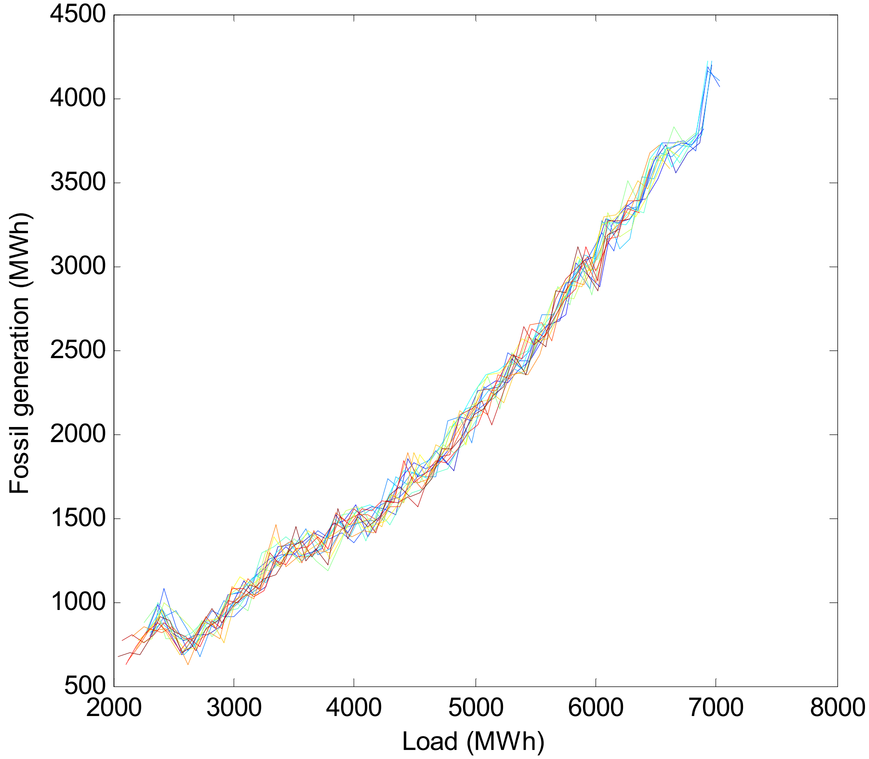


Figure 21: Scenario 3: RMR units reduce emissions. (A) Load vs. generation increases in step with load requirements, similarly to the baseline scenario. (B) Load vs. ozone season emissions. As load increases, the RMR units apply control technologies to reduce source emissions and new clean natural gas plants are brought online to answer load. New plants are dispatched simultaneously with pre-existing generators and in some cases displace RMR units. The emissions curve is displaced down and to the right.



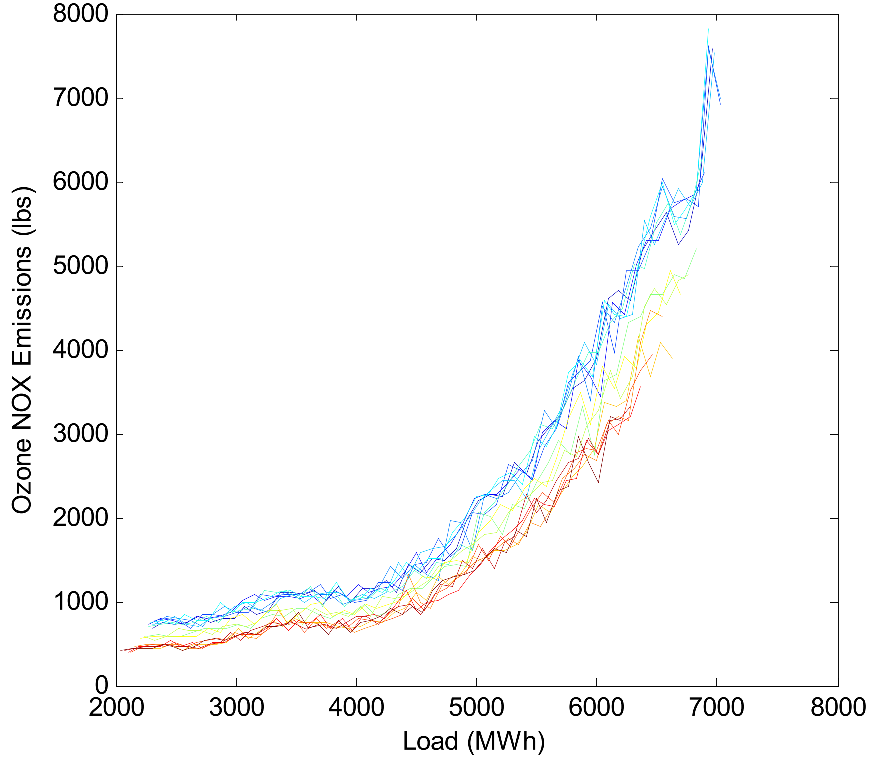


Figure 22: Scenario 4: Energy efficiency (2%) and RMR reductions. (A) Load reductions are identical to Scenario 2 (2% EE). (B) RMR units apply control technologies in 2012 and 2015, reducing source emissions. In addition, energy efficiency reduces peak demand and peak emissions. The combination of a lower slope and fewer hours at high loads results in a lower emissions profile.