Appendix O

Demand Management Program Analysis and Considerations

Appendix O-1
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By Ian Burnes and Jack Riordan
8-22-2024

Introduction

1. What is the purpose of this testimony?

The purpose of this testimony is to describe and provide information about the Efficiency Maine Trust's (the Trust's or EMT's) Demand Management Program (DMP), which is incorporated in the Trust's Triennial Plan VI. The DMP will comprise three initiatives: the Demand Response Initiative, the Distributed Energy Resource (DER) Initiative, and the Large Battery Initiative.

2. Who is introducing this testimony?

The testimony is provided by the Trust's Ian Burnes, Director of Strategic Initiatives, and Jack Riordan, Program Manager.

3. Mr. Burnes, please state your name, title, and business address.

My name is Ian Burnes, and I am employed by the Trust as the Director of Strategic Initiatives. My business address is 168 Capital Street, Suite 1, Augusta, ME 04330.

4. Mr. Burnes, please summarize your education experience.

I have a Bachelor of Arts degree in Economics from Wesleyan University. I have been working at the Trust since 2009. My responsibilities include overseeing the strategic initiatives team that implements the Trust's customer tracking database, maintaining the Technical Reference Manuals, overseeing the program evaluations, and managing the Trust's resource in the Independent System Operator for New England (ISO-NE) Forward Capacity Market (FCM). I also have been leading the Trust's involvement with the Non-Wires Alternative Coordinator. Before coming to the Trust, I worked at the Governor's Office of Energy Independence and Security.

5. Mr. Riordan, please state your name, title, and business address.

My name is Jack Riordan, and I am employed by the Trust as the Program Manager. My business address is 168 Capital Street, Suite 1, Augusta, ME 04330.

6. Mr. Riordan, please summarize your education and experience.

I have a Bachelor of Science degree in Conservation Biology from St. Lawrence University. I have been working at the Trust since 2016. My responsibilities include the management of the Demand Management and Innovation Programs, management and oversight of customer data exchange between the Trust and utilities, management of various program evaluations, programmatic reporting, and support to the Trust's Non-Wires Alternative activity.

Demand Management Program Overview

7. **What is the goal of the Trust's DMP?**

The Demand Management Program seeks to increase the efficiency of electricity use in Maine by deploying measures and strategies that mitigate the impacts of demand on electricity utility transmission and distributions systems and balance the increased penetration of intermittent renewables on the grid.

8. **Please briefly describe the Demand Response Initiative.**

The Demand Response Initiative (DRI) is a traditional demand response program where participants are compensated for reducing their electricity usage when called upon to do so.

9. **Please briefly describe the DER Initiative.**

The DER Initiative is focused on using both passive and active load-shifting strategies across fleets of devices. These devices and deployment strategies are programmable and, in some cases, networked, operating in response to internal or remote dispatch signals. The initiative incentivizes participants to modify the timing of their electricity consumption from the grid -- shifting away from periods of peak demand to periods of lower demand -- which reduces overall system costs for all ratepayers.

10. **Please briefly describe the Large Battery Initiative.**

The Large Battery initiative offers performance-based incentives for the installation and dispatch of batteries at demand-metered customers.

DRI Considerations

11. **Please describe how and when DRI resources will be dispatched under the Triennial Plan.**

The Demand Response Initiative targets eligible customers through pre-qualified third-party Curtailment Service Providers (CSPs). The CSPs recruit these customers -- end-users of electricity -- and manage all aspects of demand response event participation and reporting to the Trust.

The CSP will notify the customer of demand response events the day ahead of the event. CSP notifications will be based on the ISO-NE system peak load forecast, and the CSP will be responsible for notifying the customers when an event has been scheduled. Typically, CSPs offer a variety of notification choices, including email, voicemail, phone call, text message, or machine-to-machine communication. Customers and CSPs are responsible for implementing the necessary communications so that customers are notified of the events.

When an event is called, customer equipment will be dispatched by the CSP using remote electronic signals from an internet-based controls platform. The customer-owned devices are integrated with this platform and will respond accordingly to the signal.

