MIT CEEPR
Center for Energy and Environmental Policy Research

Working Paper Series

# An Informational Nudge to Shave Peak Demand

Gilbert E. Metcalf

JULY 2025

CEEPR WP 2025-13

# Working Paper Series.

Since 1977, the Center for Energy and Environmental Policy Research (CEEPR) has been a focal point for research on energy and environmental policy at MIT. CEEPR promotes rigorous, objective research for improved decision making in government and the private sector, and secures the relevance of its work through close cooperation with industry partners from around the globe. Drawing on the unparalleled resources available at MIT, affiliated faculty and research staff as well as international research associates contribute to the empirical study of a wide range of policy issues related to energy supply, energy demand, and the environment.

An important dissemination channel for these research efforts is the MIT CEEPR Working Paper series. CEEPR releases Working Papers written by researchers from MIT and other academic institutions in order to enable timely consideration and reaction to energy and environmental policy research, but does not conduct a selection process or peer review prior to posting. CEEPR's posting of a Working Paper, therefore, does not constitute an endorsement of the accuracy or merit of the Working Paper. If you have questions about a particular Working Paper, please contact the authors or their home institutions.

An Informational Nudge to Shave Peak Demand

Gilbert E. Metcalf[1]

May 12, 2025

*Abstract:* Informational nudges to encourage energy conservation or load shifting have been tried in various contexts. This paper studies a program run by a small municipally owned electric utility to reduce demand on certain peak demand days. An email alert is sent out to residential customers who sign up for the alerts. Some recipients of those alerts forward the alerts to other customers or community groups, making it difficult to determine how broadly the alerts are disseminated. The alerts encourage load shifting and energy saving during specific hours on the following day.

Using hourly load data for the utility, I estimate the reduction in electricity load caused by the alert emails. Using an instrumental variables approach, estimates suggest that load is reduced by roughly 0.7 MWs per hour during the hours covered by the alert. This works out to a reduction in load on the order of 2 percent. I calculate the cost savings to the municipal utility and discuss social and private benefits of the program. The private benefits of the peak alert program swamp the social benefits.

[1] Department of Economics, Tufts University; Visiting Professor, MIT Sloan School and the MIT Center for Energy and Environmental Policy Research (CEEPR); and NBER. gmetcalf@tufts.edu. I am grateful for helpful insights and data assistance from Laura Scott at Concord Municipal Light Plant and Scott Bertrand at ISO-NE. All errors are my own.

An Informational Nudge to Shave Peak Demand

## I. Introduction

Coordinating electricity markets is a critical and complex operation, given the need to balance supply and demand at all times. To facilitate that co-ordination, the Federal Energy Regulatory Commission (FERC) encouraged the development of regional transmission and independent system operators (RTO/ISOs) to operate over larger geographic regions. Currently, RTOs and ISOs cover roughly two-thirds of the electricity load in the United States (Federal Energy Regulatory Commission, 2023). In New England, ISO New England (ISO-NE) is responsible for operating wholesale power markets and ensuring adequate capacity to serve load throughout the year. Theory suggests that competitive power markets should incentivize adequate capacity to serve load in all scenarios. In practice, however, a variety of real-world market impediments preclude that theoretic outcome. As a result, RTOs and ISOs have fallen back on other approaches to ensuring adequate capacity, including the introduction of capacity markets.

ISO-NE holds annual capacity auctions to lock in capacity for future years and charges load serving entities (LSEs) for that capacity. Charges to LSEs are based on their share of system load in the single highest peak hour during the summer each year. This creates incentives for LSEs to predict the peak hour and undertake measures to reduce load during that hour. The Concord Municipal Light Plant (CMLP), a small municipally owned utility in Concord, MA, has implemented an alert program to encourage residential consumers to reduce demand during a potential peak alert hour in the months of June through September.

This paper measures whether and how much these informational alerts lower the utility's load during those hours. Using hourly data in the summer months when alerts are sent, I carry out an econometric analysis of hourly load over the years 2013 to 2024. I estimate that the alerts reduce load demand on the order of two percent during peak alert hours. Depending on ISO-NE's cost of purchasing capacity in a given year, the benefits of a small reduction in load at peak can be substantial for a peak alert program that has almost zero cost. I estimate expected savings to CMLP in 2018, a high cost year, on the order of $127,000. The expected savings have declined over time but are beginning to rise again and are anticipated to rise further, given ISO-NE's projections of rising clearing prices in the forward capacity auction over the next few years (ISO New England Internal Market Monitor, 2024). The private benefits to CMLP from this program are substantial but come at the cost of shifting capacity costs on to other LSEs in ISO-NE. There are social benefits from the program, however. But I find that those social benefits are swamped by the private benefits.

Section II provides some background on CMLP's peak alert program and relate it to other informational programs studied in the literature. Section III describes the data and the statistical analysis of hourly load data over a twelve-year period. A final section draws some implications and concludes.

## II. Background

ISO-NE, the grid operator for New England charges load consumers an annual capacity charge based on each load's share of system load in the single highest peak demand hour for the system in a year. To reduce its charge, the Concord Municipal Light Plant (CMLP), a municipally owned utility located in Concord Massachusetts, takes various actions to encourage customers to reduce their load when it believes ISO-NE load will hit an annual peak. Among other actions, it sends out an alert, typically one day ahead, encouraging residential customers to reduce load during the hours when the utility predicts system load might peak. Those alerts are sent to anyone who signs up to receive the emails. The total number of email recipients is not known as some recipients forward them to other individuals or groups in the community.

CMLP's informational alert is a type of nudge that is increasingly used by utilities to manage demand. Carlsson et al. (2021) define a pure nudge as a "behavioral intervention that aims to make it easier for the individual to 'do the right thing'" (p. 217). The peak alert program takes the burden off of consumers to determine when a seasonal peak might occur. There is a "moral nudge" element to the program as well since the messaging makes clear that an individual's effort to reduce energy load at peak benefits all CMLP customers.[1] Carlsson et al. survey the large and growing literature on green nudges. They argue that moral nudges can be welfare improving even when put in place in the presence of an optimal tax system. In the absence of tax optimality, nudges can be efficiency improving. While energy and pollution savings may be quite modest, most nudge type programs have a high benefit-cost ratio given the low cost of the programs.

Reiss and White (2008) provide early evidence of the impact of public exhortations to reduce electricity consumption. Like most other electricity consumers in California, households in San Diego experienced a sharp and unexpected increase in electricity prices in 2000. Over a three-month period,

[1] Carlsson, et al. (2021) define a *moral nudge* as a nudge that rewards people for "doing the right thing through psychological utility" (p. 218).

prices more than doubled.[2] Following state intervention in electricity markets, prices eventually stabilized. The city of San Diego instituted a large-scale public relations campaign to encourage households to reduce electricity use. They find that electricity use declined by 7 percent over the six-month period of the publicity campaign.

The Reiss and White analysis is instructive regarding the possibilities of public information campaigns to encourage energy saving, but it is difficult to prove causality. Ito et al. (2018) describe a field experiment carried out in Japan to reduce energy consumption during peak demand periods that is better suited to identifying causality. One of the treatment arms is a "moral suasion" treatment where households received text messages asking them to reduce electricity consumption during summer or winter peak hours. Households in this group would receive a messages on their phone, computer, and an in-home display that they were given at 4 pm on the day previous to the peak. Peak alerts were based on a specific trigger (that the next-day temperature would exceed 88 degrees F in the summer or fall below 57 degrees F in the winter) and would request reductions in electricity consumption for fixed time periods (1 to 4 pm in the summer and 6 to 9 pm in the winter). Households in the study had advanced meters installed and the researchers tracked household consumption at 30-minute intervals. The researchers find that the moral suasion treatment leads to an 8 percent reduction in consumption initially, but that the effect wears off over time with repeated messaging (what the researchers call dishabituation). They do find that after a "rest period" of three months, a repeated application of the moral suasion treatment leads to a response similar to the original response, though once again the effect wears off over time. This will be relevant when considering the design of CMLP's program.

Brandon et al. (2019) also employ a nudge to encourage energy conservation during peak demand periods. Their nudge consisted of a personal contact (automated telephone call or email) announcing a possible peak demand on the following day. Their nudge also included information about the performance of their house in saving energy relative to other similar homes in the last peak alert. They found a 3.8 percent reduction during a peak event as a result of this intervention.[3]

The Concord Municipal Light Plant (CMLP) is a municipally owned electric utility (one of 41 in Massachusetts) in Concord, MA. Concord is a wealthy, suburban community with a population of over

---

[2] Borenstein (2002) documents the causes and consequences of this state-wide electricity market crisis.

