Accounting for Big Energy Efficiency in RTO Plans and Forecasts: Keeping the Lights on While Avoiding Major Supply Investments

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ABSTRACT

States in several regions are investing in "Big EE"—defined as energy efficiency programs with annual energy savings of around 2% or more of retail sales—to meet significant portions of customer energy needs. Energy efficiency is the largest future energy resource in several states, and its share of the total resource mix is growing quickly. Regional Transmission Organizations (RTOs) in these regions are examining their planning practices to consider and account for the impacts of Big EE, now that energy efficiency is no longer background noise in their forecasts. It is crucial to neither under-count nor over-count the impacts of Big EE: on the one hand, under-counting will lead to billions of dollars of unneeded supply and transmission investments, thereby eliminating a portion of the economic value of the EE programs; on the other hand, over-counting the impacts will result in reductions in system reliability. Since the stakes are high, several RTOs are paying closer attention, although questions remain about the accuracy and effectiveness of the revised RTO planning methods. In this paper we review the changing planning and forecasting practices of RTOs in two regions that have substantial EE programs by analyzing how RTOs: (1) treat EE in their forecasts, (2) forecast EE impacts in future years beyond the time period covered by available EE plans, (3) distinguish energy vs. peak demand impacts, and (4) address the performance uncertainties and risks of future EE, including any discounting practices. We conclude with a summary of best practices to date among RTOs.

Introduction

In this paper we examine the forecasting methods and practices of two RTOs—ISO New England (ISO-NE) and PJM (the RTO covering the Pennsylvania, New Jersey, and Maryland area) —to assess the importance of accounting for EE impacts in the forecasts used for transmission planning. We chose these two RTOs because of our awareness of the significant EE programs in the two regions, plus some differences in how the two RTOs were addressing EE in their planning and forecasting efforts.

First, we review the EE forecasting practices, methods, and results at ISO-NE. Second, we summarize the practices at PJM and analyze the likely effects of including and accounting for EE impacts in the PJM forecasts. By comparing and contrasting the different forecasting practices and the forecast results at the two RTOs, we document the current state-of-the-practice (as of 2013) at these two RTOs and identify potential improvements for the future.

Accounting for EE in ISO-New England Transmission Planning

The six New England states have long been leaders in state-funded energy efficiency, often occupying the top slots in the annual ACEEE State Energy Efficiency Scorecard. Some states in the region have been achieving EE levels near 2% of retail sales for several years, and all states are achieving savings that exceed 1% of annual retail sales. In addition, ISO New England allows providers of EE to offer their portfolio as a resource into the region's wholesale forward capacity market, competing alongside traditional and renewable generation to meet the ISO-NE's capacity requirement to operate a system that will reliably serve forecast demand.

Every year, the ISO-NE develops and publishes its Regional System Plan (RSP), which details the energy and peak load forecasts for the upcoming ten years, lists approved transmission projects, and contains discussions of a number of key issues in the region, such as state Renewable Portfolio Standards, possible factors affecting existing generation stations, and key fuel issues such as the natural gas pipeline infrastructure. Since the preparation of RSP12 in 2012, the ISO has also included a forecast of future EE installations and, importantly, incorporates this forecast into the energy and peak load forecasts that it uses for transmission planning.

History

On June 16, 2006, the FERC officially accepted the ISO-NE proposal for a new form of capacity market for the region, the Forward Capacity Market. Two key features of this market are relevant here. The first is that it is a forward market, meaning that an auction is held to procure capacity for a delivery period that is in the future—in this case three years after the auction. The second is that the market rules allows for bidding into the system of not only generation supply, but also demand reductions, including energy efficiency. In February 2008 more than 600 MW of EE cleared in an auction, with an obligation to deliver over a 12-month period starting on June 1, 2010. Ten months later in December 2008, more than 200 MW of additional EE cleared in a second auction, with an obligation to provide savings for a 12-month period beginning June 1, 2011. Ten months after that, another 200 MW of EE cleared for June 1, 2012. A clear trend had begun.

Figure 1 prepared by ISO-NE shows the growth of energy efficiency and demand resources in ISO-NE markets in the region, specifically in the ISO-NE Forward Capacity Market (FCM), since 2010 (Yoshimura 2014). The figure shows historical demand resources (in gray on the left of the chart) prior to the start of, and forecast demand resources since the beginning of, the ISO-NE Forward Capacity Market. Energy Efficiency is labeled by ISO-NE as a "Passive Demand Resource" to contrast it from "active" demand resources that respond to a reliability call or price.