Dispatch event call periods will typically last for a limited number of hours and occur on weekdays from approximately 2 p.m. to 7 p.m. during the months of June through September. Initially, there will be no option to participate in weekend events. If weekend events are called in the future, they will be optional. A program holiday calendar will be provided to all participants, and no events will be called on these days. A typical season will include two to eight dispatch events.

12. What are the eligibility criteria that the Trust will utilize to screen DRI participants?

To be eligible for the Trust's DRI, customers must have an account with a Maine electric utility at the site of the proposed project and pay into the Trust's Electric Efficiency Procurement through their electric bill. The customer must have an electrical demand greater than the total demand reduction from the measure proposed at each site and have an interval meter for performance validation. Customers must enroll in the program prior to the relevant enrollment deadline, which is typically May 31 for summer dispatch programs. The following properties or facilities will be excluded from eligibility under DRI:

- Properties/facilities that do not have working interval meters (customers, at their expense, may choose to install an interval meter if they currently do not have one);
- Properties/facilities that are not served by a Maine electric utility; and
- Properties/facilities customers (or properties/facilities) that do not pay into the Trust's Electric Efficiency Procurement.

To receive compensation under DRI, reductions must offset coincident, on-site consumption of grid-supplied energy. The reductions must be measurable, and the customer's equipment must be grid-connected. Projects must also be reasonably expected to provide the load reductions forecasted.

13. How does the Trust market to and enroll customers for DRI?

The Trust will continue to partner with qualified CSPs to complete customer recruitment and enrollment. CSPs will work directly with customers and provide the demand management expertise and services to assist customers with the identification of demand management solutions that align with the Trust's incentive program requirements that are technically feasible. The Trust has a dedicated DRI webpage that provides program requirements and application materials. In addition, the Trust leverages its existing customer and vendor relationships to make potential participants aware of program offerings. The Trust and its third-party evaluators and technical assistance providers will support CSP program staff to address any additional information needs of the program participants.

14. What is the CSP role in DRI?

CSPs support the customer and maximize the customer's curtailment performance and incentive. Enrolling through an approved CSP is a requirement of the program at this time, but customers may choose any Trust-approved CSP. The Trust will maintain a list of approved CSPs for reference by potential program participants. The Trust will also build upon relationships with customers who have participated in past Trust programs and make appropriate connections between CSPs and potential program customers. Recognizing that customers may decide to opt out of the program at any time, the

Trust will work with CSPs to enroll customers on an annual basis and aim to retain participants in subsequent years.

15. How is a DRI participant's baseline and performance calculated?

The first step to assessing a DRI participant's performance during a demand response event is to calculate the customer's typical power use and estimate what the power use would have been if no dispatch event were called.

DRI will use a top 5-of-10 model for baseline calculations. This approach is comparable to the baseline calculation methodology of ISO-NE's demand response program.[1] It involves looking at the customer's last 10 "similar days" and selecting the top 5 of those days to serve as a baseline. Similar days are days of the same type (weekday) that are not holidays and did not see a call for a demand response event from either ISO-NE or a utility. The Trust may alter this baseline methodology as long as customers are unable to predict the days on which the baseline will be set. Days on which a customer has a scheduled shutdown are not considered similar days. For shutdown days to be excluded from the baseline calculations, customers or their CSP must inform the Trust of the shutdown with at least one week's notice.

The day of a demand response event may be hotter than the previous 10 similar days, and the customer's load may be higher that day. To account for this, the baseline is adjusted to reflect the customer's load during the demand response event day. This is called the baseline adjustment—the difference between the customer's average load during the hour starting the 2 hours before the event and the load during the event day. A customer's load also may be lower during an event day than the last 10 similar days because the customer is responding to the demand response event. In this case, a baseline adjustment will not be made – a baseline adjustment will never penalize a customer.

Performance for an individual demand response event is calculated by subtracting the customer's average power (kW) use over the demand response event from the customer's adjusted baseline power. The Trust reserves the right to account for any anomalies in the customer's interval data and adjust the baseline to accurately reflect the customer's performance. Although rare, sometimes the baseline adjustment results in a baseline at a level higher than the customer ever uses. A customer cannot curtail more load than they use. To avoid this situation, the performance on the event day must be smaller than the customer's maximum load during the last 10 similar days. Negative performance is not penalized.