[3] Burkhardt et al. (2023) also does a field experiment with an alert message to warn of a peak event similar to the messaging in Ito et al. and this study. They find no impact of messaging by itself on consumption. They do find that critical peak pricing does reduce consumption at peaks, primarily by reducing air conditioner use during the peak period.

18,000 and CMLP serves over 8,300 customers in Concord (and a handful of customers in adjacent communities). The utility's total load in 2023 was 164,474 MWh, nearly 45 percent of which was load of residential customers. Another 20 percent of load serves small commercial and industrial customers while 30 percent serves large commercial and industrial customers. Municipal load makes up the balance (Concord Municipal Light Plant, 2023).

Beginning in 2009, CMLP initiated an email alert program to encourage energy saving during hours of projected ISO-NE peak load. Reducing demand during potential system-wide peaks has two benefits. First, it reduces the utility's need to purchase expensive peak power. Second, ISO-NE charges load consumers an annual capacity charge for an entire year based on each load consumer's share of system peak load in that single peak hour. That charge is applied for a year-long capacity commitment period (CCP). For example, the annual capacity commitment period for June 1, 2024 through May 31, 2025 is based on a system peak occurring in calendar year 2023. In that year, the system peak load occurred in the hour between 5:00 and 6:00 pm on Sept. 7, 2023. CMLP's peak during that hour equaled 0.161 percent of the system-wide peak. CMLP's share of the forward capacity charge for the CCP ending May 31, 2025, therefore, is 0.161 percent of the total ISO-NE capacity charge that is assessed to load.[4,5]

Alerts are sent out typically 4 to 6 times a year. Figure 1 illustrates a typical alert sent to members of the CMLP *Concordians Addressing the Peak* (CMLP CAP) google group. Currently the CMLP CAP group contains roughly 600 email addresses.[6] The overall reach of the emails, however, is a bit hard to determine since email recipients often forward the emails to friends and neighbors as well as to local community groups.[7] To put this in context, there are just over 7,000 residential customers in the CMLP system.

---

[4] Data on CMLP's CCP share from Laura Scott, CMLP employee in charge of the peak alert program, contained in an email dated June 24, 2024.

[5] ISO-NE's approach to allocating capacity charges is very similar to NYISO's approach. Both transmission organizations base the allocation off the single highest peak hour in the year (with some exceptions, in NYISO's case). ERCOT focuses on the highest load 15 minutes in each of four summer months (June through September) and averages the results. Like ERCOT, PJM constructs an average but it is over the five highest hours from the five highest peak days in the year (Energy by 5 (2022)).

[6] Number from Laura Scott (email sent on Aug. 13, 2020). According to Scott, "Some of those [email] addresses are list serves. Other folks automatically forward the alerts on to their neighbors or others. So we don't really have a precise idea of how many people we are reaching."

[7] One prominent local group is the Concord Climate Action Network (Concord CAN).

For my analysis below, I code the peak alert in Figure 1 as occurring on Sept. 7, 2023 for the hours ending 5 pm, 6 pm, and 7 pm. Figure 2 shows that most peak alerts cover the hours between 3 and 6 pm.

## III. Analysis

### A. Data

For my analysis, I have CMLP hourly load data covering the years 2009 – 2024 for summer months (June through September) when peak alerts might be sent out.[8] I also have all of the peak alert messages sent out by CMLP since the alert program's inception in 2009. The analysis below primarily focuses on hourly load for the years 2013 through 2024, given lack of other data required in the analysis. My analysis focuses on the load data, but it is important to distinguish load from demand. Load is the amount of electricity CMLP purchases for its customers. Demand is the amount of electricity consumed by CMLP customers. The difference between the two arises from locally generated electricity. Knowing demand is useful for estimating how large a percentage reduction in demand results from the peak alert program.

The town of Concord owns several solar arrays in town with aggregate capacity of 6.355 megawatts. In addition, behind the meter solar capacity, primarily in the form of residential rooftop solar, totaled 4.684 megawatts as of September 2024. Given a summer monthly peak load between 30 and 40 megawatts (see Figure 3 data for 2023[9]), there could potentially be a significant discrepancy between load and demand in a peak hour.

In order to estimate hourly solar electricity production in Concord, I have capacity data for the three central solar arrays in town for various years. In addition, I have monthly behind-the-meter (BTM) solar capacity. Finally, I have some hourly solar production data for the three town owned arrays. Two of the arrays are ground-mounted solar arrays. The third array is a set of three roof-top solar panels on buildings in an industrial park in Concord. For the three roof-top systems, I have hourly production data for the summer months for 2018 – 2024.[10] I do not have any measure of production for the BTM panels.

Below, I will use the electricity production data from the three buildings with roof-top systems to estimate hourly capacity factors as functions of hourly weather conditions. I then use those

---

[8] CMLP is only now beginning to roll out the installation of smart meters. Thus, I am forced to use aggregate CMLP data for my analysis.

[9] CMLP's monthly peak load in 2023 is similar to peak load profiles for other years. Those data are reported in CMLP's annual report to the Commonwealth of Massachusetts Department of Public Utilities

[10] Two of the three rooftop systems have data from 2018 forward. The third one has data starting in 2021.

coefficient estimates to estimate BTM solar electricity production. Estimated BTM production along with actual production for the town-owned arrays allows me to report total demand in various years.

From NOAA's National Center for Environmental Information (NCEI) I have hourly weather data for Hanscom Air Field, located in Bedford, MA, just adjacent to Concord. Weather data include temperature, relative humidity, precipitation, and cloud cover, among other data.

From ISO-NE, I have one- through four-day ahead capacity peak forecasts (and hour of predicted peak) for 2008 through 2023 along with predicted high temperatures and dew points for Boston MA and Hartford, CT (as illustrated in Figure 1). It is these day-ahead forecasts that CMLP relies on, for the most part, for issuing a peak alert. From ISO-NE, I also have real-time hourly load data for the ISO-NE system for the years 2017 through 2023.

Table 1 provides descriptive statistics for the dataset. CMLP load during midday hours (when a peak might occur) varies between 8.7 and 45 MW with a mean of 25.[11] As Figure 3 illustrates, peak hourly loads can be above 30 and approach 40 MW. Peak alerts are infrequent with less than 2 percent of hours during the midday hours (between 1 and 8 pm) covered by a peak alert. Concord is a small load in ISO-NE with its load accounting for less than 0.2 percent of total load in the region.

## B. Results

### *1. Regression Results*

The purpose of this paper is to measure the reduction in CMLP hourly load due to the informational peak alert messages sent out. To do that, I run regressions of the following form:

$$Load_{hdmy} = \beta \cdot Alert_{hdmy} + \gamma X_{hdmy} + \alpha_h + \alpha_d + \alpha_m + \alpha_y + \varepsilon_{hdmy} \quad (1)$$

where $Load_{hdmy}$ is the CMLP aggregate load in hour of day $(h)$, day of week $(d)$, month of year $(m)$, and year $(y)$. The variable *Alert* is an indicator variable equal to 1 in hours covered by an alert and zero otherwise. Weather regressors are included in $X$ as well as load in the rest of the ISO-NE region. Between the various fixed effects and Concord area weather conditions, I should control for much of the variation in electrical load in Concord. Including load in the rest of the ISO-NE region captures unexplained variation in load demand not captured by my fixed effects and weather variables.

[11] The interquartile range is 21.1 to 28.2 MW. Low values typically occur in late September and indicate the importance of electricity for cooling in the summer months.

A major concern with running OLS regressions is that peak alerts are endogenous. CMLP issues a peak alert when the expected load in ISO-NE for the next day is predicted to be high. A high demand day in ISO-NE is very likely associated with a high demand day for CMLP. Despite my inclusion of a rich set of weather-related variables, we can expect a positive correlation between load and the alert. To address this, I run instrumental variable regressions where I include instruments correlated with the decision to issue a peak alert but not correlated with unexplained load variation. The alerts sent to households (figure 1) suggest that the day-ahead ISO-NE projected peak load should serve as a valid instrument.[12] To allow for the possibility that the day-ahead ISO-NE projected peak load forecast may affect the decision to issue a peak alert differently depending on the hour of the day, I interact the forecasted peak load (a single number per day) with hour dummy variables.

