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April 23, 2021

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: DG Interconnection – D.P.U. 20-75

Dear Secretary Marini:

On behalf of NSTAR Electric Company d/b/a Eversource Energy ("Eversource"), enclosed is Eversource's response to the request by Department of Public Utilities on March 23, 2021 to develop a system planning analysis proposal to implement the distribution system assessment process.[1]

Thank you for your attention to this matter. Please contact me if you have any questions regarding this filing.

Sincerely,

John K. Habib

John K. Habib

Enclosures

cc: Katie Zilgme, Hearing Officer

[1] D.P.U. 20-75, Hearing Officer Memorandum at 3 (March 23, 2021).

D.P.U. 20-75 System Planning Memorandum

1. INTRODUCTION

In its December 2020 filing in response to the Department's Straw Proposal in D.P.U. 20-75, NSTAR Electric Company d/b/a Eversource Energy (Company) proposed a comprehensive ten-year distribution system assessment to be performed on a yearly basis, that considers infrastructure investment in consideration of clean energy and climate policy objectives. The driver for this assessment is the growth in distributed energy resources (DER) in key areas, especially Southeastern Massachusetts (SEMA), leading to saturation at substations, and resulting in the need for system modifications to provide the capacity and operational flexibility needed to serve customers.

While the Company fully supports the goals of the Department's Straw Proposal it is important to reiterate that the Company's traditional distribution and transmission system planning process is designed to support the Company's public service obligation to provide safe and reliable electric service to all customers regardless of DER impacts. The Company's traditional system-planning analysis to develop annual and long-term plans for load customers necessarily involves a holistic view of engineering needs across the distribution system, focused on the goal of providing safe and reliable service. The Department's Straw Proposal recognizes that the incorporation of broad, policy-related assumptions to the traditional system-planning process would introduce assumptions that do not necessarily correlate to the Company's obligation to provide safe and reliable service to customers.

Therefore, it is important to clarify that the Company does not support extending the system assessment and the stakeholder process to the development or review of system planning criteria. Planning criteria rest on a series of standards, engineering parameters and other delineations that are critical to the safe and reliable operation of the distribution system for the benefit of customers that support and depend on that system. This distinction is critical to Eversource, as it remains the sole responsibility of the Distribution Company to provide safe and reliable electric service to its customers under the Department's purview.

High DER penetration especially at saturated stations requires Electric Distribution Companies (EDCs) to develop a comprehensive, holistic approach to system planning considering the integrated impacts of both load growth (including electric vehicle (EV) adoption, energy efficiency, demand response, sector conversion, etc.), as well as DER adoption, rather than looking at these two dynamics as separate and independent activities. Therefore, any assessment of long-term system planning needs should identify upgrades that provide a broader benefit and can accommodate various types of load growth, as well as high penetration of DER. Not doing so may result in upgrades constructed that are either sized inadequately or would need to be upgraded prematurely.

Naturally there are synergies and overlaps in the upgrades and activities undertaken to integrate DER safely and reliably and the planning activities to accommodate new load types and provide reliable, resilient service to customers. Integrated system planning drives the most optimal infrastructure solution set that yields value to not just DER enablement but, simultaneously, much broader benefits for many more customers.

To enable this integrated planning approach, Eversource is developing a probabilistic scenario-based DER adoption rate and load forecast methodology to evaluate the system's performance and assess the need for substation capacity upgrades over the ten-year planning horizon. Using a Scenario Planning approach, Eversource seeks to build on scenarios starting with the base need to reasonably forecast DER and load growth, but then build on that base scenario by also projecting EV growth or gas to electric sector conversion. Running multiple scenarios provides system planners with the full scope of system needs to inform sizing of infrastructure upgrades appropriately.

In proposing a ten-year integrated distribution assessment, Eversource is considering short-term and long-term upgrades to the electric power system (EPS) that will meet the capacity, reliability, and operational flexibility required to serve all customers. One of Eversource's key planning objectives is to provide the same level of safe, reliable service to DER customers that we provide to our load customers. This implies that the EPS should preserve the safety and reliability under normal conditions, emergency conditions, and scheduled maintenance conditions. The assessment includes the following general steps:

1. **Define and establish planning scenarios**, sub regions or study areas, modeling assumptions and the scope and drivers for system expansion, applying Eversource planning criteria.
2. **Forecast deployment** of future large- and small-scale DER, in alignment with the Commonwealth's clean energy and climate objectives.
3. **Assess impact of high DER penetration** on the bulk substations and distribution feeders applying Eversource Distribution Planning criteria as well as impacts on the transmission system applying NERC, NPCC and Eversource Transmission Planning criteria. This analysis leverages the same advanced models, planning tools and methodologies currently used in steady-state and transient analyses to assess system deficiencies and needs for providing adequate capacity, reliability, voltage and power quality to all customers.

4. **Determine transmission and distribution upgrades** required to reliably integrate existing and future DER while maintaining a safe and reliable system, including upgrades that benefit more than one interconnecting facility or distribution customers at large.
5. **Define and allocate system capacity** between DER customers and all customers. This step will determine the portion of upgrades that provide operational flexibility and reliability benefits for all customers.

