AESC Supplemental Study

Part I: Considering Winter Peak Benefits

Prepared for Massachusetts Electric Energy Efficiency Program Administrators

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EXECUTIVE SUMMARY

In 2019, the Massachusetts electric energy efficiency Program Administrators (EE PAs) contracted Synapse Energy Economics, Inc. (Synapse) and Resource Insight, Inc., (together, the Synapse Team) to examine possible winter peak avoided costs for energy efficiency (EE) and other distributed energy resources (DERs).

Working on behalf of the AESC Supplemental Study Group, which consisted of electric EE PAs from Eversource, National Grid, Unitil, and Cape Light Compact, along with observers from Massachusetts state agencies including Massachusetts Department of Energy Resources (DOER), Massachusetts Energy Efficiency Advisory Council (EEAC), Massachusetts Attorney General's Office (AGO), and Massachusetts Clean Energy Center (MassCEC), the Synapse Team conducted an assessment of three categories of winter peak benefits.[1] Each of these categories relates to benefits arising from reducing load at times of high load and/or high cost, but the nature of the peak conditions varies among the potential benefits. In order to avoid confusion, we articulate the specific definitions for each section below.

Benefits include:

1. **Winter Peak Capacity Benefits**: At the outset of this scope of work, the Synapse Team theorized that ISO New England's calculation of its reserve margin in the Installed Capacity Requirement (ICR) could be influenced not only by summer peak quantities, but also by high-load winter hours (including the highest-load winter hour, when the system experiences the winter peak load). Under this construct, some of the capacity value that prior AESC reports have historically attributed to the summer peak might be reallocated to the winter peak. ISO New England's resource adequacy staff members informed the Synapse Team that under the ISO New England planning methodology, winter peak hours do not impact the calculation of ISO New England's ICR.[2] As a result, reductions in winter peak hours (through EE or other DERs) would have no effect on avoided capacity costs under the current modeling assumptions.

2. **Potential New Winter Benefits:** The Synapse Team identified five categories of potential additional winter benefits. These five categories are "deeper dives" into winter peak benefits (e.g., avoided energy and energy DRIPE) that may span a number of high-load or high-price hours in the winter. Under these situations, the identified winter benefits are not truly new categories, but are instead refined methodologies used for calculating winter benefits for measures with particularly peak-concentrated load shapes, such as space heating and active demand response. In this document, the Synapse Team has

[1] Note that the Synapse Team did not evaluate any potential winter peak benefits associated with ISO New England's proposed Energy Security Initiative (ESI). At the time of this report's publication, the ESI has not yet been voted on by NEPOOL or approved by any of the relevant regulatory bodies (e.g., FERC), and any estimation of avoided costs at this time would be speculative.

[2] Specifically, ISO New England has found that all of the modeled system violations used in the ICR simulations occur between July and August.

provided the AESC Supplemental Study Working Group with an overview of each potentially new avoided cost category, along with a methodological description of how this new avoided cost could be calculated in a future AESC Study.

3. **Winter Peak Period Benefits in AESC 2018:** The 2018 AESC Study provided a "User Interface" workbook that contains avoided costs (including energy and DRIPE) for all 8,760 hours of the year, for every year in the AESC study period. Data from this workbook was condensed in the 2018 AESC Study to produce avoided costs for the four ISO New England costing periods (summer on-peak, summer off-peak, winter on-peak, and winter off-peak) that are most commonly used by PAs to screen energy efficiency measures. However, any user of the user interface may extract data specifically associated with winter peak periods, however they choose to define the term. To demonstrate the current range of avoided costs associated with illustrative winter periods that some might treat as winter peak hours, the Synapse Team has highlighted the energy avoided costs based on selected hours and loads from the User Interface tool. We find that avoided energy costs measured over the top 1 percent to 10 percent of winter hours with the highest prices were 53 to 86 percent higher than the "Winter On-Peak" value reported in AESC 2018, which is an average for about 2,900 hours (16 hours each weekday in October–May). Likewise, avoided energy costs measured over the top 1 percent to 10 percent of winter hours with the highest loads 38 to 68 percent higher than to the standard "Winter On-Peak" value.

The following sections describe each of these three winter peak benefits in more detail, along with information on which benefits might produce the most substantial changes in overall avoided costs.