Ordinary least square regressions of Equation (1) confirm the endogeneity issue (Table 2). If we simply split the data between hours with a peak alert and hours without, the mean hourly load is 11.6 MW higher during hours when an alert is called relative to a non-alert hour. Controlling for fixed effects lowers the mean difference from 11.6 MW to 9.0 MW. Controlling for load in the rest of ISO-NE does appear to soak up a great deal of unexplained variation in CMLP load demand. However, there is still a positive and statistically significant correlation between a peak alert hour and CMLP load (column 3). Adding weather variables does not appreciably change the coefficient. Taking the OLS regressions at face value, it would appear that issuing a peak alert is associated with higher load in the order of 0.8 MW during the peak alert hour. This, of course, is simply a correlation that does not account for any causal impact of the alerts on load.

Table 3 reports results from instrumental variable regressions. The first regression includes fixed effects for hour of day, day of week, month, and year as well as the ISO-NE hourly load (excluding CMLP's load). In this and all regressions, the ISO-NE hourly load coefficient is strongly significant; an increase in regional load of 1 MW is associated with an increase in CMLP load of roughly 1.7 MWs. The peak alert coefficient is now negative, but not statistically significant. Adding weather variables to the regression (column 2) leads to a larger and now statistically significant coefficient (at the 10 percent level) on the peak alert variable. The coefficient suggests an alert lowers load by 0.7 MWs during the

[12] CMLP staff member Laura Scott, who decides when to issue peak alerts, confirms that this is an important determinant of her decision to issue an alert. She also looks at day-ahead Boston temperature and relative humidity as well as forecasts of cloud cover. I do not have access to historical cloud cover forecasts and the data series on day-ahead Boston weather is incomplete. I report some runs where I include the data that I do have below.

alert hour. Given that less than two percent of midday hours are subject to a peak alert, it is not surprising that the regressions struggle to pick up a strong signal of the alert's impact on load.

Column 3 adds one-day ahead Boston high temperature forecasts (interacted with hour of day dummies) to the instrument set. Because of incomplete data on this day ahead forecast, I lose roughly 15 percent of my observations. The coefficient on the peak alert variable continues to be negative (albeit a bit smaller) but is now not statistically significant.[13] In the final column, I consider the possibility that the peak alert program effect has changed over time. Again, given the small number of peak alerts issued, it is challenging to allow for much flexibility in how this variable impacts load. The regression shown in column 4 allows for the impact to differ for years prior to 2020 and for the years 2020 – 2024. The results suggest that the effect of the peak alert program is stronger in recent years, but neither estimated coefficient is statistically significant.[14]

Are these estimates plausible? Consider the coefficient estimate of -0.714 from column 2 in Table 3. The average July and August peak in 2022 was 38.7 MW. This suggests that the peak in the absence of the alert would have been 39.4 MW and that the alert reduced load by 1.8 percent. Given that this is a voluntary program with limited participation by CMLP customers, this strikes me as a large response. Consider this thought experiment. Residential load accounts for 45 percent of total CMLP load on average. Assuming only residential customers respond to the informational nudges, this suggests that residential load has responded by 4 percent. Depending on whether the alerts are shared with other households, the total number of households exposed to the alerts could be anywhere from 600 to 1,400 (or more). This range represents 8.5 to 20 percent of residential customers, suggesting the load reduction could be substantially higher.

To understand the impact of the program on actual electricity demand, we need an estimate of CMLP demand. That requires adding local solar production to load. As of 2023, solar capacity in the CMLP area equaled 10.76 MWs.[15] Average production from the three solar arrays in Concord in 2023 during the summertime midday hours was 1.96 MWs and during hours when a peak alert was called it

---

[13] In regressions not reported here, I ran the regression using the ISO-NE peak load forecast only as an instrument (interacted with hour dummies) on the same observations included in the column 3 regression. The estimated coefficient is smaller than in column 2 and not statistically significant. It appears that the smaller number of observations is the driving factor for the change in the estimated coefficient between columns 2 and 3 rather than the expanded instrument set.

[14] I have explored various alternative specifications (different year cut-offs, interactions with a time trend, etc. In all cases, estimated coefficients are not statistically significant once I allow for more flexible formulations.

[15] I report values for 2023 because solar production data for some of the arrays are corrupted in part for 2024. No corrupted data are used in capacity factor regressions or estimated solar production.

was 1.51 MWs. To estimate behind the meter (BTM) solar production, I run a fractional probit regression of the capacity factors for the three roof-top installations for which CMLP collects production data as a function of weather conditions. Regression output is in appendix table A3. I then predict BTM production by multiplying the monthly BTM capacity values by the predicted capacity factor from the regression. The average predicted capacity factor for summertime midday hours is 26.3 percent. This compares to the average capacity factor for the three rooftop arrays during midday hours of 32 percent. Conditional on a peak alert being called, the average predicted capacity factor is 23.2 percent. Behind the meter solar production during summertime midday hours averages 1.16 MWs and, conditional on a peak alert being called, 0.98 MWs. Total summertime midday solar production averages 3.10 MWs and, conditional on a peak alert, 2.52 MWs. It appears load underestimates demand by roughly 13 percent on average and 7 percent conditional on a peak alert occurring.

*2. Welfare Analysis*

I next turn to the question of the benefits of the peak alert program. There are private benefits to CMLP customers if the program leads to a reduction in CMLP's share of the system peak used to allocate capacity charges. There may also be social benefits to the extent the program reduces load and system peaks. The value to CMLP of reducing its coincident peak by one kilowatt in month $m$ and year $t$ equals $\kappa_{mt}$ where:

(2) $$\kappa_{mt} = \frac{P_{mt}\ x\ \widetilde{CSO}_{mt}}{Peak_t}.$$

In equation (2), $P_{mt}$ is a price per kilowatt paid by load serving entities to finance payments to capacity purchased in the forward capacity market, $\widetilde{CSO}_{mt}$ is the capacity purchased in the capacity market (adjusted for payments for Hydro Quebec imports and, in recent years, for intermittent capacity). The denominator, $Peak_t$, is the ISO-NE peak demand for a given year. While $\widetilde{CSO}_{mt}$ and $P_{mt}$ are initially set in the initial forward capacity market auction, these values change on a monthly basis, primarily due to monthly and annual reconfiguration auctions.[16] The denominator is fixed as the value of the system peak in the year preceding the capacity commitment period in question.

Figure 4 shows CMLP's annual average value of $\kappa_{mt}$ for CMLP. The average value for CCP12 (2022) was \$8.99 per kW-Month. In terms of the annual savings per megawatt of peak reduction, this equates to \$107,921.[17]

---

[16] While not indicated in the formula, the price varies across capacity zones in ISO-NE depending on whether the zone (a geographic region) is import or export constrained. The appendix discusses this in more detail.

[17] In Appendix A, I describe how these values are computed. I also report monthly values of $\kappa_{mt}$.

While the price, $P_{mt}$, is a price paid by CMLP (and other LSEs) for their capacity load obligation, it is determined by the payments made to the capacity purchased in the forward capacity market. ISO-NE capacity payments peaked in 2018 and have significantly declined through CCP 2024. Forward capacity market payments to cleared capacity actually peaked in FCA 9 (CCP 2018 – 2019) with payments totaling $4 billion. This reflected a deficit in FCA 8 arising, in large part, from the retirement of the four coal-fired Brayton Point units (totaling 1.5 MW of nameplate capacity) in 2017. The clearing price for new and existing capacity in the forward capacity market peaked in FCA 9 and then began a steady decline as new capacity entered in response to the high auction clearing price (ISO New England Internal Market Monitor, 2016).[18] Forward capacity auction clearing prices have declined from a peak of $9.55 per kW-month in FCA 9 to $2.00 per kW-month in FCA 14 (for capacity charge year 2023 – 2024). These declines are reflected in the incremental savings to CMLP from shaving peak. The most recent ISO-NE Annual Markets Report (2024) predicts they will start rising over the next four years to $3.58 per kW-month, an increase of nearly 80 percent. This is also reflected in the higher marginal cost for CCP 2025.