The electric power industry is undergoing significant change with increasing customer expectations for reliability and resiliency; widespread adoption of new, often disruptive, technologies; and a rapidly evolving regulatory landscape. These changes and other advancements have not altered the basic mission of the distribution system, but have impacted the way we way approach planning, the data sources and study methods, scenarios and simulation cases, and the range of possible solutions considered for mitigation.

Eversource is therefore proposing a comprehensive distribution planning analysis which includes not only traditional planning considerations for expanding the system to avoid capacity, voltage, and reliability violations but also advanced planning concepts related to Non-Wires Alternative (NWA) Solutions, Battery Energy Storage Systems (BESS) and other DER applications, and integrated load/DER forecasting with EV adoption.

2. SCOPE OF THE ANALYSIS

With the growth of Distributed Generation (DG), evolving customer needs and interests, and the increasing influence of climate policy objectives on system investment decisions, the Department of Public Utilities (the DPU or the Department) finds it appropriate to consider a new long-term system planning program with the goal of assessing resilient and sustainable solutions for the interconnection of DG facilities, taking a long-term planning perspective. This is, in part, because more readily implementable, short-term, approaches may not sufficiently enable the Commonwealth's clean energy and climate objectives. The scope of analysis will include DG interconnecting at a station or a group of stations (DER Study Group) that are electrically dependent such that during a single contingency (N-1) event, transfers can be made to prevent loss or load or DG output during the event. This section will describe the methodology for defining the DER Study Group.

As documented in our initial comments to the D.P.U. 20-75 straw proposal filed on December 23, 2020, as well as the Company's response to the Department's First Set of Information Requests, Information Request EDC-1 D.P.U. 20-75, filed on April 6, 2021, the anticipated EPS upgrades, in addition to enabling renewable energy to fully support the Commonwealth's climate goals, also allow the Company to preserve and maintain safe, reliable operation of the EPS for all customers with high penetration levels of potentially disruptive DG, particularly solar PV. The key to maintaining safe, reliable operation is preserving operational flexibility under all scenarios for which the system is planned and designed to accommodate. As systems become more saturated with DG, it becomes increasingly difficult for the Company to preserve reliability and operational flexibility under all scenarios. EDCs' policies and programs need to keep pace and be consistent with State policy and programs to send the appropriate message to MA stakeholders. The capacity released by EPS upgrades allows the company to maintain its operational standards despite the challenges presented by the DG. The examples below from actual substation areas with various levels of saturation will illustrate this point. The company will utilize its advanced forecasting capabilities (see Section 4) to identify areas on the EPS with high forecasted adoption propensities.

Low DER Saturation Area

In areas of low DER penetration, substations and circuits can typically be analyzed independently and not as part of an interconnected, inter-dependent group. This is because, even though substations might still have N-1 dependency, the DER penetration has not reached the critical point of affecting the reliability and operational flexibility of the larger EPS. Individual and nearby substations are not saturated to the point of restricting permanent, emergency, and planned system reconfigurations. The low DER penetration scenario is illustrated in Figure 1 below. In this scenario, lines 1, 2, and 3 provide transfer capability between substations A-C, C-D, and B-D, respectively, and Line 4 provides transfer capability between Circuits 1-4 and 4-3. In this system, reliability and operational flexibility are not affected because system reconfigurations under contingent conditions do not result in adverse conditions (thermal issues, steady-state or transient voltage violations) at individual substations or adjacent substations. Moreover, each substation can be analyzed independently to determine the trigger points for upgrades required to accommodate future DER, i.e., cost causation can be easily determined when looking at individual substations within this static system.

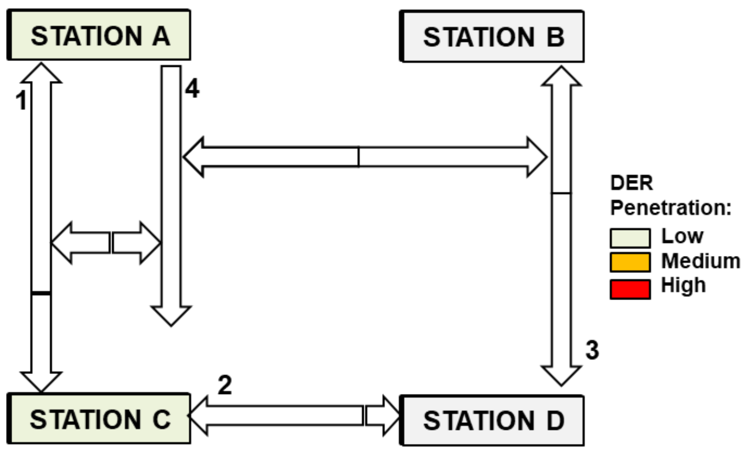

Figure 1. Low DER Penetration Scenario

Medium/High DER Saturation Area

A high DER penetration scenario is depicted in Figure 2 below. In this figure both Substations B and C are expected to have high DER penetration (or saturated) which affects the system reconfiguration capability between A-C, A-B, C-D and B-D. Moreover, reconfigurations that were previously available between circuits 1-4 and 4-3 could also be limited depending on the amount and location of new DER connected to the circuits. Not only are Substations B and C saturated, but this condition may also result in saturation at Substations A and D since transfer capability that was previously available via circuits 1, 4, and 3 is now limited due to saturation at Substations B and C. This is because under scheduled or forced outage conditions, the station tie-lines that traditionally help boost station load serving capability, serve as conduits to transfer additional DERs (in excess of load) to neighboring stations.