1. WINTER PEAK CAPACITY BENEFITS

At the outset of this Supplemental Study, the Synapse Team hypothesized that ISO New England's calculation of its reserve margin in the ICR could be influenced not only by summer peak quantities, but also by winter peak and other high-load winter hours. AESC Studies have historically only reported a single avoided capacity value that is attributed to reductions in the ISO New England summer peak.[3] The Synapse Team hypothesized that some of the capacity value that prior AESC Studies have attributed to the summer peak might be reallocated to a winter peak capacity value that had not been previously evaluated. Neither the current Market Rules nor ISO New England's published documentation explicitly describe the specific inputs used to determine the ICR.[4] To date, the publicly available information has been unclear whether the ICR formulation specifically relies on inputs from winter peak hours as well as summer hours.[5]

On February 26, 2020, members of the Synapse Team held a phone conversation with Peter Wong, Manager of Resource Studies and Assessment at ISO New England and Weezie Nuara, ISO New England's Senior External Affairs Representative, to discuss the potential impact of winter load reductions on the ISO New England ICR calculation. In the course of our conversation, Mr. Wong and Ms. Nuara clarified that under the current load and supply assumptions used in the ICR calculations, the model identifies no loss-or-load risk in even the highest winter hours. Since the ICR is set to the level required to maintain the ISO New England's target reliability, this means that the winter peaks do not impact the ICR. Specifically, ISO New England noted that its current loss-of-load expectation (LOLE) is almost entirely based on peaks observed in July and August (with the potential of several minor impacts from June and September), given current system conditions. Upon our request, ISO New England provided a memo to the Synapse Team on March 10, 2020 that documents the current ICR assumptions, including the impact of winter peak hours. This memo, *A High Level Description of the New England Installed Capacity Requirement Determination Methodology*, is attached to this document as Appendix A. Per ISO New England:

> The current New England bulk power system is a summer peaking system. The summer net peak demand (after accounting for behind-the-meter photovoltaic and energy

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[3] For future years, the capacity value is the same throughout the entire New England system, rather than varying among load zones, as it did in some earlier years.

[4] The ICR is calculated according to Section III.12 of Market Rule 1, available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf. ISO New England also published a slide deck summarizing how the ICR is developed, which is available at https://www.iso-ne.com/static-assets/documents/2019/05/a2_icr_dev_backgrnd_05152019.pdf.

[5] Note that ISO New England does share its detailed assumptions on its ICR development with stakeholders. Stakeholders have access to every data element from ISO New England's ICR simulation (except for proprietary unit-specific information). The input assumptions used in these analyses are vetted through NEPOOL's Power Supply Planning Committee (PSPC) and its Reliability Committee, before being filed with FERC. For more background on ISO New England's development of ICR, see https://www.iso-ne.com/static-assets/documents/2019/07/loadandresourceassumptionsforfca14revision4.pptx and https://www.iso-ne.com/static-assets/documents/2019/09/pspc_a03_icr_values_fca14_excluding_mysticunits_final.pptx.

> efficiency resources) is approximately 5,000 MW higher than the following winter's net peak demand. The risk of loss of load occurs mainly during the peak load months of July and August. Therefore, the amount of installed capacity resources needed to meet the region's resource adequacy criterion of disconnection firm load no more often than 0.1 days/year is driven by the risks of load loss during July and August. Decreasing the winter peak loads would have no impact on New England ICR. New England ICR would be lowered only by lowering the summer peaks, assuming all else being equal.

ISO New England uses a probabilistic simulation model to provide estimates of the expected number of days per year in which supply would be insufficient to meet demand.[6] Under the most recent ISO New England assumptions—which rely on an hourly load shape from 2002, net of estimated future reductions from behind-the-meter solar—the simulation model finds that only days in July and August contribute to the ICR.

ISO New England staff did not preclude the possibility that, should winter and summer peak loads converge (through increases in winter loads, decreases in summer peak loads, or addition of solar generation that reduces the summer peak but not the winter peak), future winter loads could begin to impact the ICR calculation.[7] This could become true even if the maximum winter load (or load net of solar output) remains lower than the summer maximum and even if very high loads are less common in the winter than the summer; some winter hours can contribute to LOLE, even if the summer dominates the risk of insufficient capacity.