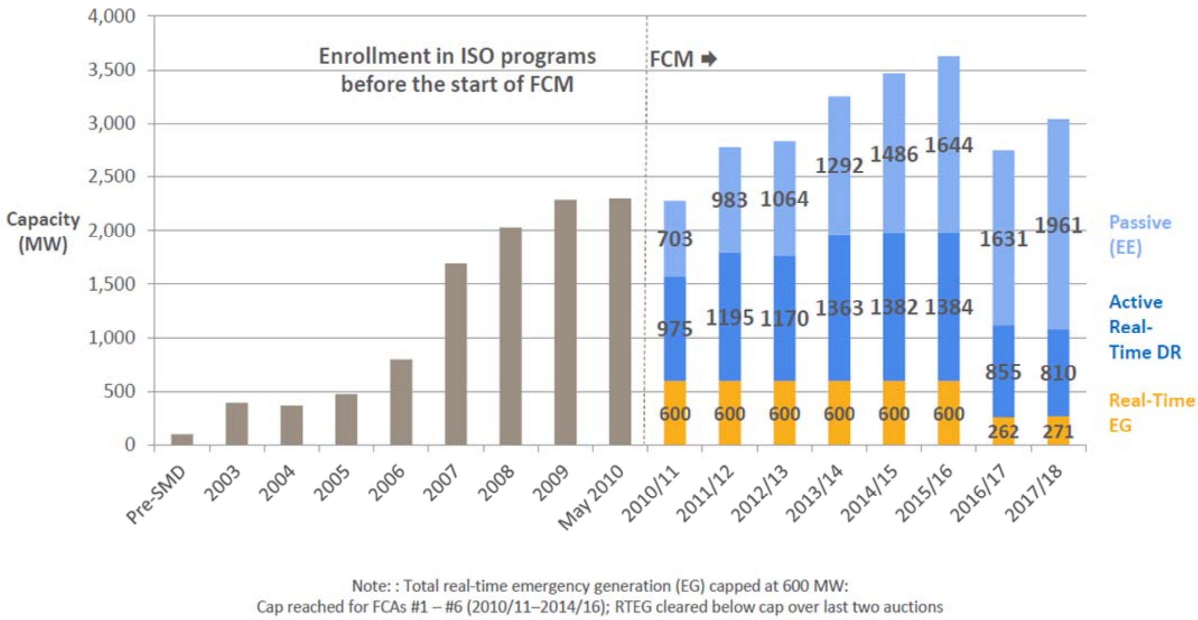

Figure 1. Participation of Demand Resources in the ISO-New England Forward Capacity Market (ISO-NE 2013a).

However the ISO-NE planners were faced with a new problem to solve. They now needed to account for heretofore ignored EE in their load forecasts. With a financial obligation to deliver specific amounts of EE in future years, it became relatively straightforward to do this for a time period of three years into the future. During the spring and summer of 2010, the ISO was developing with their stakeholders the contents of RSP11. At that point, the first three FCM auctions had already occurred, and EE had cleared the MW values listed above. The ISO could easily use these values in their load forecasts, and did so—using the level of EE resources that cleared in the FCM auctions.

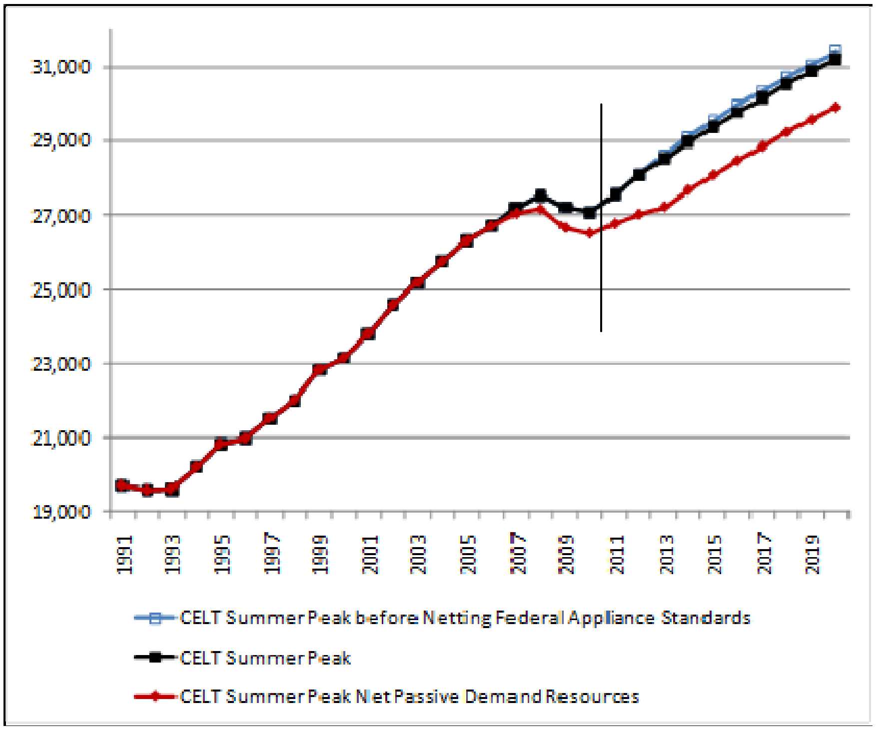

Figure 2. Historical and forecast annual summer-peak loads, 1991 to 2020.[1]
(ISO-NE 2011, Fig 3-3)

The problem, at that time, was that the ISO was assuming that no new EE would be installed after the time period for which the EE resource had assumed an obligation in the capacity market. In Figure 2, from RSP11, new EE was assumed for June 2011, June 2012, and June 2013, but beyond those years ISO-NE assumed 0 MW of new EE would be installed. The lines cease their growing divergence and become parallel in the final six years of the forecast. There was no obligation for new EE to be delivered, so ISO-NE assumed none would be. The program administrators, state agencies, and state regulatory commissioners familiar with EE budgets and planning knew that this assumption was wrong, and argued to change this practice. After some discussion, ISO-NE agreed, and formed an Energy Efficiency Forecast Working Group.