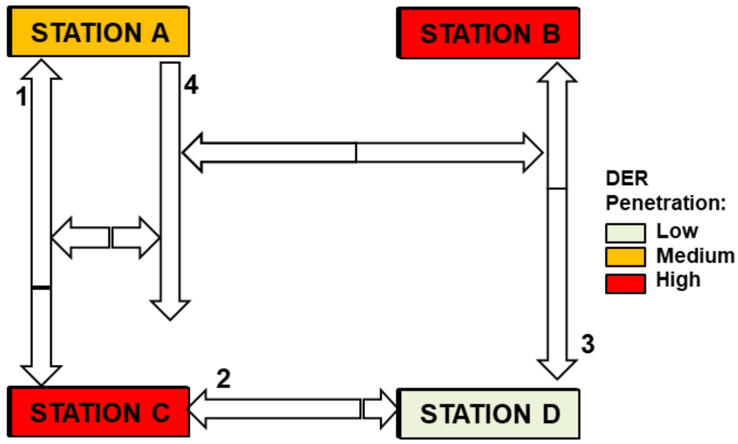

Figure 2. Medium to High DER Penetration Scenario

In areas of medium to high DER penetration, the substations must be analyzed as a Study Group to find the most cost beneficial solution that integrates new DER while maintaining the current level of reliability and operational flexibility of the EPS. In this scenario, the standard approach of analyzing individual substations used for areas of low DER penetration, has the potential of increasing cost, reducing reliability, and limiting operational flexibility. For example, even if upgrades are completed at Substation B and C to reduce the negative effects of increased DER penetration at those stations, this could still result in saturation at Substation A and D by limiting the transfer capability between A-C, D-C, and B-C, and lines 4-3. The Group Study analyzes the group as a whole to determine the most cost beneficial solution for all stations in the group, and to evaluate the need to reserve or build the capacity to maintain safe, reliable operation of the EPS.

Similarly, Figure 3 below, illustrates some of the operational challenges that can result at the distribution feeder level in areas of medium to high DER penetration. The left side picture shows the existing "as is" system under Normal conditions where 3 of the 4 substations are already at medium level DER saturation.

The right side shows a potential scenario in which Substation A saturates as a result of reliability improvement work that is completed at the distribution feeder level. The work could consist of transferring a section of a circuit from Line 3 to Line 4, a common operation used to balance load or customer count between the two circuits or substations or to reduce exposure for customers on a poor performing circuit. In this scenario, depending on the ratio of DER to load connected to the section, transfer of both load and DER from Line 3 to Line 4 might not be constrained unless a significant amount of reinforcement work is completed on both Circuit 4 and Substation A. This "constrained" condition that results from having a system at high saturation levels limits the flexibility of operators during normal and emergency conditions.

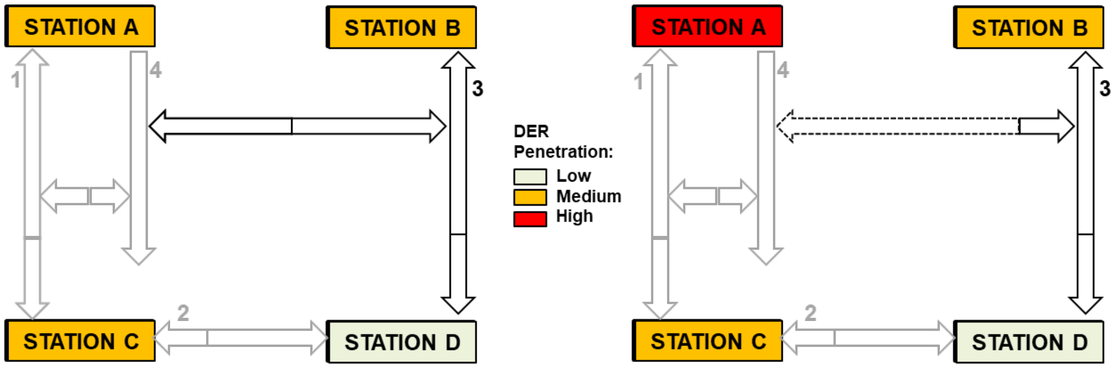

Figure 3. Operational Challenges at Distribution Feeder Level

Moreover, the constrained condition also limits the ability of planners and engineers to propose system design changes that will improve the performance of the EPS and enhance service to existing ratepayers. Utilities faced with significant DER growth, without the ability to address these types of conditions, could experience reliability deficiencies in the near-term when low DER saturated areas progress to medium or high saturation and left unaddressed. DERs would be forced offline for long periods to facilitate any scheduled work at these stations as well as under forced (unplanned) outage scenarios.