Nonetheless, we anticipate that winter loads are unlikely to affect the ICR over the next several years. The gap between summer and winter loads is currently large. ISO New England's 2020 CELT forecast shows that the coincident summer peak for 2019 was 5.3 GW (28 percent) higher than the coincident 2019 winter peak.[8] In 2029 (the last year of the 2020 forecast), summer peak is estimated to be 4.4 GW (22 percent) higher than winter peak. The projected gap continues the observed trend over the last few decades. The 2020 forecast reports that historical annual summer peaks averaged 5 percent higher than winter peaks from 1991 to 2000. After 2000, with the widespread adoption of air conditioning throughout New England, annual summer peaks have routinely exceeded annual winter peaks by a greater margin. From 2001 to 2019, annual summer peaks have been 22 percent larger than each year's corresponding annual winter peak.

While changes in the energy markets are likely to erode that large seasonal load differential, it is not clear when winter loads would contribute to the ICR. The Synapse Team reviewed ISO New England's first-ever electrification forecast, which is included in the 2020 CELT. ISO New England projects that heating electrification (e.g., heat pumps) and transportation electrification will increase ISO New

[6] ISO New England uses the Multi-Area Reliability Simulation (MARS) model to conduct the analysis.

[7] The actual computation of LOLE also reflects the fact that most thermal generation has higher capacity under peak winter conditions than under peak summer conditions, and that wind tends to produce more energy at winter peak than summer peak.

[8] Available at https://www.iso-ne.com/static-assets/documents/2020/04/forecast_data_2020.xlsx.

England's 2029 winter peak by 793 MW (relative to summer peak). This future assumes that about 13 percent of households in 2029 will have heat pumps (contributing 661 MW to winter peak) and that about 500,000 EVs—or 4 percent of total New England light-duty vehicles—will be on the road in 2029 (contributing 132 MW more to winter peak than summer peak).[9] Electrification may occur faster than ISO New England expects.[10] Extrapolating the ISO forecast to a situation in which 100 percent of homes are converted to heat pumps and 100 percent of light-duty vehicles are electrified in 2029 suggests that winter peak would increase by 8,662 MW more than summer peak. While this number exceeds the projected 6,500 MW winter peak gap projected by ISO New England for the late 2020s, complete electrification of residential space heating and light-duty vehicles would require extraordinary efforts by government and other parties. On the other hand, New England may experience significant electrification of larger vehicles (e.g., rail, buses and trucks), non-residential space heating, and industrial processes, as well as expanded solar generation, all of which would likely contribute to closing of the seasonal load gap.

These winter load projections are complicated by the paucity of historical data on heat pump operation or EV charging to develop statistically valid and reliable load shapes. Our current understanding is that for the purposes of developing future ICRs, ISO New England is planning to combine its forecast of heat pump demand (in GWh) with its forecast of "conventional" demand (i.e., demand absent any impacts from distributed solar or energy efficiency). ISO New England will then apply the 2002 hourly load shape to this load component to determine the hourly loads for all future years. Next, ISO New England will apply a separate, EV-specific hourly load shape to their annual forecast of EV charging loads.[11] These hourly load impacts will then be added on an hour-by-hour basis to (a) the conventional demand plus heat pump load impacts and (b) the anticipated hourly load impacts from distributed solar to develop total hourly loads for each studied year. This aggregated total load will then be analyzed by ISO New England's to determine which days (from which seasons) impact the ICR. In effect, this means that while EVs have the potential to modify the overall hourly load shape (and thus potentially change the contribution of winter peaks to the ICR), for now, heat pumps do not.

We caution that these processes are still in development, and that what is represented above is our current understanding of ISO New England's future plan for calculating the ICR at the time of this report's writing. Given that this is ISO New England's first electrification forecast, it is possible that this process may be modified between the publication date of this report and when the next ICR is

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[9] ISO New England's 2020 forecast assumes that heat pumps have an impact of 0 MW on summer peak in all years and all regions.

[10] For example, actual load reductions from energy-efficiency programs and behind-the-meter solar have exceeded ISO New England's early forecasts of these resources' effects.

[11] More information on the EV load shapes is available at https://www.iso-ne.com/static-assets/documents/2020/04/final_2020_transp_elec_forecast.pdf. Detail on the ISO's heat pump forecast is available at https://www.iso-ne.com/static-assets/documents/2020/04/final_2020_heat_elec_forecast.pdf.

formulated. In addition, we anticipate that ISO New England will likely revisit this methodology in future years as more data on heat pumps and EV charging becomes available.