16. How will utility data be used to evaluate DRI performance?

Customer performance will be measured using interval data collected through the utility meter. All participants are required to have metering capable of sending real-time interval data. In most cases, the customer already has a utility interval meter that records and transmits the information needed to

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[1] See, e.g., ISO New England Inc., *Measurement and Verification of Demand Reduction Value from Demand Resources*, Manual M-MVDR, Revision 6, 2014, slides 21-34.

complete the performance calculations. If this is the case, no other metering is required to participate in DRI. Customers who do not have an interval utility meter may also participate, but the customer or the CSP must install revenue grade metering to measure the customer's electrical load in at least 15-minute intervals for the entire dispatch season. This data must be shared with the Trust. The cost for this added metering is the sole responsibility of the customer or the customer's CSP. The participant and the CSP must ensure that the Trust receives the interval meter data for performance validation. The establishment of the participant's baseline and performance validation will not be completed without interval data.

In FY2025, the Trust sought to reduce the barriers to program entry for commercial customers enrolling with CSPs by allowing customers with certain types of behind-the-meter (BTM) generation to participate in the program. With these changes, the burden of proof falls on both the customer and their representative CSP to provide all the necessary information to the Trust and its sub-contractors to adequately rule out the gaming of baselines or manipulating demand reduction performance during targeted events. Failure to provide sufficient data to the Trust will result in the reduction in, or forfeiture of, potential performance incentives.

17. How will the Trust calculate and distribute incentives for DRI?

The incentive award will be capped based on the demand reduction in grid-supplied energy (kW) as validated through meter data analysis. The Trust will adjust final incentive amounts at the end of a season as necessary to reflect the validated demand reduction. The incentive rates are determined by the average amount of demand that is curtailed across every event of the demand management season. If a customer chooses not to participate in an event, the Trust will calculate the baseline and performance results as if the customer had participated. This will likely result in a low calculated performance for that event, which will reduce the customer's average performance and incentive for the season. Incentive payments for the program will be made after the season ends. All incentives will be based on a customer's validated performance and paid after the season is over. Additionally, for a customer to receive the performance incentive, a customer must remain in the program for the entirety of the season. A customer cannot enroll partway through a season and receive the performance incentive for fewer events than all the other program participants.

18. Will DRI customers be penalized for poor performance?

The DRI is a voluntary program and will not penalize customers for poor or non-performance. If a customer chooses not to participate in an event, the Trust will calculate the baseline and performance results as if the customer had participated but delivered zero reduction. This will result in a lower calculated performance for that event, which will reduce the customer's average performance and incentive for the season. DRI will allow customers a certain amount of shutdown days per season. Shutdown days are typically related to facility maintenance requirements and are limited to 10 per year. Shutdown days will be excluded from the customer's baseline calculations and will generally benefit calculations of the customer's seasonal performance.

DER Initiative Considerations

19. Please describe the different measure categories within the DER Initiative.

The DER Initiative will initially be focused on two equipment categories: managed charging of electric vehicles (EVs) and small battery systems. Each of these categories can be further broken into two measure categories: intervening at the time a customer is purchasing new equipment or enrolling a customer after they have already made a purchase. Each of these four situations represents a different demand management measure in the DER Initiative.

Smart Charger

For managed EV charging, the first measure involves encouraging a customer to pair the purchase of a new or used EV with home charging infrastructure that connects to the internet and can maintain a schedule. The Trust will refer to this measure as a Smart Charger. The Trust's surveys indicate that 85% of electric-only (or "BEV") owners use Level 2 (40-60 Amp 220V) chargers at home. Absent an incentive, a Level 2 charger with no connectivity or scheduling capability or even a 40-60 Amp 220V outlet is the most affordable option. Offering an incentive to offset the incremental cost of a Smart Charger at the point of EV purchase has shown to be the most successful strategy for incentivizing customers to join managed charging programs.