In addition to the substation reliability benefits to all customers, new distribution lines and line upgrades driven by DER growth are likely to create opportunities to rebalance feeders, reduce exposure and transfer load, which would lead to improved reliability and voltage quality for ratepayers.

Once the existing and future DER values are calculated for each DER study group/substation, the next step is to determine the upgrades required to accommodate the existing and future DER interconnections. Future transmission, substation and distribution line reinforcements are determined after completion of detailed load flow, dynamic and transient analyses that account for equipment firm capacity and emergency transfer capabilities. Final reinforcements would result from detailed analyses accounting for capacity, stability, voltage, and reliability constrained conditions that could result from DER saturation.

3. SYSTEM ANALYSIS

In September 2020, Eversource developed a comprehensive Distribution System Planning Guide (Planning Guide)(Attachment 1) to provide a consistent, uniform approach to designing an efficient and reliable EPS that ensures the quality of service expected by our customers. The Planning Guide aligns with applicable safety codes, regulatory requirements, and industry standards. It establishes uniform criteria and design standards across the Company's Service territory for all aspects of the System Planning Process, including goals for system performance and identification of suitable design solutions, including non-wires alternative (NWA) solutions to meet those goals. In 2021, the Company developed an NWA Framework (Attachment 2) to provide a standardized and expedited process to screen an NWA solution's technical and economic feasibility to meet a need at a specific location identified in accordance with the distribution planning criteria, and where deemed feasible, inform the application of non-wires technology or a combination of technologies through comparison of their relative benefits, performance and costs. Both the Planning Guide and the NWA Framework are therefore essential components of our comprehensive approach to distribution planning and assessment of systems with high DER penetration.

The Planning Guide also describes the load model development and DER forecasting, a common planning model and study methodology for both distribution and DER planning, and comprehensive solution development to address system needs. This approach to system planning will increase efficiencies and provide the least cost option through better coordination of capital projects. The fundamental processes outlined in the Planning Guide form the basis of the comprehensive system assessment described below. The following sections will walk through, at a high level, the analysis conducted for Transmission and Distribution Systems.

Model Development

Historically, EDCs focused primarily on maximum (peak) load analysis as the driver for system design changes. Peak load analysis is focused around a specific time during a peak day when the system experiences the highest net demand, typically occurring during high load and low DG generation times. With the introduction of large quantities of DG potentially leading to reverse flow during low load periods, this paradigm has shifted, and minimum load models have become just as important, depending on the amount of installed DG.

- **Maximum Load Model**: For the maximum load model, system planning considers current worst-case loading conditions on the system in combination with low DG output projections, ensuring that the system can supply loads on a hot, humid, cloudy summer day without failure. This can lead to increased equipment loading and sub-standard (under-) voltages. When developing maximum load models, EDCs use 90/10 weather-normalized load forecasts, ensuring that any design decisions made will adequately address the most demanding scenarios. Construction of the maximum load models typically begins each year after the peak cooling season, for Summer peaking areas this is typically around the September to October timeframe.
- **Minimum Load Model**: The minimum load model has become more relevant with the adoption of large quantities of DGs on the distribution system. During low loading conditions, typically spring or fall months, distributed generation can significantly offset load, or even surpass it, causing what is more commonly referred to as reverse power flow. This can also lead to increased equipment loading and power quality concerns, such as elevated (over-)voltages. Construction of the minimum load models typically starts later than the maximum models, ensuring low load Fall months can be captured in the model.

Because the interaction of load and DG is weather and time dependent, the analysis has shifted from a peak load analysis to an 8760 load-flow model that accounts for all hours of the year.

Within the minimum load model evaluation and development process, Eversource is proposing to use the group study concept to determine system upgrades required for safe, reliable integration of DG, and to determine the portion of the upgrades eligible for special ratemaking treatment with cost recovery through a Reconciling Charge. The minimum load model is significantly driven by the adoption propensity of DG at various stations, for which Eversource is developing advanced forecasting capabilities, as outlined later in this proposal. For the forecasting of DG, Eversource is proposing the stakeholder process to inform planning assumptions made by the company.

The first step in analyzing distribution and transmission level upgrades is to identify geographic areas experiencing high DER growth that are expected to saturate due to existing, in queue, and future projected DER. Distribution bulk substations in these areas are assigned to a study group based on physical location, topology, load transfer capability, reliability, and capacity dependency with nearby substations. Using the following process (as illustrated Figure 4 below) the critical system condition (low load model) for the group study is determined:

I. **For each station or group of stations**, the Minimum Load is calculated by using historic PI readings (Net Station Load) and removing the contribution of existing DER to create a true, or gross load data set. Thereafter, the minimum load condition is identified as the coincidence of the maximum possible DER output scenario with light load conditions, representing the worst-case condition the system can experience (e.g., a low load condition during midnight hours is not relevant for the group study).

   a. DER generation values are determined using historic PI readings where available, time of use metering data, or historic solar irradiance profiles for behind the meter applications (when applying solar irradiance data to determine historic output, Eversource assumes a DC/AC rating ratio of 1.2, unless the panel rating is known). With all generation subtracted from the recorded Minimum Load, this gives the true demand value (load that is not offset by DER) during light load conditions at the substation.

   b. For other DERs such as hydro installations, wind turbines, combined heat and power generation, or other non-solar DG, PI readings or time of use (TOU) metering is used where applicable.