2. POTENTIAL NEW WINTER PEAK BENEFITS

Beyond winter peak benefits associated with ISO New England's capacity market, the Supplemental Study group has indicated interest in describing avoided costs for DER portfolios that reduce electric and/or natural gas consumption in critical winter periods. In this section, the Synapse Team provides an overview of each of the new potential avoided cost categories, along with a brief methodological description of how this avoided cost could be calculated in a future AESC Study.

The first set of potential avoided costs refer to those avoided costs which do not necessarily constitute new categories but rather additional considerations about the existing categories of avoided costs with a focus on winter peak periods. These potential benefits include:

1. Electric energy costs, intrastate electric DRIPE, and interstate electric DRIPE: The 2018 AESC report contained a user interface workbook that includes hourly avoided energy costs for future years based on the ISO New England's hourly load shape from 2002. This load shape informs the resulting avoided costs for electric energy, intrastate electric DRIPE, and interstate electric DRIPE in AESC 2018.[12] However, it is possible that the 2002 load shape may not necessarily completely capture the kind and magnitude of winter peak load events observed in the past several years (e.g., since winter 2014) and may thus cause AESC to under-represent winter peak energy and DRIPE prices in some or many hours.[13]

   First, ISO New England chooses 2002 as the modeled year because that year is consistent with the load shape assumptions used by Northeast Power Coordinating Council (NPCC) for resource adequacy and has "adequate peak eliciting weather."[14] According to 2018 analysis by ISO New England, 2002 featured seven summer days where weather exceeded ISO New England's 50/50 threshold, which ranked third among all years from 1960 through 2016. 2002 also featured two summer days where weather exceeded ISO New England's 90/10 threshold, which ranked it tied for first (with three other years) among all years from 1960 through 2016. For this reason, ISO New England interpreted that the 2002 load shape adequately captures summer peak load shapes. Note that ISO New England has not previously characterized whether the 2002 load shape includes peak-eliciting weather for winter months, as it does for

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[12] Note that in previous editions of AESC, where the authors were not required to model all 8,760 hours of each year in the study period, other sources were used to develop the on- and off-peak seasonal load shapes.

[13] In AESC 2018, the Project Team's model was calibrated to hourly grid operation in 2016, assuming the actual hourly 2016 load shape.

[14] More information on ISO New England's reasoning for using a 2002 year can be found in the 2018 report *Review of Assumptions Relating to ICR and Related Values - 2002 Load Shape*, available at https://www.iso-ne.com/static-assets/documents/2018/04/a7_pspc_review_icr_2002_load_shape_04182018.pdf.

summer months. Upon request from the Synapse Team, ISO New England is investigating this issue.[15]

If it becomes apparent that the 2002 hourly load shape is not representative for modeling winter peak weather, the AESC Study Group has a few options to consider for the next AESC study.[16] One, in addition to modeling electric energy and DRIPE values under a "main" AESC projection which continues to rely on the 2002 load shape (or substitutes the 2002 load shape with a year that is determined to have more representative—e.g., typical or average—winter weather), the next AESC could also include analysis of a "high winter peak" scenario in the production cost modeling.[17] This second modeling run would utilize an hourly load shape from a suitable winter peak year (e.g., 2014, 2015, or 2018). Program administrators could use the results from this "high winter peak" projection for DER measures that they expect to primarily provide benefits in winter hours, or future AESC authors could then merge avoided costs in the two studies with a probability weighting to create one single avoided cost stream that adequately considers both summer peak loads and winter peak loads.

An alternative approach could involve a separate statistical analysis of likely avoided costs in winter peak conditions. Production cost models like the one used to produce energy and DRIPE avoided costs in previous AESC studies are sophisticated, industry-standard models used for analyzing the electric power sector. However, these models are only as good as the inputs used to populate them. Because winter peak events are rare by definition, little data exists on power plant operations and grid dynamics during these situations, and accurately these events with a production cost model can be difficult. For example, in 2019, Synapse conducted an analysis on behalf of MassCEC to examine hourly grid dispatch during the 2018 Cold Snap. While we were able to gather data and accurately reproduce this cold snap in our production cost model, this undertaking was challenging and time-consuming. Instead, in the next AESC, the project team could conduct a statistical analysis of likely changes to energy and energy DRIPE avoided costs that result from winter peak weather events outside of the production cost model. The team would rely on published hourly data on weather, energy prices, generation by fuel, and emissions data to better understand how avoided costs might be different in 1-in-5-year or 1-in-10-year winter peak events, relative to a typical winter. These avoided costs would then be added, substituted, or averaged (i.e., with a

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[15] As of the publication date of this report, ISO New England has contacted NPCC for analysis on this issue. However, NPCC has communicated that this data is located at NPCC's office and is not available for remote access during the COVID-19 pandemic. Hourly load data are available for around twenty years; if ISO New England and/or NPCC do not provide the requested analysis, the next AESC Study could include an analysis of the representativeness of the 2002 load data.