Open Access Charging

In Triennial Plan V, the Trust developed and launched an EV charging management initiative focused on offering incentives to customers who have already purchased a networked charger and/or an EV that supports remote, onboard charging management control ("telematics"). The program has effectively employed this strategy with the use of a distributed energy resource management ("DERMS") platform. Customers who do not have a supported, internet-connected home charger or a vehicle with a telematics solution cannot participate in this strategy. The Trust will refer to this measure as an Open Access Charging Incentive.

Open Access Battery

For customers that already have, or are choosing to install, a supported battery system, the Trust will offer an opportunity to enroll projects in a pay-for-performance capacity program through its DERMS platform. This is a continuation of an offering that the Trust initiated in Triennial Plan V. The Trust will refer to this measure as an Open Access Battery Incentive.

Renewable Reliability

The Trust will also look to leverage customer interest in emergency back-up power into a battery system that can, during non-emergency periods, dispatch the batteries' stored energy to create savings for all ratepayers. The Trust will work with aggregators to offer customers affordable options to install batteries in conjunction with an existing solar system or at the same time as a new solar system, since batteries on their own are not eligible for net metering. The Trust uses the term aggregators broadly to refer to private enterprises that offer customers the services of a piece of equipment, like a battery, and then monetize energy attributes of that equipment. This term is meant to be inclusive of original equipment manufacturers (OEMs), third-party electric load aggregators, and third-party owners. For this measure, the program will pay the incentive directly to the aggregator who will manage all aspects of the transaction. In doing so the Trust will create customer protection mechanisms to ensure customer value and guard against predatory sales practices. The Trust will refer to this measure as Renewable Reliability.

20. What are the eligibility criteria for each of the DER Initiative measure categories?

To be eligible for any of the DER Initiative measures, customers must have an account with a Maine electric utility at the proposed project's site and pay into the Trust's Electric Efficiency Procurement.

To be eligible for a Smart Charger incentive, the pre-approved OEMs must ensure that the charger is configured to have a default off-peak charging schedule. The customer must be able to opt out on any day, but the charger must automatically revert to the predetermined off-peak schedule the following day. Customers and OEM must agree to periodically share key charging data under a confidentiality agreement for the purpose of measurement and verification.

To be eligible for the Open Access Charging and Battery incentives, equipment must be deemed compatible with the Trust's DERMS requirements and include the capability to allow for dispatch controls programming.

To be eligible for Renewable Reliability, the participating aggregator will be subjected to a certification process. An aggregator's certification may include review and approval of customer contracts, outreach materials, and sales activities. These entities must demonstrate to the Trust that they are able to manage the entire process of customer engagement, including enrollment, equipment installation, equipment commissioning, and dispatch, for the agreed-upon term. The load-aggregating entities will enter into a service level agreement with these customers. The agreement will guarantee the delivery of "reliability services" to the endpoint customer for the duration of the load-aggregating entities' term with the Trust. While the primary focus of Renewable Reliability will be residential customers, small commercial customers taking volumetric service will also be eligible.

21. How does the Trust propose to market and enroll customers for the DER Initiative?

Each measure category will have its own marketing and enrollment strategies. Across all measure categories the Trust will establish measure-specific web pages that list requirements and application materials. The Trust will implement online advertising strategies where applicable. In addition, the Trust will leverage its existing customer and vendor relationships to make potential participants aware of program offerings. The Trust's program delivery staff will also support potential customers and project developers in assessing potential customer participation.

For the Smart Charger measure, OEMs will serve as the primary fulfilment and program partner. As demonstrated within the Innovation program's Level 2 Smart Charging Pilot, vendors can set up white-labeled online storefronts to apply instant rebates and volumetric discounts directly to customer's purchases. The Trust's goal with this program is to establish a group of pre-qualified, smart charger manufacturers with direct-to-consumer sales capability to serve as equipment partners; other programs in the Northeast have had the most success when these programs allow customers to choose between a variety of pre-qualified manufacturers of supported equipment. As discussed in Appendices L and H, EV Accelerator (EVA) participants will be required to participate in this measure. This will require the DMP to work closely with the dealership's sales staff to integrate this measure into their sales process.