Capacity costs are non-trivial for CMLP. Its annual payments in CCP 2022 came to over $3.3 million a year. Reducing CMLP's peak can bring about substantial savings. The value of reducing CMLP's coincident peak per kilowatt in CCP 2022 was $8.993. On a megawatt basis, this is $8,993 per month or $107,921 annually.[19]

My preferred estimate of the impact of the peak alert program is to reduce the coincident peak by 0.714 MWs. Conditional on a peak alert being called for the hour that CMLP's coincident peak occurs, the value of the program, on average, is 0.714 x $107,921 or $77,056 in CCP 2022. This assumes CMLP correctly identifies the ISO-NE peak hour each year. In actuality, CMLP calls an alert for an hour that turns out to be the ISO-NE peak hour for that year in eleven out of the sixteen years that the alert program has been in effect. The expected value of the peak alert program then is

$$E(Savings) = \left(\frac{11}{16}\right)(\$77{,}056) = \$52{,}976.$$

Table 4 reports the yearly expected savings to CMLP from its peak alert program. Expected savings have declined from just under $130,000 to a little more than $37,000 in year ending May 2025. While the auction clearing price for capacity in the forward capacity market has trended downward until CCP 2024 and been flat for the following three years, it jumped 38 percent in the auction for CCP 2028, reflecting

[18] CMLP's annual capacity cost and average per kW of coincident peak actually peaked the previous year.
[19] I ignore the effect of a reduction in CMLP's coincident peak on ISO-NE's peak load given that CMLP's peak is about 0.15 percent of the system peak.

higher costs of new potential entry due to inflation (ISO New England Internal Market Monitor, 2024).[20] This suggests that the value of reducing the coincident peak, $\kappa_{mt}$, that started rising in the CCP year 2024-2025 will continue to rise in the next few years.

CMLP also saves the cost of purchased power, to the extent that the program leads to reduced as opposed to shifted demand. An upper bound estimate on purchased power savings assumes the peak alert leads to reduced demand only and no shift in demand.[21] Savings in private power purchase from the peak alert program are dwarfed by the savings in capacity charge. Consider 2022 when wholesale electricity prices were at a local peak over the last decade. In July of that year, the average on-peak locational marginal price for Southeast Massachusetts region was $108.63 per MW.[22] The average number of peak alert hours in a year is 15.7. Using the peak power price from July 2022, average power purchase savings were no more than $\$108.63\ x\ 15.7 \text{ hours } x\ 0.714$ equals $1,218.

Estimating the social value of the program is complicated. In addition to needing to know the actual change in consumption, we need to know the marginal generator. In 2023, the most recent year for which data are available, marginal emissions on high-demand days averaged 903 pounds per MWh.[23] Marginal emission rates for nitrous oxides ($NO_x$) and sulfur dioxide ($SO_2$) were 0.5 and 0.1 pounds per MWh, respectively. The U.S. EPA's National Center for Environmental Economics (2023) reports a social cost of carbon dioxide ($CO_2$) for 2025 (in 2020 dollars) of $212 per metric ton and a social cost of nitrous oxide ($N_20$) is $60,267 per metric ton.[24] This translates to a social cost of carbon per MWh on high demand days of $86.83 for carbon dioxide and $2.73 for nitrous oxide. Using these numbers, the annual

[20] The capacity auction clearing price determines the price per MW paid to capacity purchased in the auction (subject to adjustments through monthly and annual reconfiguration auctions). Appendix I traces through how payments to capacity determine monthly capacity charges to load serving entities.
[21] If all load is simply shifted, the private savings is simply the difference in the locational marginal price (LMP) of electricity between the two hours. Note that It is possible that the load reduction could be negative if, for example, households use more electricity to cool their homes prior to a peak alert period in anticipation of the alert's call to reduce load. In that case, there would not be a savings unless a reduction in the LMP for the hours of shifted demand more than offset the increased electricity consumption.
[22] Monthly ISO-NE average locational marginal prices are available at https://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/monthly-lmp-indices, accessed on March 18, 2025.
[23] Averages are load-weighted, reflecting the fact that generation of renewables is more likely to occur in export constrained areas. Data are from ISO New England (2024). The 2023 high-demand days match closely with days on which CMLP issued peak alerts. Note however that true marginal emissions can differ from ISO-NE specific measured emissions given the ability to import or export electricity from other regions. See Holland et al. (2024) who discuss possible biases when ignoring the impact of load in one region on marginal generation in other regions.
[24] These are the vues assuming a near-term discount rate of 2 percent. No values for sulfur dioxide are reported.

reduction in environmental costs due to CMLP's peak alert program is $15.7 \cdot (86.83 + 2.73)(0.714) = \$1{,}004$.

## IV. Conclusion

The Concord municipal peak alert program is an interesting example of an informational nudge program to reduce peak demand. It is but one of a large number of programs that have been carried out across the country. Despite the fact that there is limited information dispersion through the email group and no individual financial incentive to reduce or shift demand, the program appears to reduce load during peak hours when an alert is called. Annual social benefits are modest, but the costs of the program are trivial. Private benefits, however, are significant for this small, municipal utility as any reduction in its capacity share shifts aggregate ISO-NE capacity charges onto other utilities and load customers in the region. This, of course, suggests a unproductive competition where ISO-NE utilities implement similar programs to reduce peak demand during the hour that ISO-NE is predicted to hit its annual peak. A focus on reducing this singular hour of demand is unlikely to reduce overall peak demands and the need to have capacity available for high-demand summer hours. Such a competition would suggest that it would be fruitful for ISO-NE to consider alternative ways to allocate capacity charges across its customers that don't focus on a single peak hour of the year to allocate annual charges.

**Figure 1. A Typical Peak Alert Message**

**CMLP**
to CMLP CAP

Sep 6, 2023, 10:33:48 AM

Thank you for participating in Concord Light's CAP Google Group and helping to **reduce the summer peak demand for electricity** on New England's electrical grid (Connecticut, Rhode Island, Massachusetts, Vermont, New Hampshire, and most of Maine.)

The current weather forecast confirms a peak electricity day is possible for Thursday September 7th 2023 from 4PM to 7PM.

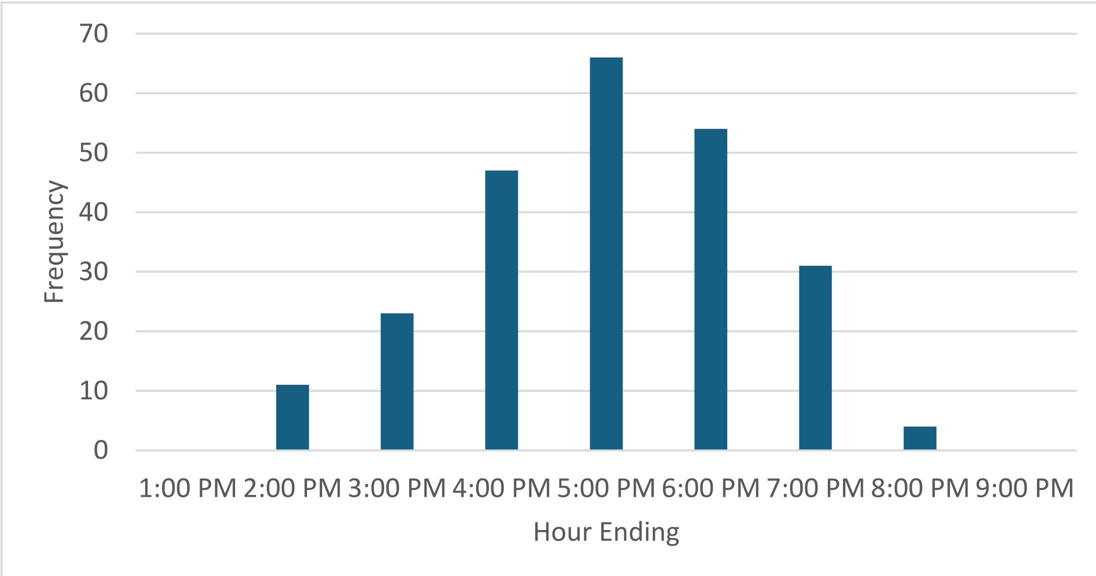
Forecast for 2023-09-07 (as of 09/06/2023 09:31 AM EDT)

| Weather | Day 1 | Day 2 | Day 3 | Day 4 | Day 5 | Day 6 |
|---|---|---|---|---|---|---|
| | Wed | Thu | Fri | Sat | Sun | Mon |
| | 6-Sep | 7-Sep | 8-Sep | 9-Sep | 10-Sep | 11-Sep |
| High Temperature - Boston | 81 | 86 | 86 | 82 | 78 | 76 |
| Dew Point - Boston | 68 | 70 | 71 | 70 | 70 | 68 |
| High Temperature - Hartford | 93 | 94 | 88 | 83 | 79 | 77 |
| Dew Point - Hartford | 68 | 69 | 72 | 71 | 71 | 69 |
| Projected Peak Load | 22,800 | 23,500 | 21,250 | 18,750 | 17,500 | 17,500 |
| Peak Forecast Hour | 6PM | 5PM | 5PM | | | |
| Peak Occurrence Probability | POSSIBLE | POSSIBLE | UNLIKELY | UNLIKELY | UNLIKELY | UNLIKELY |