Since its inception in early 2012 the ISO-NE, with the input of the EE Forecast Working Group, has developed a methodology for including a forecast of EE that will be installed in the years beyond those where obligations have already been taken in the FCM. For example, in the most recent final forecast to be included in the upcoming RSP14, the ISO will use FCM obligations for the summers of 2014, 2015, 2016 and 2017 because the auctions for these time periods have already taken place. ISO-NE will then use the EE forecast to project the amount of EE that will be installed for 2018-2023—the remaining six years of the RSP 10-year planning period.

[1] In the figure, CELT stands for the ISO New England annual report on Capacity, Energy, Load and Transmission.

Summary of the EE Forecast Methodology

After several months of discussions, ISO-NE and the EE Forecast Working Group agreed on a methodology that would be used to forecast the amount of EE that the ISO would include in its forecasts of energy and peak loads. Each program administrator submitted to ISO-NE data from their recent annual reports on budgets approved, expenditures, and planned and achieved energy, summer peak and winter peak savings. These data were categorized by program and end use, and the data from the latest annual reports are now collected each year. ISO-NE staff aggregate the data by state and then further compile to a regional level to arrive at historical cost and savings trends. The costs, energy savings and peak load reductions are then used to arrive at historical production cost values (e.g., cost per MWh saved) and peak-to-energy ratios. These historical data on EE performance are then combined with data on future budgets to forecast future EE impacts. Specifically, using the ISO-NE formulae below, the historical production cost and peak-to-energy ratios are applied to the approved and/or forecast future EE budget amounts, with various discounting factors, to arrive at a forecast future amount of EE energy savings and peak demand reductions by state (ISO-NE 2014a).

1) MWh = [(1-BU) * Budget $] / [$/MWh * PCINCR]

where:

Budget $	= an estimate of the dollars to be spent on EE ($)
	(System Benefit Charge + RGGI + FCM + Policy)
BU	= budget uncertainty (%)
$/MWh	= production cost ($/MWh)
PCINCR	= production cost increases (%)

2) MW = MWh * PER

where:

PER	= peak-to-energy ratio (MW/MWh)

Figure 3. ISO-NE methodology and formulae for forecasting the amount of EE.

The discounting factors used by ISO-NE are important, have been somewhat controversial, and continue to be debated. For example, ISO-NE assumes that in all six states the production cost per unit of savings will rise annually at a rate of 5% plus 2.5% for inflation. The ISO makes no counter-assumption for improvements in the cost of program delivery or other economies of scale. In certain states an additional Budget Uncertainty factor is applied, which further discounts the amount of assumed new EE in future years; this factor has been discussed and applied more in states that have underspent their authorized EE budgets in recent years. While numerous stakeholders have acknowledged that ISO-NE is to be commended for having an EE forecast at all, many parties have also commented that these discounting factors have no specific basis in fact (for example, NESCOE 2014; ISO-NE 2014b). Stakeholders have also suggested that ISO-NE should use the state forecasts of future EE energy savings and peak demand reductions, when available, directly rather than the ISO method of applying historical production costs and peak-to-energy ratios to future EE budgets.

Even with the discounting factors applied by ISO-NE, the results of the EE forecast are very significant. The preliminary forecast for the RSP14 planning period (with EE impacts incorporated) estimates an annual average increase for the six-state region of 204 MW. From 2017-2023 this amounts to a peak load forecast that is 1,426 MW lower than it would have been absent this EE forecast. That amounts to 1,426 MW of load on a hot summer day that no longer needs to be served by the transmission system. Figure 4 from RSP13 published in October 2013 shows this result clearly, with the RSP13-FCM-EEF line (Regional System Plan 2013 minus FCM, minus EE Forecast, the bottom line in Figure 4) representing the forecast summer peak accounting for the new EE forecast.

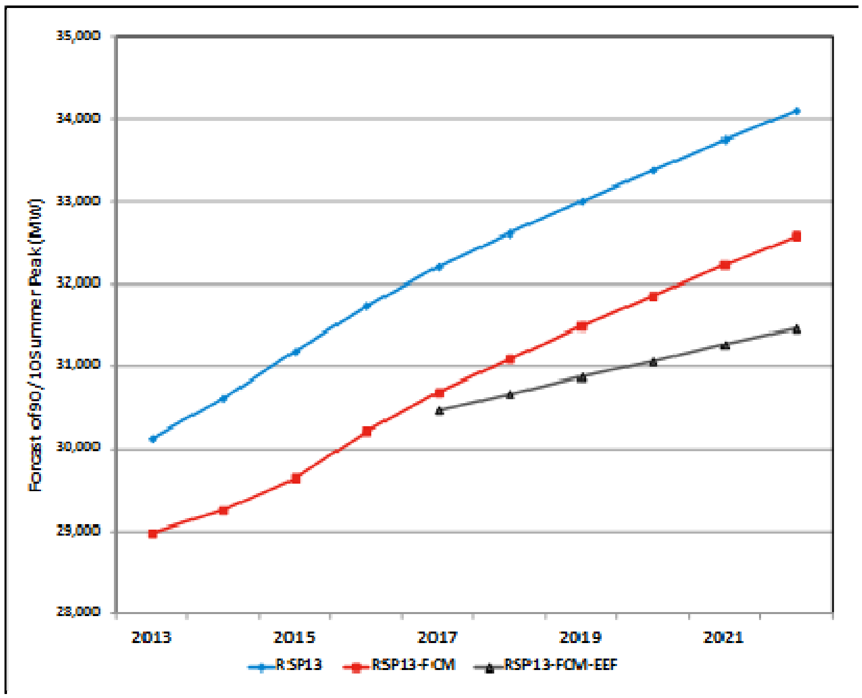

Figure 4. Impact of EE on ISO-New England Forecast of Summer Peak through 2022 (ISO-NE 2013a).