[16] As of this report's publication, our understanding from ISO New England is that the electrification components of ISO New England's 2020 load forecast will not be published as separate hourly load shapes. Instead, because ISO New England has determined that statistically significant historical data is not yet available, the annual contributions of these measures will be grouped in with the "main" ISO New England forecast. Under this approach, we would expect that the impacts of electrification would not cause any change to load shapes or elicit any shift to winter peak in any future years.

[17] Note that the 2018 AESC Study modeled a "high load" sensitivity. While the "main" part of the load forecast, relied on the same 2002 load shape used in the main AESC analysis, in the 2018 AESC Study, the authors applied separate load shapes to the heat pump and EV components. The next AESC Study could include an application of specific load shapes for these measure types, just as was done in the 2018 AESC Study sensitivity.

probability distribution function) with the "main" AESC projection to develop a more robust forecast of winter peak avoided costs.

It is our hypothesis that quantifying and integrating the effects of load variability will likely lead to increased avoided winter energy costs in all years of the AESC projection. Because these higher avoided costs could occur in any future year, they should appropriately be added to every year of the analysis (after being scaled to reflect their relatively likelihood of occurring in any given year). However, at this time, we cannot speak to the magnitude of the probable increase.

2. Intrastate and interstate natural gas cross-DRIPE: The 2018 AESC report includes winter-specific estimates of the reduction in gas prices (and hence electric energy prices) from reductions in winter gas use, for a normal year. Electric demand response does not normally reduce loads for the entire gas day, which is the minimum unit required to reduce market gas prices. Nevertheless, some electric peak shaving that does not result in rebound (such as dimming of lights during the business day) could have a particularly large effect on gas prices.[18] Similarly, since AESC 2018 did not differentiate gas DRIPE between typical and extreme winter conditions, space-heating measures may have much larger gas DRIPE effects than other measures that reduce winter loads. The data used in AESC 2018 could then be reworked to estimate the effects of particularly peaky winter measures.

   As with energy and energy DRIPE, we estimate that accounting for this avoided cost category will lead to increased avoided costs in all years of the analysis, although the impact in any one year (as a result of scaling the factors based on probability) may be small.

3. Avoided electric transmission and distribution costs: The bulk of the electric transmission system is designed for summer peak conditions with multiple outages of generation and/or transmission facilities. In our review of avoidable transmission projects for AESC 2018, we did not identify any avoidable winter-load-driven transmission projects. However, the consultants for the next AESC Study could ask if any of the participating utilities are able to identify such circumstances as part of their distribution planning process. It is possible that some circuits/ feeders may exhibit these conditions, especially for local areas at lower voltages. Under these conditions, these avoided costs may be calculated using the methodology described in the accompanying AESC Supplemental Study Part II report on Localized Transmission and Distribution Avoided Costs.

   An analogous analysis could be performed for avoided distribution costs to determine whether DER measures could be used to avoid or defer investments in distribution infrastructure that would otherwise be needed to meet current or future winter peak demand. Some distribution projects may be driven by winter peak loads, especially with

[18] The winter energy DRIPE in the 2018 AESC Study reflects typical load conditions; as for energy, winter DRIPE may be somewhat higher, if averaged over a range of moderate and extreme weather. Peak-shaving efforts would be concentrated in the highest-value hours and days, so winter DRIPE per MWh for those efforts would be even greater.

future growth in electrification.[19] The AESC 2018 Project Team was not directly involved in how the utilities currently estimate avoided distribution costs, and it does not have access to the details of recent or expected distribution planning decisions. In a future AESC study, the utilities could examine and provide their distribution project descriptions and planning results to help identify whether there are any such projects and estimate a winter avoided distribution cost from the cost of those projects and the associated load growth.