If you are able to reduce your electricity use during these hours, you can help reduce electricity costs for all CMLP customers. During these hours, you might consider doing any of the following:

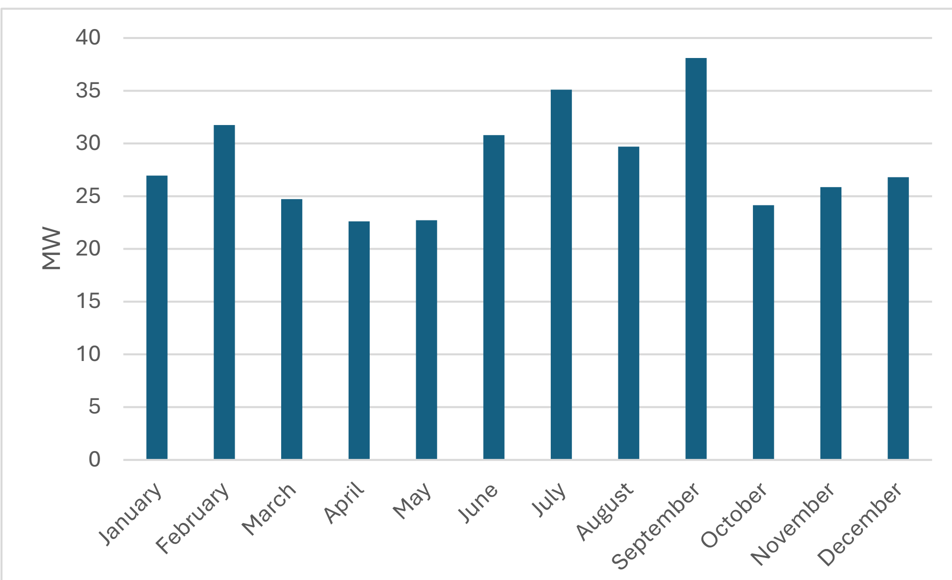
- turn your A/C up a few degrees
    - turn off lights anywhere they are not needed and dim others if they are dimmable
- postpone use of pool pumps, dryers, washing machines, and other appliances
- reduce plug load by turning off computers, televisions, etc.
- Cook dinner on the grill or have a picnic supper
- Do not charge an electric vehicle during a peak demand event
    - Pre-cool your home and then let it coast without A/C until after the peak demand event
    - Use fans instead of or in addition to A/C as fans use much less electricity than air conditioning
- Close blinds on windows facing the sun
- Use smart power strips to turn off multiple devices with one touch
- Get an energy assessment for your home or business to see if there are more electricity-saving opportunities. Find out more information here: http://www.concordma.gov/1751/Energy-Management-Renewable-Energy-Effic

**Figure 2. Frequency of Peak Alert Messages by Hour Ending**




Source: CMLP Peak Alert Data on peak alerts for years 2009 – 2023
from the CAP Google Group

**Figure 3. Monthly Peak Load in 2023**




Source: Concord Municipal Light Plant (2023)

**Figure 4. CMLP Marginal Peak Cost**


Source: CMLP and ISO-NE Data. Year labels indicate the ending year for a Capacity Commitment Period. The year 2025, for example, covers the CCP from June 2024 through May 2025.

**Table 1. Descriptive Statistics**

| Variable | N | Mean | Std. Dev. | Min | Max |
|---|---|---|---|---|---|
| CMLP Real Time Load (MWh) | 13664 | 24.674 | 5.56 | 8.657 | 45.019 |
| Peak Alert Hour | 13664 | .018 | .134 | 0 | 1 |
| Day Ahead ISO-NE Peak Forecast (GW) | 13664 | 18.08 | 2.991 | 12.45 | 27.7 |
| ISO-NE Load (GWh) | 10248 | 16.953 | 3.147 | 8.698 | 27.334 |
| Dry Bulb Temperature | 13637 | 74.323 | 9.168 | 42 | 101 |
| Wet Bulb Temperature | 13562 | 64.832 | 6.801 | 39 | 82 |
| Dew Point Temperature | 13614 | 58.571 | 8.748 | 26 | 79 |
| Relative Humidity | 13614 | 61.071 | 19.075 | 16 | 100 |
| Interaction of Dry Bulb Temp and Relative Humidity | 13614 | 44.463 | 12.01 | 13.12 | 76 |
| Barometer Reading | 13602 | 29.798 | .174 | 28.87 | 30.46 |
| Hourly Precipitation (inches) | 13482 | .006 | .043 | 0 | 2.23 |
| Visibility in Miles | 13636 | 9.547 | 1.628 | .5 | 10 |

Summary statistics for years 2009 - 2024, summer months and midday hours only when peak alerts might be called. ISO-NE load excludes CMLP load.

**Table 2. OLS Regressions on CMLP Load**

| VARIABLES | CMLP Load | | | |
|---|---|---|---|---|
| | (1) | (2) | (3) | (4) |
| Peak Alert | 11.60*** | 9.023*** | 0.826*** | 0.810*** |
| | (0.340) | (0.274) | (0.0869) | (0.0864) |
| ISO-NE Load | | | 1.771*** | 1.716*** |
| | | | (0.00493) | (0.00841) |
| Observations | 13,664 | 13,664 | 10,248 | 10,018 |
| R-squared | 0.079 | 0.421 | 0.955 | 0.956 |
| Fixed Effects | No | Yes | Yes | Yes |
| ISO Load | No | No | Yes | Yes |
| Weather Variable | No | No | No | Yes |

Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

Fixed effects control for hour of day, day of week, month, and year included. ISO Load excludes CMLP load. Midday hours only in regressions

**Table 3. Instrumental Variable Regressions on CMLP Load**

| VARIABLES | CMLP Load | | | |
|---|---|---|---|---|
| | (1) | (2) | (3) | (5) |
| Peak Alert | -0.444 | -0.714* | -0.586 | -0.576 |
| | (0.373) | (0.370) | (0.438) | (0.877) |
| Peak Alert (2020 – 2024) | | | | -0.318 |
| | | | | (1.830) |
| ISO-NE Load | 1.789*** | 1.742*** | 1.731*** | 1.742*** |
| | (0.00709) | (0.0105) | (0.0121) | (0.0105) |
| Observations | 10,248 | 10,018 | 8,464 | 10,018 |
| R-squared | 0.954 | 0.955 | 0.952 | 0.955 |
| Weather Variables | No | Yes | Yes | Yes |
| Instrumental Variables | IV1 | IV1 | IV2 | IV1 |

Standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1
Controls for hour of day, day of week, month, and year included in all regressions. ISO Load excludes CMLP Load. Midday hours only in regression. IV1 is a set of instrumental variables comprising the one-day ahead ISO-NE peak forecast interacted with hour of day dummies. IV2 adds the one-day ahead temperature forecast for Boston interacted with hour of day dummies to IV1.

**Table 4. Expected Private Value Of Peak Alert Program**

| CCP | Marginal Peak Cost (kW-Mo) | Annual per MW | Value of Peak Alert | E(Value of Peak Alert) |
|---|---|---|---|---|
| 2018 | $21.57 | $258,890 | $184,847 | $127,082 |
| 2019 | $16.89 | $202,628 | $144,676 | $99,465 |
| 2020 | $11.36 | $136,279 | $97,303 | $66,896 |
| 2021 | $10.24 | $122,928 | $87,771 | $60,342 |
| 2022 | $8.99 | $107,921 | $77,056 | $52,976 |
| 2023 | $6.03 | $72,366 | $51,669 | $35,522 |
| 2024 | $3.70 | $44,340 | $31,659 | $21,766 |
| 2025 | $6.36 | $76,356 | $54,518 | $37,481 |

Source: Author's Calculations. Coincident peak occurs during peak alert hour with probability 11/16.

## References

**Borenstein, Severin.** 2002. "The Trouble with Electricity Markets: Understanding California's Restructuring Disaster." *Journal of Economic Perspectives*, 16(1), 191–211.

**Brandon, Alec; John A List; Robert D Metcalfe; Michael K Price and Florian Rundhammer.** 2019. "Testing for Crowd out in Social Nudges: Evidence from a Natural Field Experiment in the Market for Electricity." *Proceedings of the National Academy of Sciences*, 116(12), 5293-5298.