More specifically, Figure 4 shows the revised RSP13 summer peak demand forecast (90/10) (diamond), the load forecast minus FCM #7 auction results through 2016 (square), and the load forecast minus FCM results and minus the energy-efficiency forecast (triangle) for 2017 to 2022 (MW) (ISO-NE 2013a, 41).

Without EE in the FCM, the forecast peak load in 2022 would have exceeded 34,000 MW. With just the four years of FCM results already known, this amount drops to approximately 32,500 MW, a drop of more than 1,500 MW. When the results of the EE forecast are included, the amount drops further to roughly 31,500 MW.

Although the RSP energy forecast is not specifically used for transmission planning, the forecast of annual energy is even more striking. As shown in Figure 5, with the inclusion of an EE forecast, energy use is assumed by the regional system planner to be essentially flat in New England for the upcoming 10-year period.

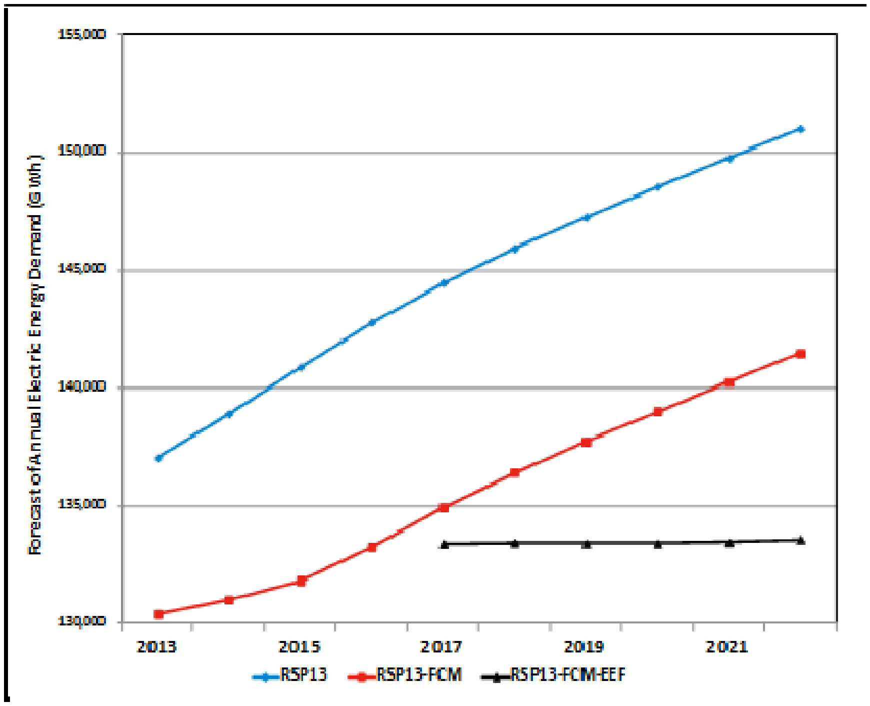

Figure 5. Impact of EE on ISO-New England Forecast of Annual Energy through 2022 (ISO-NE 2013a).

Deferral of Transmission Projects

In the ISO-NE planning process, the inclusion of the EE forecast into the load forecasts is not merely hypothetical or academic. In early 2012, the ISO conducted a follow-up assessment of its New Hampshire-Vermont Transmission System Needs Analysis and Solutions Study (ISO-NE 2012c) in which it included the newly released proof-of-concept Energy Efficiency Forecast (Ehrlich and Winkler 2011). In a March 15, 2012 presentation, the ISO announced that a total of approximately $265 million in previously-identified line upgrades, capacitor additions, and other transmission needs would be avoided or deferred in Vermont and New Hampshire. While ISO staff cited a number of factors that led to the changes, including small additions of demand resources and renewable energy projects, the main reason for the deferrals was a 180 MW load reduction in the NH-VT area documented in the new EE forecast. These initial changes were incorporated into the 2012 Regional System Plan, which stated that “[a] number of transmission system upgrades were identified, which are no longer required within the 10-year planning horizon and could be deferred from the preferred solution identified in the New Hampshire/Vermont Solutions Study. These deferred transmission system upgrades are located in almost every portion of the New Hampshire and Vermont transmission systems” (ISO-NE 2012a, 79-81).