II. **Once the Gross Load is determined**, existing DG are added back into the model at their maximum output level (AC nameplate capacity) in accordance with their clear sky capabilities (time series irradiance profile under ideal weather conditions for solar assets). As a result, the worst-case Minimum Net Load condition at the substations can be determined, the minimum load model (Note: the minimum net station load must not correlate with the minimum gross system load, as it can be offset by time dependent DGs)

   a. In the next step, all DGs of the group study are added at their respective locations to the model. Same as already existing DG, they are studied at maximum clear sky output limits.

   b. Storage applications in the vicinity of the group study are treated as sources (discharging) at maximum output. However, any technical limitations on such assets, (e.g. a DC coupled installation behind the solar inverter or 32 relay limitations), are taken into consideration.

   c. System planners can now identify if system violations occur, where they are, and their magnitude and frequency.

III. **At this stage forecasts for load and DER adoption** are added to the minimum load model and analyses can be conducted to determine the reinforcements needed to safely and reliable accommodate the current DER group as well as future projected DER in the area. This step provides a crucial opportunity to develop a comprehensive long-term solution that creates significant headroom for additional DG growth beyond the existing DER Group Study.

Figure 5 below shows the results of this process on sample data files. The station modeled has 70 MW of installed solar generation. Figure 5(a) shows the calculation of the Gross Load Curve. Figure 5(b) shows the reapplication of the existing solar at maximum clear sky output to determine the minimum load condition that the group study needs to account for.

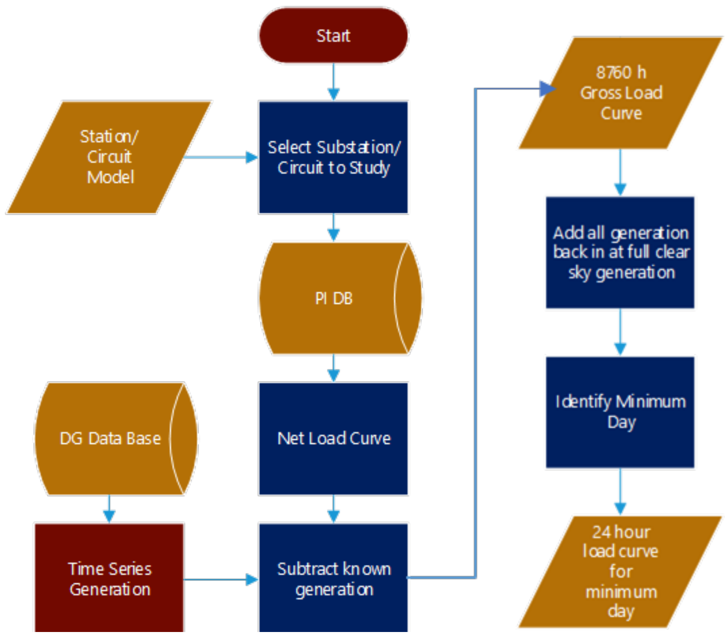

Figure 4. Process Flow for Determination of Critical Load and Generation Condition

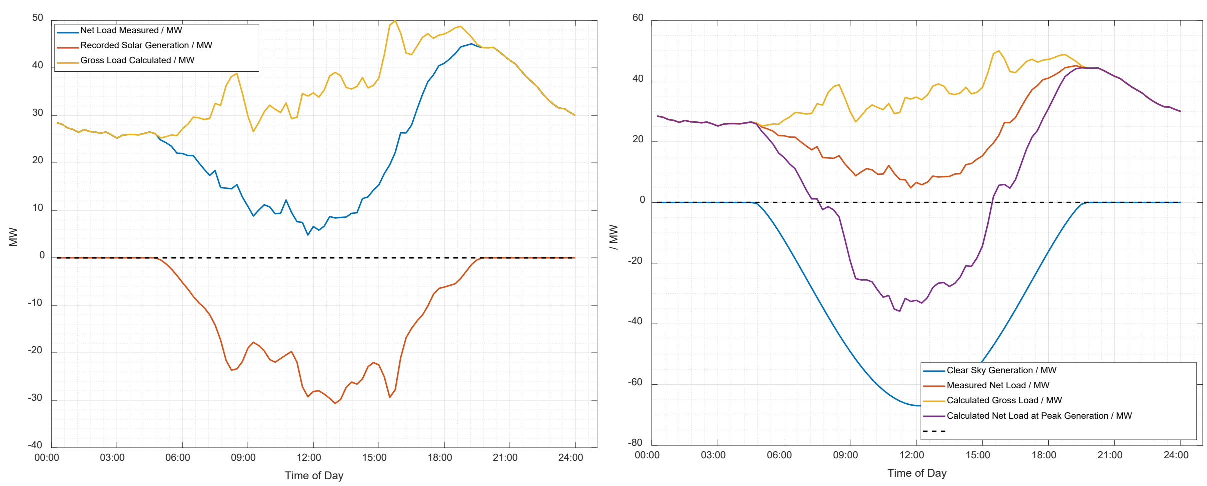

Figure 5. (a) Sample Data Sets for Measured and, (b) Calculated Net and Gross Load Data

Please note, that this observation is ideally done on an 8760 hour basis as high DER penetration makes it nearly impossible to determine the true minimum conditions by observing a single day.