**Burkhardt, Jesse; Kenneth T. Gillingham and Praveen K. Kopalle.** 2023. "Field Experimental Evidence on the Effect of Pricing on Residential Electricity Conservation." *Management Science*, 69(12), 7784-7798.

**Carlsson, Fredrik; Christina Gravert; Olof Johansson-Stenman and Verena Kurz.** 2021. "The Use of Green Nudges as an Environmental Policy Instrument." *Review of Environmental Economics and Policy*, 15(2), 216-237.

**Concord Municipal Light Plant.** 2022. "Return of the Municipal Light Department of the Town of Concord," Commonwealth of Massachusetts Department of Public Utilities: Boston, MA.

**Concord Municipal Light Plant.** 2023. "Return of the Municipal Light Department of the Town of Concord," Commonwealth of Massachusetts Department of Public Utilities: Boston, MA.

**Energy by 5.** 2022. "Coincidental Peaks Should Peak Your Interest," https://www.energyby5.com/coincidental-peaks-should-peak-your-interest#. Accessed on March 4, 2025.

**Federal Energy Regulatory Commission.** 2023. "Electric Power Markets," https://www.ferc.gov/electric-power-markets, Accessed on March 19, 2025.

**Holland, Stephen P.; Erin T. Mansur; Valentin Verdier and Andrew J. Yates.** 2024. "Regularization from Economic Constraints: A New Estimator for Marginal Emissions." *National Bureau of Economic Research Working Paper Series*, No. 32065.

**ISO New England.** 2022. "Monthly Market Operations Report January 2022," ISO-NE, Holyoke, MA.

**ISO New England.** 2024. "2023 ISO New England Electric Generator Air Emissions Report," ISO-NE, Holyoke, MA.

**ISO NEw England.** 2025. "Monthly Market Operations Report March 2025," ISO-NE, Holyoke, MA.

**ISO New England Internal Market Monitor.** 2016. "2015 Annual Market Report," ISO New England, Holyoke, MA.

**ISO New England Internal Market Monitor.** 2024. "2023 Annual Markets Report," ISO New England, Holyoke, MA.

**Ito, Koichiro; Takanori Ida and Makoto Tanaka.** 2018. "Moral Suasion and Economic Incentives: Field Experimental Evidence from Energy Demand." *American Economic Journal: Economic Policy*, 10(1), 240-267.

**National Center for Environmental Economics.** 2023. "Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances," Climate Change Division: Washington, DC.

**NOAA National Centers for Environmental Information.** 2025. "Local Climatological Data (Lcd)," NOAA NCEI, Washington, DC: NOAA,

**Reiss, Peter C. and Matthew W. White.** 2008. "What Changes Energy Consumption? Prices and Public Pressures." *The RAND Journal of Economics*, 39(3), 636-663.

**Appendix I: Capacity Charging in ISO-NE**

*A. Introduction*

In this appendix, I derive the formula for $\kappa_{imt}$, the monthly value to an LSE $i$ (e.g. CMLP) of reducing its coincident peak demand in the summer months. In the process of deriving the formula, I explain how payments in the forward capacity market work.

To ensure adequate supply of electricity in the region, ISO-NE pays resources to be available at all times to provide electricity as needed. Those resources may be generation, demand response, or import resources. A resource that has been paid through the Forward Capacity Market has a *capacity supply obligation* (CSO) and must be available to supply electricity if called upon. A resource with a CSO that fails to provide electricity when required can be subject to financial penalties.

To finance payments to CSOs, all load serving entities (LSEs) in ISO-NE take on *capacity load obligations* (CLOs) and must make monthly payments for their CLOs, payments that are used to pay for the monthly CSOs. In brief, each LSE shares in the responsibility for payments to CSOs based on its share of the system peak on the highest peak hour of the summer. This distributional rule determines what share of CSO megawatts each LSE must pay for. The price per megawatt each LSE pays for the CSO megawatts allocated to it varies based on which region (or capacity zone) within ISO-NE each LSE resides.

Payment rates (either payments to CSOs or from CLOs) vary depending on whether a region within ISO-NE is *import constrained* or *export constrained*. A zone within ISO-NE's service area (the pool) is import constrained if transmission constraints create a risk that resources within that zone along with transmission imports may not be adequate to serve local demand reliably. Conversely, a zone in the pool is export constrained if transmission constraints create a risk that after serving demand within the zone, surplus resources may not be available for export to other parts of the pool. Resources contained in import-constrained zones are paid more for their CSOs while resources in an export-constrained zone are paid less for their CSOs. At the same time, LSEs in import-constrained areas pay more for their CLOs while those in export-constrained areas pay less for their CLOs. [26] In recent years, the Boston and Providence metropolitan areas tend to be

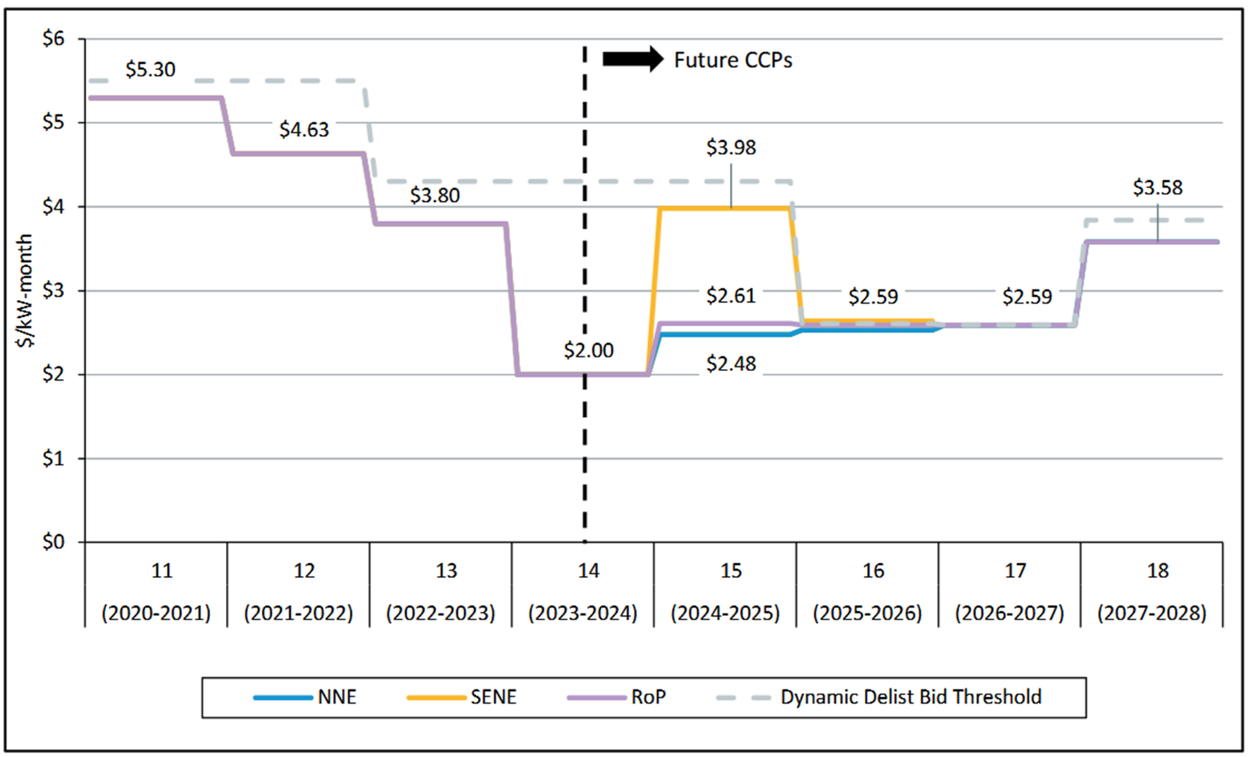
[26] Import constrained zones generally have a higher effective charge rate than the rest of pool (ROP) while export constrained zones generally have a lower rate than the rest of pool. For a period in 2023 and 2024, the ROP had a higher rate than SENE due to a high multiyear-rate existing capacity obligation (MRECO) charge for ROP that drove its total charge rate higher than the rate for SENE.

import-constrained while Northern New England tend to be export-constrained. Western Massachusetts and much of Connecticut are neither import nor export constrained.