More than a year later, the ISO-NE again came before the Planning Advisory Committee to present the results of an updated New Hampshire-Vermont Needs Assessment (ISO-NE 2013b). In this study, the ISO included the final Energy Efficiency Forecast for 2012, which had been presented to the Planning Advisory Committee on April 18, 2012 (ISO-NE 2012b). The updated analysis showed that, due to an additional approximately 80 MW load reduction in the final EE forecast, the need for a new 345 kV line at an additional cost of $157 million could be deferred (ISO-NE 2013b, slide 36). These deferred transmission system upgrades were incorporated and memorialized in the 2013 Regional System Plan (ISO-NE 2013a, 76).

Together, incorporating the EE Forecast into ISO-NE transmission planning has resulted in over $420 million of deferred transmission upgrades in New England. As the EE Forecast is applied and reflected in future needs assessments, and as the level of EE investments grow in New England, we expect that additional ratepayer savings will be identified.

Potential in the PJM Territory

There is no obvious reason why the EE forecast methodology used in New England cannot also be used in other RTO regions. The auction held by PJM to purchase capacity for their 2017-2018 power year cleared 1,340 MW of EE, which was 0.78% of the total unforced capacity obligation for that year of more than 171 GW. The total amount of EE being installed in PJM territory is certainly larger than this amount, but this is how much was offered into that market and cleared. While this amount is a smaller percentage than we have seen clear in the ISO-NE capacity market auctions, below we address the possibility of using a similar EE forecast methodology in the PJM territory.

Current PJM Transmission Planning Practices

PJM produces an annual load forecast for the RTO region and for each individual zone. As is done in other regions, these are based largely on economic forecasts and historical weather data. PJM's annual Regional Transmission Expansion Plan (RTEP) considers transmission projects needed for reliability throughout the region. The PJM load forecast provides the peak loads for testing the transmission system in that year's RTEP process (PJM 2013b). The RTEP covers transmission planning for both a short-term (five years) and long-term horizon (fifteen years). For instance, the 2013 PJM Load Forecast is used in the 2013 RTEP, which evaluates transmission capability under a short-term horizon for 2018 and a long-term horizon for 2028 (PJM 2013a).

The RTEP process includes a series of stress tests on the PJM grid to see where transmission bottlenecks occur under a number of sensitivities. The load levels used in these tests are derived from the PJM peak load forecast, after subtracting out demand-side resources, since "the status and availability of demand resources can have a measurable impact on the assessment of future system conditions that drive the need for new transmission to meet load serving responsibilities."[2] Thus the forecasting of demand-side resources has direct implications for transmission planning. This bears repeating: PJM includes a sensitivity forecast that includes demand-side resources, but ignores them in the forecast of peak load used for planning purposes.

Unfortunately, demand-side resources are not projected into the future by PJM as is done for peak load. Demand response (or "load management") has been incorporated into the PJM's capacity auction since its inception, and energy efficiency was incorporated in the 2011/2012 delivery year. For planning purposes, only the amount of energy efficiency and demand response that clears each auction is included in the PJM peak load forecasts. PJM assumes that no energy efficiency will exist in years beyond the most recently cleared capacity auction obligations. This is the same method that was originally used by ISO-NE. This planning practice continues despite

[2] 2013 RTEP: Inputs, Data, Assumptions and Scope, p.17. Available here: http://www.pjm.com/~/media/documents/reports/rtep-plan-documents/2013-rtep-process-white-paper.ashx

readily-available energy efficiency planning data at the state level and continually decreasing PJM load forecasts for each year (see Figure 6 below).