System Analysis

As part of the DER Group Study the following analyses are conducted in accordance with the applicable standards and criteria identified in the Distribution System Planning Guide:

I. **Steady-state analysis** to assess thermal overloads and voltage limit violations resulting from the DER interconnections. The steady state analysis is conducted through time series power flow simulations in the Synergi distribution analysis package.

II. **Dynamic/transient analysis** to verify acceptable model performance and to identify any violations of stability criteria or transient overvoltage criteria following system disturbances and switching actions. For this, the electric models from Synergi are converted to PSCAD models to allow for power systems (electromagnetic transients) EMT simulations.

III. **Short-circuit analysis** to assess if circuit breaker fault circuit interrupting capability or bus work short-circuit structural limitations are exceeded as a result of the interconnection.

IV. **Protection review** to assess if direct transfer trip (DTT), ground fault (zero sequence) overvoltage (3V0) protection or other special protection schemes are required based on the risk of islanding, back-feed at stations, and other operational requirements.

V. **Reliability and operational flexibility assessment** to determine loss of load/DER reliability risk and degradation in transfer capability following a single-contingency event. This does not constitute a stand-alone analysis, but rather signifies that all previous analyses must account for the various permutations of system configuration, ensuring that the EPS is safe and reliable under all practical scenarios.

Solution Design

Eversource engineers design and implement a variety projects to resolve thermal/capacity, power quality/voltage, reliability and stability violations where station and line equipment may be operating under conditions beyond their design limits. As described above, the annual planning process begins with load/DER forecasts, model development and analyses to identify violations affecting distribution substations and backbone feeder sections that impact substation load-carrying capability (LCC) under Normal (N-0) and Contingency (N-1) system conditions. As part of this process, Eversource generally applies several design concepts to resolve and mitigate issues identified in system analysis. Four of the more common design concepts are briefly described below:

I. **Upgrade existing equipment:** By replacing existing equipment with similar equipment with greater capacity, such as increasing the transformer size at a station or reconductoring a distribution feeder, the system capacity is increased.

II. **Add new equipment/capacity:** Through additional hardware, such as new circuits, substations, or the addition of an extra transformer to a substation the system capacity is increased. An example is the upgrade of substations to standard multibank substation configuration[1] using standard transformer sizes[2] and increasing capacity of the substations that will maximize group firm capacity at the lowest capital cost[3], up to the point where transmission cost becomes the limiting factor[4].

III. **Reconfigure the system:** Through load transfers, customers can be moved to different circuits or stations permanently to better utilize resources. This however is limited by the need for sufficient capacity on nearby equipment to support potential N-1 scenarios.

IV. **Apply non-wires alternative solutions**: Where technically feasible and economically viable, NWA solutions can be used to modify the load shape or resolve technical constraints, in order to defer distribution level upgrades.

The high-level solution and benchmark cost estimates may be determined during the system analysis phase. However, final system modifications and costs estimates would require some level of engineering to resolve site-specific issues related to environmental permitting, physical constraints and rights of way, procurement and construction scheduling, all of which might significantly impact the cost. This will be further discussed below in Section 4 – Implementation of Construction.

[1] Substations with two or more transformers connected to a Common bus provide better reliability than single transformers substations which are limited by distribution line capacity.

[2] Using standard transformer sizes is more cost-effective than step size upgrades (e.g., upgrading from 20MVA to 50MVA to 75MVA in a short time period).

[3] A DER Group Study approach looks at all the substations in the group instead of finding solutions for individual substation or feeder. Accounting for the capacity of nearby substation provides an opportunity for developing cost effective solutions while maintaining the reliability and operational flexibility of the group.

[4] For example, if upgrading a substation from 1 to 3 transformers is cost effective due to minimum transmission cost, then this solution is proposed. If upgrading the same substation from 1 to 4 transformers is cost prohibitive due to significant transmission costs, the proposed substation upgrades will be limited to 3 transformers.

System Assessment Timelines

The planning process starts with the development of regional planning models which are used to perform capacity, reliability, and power quality studies for distribution substation, including 10-year substation capacity plans. Figure 3 illustrates these annual model-building activities, aligned with the proposed stakeholder process in Figure 9. As shown in the figure, the Company is proposing to undertake the Minimum (Min) Load model building process from July to December. Concurrent with this Min load model building process, the Maximum (Max) Load model building process starts during the summer and continues until the end of the year to allow for time to analyze summer peak load demand and identify any capacity, power quality or reliability reinforcements required during peak load times.

As mentioned previously, reinforcements proposed as part of traditional distribution (Max Load) planning process are designed to support the Company's public service obligation to provide safe and reliable electric service to all customers. These projects will be defined and incorporated into the Company's capital plan *independent* of the stakeholder process. Projects proposed under the Company's capital plan will be finalized prior to the development of the Preliminary Solution presented at the September Stakeholder meeting (refer to Figure 9). This guarantees that projects proposed as part of the traditional capital process are authorized ahead of time and included in the Min Load base models prior to developing high level DER-driven solutions. Moreover, this timeframe also provides an interval from January to March to complete any necessary analyses prior to the first stakeholder meeting in March.