These avoided costs are most likely to be prevalent in the out-years of the analysis, as electrification (and conventional load) grows and avoiding transmission and distribution investments become more valuable. Because avoided costs in future years are typically discounted, avoided costs that are made in a future year are less valuable than avoided costs that occur in the near-term. For example, using the real discount rate applied in the 2018 ASESC Study—1.34 percent—a $1 million of avoided costs made in 2020 and sustained for five years is worth roughly 7 percent less than $1 million of avoided costs made in 2025 and sustained for five years, on a 15-year levelized basis.

4. Avoided gas distribution costs: Reduced natural gas use is likely to avoid some load-related gas distribution projects due to potentially lower design day requirements. The avoided gas distribution cost could be estimated in much the same manner as avoided electric distribution cost. Note that the 2018 AESC Study and previous AESC studies estimate of avoided gas distribution costs were quantified at a high level with data provided by National Grid's natural gas planning group.[20] More analysis of this category (requiring data from the PA's gas planning groups) would be necessary to determine the magnitude of any additional winter peak benefits beyond the benefits that are already captured within the existing AESC process.

   In a future that has little electrification, we would anticipate that these avoided costs are more likely to become apparent and meaningful in the medium- to long-term. Conversely, in a future with large amounts of electrification, we would anticipate that natural gas use to decrease, and these avoided costs to be most prevalent in the near-term and/or small or non-existent in future years. In all situations, avoided costs that are less prevalent in the near-term but more prevalent in the medium- to long-term are reduced through discounting.

5. Avoided greenhouse gas emissions: Currently, the Massachusetts PAs employ an avoided greenhouse gas emission cost (measured in $/MWh) that is calculated by multiplying a GWSA compliance cost (measured in $/ton) by a seasonal emissions rate (measured in tons/MWh). Reductions in winter electric load, especially weather-sensitive loads, are likely to result in higher avoided CO_2 levels per MWh saved, relative to the seasonal average. In the same way that analyzing a load shape that features more

[19] Winter-peaking circuits are probably more common in Northern New England than in Massachusetts, and in Western Massachusetts than Greater Boston. Some Massachusetts suburbs were built during the 1970s and have little or no gas service; some circuits are dominated by customers such as colleges that may have limited summer operations. As space heating and transportation are electrified, residential feeders and substations may be more likely to be winter-constrained.

[20] See 2018 AESC Study (available at https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf), page 43 "Avoidable LDC margins."

representative winter peak events could be helpful to provide more robust winter peak avoided costs for energy and energy DRIPE, these same runs could be used to better inform the anticipated avoided GHG emissions rate that a DER measure could avoid during a winter peak event. As with energy and energy DRIPE, these winter peak emission rates could then be combined with the "main" AESC projections of emission rates using a probability distribution.

As with energy, energy DRIPE, and natural gas cross-DRIPE, we estimate that accounting for this avoided cost category will lead to increased avoided costs in all years of the analysis, although the impact in any one year (as a result of scaling the factors based on probability) may be small.

In the interest of completeness, we also describe the following categories of avoided costs analyzed in the 2018 AESC Study, and describe how additional winter peak benefits are unlikely to be derived:

6. <u>Electric capacity quantity and DRIPE:</u> For the foreseeable future, winter loads will not affect ISO New England's determination of the amount of capacity required, as discussed in the previous sections. Hence, under ISO New England's current ICR assumptions, winter load reductions do not provide capacity benefits.

7. <u>Improved electric generation reliability:</u> In principle, lower loads in high-load winter hours should reduce the risk of outages due to inadequate generation. At this point, ISO New England's modeling indicates that winter loads are not high enough to contribute to the risk of insufficiency. That may change over time, as winter loads approach summer loads.

3. WINTER PEAK BENEFITS IN AESC 2018

Within the 2018 AESC Study, numerous avoided cost components, including energy and energy DRIPE, were developed using 8,760-hour modeled data. For the purpose of a program administrator's current benefit-cost ratio (BCR) model and regulatory review by Massachusetts Department of Public Utilities, the Synapse Team, as required, condensed the 8,760 hours into ISO New England's four summary periods for reporting purposes: summer on-peak, summer off-peak, winter on-peak, and winter off-peak. Colloquially, the "winter on-peak period" may conjure ideas of the winter hours of the year with the highest demand for electricity or natural gas, or the winter hours with the highest prices. However, within the context of AESC's conventional costing periods, winter on-peak includes all weekday hours from 7 AM to 11 PM in the months of October, November, December, January, February, March, April, and May, or roughly one-third of the yearly hours.[21] Because the avoided costs calculated within the winter on-peak period are a load-weighted average over all modeled prices, the "peakiest" hours or most extreme prices tend to get smoothed out and are not obvious components of the resulting "winter on-peak" avoided costs.