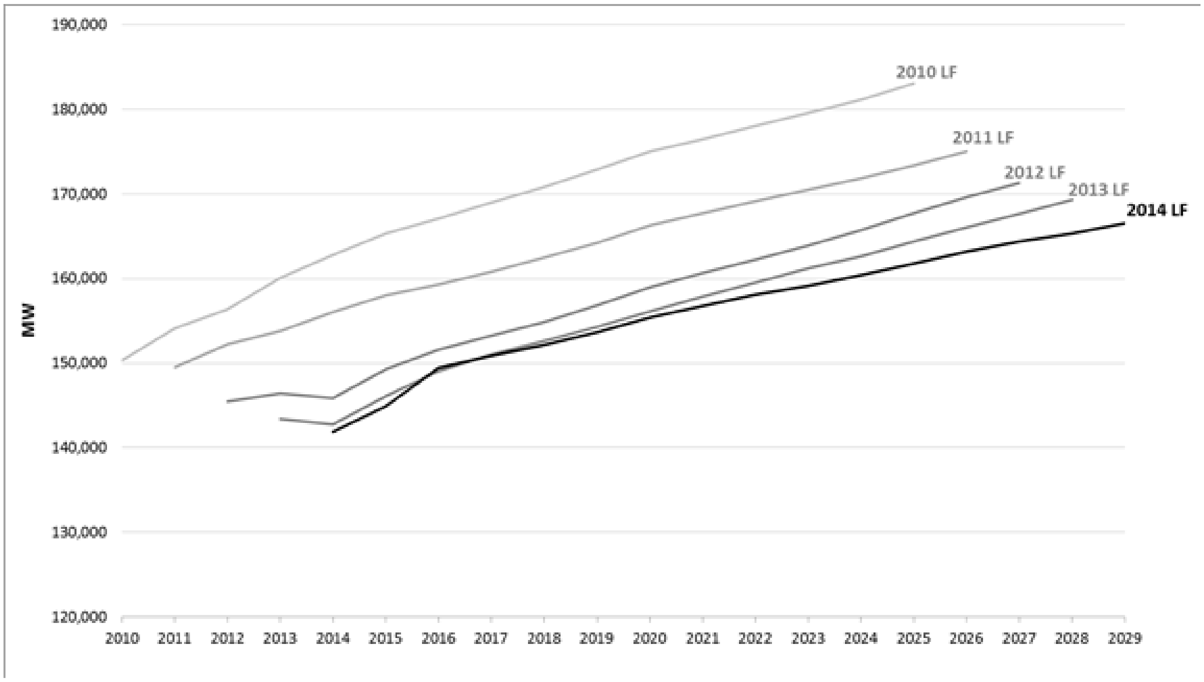

Figure 6. PJM Annual Non-Coincident Peak Load Forecasts, from corresponding RTEP reports.

A Simple Option to Incorporate EE into PJM Planning

A proper forecast of peak load in PJM would take into account the downward trend in previous load forecasts. We have not provided a specific proposal to address that defect here. However, we demonstrate how inclusion of forecasted new energy efficiency (i.e. beyond the capacity auction delivery year) would affect transmission planning.

As described above, RTEP planning currently only counts energy efficiency that has cleared the capacity market. However, the 2010 RTEP evaluated a sensitivity of increased energy efficiency. To demonstrate the impact of new energy efficiency, we assumed the average annual new energy efficiency that was listed in RTEP 2010 – 718 MW (see Table 1 below) – for each year after 2016.

Table 1. 2010 RTEP Available Energy Efficiency (Table 4.1)

Year	Energy Efficiency (MW)	Change from previous year (MW)	Year	Energy Efficiency (MW)	Change from previous year (MW)
2010	471		2018	6,792	*554*
2011	1,216	*745*	2019	7,516	*724*
2012	2,030	*814*	2020	8,489	*973*
2013	3,167	*1,137*	2021	9,042	*553*
2014	4,127	*960*	2022	9,579	*537*
2015	5131	*1,004*	2023	9,986	*407*
2016	5,688	*557*	2024	10,399	*413*
2017	6,238	*550*	2025	11,241	*842*
			Avg.Increment		***718***

Adding new energy efficiency resources into projected net peak load (equal to gross peak load minus demand-side resources) could lead to dramatic reductions in capacity and transmission needs. Figure 7 demonstrates this by incorporating 718 MW of new energy efficiency each year into the 2014 PJM Load Forecast. By 2020, the difference between these two projections (the black solid line compared to the dashed line) is 2,743 MW and by 2029 it is more than 8,900 MW. These represent significant reductions in net peak load, 2% and 5% of the region’s forecast net peak load in 2020 and 2029, respectively.

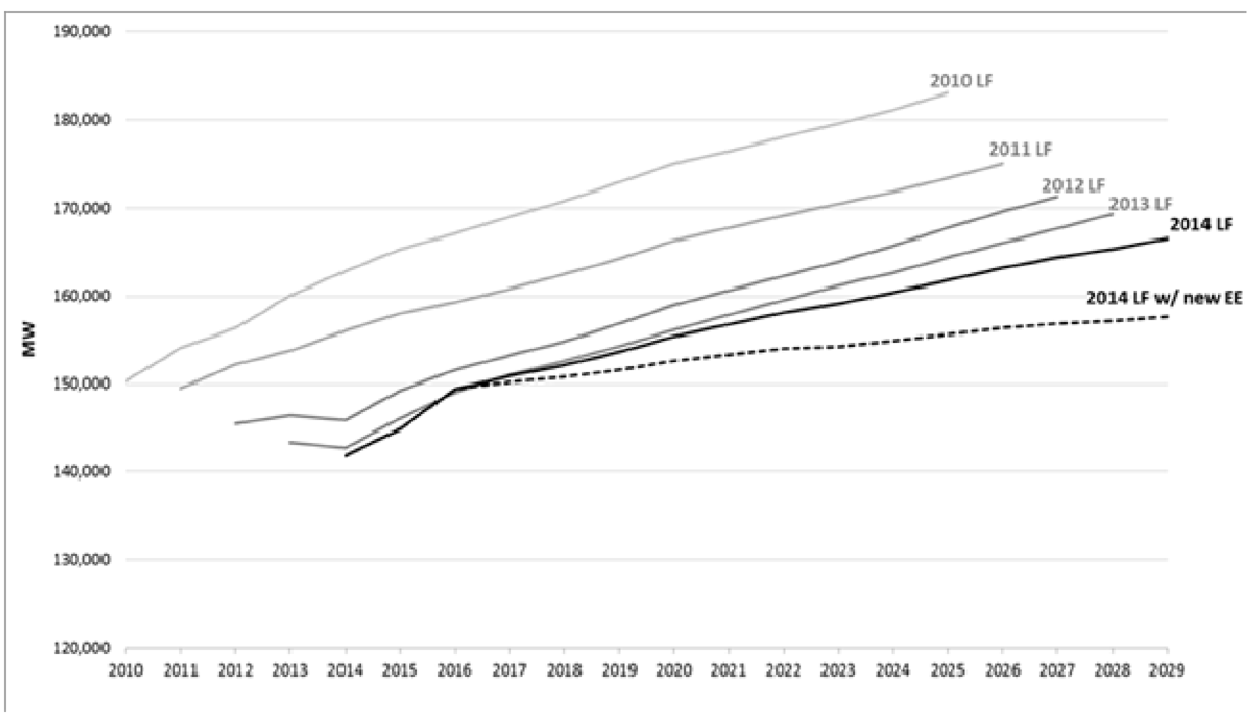

Figure 7. Impact of EE Forecast on the 2014 PJM Non-Coincident Peak Load Forecast.