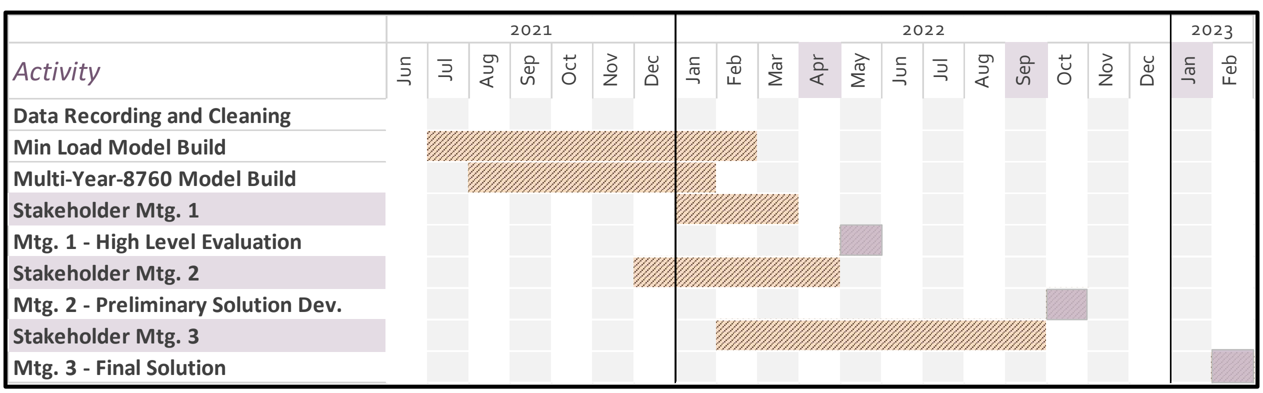

Figure 6. Overview of the proposed distribution system assessment process

The Preliminary Solution evaluation required for the September stakeholder meeting can only be completed after a Multi-Year 8760 Model is created, proposed to be completed during the December to March Timeframe. A Multi-Year-8760 Model is required for proper analysis of generation and load for all hours during a 12-month cycle to ensure no violations as a result of changing system dynamics during both peak and shoulder months.

Transmission Study Considerations

Distribution planning, and in particular planning for large amounts of DG, must often be coordinated with the ISO New England Inc. (ISO-NE) transmission study processes. More specifically, as part of a comprehensive T&D study process a transmission system impact study must also completed for the DER Study Group. The objective of this study is to demonstrate that the proposed DG Study Group projects will not in aggregate have adverse impacts on the reliability and operating characteristics of the transmission system, the transmission facilities of another Transmission Owner, or the system of a Market Participant, and if they do, to recommend system improvements that would eliminate the adverse impacts.

The ISO-NE categorizes levels of analysis needed to be performed to support modifications to the transmission system, in accordance with the ISO-NE Planning Procedure 5-3, “Guidelines for Conducting and Evaluating Proposed Plan Application Analyses”. For the purposes of this study a Level 3 analysis is required; which includes steady-state, stability, and short circuit analyses. The analysis will evaluate the impact of the proposed DER projects on the affected system operator (ASO), i.e. Eversource. Eversource therefore plans to use this same analysis framework to study impacts of these future projected DERs to identify reliability transmission constraints and plan appropriate associated transmission upgrades.

For the purposes of stakeholder engagement, our Stakeholder Process also draws inspiration from the ISO-NE stakeholder processes, which follows the fundamental planning principles established by the Federal Energy Regulatory Commission in its Order No. 890. For example, our Stakeholder Process was structured to coordinate openly with external parties and facilitate the transparent development of study results and reports. This robust information exchange will include explaining basic study criteria, assumptions, data, and methodologies thereby promoting standardization and consistency across studies. Stakeholders will have opportunities to review and comment on the process, results, and reports. Further, and as stated earlier, a key objective is to ensure that similarly situated customers are treated comparably. Another component is regional participation and collaboration with interconnected systems and other affected entities. All of which is intended to cultivate a coordinated, open and transparent distribution system assessment process and avoid opportunities for undue discrimination.

4. IMPLEMENTATION OF PROPOSAL

To facilitate completion of the proposed group studies within a one-year period and engage in the stakeholder process, the company has already put forward considerable effort, and will continue to do so, to ensure that the right processes are in-place internally to support the proposal activities. Implementation processes are focused on a set of key areas, starting with advanced forecasting capabilities all the way to modeling, approval, and construction activities.

Implementation of Advanced Forecasting

To better demonstrate how Eversource intends to use forecasts for system assessment and the proposed stakeholder process, a definition of the various types of forecasts Eversource would use is helpful.

Types of Forecasts

I. **Current Group Study Queue (1-2 years)**: The current group study represents the projects that have been aggregated into the ongoing group study for a specific area. This queued volume of interconnecting assets is viewed as likely to go online within a given time frame.