The 2018 AESC Study included a user interface, an Excel workbook containing the avoided costs and loads for every region analyzed in AESC, for every hour of the year. While this data is the foundation of the "condensed" avoided costs for the four conventional costing periods, Program Administrators in Massachusetts and other New England states have the option of incorporating customized load shapes that can then be multiplied by all 8,760 hours—or just a subset—to determine user-defined avoided costs. This data is provided to assist the Study Group in determining what subsets of winter or any other user defined hours appear to be the most useful for screening measures in their existing BCR models. Per the request of the AESC Supplemental Study Group, the Synapse Team has extracted avoided costs for several time periods that may more closely fit a colloquial understanding of "winter peak." Table 1 displays illustrative avoided energy costs, for the WCMA load zone, for selected winter peak definitions.

[21] See 2018 AESC Study, October release, footnote 57, available at https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf.

Table 1. Illustrative energy avoided costs from AESC 2018 for selected winter peak definitions

		Number of hours spanned	Wholesale energy avoided cost ($/kWh)	Percent increase relative to "AESC Winter On-Peak" value
AESC Winter On-Peak value		2,907	$0.0557	-
Prices in hours that span top X% of winter loads	1%	58	$0.0918	65%
	5%	292	$0.0829	49%
	10%	583	$0.0771	38%
Prices in hours that span top X% of winter prices	1%	58	$0.1036	86%
	5%	292	$0.0919	65%
	10%	583	$0.0852	53%

Notes: All values are reported in 2018 $/kWh. All values shown are levelized over 15 years (2018-2032). All values are wholesale and do not include any additional factors, such as distribution losses or wholesale risk premiums. As a point of comparison, the Summer On-Peak value, typically used to report summary values from AESC, is $0.0429 per kWh for the WCMA region under these parameters.

These prices show the range in avoided costs that are available to resources that provide savings coincident with the periods described above. Should the EE PAs wish to screen any such measures in their BCR models, the Synapse Team recommends that these measures be evaluated only with more specific avoided costs; measures should not be evaluated using both more temporally specific avoided costs (e.g., the avoided cost associated with the top 1 percent of prices) and the conventional time period (e.g., winter on-peak).

APPENDIX A. A HIGH LEVEL DESCRIPTION OF THE NEW ENGLAND INSTALLED CAPACITY REQUIREMENT DETERMINATION METHODOLOGY

The following document, *A High Level Description of the New England Installed Capacity Requirement Determination Methodology*, was authored by Peter Wong, ISO New England's Manager of Resource Adequacy, and was provided to the Synapse Team on March 10, 2020.

A High Level Description of the New England
Installed Capacity Requirement Determination Methodology

ISO New England Resource Studies and Assessments

March 10, 2020

A. Background - General Introduction to Loss of Load Expectation (LOLE)

In general most large power systems use a probabilistic method to assess the reliability of its bulk power supply system. The most widely accepted level of system reliability is generally stated as follows:

"The loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year or not more than once in ten years". ISO New England also prescribes to this reliability/resource adequacy planning criterion.

To comply with this LOLE standard it must be calculated using a probabilistic method, and take into account the following factors that affect system reliability:

- Uncertainty of the load forecast due to weather and economic conditions
- Forced outage rates and scheduled maintenance for the various generating resources
- Seasonal variations and capacity deratings of generating resources
- Emergency operating procedures for maintaining system reliability
- Reliability benefits of transmission interconnections to other systems

The daily Loss-of-Load Expectation (LOLE) can be interpreted as the "expected" number of days per period that a system will not have sufficient generating resources to meet load at time of daily peak. There are basically two methods to calculate the LOLE values, namely: The Analytical Method and the Monte Carlo Simulation Method.