Figure 8 overlays the deferral of hypothetical transmission projects by indicating their “year of need” using the 2014 PJM Load Forecast compared to an alternative forecast that includes new energy efficiency resources each year. Including PJM's own estimate of incremental EE delays the need for additional transmission from 2019 to 2021 and from 2022 to 2029—simply due to accounting for new energy efficiency resources after 2016. Any transmission projects whose year of need is currently estimated to be after 2022 would theoretically be deferred indefinitely if this method for including EE was included in the load forecast.

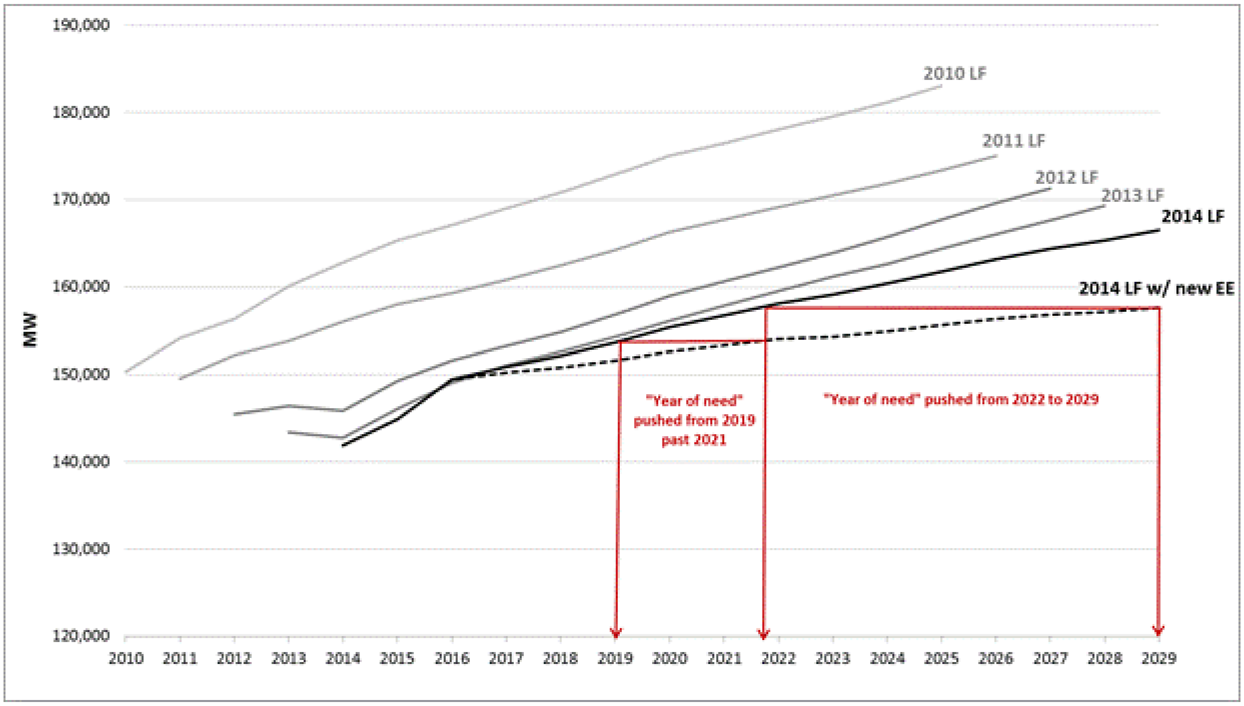

Figure 8. Demonstration of Deferral of Transmission Project Year of Need. *Source:* 2010, 2011, 2012, 2013, and 2014 PJM Load Forecasts (excluding EKPC and DEOK which joined after 2010).

Case Study: The PATH Project

The proposed Potomac-Appalachian Transmission Highline (PATH) transmission line is an example of a major investment that was delayed, and ultimately abandoned, because PJM Mid-Atlantic peak load was consistently overestimated. Although the annual peak load projection we discuss here is independent of an EE forecast (which was not incorporated by PJM planners), it demonstrates the effect that reduced peak load forecasts can have on costly transmission projects. The project was originally identified in 2007, with a year of need of 2012 for delivery of power to the Washington, DC and Baltimore region; the cost estimate of the project was $2.1 billion. However, the need for the project was continually delayed each year, based on the updated data in the annual RTEP.

During RTEP 2011, the project was temporarily suspended due to "reduced demand growth, increased demand resource commitments and new generation coming on-line" (Bruner 2012). Finally in 2012, the project was cancelled because "the reliability needs justifying development of the PATH project no longer exist throughout PJM's 15-year planning horizon" (Bruner 2012).