*B.* *Capacity Supply Obligations*

I begin by describing the supply side of the capacity market as this will determine how much LSEs need to pay in monthly capacity charges. ISO-NE runs an annual forward capacity auction (FCA) to ensure adequate supply for the New England region. The auction sets an initial price for firm capacity for a Capacity Commitment Period (CCP). As an example, CCP12 covers the period running from June 2021 through May 2022 and the initial auction was held in February 2018. That annual auction was supplemented by subsequent annual and monthly reconfiguration auctions that occurred up to and during the CCP. Figure A1, taken from the 2024 Annual Markets Report graphs the auction clearing prices for the last eight auctions. In general, a single price clears all regions. In FCA15, prices varied across the regions, due to transmission constraints that were binding in that auction.

**Figure A1. Forward Capacity Auction Clearing Prices**




Source: Figure 6-4 from ISO New England Internal Market Monitor (2024)

Payments in the forward capacity market can be substantial. In March, 2025, for example, monthly payments to CSOs totaled nearly $120 million.

*C.* *Capacity Load Obligations*

Funds for payments to CSOs come from capacity load obligation (CLO) charges paid by load serving entities (LSEs) in ISO-NE. They pay an effective charge rate per MW of their CLOs that varies from month to month. The charge to LSE $i$ in capacity zone $j$ in month $m$ is equal to

$$CLO\ Charge_{ijm} = P_{jm} \cdot CLO_{ijm},$$

where $P_{jm}$ is charge rate per kW charged to all LSEs in capacity zone $j$ in that month and $CLO_{ijm}$ is the $i^{\text{th}}$ LSE's capacity load obligation that month. Prior to June 1, 2022, the CLO price, $P_{jm}$, was determined by the formula[27]:

$$P_{jm} = \frac{Gross\ Credit_{jm}}{CSO_{jm} - Self\ Supply_{jm}}. \quad \text{(A1)}$$

In equation (A1) the gross credit is the total payments made to capacity obligated in the forward capacity market in month $m$ for region $j$ ($CSO_{jm}$). Self-supply is not included in the price nor is it taken into consideration in determining each LSE's $CLO_{ijm}$.

As of June 2022, the CLO price, $P_{jm}$, is determined on the basis of the marginal value of capacity reflected in the MRI-based demand curves. According to ISO-NE,

> "The new cost allocation changes allocate capacity market costs that are determined using the MRI-based demand curves and a marginal value approach. Under this approach, the zonal charge rates are calculated based on the marginal value of the capacity located in each zone, as reflected in the zonal clearing prices determined using the MRI-based demand curves. FCM costs that are not associated with the locational value of capacity are allocated to the capacity load obligation (CLO) across the total region on a pro rata basis rather than using the marginal value approach. The costs for specifically allocated CTRs associated with transmission upgrades will be allocated pro rata to CLO in the affected capacity zone." (June 2022 MMOR, p. 47)

The CLO charge rates for January 2022 (old system) and for March 2025 (new system) for the various capacity zones are reported in Table A2.[28] Maine and Northern New England are export constrained zones and so face a lower CLO price, while Southeast New England is an import constrained zone and so faces a higher CLO price. The rest of the pool is neither import nor export constrained.

[27] Prior to June 2022, this price was referred to as the Net Regional Clearing Price.
[28] In recent years, Maine is a nested zone within the Northern New England capacity zone.

**Table A2. Zonal Charge Rates ($P_{jm}$)**

| | Charge Rate (per kW) | |
|---|---|---|
| **Zone** | **Jan. 2022** | **March 2025** |
| Maine | $4.612 | $ 2.480 |
| Northern New England (NNE) | | $ 2.557 |
| Southeast New England (SENE) | $6.136 | $ 4.491 |
| Rest of Pool (ROP) | $5.090 | $ 3.845 |

Source: ISO New England (2022), pp. 49, 51, and ISO NEw England (2025), p. 54.

In March 2025, the actual forward capacity auction charge comprises the bulk of the charge rate ranging from $2.363 in NNE and Maine to $3.797 in SENE.[29]

The CLO for LSE $i$ in capacity zone $j$ and month $m$ equals

$$CLO_{ijm} = Capacity\ Requirement_{ijm} - HQICC_{ijm} - SelfSupply_{ijm} + Bilaterals_{ijm} \quad \text{(A2)}$$

where $HQICC_{ijm}$ is the LSE's Hydro Quebec Installed Capacity Credits and $Bilaterals_{ijm}$ are any bilateral contracts the LSE has, and

$$Capacity\ Requirement_{ijm} = \left(\frac{Peak_i}{Peak_j}\right)\left(Capacity\ Requirement_{jm}\right), \quad \text{(A3)}$$

where the capacity requirement in zone $j$ for a given month is

$$Capacity\ Requirement_{jm} = \left(\frac{Peak_j}{Peak_{Pool}}\right)\left(CSO_{Pool,m} + HQICC_{Pool,m} - IPR_{Pool,m}\right), \quad \text{(A4)}$$

where $HQICC_{Pool,m}$ is aggregate Hydro Quebec Installed Capacity Credits and $IPR_{Pool}$ is an adjustment for intermittent power resources (e.g. wind and solar) in non-summer months.[30] While a LSE's capacity requirement (and capacity load obligation) is framed in terms of its coincident peak relative to its capacity zone's coincident peak, in actuality what matters is the LSE's coincident peak relative to the total pool's system peak. To see that, combine equations (A2), (A3), and (A4) to obtain:

[29] The largest additional charge contained in the CLO charge rate for ROP and SENE is the multiyear-rate existing capacity obligation (MRECO) adjustment rate. It equaled $1.237 in ROP and $0.579 in SENE.
[30] The zonal capacity requirement is called the Zonal Capacity Obligation (ZCO) starting in June 2022. Intermittent power resources were not included in the zonal capacity requirement prior to June 2022.

(A5)
$$CLO_{ijm} = \left(\frac{Peak_i}{Peak_{Pool}}\right)\left(CSO_{Pool,m} + HQICC_{Pool,m} - IPR_{Pool,m}\right) - HQICC_{ijm} - SelfSupply_{ijm} + Bilaterals_{ijm}.$$

The monthly capacity load obligation charge then is

(A6)
$$CLO\ Charge_{ijm} = P_{jm}\ x\ CLO_{ijm}$$

In the text, I define $\kappa_{ijm}$ as the marginal cost of a one kilowatt increase in LSE $i$'s coincident peak. It is the monthly savings that accrues to the LSE of reducing its coincident peak by one kilowatt.

Combining equations (A5) and (A6) and rearranging, I get:

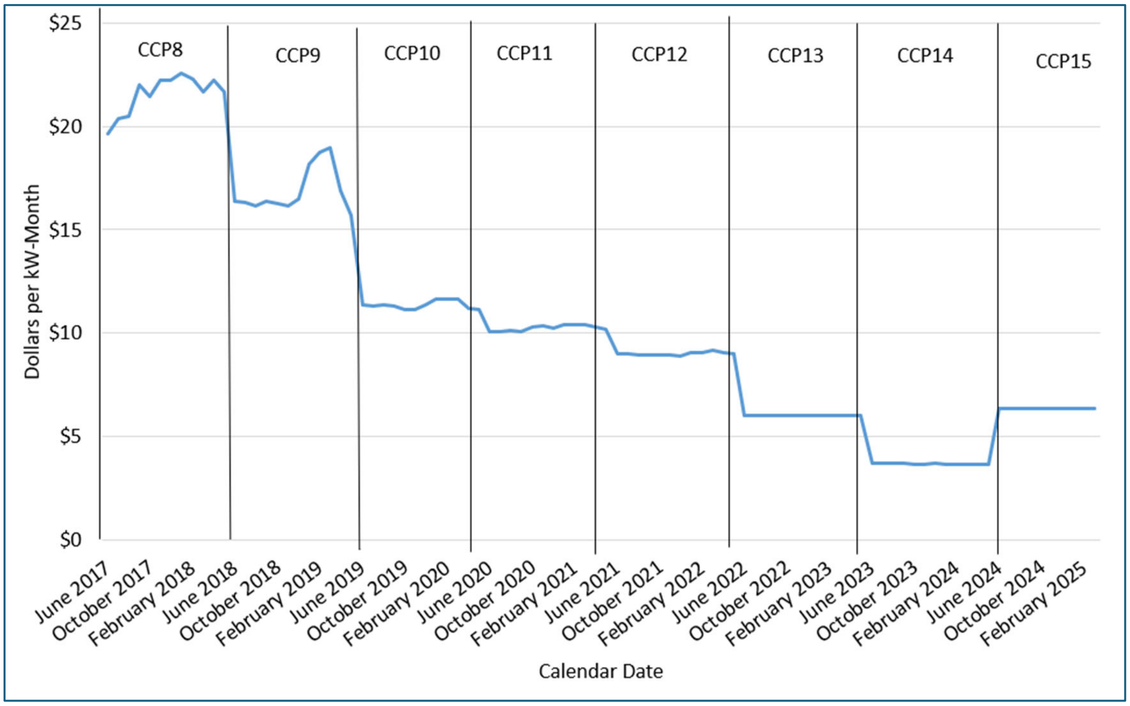
(A7)
$$CLO\ Charge_{imj} = \kappa_{ijm} \cdot Peak_{ij} - P_{jm} \cdot \left(SelfSupply_{imj} - Bilaterals_{ijm}\right)$$

where

(A8)
$$\kappa_{ijm} = \frac{P_{jm} \cdot \left(CSO_{Pool,m} + HQICC_{Pool,m} - IPR_{Pool,m}\right)}{Peak_{Pool}}.$$