The Analytical Method is based on developing a "capacity outage" table which shows the probability of having a certain amount of capacity or more on outage. The graph of this table is also called the "cumulative margin distribution function". The values on this table reflect the enumeration of all possible outage combination with the corresponding MW on outage and probability of occurrence. This table changes whenever the generating system changes when units are retired, added, or removed for planned maintenance. The probability of each day of not having sufficient capacity to meet the daily peak load can be determined from the appropriate capacity outage table. The final step to calculate the annual LOLE is to sum the daily probabilities over the entire year to calculate the expected number of days per year. When the resource adequacy analysis includes the interface limit between the subareas, the problem is modeled as a probabilistic flow network. It becomes a highly multidimensional problem and Monte Carlo simulation becomes more suitable. So in the multi-area reliability analysis involving transmission interfaces, the Monte Carlo approach or the hybrid Monte Carlo/Analytical Approach is usually required.

The Monte Carlo Simulation Method is based on a "Roll-the-Dice" approach to determine the capacity available from each generating unit on the system based on the unit's rating and forced outage rate. The second step is to sum the available capacity in the system (or each zone for multi-area cases), and count the number of days per year that the available capacity is less than the daily peak load. The third step is to simulate the year with additional sets of random outages (each simulation is also referred to as a "replication"). The final step in calculating the expected loss of load value is to average the results for each of the individual simulations. This method requires many replications in order to obtain a reasonable degree of statistical convergence as measured by standard deviation of the reliability index. Typical cases will normally require 1,500 to 3,000 replications to obtain reasonable convergence. This method has proven to be feasible for very large systems or multi-area systems in terms of statistical convergence and reasonable computer running times.

Most state-of-the-art commercially available reliability modeling software programs use the Monte Carlo Simulation Method to calculate LOLE values for very large and multi-area power systems.

B. New England uses the Monte Carlo Method to determine New England Installed Capacity Requirement (ICR)

To determine the ICR for the Forward Capacity Market (FCM), the ISO employs the General Electric Multi-Area Reliability Simulation Program (GE MARS) Monte-Carlo based probabilistic simulation model. This model provides estimates of the expected number of days per year in which supply would be insufficient to meet demand during the CCP (known as the Loss of Load Expectation, or LOLE), taking into account the factors that affect system reliability mentioned above. The internal transmission interface limit constraints are considered in the tie benefits study but relaxed by modeling the LSR (Local Sourcing Requirement and MCL (Maximum Capacity Limit). The ICR is the amount of installed capacity needed by New England to meet its resource adequacy planning criterion of disconnecting firm load no more often than 0.1 days per year Loss of Load Expectation.

The GE MARS model, applying Monte Carlo simulation techniques, evaluates the annual bulk power system resource adequacy by simulating the availability of resources and the assumed demand on an hourly basis, taking into account resource availability assumptions and load forecast uncertainty. If the amount of available resources in the system is not adequate to meet the system load for the hour of interest, the program registers a shortage. Once the day registers a shortage hour, that day is considered to be a shortage day, disregarding the number of shortage hours in that day. At the end of the simulation, the total number of shortages days for the year is summed up and compared with the desired criterion. The “expected days” of unserved load are calculated, after thousands of Monte Carlo iterations, as the average number of shortage days during a year.

As a reliability tool mainly used for assessing the resource adequacy of the system, GE MARS captures the randomness of the resources’ outages. It does not, however, consider the operational parameters associated with the resources such as ramp rate, minimum up/down times, maximum number of starts per day, etc. In addition, operational requirements associated with unit commitment/economic dispatch; or transmission constraints associated with transmission maintenance, system upgrades or unforeseen loss of transmission elements are also not considered. Therefore, the calculated LOLE does not reflect any shortages that could arise relating to operational risks, such as under-commitment due to load forecast error in operations, loss of critical transmission elements, loss of fuel supply facilities or lack of fuel supply, etc.

C. The Current New England Bulk Power System

The current New England bulk power system is a summer peaking system. The summer net peak demand (after accounting for behind-the-meter photovoltaic and energy efficiency resources) is approximately 5,000 MW higher than the following winter’s net peak demand. The risk of loss of load occurs mainly during the peak load months of July and August. Therefore, the amount of installed capacity resources needed to meet the region’s resource adequacy criterion of disconnection firm load no more often than 0.1 days/year is driven by the risks of load loss during July and August. Decreasing the winter peak loads would have no impact on New England ICR. New England ICR would be lowered only by lowering the summer peaks, assuming all else being equal.