For Open Access Charging and Open Access Battery incentives, the Trust will work to provide pathways for customers with existing devices to participate in the program but will likely de-emphasize this measure from a marketing and outreach perspective.

Renewable Reliability will be administered through partnerships with pre-approved load aggregating entities as discussed above. The Trust will rely extensively on the aggregators to directly market and enroll customers.

22. Please describe how and when each DER Initiative measure will be dispatched.

The Smart Charger measure will not be actively dispatched. The measure will rely on a schedule that delays the initiation of charging until no earlier than 9:00 in the evening. As discussed above, customers may opt out of the schedule if they have an unusual or urgent charging need, but the charger will automatically revert to the scheduled operation the following day.

Customers participating in the Open Access Charging and Open Access Battery measures will be connected to the Trust's DERMS platform and the Trust will dispatch the measure during ISO-NE peak conditions. Customers will be notified ahead of time and will have the opportunity to opt out. Open Access Battery devices will be dispatched through targeted demand response events between 30 and 60 times per summer capacity season. The Trust will offer Open Access Battery participants the option to participate in monthly RNS dispatch events.

The primary target for Renewable Reliability will be the ISO-NE peak. To the extent that it does not conflict with primary targets, the program will also dispatch to reduce monthly RNS peaks.

23. How does the Trust propose calculating and distributing incentives to participants in the DER Initiative and monitor device performance?

The Trust's incentive calculations will vary by DER Initiative measure.

The Smart Charger measure incentive is designed to help bridge the incremental cost between home charging infrastructure that can connect to the internet and maintain a schedule (a "smart charger") and the lowest cost alternative charger capable of providing a 40-60 AMP charge. The Trust will have an agreement with the OEM's participating in the program to monitor the ongoing functionality of the equipment and the frequency that customers opt out of the schedule.

Open Access Charging participants will be paid a one-time incentive for enrolling, in addition to a recurring annual incentive payment for continued participation, verified based on device connectivity. The Trust will have visibility into device performance through its DERMS platform. The Trust will offer increased incentives to Open Access Battery participants who choose to participate in monthly RNS dispatch events.

Incentives for Open Access Battery participants will be based on performance verification completed after the seasonal peak demand dispatch window is closed and will be paid based on the amount of kW capacity made available during these dispatch windows. Performance verification will be completed for all installations and be based on analysis of metering data for the battery storage systems. The Trust will offer one year commitment to Open Access Battery participants with an opt-out re-enrollment in the following curtailment season. The Trust will offer increased incentives for Open Access Battery participants who choose to participate in monthly RNS dispatch events.

For Renewable Reliability, the Trust is planning on entering into 5-year contracts with certified aggregators. Initially Renewable Reliability will offer $200 per kW/year to be paid directly to the aggregator based on the amount of capacity made available during targeted peak conditions. Through discussions with potential participating aggregators, the Trust understands that there is balance with pay for performance incentives. If the Trust pushes too much risk on to the aggregators, the price of participation will be higher. As a result, the Trust has opted to incentivize the aggregators based on what they can control: the connected and responding battery systems. In the Renewable Reliability measure, the Trust will call events targeting monthly RNS peaks with allowances for high probability reliability events.

To illustrate the point, assume that a hypothetical aggregator has enrolled twenty 10 kW systems in the Efficiency Maine Renewable Reliability program (totaling 200 kW of total capacity). Under its agreement with Efficiency Maine, they are expected to dispatch in response to the Trust's signal during RNS and ISO system peaks. During a monthly RNS peak call, only half of their enrolled systems responded. The systems that did respond provided their maximum capacity output for the required period. The aggregator will be paid the program's $200/kW incentive times 100 kW for a total of $20,000.

The Trust will rely on direct reports from the aggregator's DERMS but will verify performance through a third-party evaluator that will conduct settlement evaluations as needed to verify those claims.

Large Battery Initiative

24. **Please describe the eligibility criteria for the Large Battery Initiative.**

The following are requirements for projects to be eligible for funding under the Trust's Large Battery initiative in Triennial Plan VI.