The cancellation of the PATH Project avoided $2 billion in transmission investment. However, the initial identification of need and subsequent delays meant that $121 million was already spent on planning the project before it was cancelled (Bruner 2012). Figure 9 shows the change in net peak load forecasts for the PJM Mid-Atlantic region from each RTEP year, and how this led to postponing the need for the project.

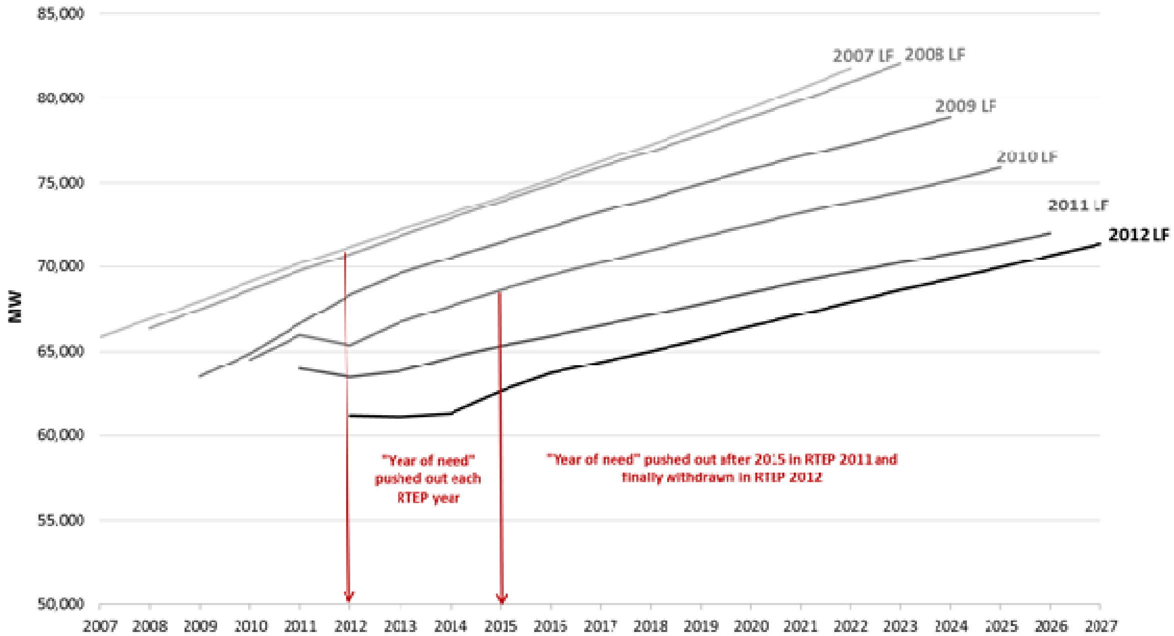

Figure 9. Impact of successive peak load forecasts on need for the PATH project.

Conclusions

By examining the forecasting methods and practices of two RTOs—ISO-NE and PJM—we have demonstrated the importance of accounting for EE impacts in the forecasts used for transmission planning. Comparing and contrasting forecasting practices and the use of EE forecast results at the two RTOs has indicated that more inclusive accounting for EE impacts in the regional load forecasts will defer or avoid transmission investments that are unnecessary, thereby saving ratepayers from paying for costly infrastructure investments that are not needed, or that could be spent on more useful projects. The corollary is that not accounting for EE impacts in the forecasts would likely result in the building of unnecessary transmission projects, with significant financial impacts. We have cited the $2.1 billion PATH project as one example of a project that was deferred after peak load forecasts were revised, albeit not due to the inclusion of an EE forecast. Based on our analysis, these findings appear to ring true for regions with Big EE, such as New England, and for regions with growing EE, such as the mid-Atlantic region of PJM. Therefore, once EE impacts become larger than the background noise in the load forecast, perhaps greater than 0.5% of retail sales annually, it is crucial to account for the EE impacts in all planning practices.

More RTOs are beginning to explore how to account for the EE impacts in their forecasts, and the RTO forecasting practices are evolving (for example, see Barbose et al. 2014). Yet the forecasting of EE costs and impacts by RTOs is still in its infancy, and best practices have not yet emerged. The critical first step is to *do something* to account for the EE impacts, and to do such accounting over the time horizon addressed by the load forecast and associated plan. This paper demonstrates that there is a major financial risk of *not accounting for the EE impacts*, or even in just accounting for the near-term EE impacts (e.g., over a three-to-four year period of a forward capacity market, or for a short-term action plan)—since such a practice can result in an inaccurate forecast that could lead to costly investments that are not in the public interest.

Those regions that have not yet created an EE forecast should undergo the process of creating an initial methodology right away, and then improving it over time. New England has experience with this process. While some parties there have raised concerns about the specific methods used by ISO-NE in its EE forecast, including the discounting factors, stakeholders appreciate ISO-NE's initial efforts to account for EE in its load forecasts and transmission planning. These early efforts have led to deferred investments and significant cost savings for customers. While the EE forecasting methods are not perfect, and while the methods are expected to improve with the growing experience of ISO-NE's planners, accounting for the majority of the EE impacts in the early years of RTO efforts, even with some discounting, is far better than not accounting for EE impacts at all. More inclusive accounting of the largest portion of the total EE impacts has proven to be an important step forward for ISO-NE and the region. This is a case in which the perfect should not be the enemy of the good – and the good progress made to date has been both important and valuable.

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