For March 2025, the value of the multiplier, $\kappa$, is \$6.346 per kW-month. Figure A2 below graphs $\kappa$, the monthly incremental savings from a 1 kW reduction in CMLP's peak load, for CCP8 through CCP15 (partial year). The monthly incremental value of a peak reduction is generally relatively constant within CCP years.

**Figure A2. Monthly Incremental value of 1 kW Peak Load Reduction**



## Appendix II: Regressions Reporting Weather Variables

**Table A1. OLS Regressions**

| VARIABLES | CMLP Load | | | |
|---|---|---|---|---|
| | (1) | (2) | (3) | (4) |
| Peak | 11.60*** | 9.023*** | 0.826*** | 0.810*** |
| | (0.340) | (0.274) | (0.0869) | (0.0864) |
| ISO-NE Load | | | 1.771*** | 1.716*** |
| | | | (0.00493) | (0.00841) |
| Dry Bulb Temperature | | | | -0.0798*** |
| | | | | (0.0185) |
| Wet Bulb Temperature | | | | 0.0380 |
| | | | | (0.0385) |
| Dew Point Temperature | | | | 0.131*** |
| | | | | (0.0132) |
| Relative Humidity | | | | -0.00647 |
| | | | | (0.00722) |
| Interaction of Dry Bulb Temp and Relative Humidity | | | | -0.0914*** |
| | | | | (0.0164) |
| Barometer | | | | 0.0126 |
| | | | | (0.0768) |
| Precipitation | | | | 1.138*** |
| | | | | (0.275) |
| Visibility | | | | -0.0617*** |
| | | | | (0.00964) |
| Observations | 13,664 | 13,664 | 10,248 | 10,018 |
| R-squared | 0.079 | 0.421 | 0.955 | 0.956 |
| Fixed Effects | No | Yes | Yes | Yes |

Standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1
Fixed effects and weather variables included in regression
Controls for hour of day, day of week, month, and year included. ISO Load excludes CMLP Load.
Midday hours only in regression

**Table A2. Instrumental Regressions**

| VARIABLES | CMLP Load | | | |
|---|---|---|---|---|
| | (1) | (2) | (3) | (4) |
| Peak Alert | -0.444 | -0.714* | -0.586 | -0.576 |
| | (0.373) | (0.370) | (0.438) | (0.877) |
| Peak Alert (2020 – 2024) | | | | -0.318 |
| | | | | (1.830) |
| ISO-NE Load | 1.789*** | 1.742*** | 1.731*** | 1.742*** |
| | (0.00709) | (0.0105) | (0.0121) | (0.0105) |
| Dry Bulb Temperature | | -0.0869*** | -0.114*** | -0.0870*** |
| | | (0.0188) | (0.0214) | (0.0188) |
| Wet Bulb Temperature | | 0.0469 | 0.0555 | 0.0468 |
| | | (0.0391) | (0.0441) | (0.0391) |
| Dew Point Temperature | | 0.133*** | 0.149*** | 0.133*** |
| | | (0.0134) | (0.0151) | (0.0136) |
| Relative Humidity | | -0.00498 | -0.0206** | -0.00539 |
| | | (0.00732) | (0.00839) | (0.00770) |
| Interaction of Dry Bulb Temp and Relative Humidity | | -0.0990*** | -0.0880*** | -0.0982*** |
| | | (0.0168) | (0.0188) | (0.0174) |
| Barometer | | -0.0166 | 0.156* | -0.0164 |
| | | (0.0782) | (0.0884) | (0.0782) |
| Precipitation | | 1.035*** | 1.047*** | 1.030*** |
| | | (0.280) | (0.300) | (0.281) |
| Visibility | | -0.0645*** | -0.0730*** | -0.0648*** |
| | | (0.00980) | (0.0108) | (0.00996) |
| Constant | -4.734*** | -2.717 | -6.634** | -2.695 |
| | (0.113) | (2.424) | (2.740) | (2.428) |
| Observations | 10,248 | 10,018 | 8,464 | 10,018 |
| R-squared | 0.954 | 0.955 | 0.952 | 0.955 |
| Instrumental Variables | IV1 | IV1 | IV2 | IV1 |

Standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1
Fixed effects and weather variables included in regression
Controls for hour of day, day of week, month, and year included. ISO Load excludes CMLP Load. Midday hours only in regression. IV1 is a set of instrumental variables comprising the one-day ahead ISO-NE peak forecast interacted with hour of day dummies. IV2 adds the one-day ahead temperature forecast for Boston interacted with hour of day dummies to IV1.

**Table A3. Solar Capacity Regression**

| VARIABLES | Capacity Factor |
|---|---|
| Ln(Temperature) | 1.077*** |
| | (0.111) |
| Ln(Relative Humidity) | -0.978*** |
| | (0.0454) |
| Visibility (miles) | 0.00660 |
| | (0.00737) |
| Indictor for 10 Mile Visibility | 0.143*** |
| | (0.0415) |
| Indicator for Broken Sky Clouds | -0.0876*** |
| | (0.0160) |
| Indicator for Overcast Clouds | -0.339*** |
| | (0.0190) |
| Constant | -0.662 |
| | (0.577) |
| | |
| Observations | 8,678 |
| Pseudo $R^2$ | 0.216 |

Robust standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1
Hour of day fixed effects included along with hour of day interactions with ln(Temperature) and ln(Relative Humidity)

**Table A4. Summary Statistics on Solar Capacity and Production in 2023**

| Variable | N | Mean | Std. Dev. | Min | Max |
|---|---|---|---|---|---|
| Predicted capacity factor from fractional probit regression | 841 | .263 | .213 | .006 | .842 |
| Predicted BTM solar production | 841 | 1.157 | .936 | .026 | 3.689 |
| Total Solar production (MWs) | 791 | 3.1 | 2.611 | .033 | 9.12 |
| CMLP Real Time Demand (MWs) | 791 | 25.583 | 5.058 | 16.763 | 41.663 |
| CMLP Real Time Load (MWs) | 854 | 22.498 | 5.057 | 10.57 | 38.102 |
| Summary Statistics Conditional on a Peak Alert | | | | | |
| Predicted capacity factor from fractional probit regression | 33 | .232 | .151 | .02 | .538 |
| Predicted BTM solar production | 33 | .976 | .622 | .087 | 2.196 |
| Total Solar production (MWs) | 33 | 2.518 | 1.691 | .087 | 5.557 |
| CMLP Real Time Demand (MWs) | 33 | 38.219 | 3.087 | 32.631 | 43.642 |
| CMLP Real Time Load (MWs) | 34 | 35.684 | 2.425 | 30.552 | 39.304 |

Summary statistics for summer months and midday hours only in 2023

# Contact.

**MIT CEEPR Working Paper Series**
is published by the MIT Center for Energy and Environmental Policy Research from submissions by affiliated researchers.
For inquiries and/or for permission to reproduce material in this working paper, please contact:

**General inquiries:** ceepr@mit.edu
**Media inquiries:** ceepr-media@mit.edu

MIT CEEPR
Center for Energy and Environmental Policy Research

**MIT Center for Energy and Environmental Policy Research**
**Massachusetts Institute of Technology**
77 Massachusetts Avenue, E19-411
Cambridge, MA 02139-4307
USA

**ceepr.mit.edu**

MASSACHUSETTS INSTITUTE OF TECHNOLOGY