- The energy storage system (ESS) must be installed behind-the-meter with non-export interconnection agreement;
- The customer's facility must be located in Maine and have an account with a Maine electric utility;

- The customer's facility must have a demand meter and the facility must have a peak electric demand greater than the total demand reduction anticipated from the energy storage technology;
- The ESS must be able to collect and transmit 15-minute interval data to the Trust;
- The ESS must be designed to maintain a minimum 80% battery round-trip efficiency;
- The ESS must carry at least a 10-year manufacturer's warranty; and,
- The ESS must be UL-listed or certified by another nationally recognized testing lab and be recognized as meeting all safety requirements;

Electricity customers receiving service at transmission voltage (44 kilovolts or more) and sub-transmission voltage (means 34.5 kilovolts) are not eligible for the program.

25. Please describe how the performance-based incentives will calculated for the Large Battery Initiative.

The Trust will require a minimum of fifteen three-hour ESS dispatches per summer season when electricity demand on the ISO-New England grid is at peak demand conditions. Timing of the ESS dispatch events are the sole responsibility of the participant and will not be dictated by the Trust. The goal of the program is to reduce facility electric load during the ISO-New England peak system hour or the installed capacity (ICAP) hour.

The Trust plans on providing an incentive award of $200/KW of validated reduction in grid-supplied energy if the ESS was dispatched during summer hours targeting the ISO NE ICAP hour. The system must be deployed at least 15 times per summer season (June, July, August, and September).

Following an evaluation period in the early fall, the Trust will verify performance and calculate incentives. The Trust will calculate incentives by taking the average performance of the dispatched energy storage capacity across all fifteen (15) dispatch events using 15-minute interval data. The Trust will discard dispatch events from the incentive calculation where those events occur when ISO NE load is not within 15% of the peak monthly load. For example, if the ESS dispatched 6 times in June, and 2 events occurred when ISO NE was not within 15% of the summer peak load, there would be 4 qualifying dispatch events for the month.

Customer performance will be measured by interval data collected at the ESS inverter or through the ESS management system. All participants are required to install revenue grade metering capable of providing 15-minute interval data. The Trust must have access to this data to complete performance validation.

Incentives will be distributed in the fall after performance is validated. A notification of the incentive award will be sent to each participant. This process will take place each fall for a total of five years. The Trust will reserve the right to delay incentive payments due to issues such as missing interval data or abnormalities in event performance that necessitate further data review.

26. **Please explain how the Trust plans on requesting and receiving funding to support the Large Battery Program.**

The Trust proposes to maintain the practice established in its June 1, 2023 Request for Significant Change in the Triennial Plan V docket (2021-00380) where the Trust will not request funding from the Electric Efficiency Procurement until the ESS projects are installed and deemed likely to perform. The Trust requests approval to commit up to $10 million in Procurement in each of the three years of Triennial Plan VI to the large battery initiative. At incentive levels that the Trust is offering, this funding would allow the Trust to award contracts for up to 10 MW of new energy storage capacity in each year.

The Trust forecasts that projects in the development pipeline will require more than two years to become operational. The Budget and Performance Metric reflect two projects that the Trust has made commitments to but have yet to get final interconnection approval from ISO-NE.

With each year's Annual Update, the Trust will provide information on the development status of pending large battery projects. Each year, the Trust will include a forecast for the total incentive payment amount required for the upcoming ISO-New England summer peak season based on the project capacity that is already operational or expected to become operational. Consistent with the recent approval of the 2024 significant change to Triennial Plan V, the Trust proposes that the Commission would then issue a procurement order for the utilities to collect the total forecasted incentive amount, and that this amount would be remitted to the Trust by July 1 of each year. The Trust plans to request annual funding levels that assume full performance of the battery portfolio under contract; any unspent funds relating to the underperformance of the portfolio would be deducted from future years' procurement requests.

DMP Cost-Effectiveness Considerations

27. **Please explain the Trust's approach for calculating the cost-effectiveness of the DMP.**

The Trust uses the methodologies and assumptions consistent with other measures included in Triennial Plan VI, with three exceptions that are needed to account for the dispatchability of demand management measures.

The first difference is that the Trust used uncleared values for benefit streams, assuming that this program would not be bid into the ISO-NE Forward Capacity Market (FCM) in its initial years since auctions for those years have already been completed. This contrasts with the rest of the Trust's energy efficiency portfolio, which uses the cleared values and bids those measures into the FCM.

A second difference is that for the estimation of Wholesale Capacity Demand Reduction Induced Price Effects (DRIPE), the Trust's analysis reflects this as the net present value (NPV) of the *Avoided Energy Supply Components in New England: 2024 Report* (AESC 2024).[2]

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[2] Synapse Energy Economics, Inc., *Avoided Energy Supply Components in New England: 2024 Report,* Prepared for AESC 2024 Study Group, March 15, 2024.

Because the Trust is not going to bid this program's capacity savings into the capacity market, the savings are "uncleared" and do not produce direct avoided costs within the capacity market.[3] However, these measures still provide system benefits by impacting ISO-NE's forecast of load, which is one of the inputs used to develop prices in the capacity market. The Trust applies a scaling factor that can be thought of as a measure of the efficiency of load reduction in reducing ISO-NE's forecast of load.[4] The Trust used the AESC Appendix K workbook to estimate the appropriate scaling factor based on the dispatch characteristics of the measure. This factor is then multiplied by the uncleared capacity or uncleared capacity DRIPE avoided cost (calculated using the AESC 2021 User Interface) and the measure's capacity savings and seasonal coincidence factor to provide the final benefit value.[5]

28. Please comment on the cost-effectiveness of the DMP.

The estimated benefit-cost ratios for each measure can be found in Appendix O-2, Demand Management Program Cost-Effectiveness Screening.

29. Does the Trust include avoided RNS value in its calculation of cost effectiveness?

No. The Trust has taken an approach to quantifying "statewide average value of avoided marginal transmission and distribution costs"[6] that adheres strictly to the analytical framework described in AESC 2024. Broadly this approach quantifies the cost of T&D infrastructure that would not have to be built because of the load reductions associated with a measure. This is a contrast to the value of RNS charges that are the costs of existing infrastructure and theoretically recoverable regardless of future load levels. If Maine successfully avoids RNS costs they will either be recovered from another New England state or from all of New England in a subsequent year. The Trust recognizes that there is real value for Maine ratepayers in attempting to avoid RNS charges and has targeted the monthly peaks with several measures. Appendix O-2 estimates the value of RNS for each measure understanding that it depends on how successful the Trust is in hitting the monthly RNS peaks.

30. What is the Trust's proposed budget for the DMP?

Please refer to Appendix A, Budget and Performance Metrics, and Appendix B-2 Program Roll-Up.

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[3] AESC 2024, p. 384.

[4] AESC 2024, p. 394-417.

[5] AESC 2024, p. 394-417

[6] 35-A MRS §10110(4)(A)2

31. **What is the Trust's proposed demand reduction target for the DMP?**

See Appendix O-2 for summarized targets for Triennial Plan VI demand reductions through the DMP. Target reduction amounts (MW) are expressed by measure (enrolled and as evaluated) for each year of the Plan.

32. **Does the Trust foresee further incentivization of demand response/load shifting projects that will enhance Maine's non-wires alternatives solutions?**

Demand response and load shifting can play a critical role in providing non-wires alternatives (NWA) resources in specific locations that serve to defer or displace traditional grid investments. Due to the locational value of NWA solutions, increased levels of incentives may encourage needed participation on targeted circuits. The Trust will offer additional incentives to those customers in locations where NWAs are being pursued. NWA solutions are screened for cost-effectiveness on an individual basis, as each project's economics can vary considerably. For this reason, the Trust will not recommend a fixed incentive amount for resources that contribute to an NWA solution. Instead, the Trust will determine incentive amounts based on each specific project's economics and as they compare to other NWA resources and the traditional transmission and distribution options.

33. **Does this conclude your testimony?**

Yes.