II. **Interconnection Queue (1-3 years)**: Once a group study is initiated, additional interconnection applications might be filed, and DG projects added to the queue. Those projects will be considered for interconnection after the current study is completed. The Interconnection Queue is somewhat volatile as applications can be withdrawn at any point in time, but it provides the Company with a good indication of which regions are the next hot zones for DG development. For both I and II, Eversource is digitizing and automating the way it tracks interconnections through the PowerClerk application.

III. **Short Term Interconnection Forecast (3-5 years)**: The Short-Term Interconnection Forecast is the most critical element in the company's efforts to address the influx of DG on the system. Its time frame is close enough to require immediate action on larger capacity projects, but the company does not yet have interconnection applications to inform the decision-making process. This is the essential part for which the company is seeking stakeholder input to help fine-tune the assumptions entered into the forecast models as it has to closely align with where developers are focusing their new projects.

IV. **Medium- and Long-Term Adoption Rate Forecast (Scenarios 2030 and 2050)**: The Long-Term Adoption Rate Forecasts are based on scenarios derived from the Commonwealth's clean energy and climate policy objectives. They specify that if these objectives are met, where and when over the next decades, DERs are expected to show the highest adoption propensity. These forecasts need to be regionally specific, and identify exactly where and when, and with what probability various DG adoption levels will be reached. They are specifically anchored around the Commonwealth's clean energy and climate objectives. Eversource is currently addressing this through the implementation of advanced forecasting capabilities discussed later on.

Current Efforts

The availability of the above-mentioned forecasts with their respective values are vitally important elements in the Eversource's proposal for development of distribution upgrades required for reliable integration of DER. Therefore, the company either already has or is currently undertaking the following steps to prepare for a start of the stakeholder process in March 2022.

I. **Development of a Company wide Distribution System Planning Guide (Completed Q4-2020)**: As discussed earlier, Eversource developed a company-wide Distribution System Planning Guide in 2020, which describes the utilization of different forecasting components and probabilities to develop the long-range capital plan for the company. This Planning Guide has already been adopted by the company as the standard reference for all distribution capital plans and includes a detailed outline for the consideration for DG forecasts and queues.

II. **Development of an Framework and NWA Screening Tool (Q1 2021):** The Company has developed an NWA Framework and NWS screening tool to provide a standardized and expedited process to screen an NWA solution's technical and economic feasibility to meet a need at a specific location identified in accordance with the distribution planning criteria, and where deemed feasible, inform the application of non-wires technology or a combination of technologies through comparison of their relative benefits, performance and costs.

III. **Development of a DER Planning Guide Aligned with the Distribution Planning Guide (Q2 2021)**: The Company is finalizing a DER Planning Guide that outlines the DER impact study process, applicable standards, tools methodologies, and solutions for safely and reliability integrating DER into the distribution system. The DER Planning guide is harmonized with the Distribution System Planning Guide to create a common platform for integrated distribution system planning with high DER penetration.

IV. **Dedicated Forecasting Capabilities (Q4-2021)**: The Company has already taken, and will take additional steps to develop dedicated forecasting capabilities in-house to work through the annual stakeholder process and to support distribution and transmission planning with a wide variety of forecasts, including but not limited to adoption rate forecasting of solar, including behind the meter, commercial, and utility scale, as well as storage, electric vehicles, and sector conversion (e.g. heat pumps). In addition, Eversource is collaborating with MassCEC and MassDOT to evaluate solutions for modeling travel patterns to allow for a more detailed study of EV charging impacts away from home base.

V. **Advanced Forecasting RFP (Q4-2021):** The Company has been granted as part of the 2021 Grid Mod Plan resources to implement solutions supporting advanced probabilistic forecasting for key resources. The Company is currently reviewing vendor proposals and intends to implement solutions by the end of 2021 to allow them to provide input to the first 2022 stakeholder meetings.

VI. **Stakeholder Process (Launch Q1-2022):** Most prominently, the Company supports establishment of a stakeholder process specifically as it relates to development of distribution upgrades required for reliable integration of DER eligible for special ratemaking treatment with cost recovery through a Reconciling Charge. Enabling greater stakeholder participation in the definition of assumptions, planning scenarios and inputs to the Short-Term Interconnection Forecast, enables the Company to gather support and data for its rolling ten-year Distribution Planning assessment which will support the Commonwealth's clean energy and climate policy objectives. The Company expects to hold its initial stakeholder meeting in March 2022.

VII. **General Study Proposal with the Massachusetts Clean Energy Council (Q1-2022)**: The Company is working with the MassCEC to evaluate planning solutions and develop a baseline cost estimate for the Commonwealth's clean energy and climate objectives. Eversource will conduct a high-level analysis to identify impacts and cost of the objectives.

With the above-mentioned efforts, the Company expects to have the first set of forecasting assumptions ready for the March 2022 stakeholder meeting with the intention of collecting feedback on those assumptions from the stakeholders. These will include:

I. **Solar Adoption Rate Forecasting**: Adoption rate forecasts for behind the meter to utility scale solar using socio economic parameters, customer profiles, and policy impacts.

II. **Electric Vehicle Impact Forecasting**:

   a. Electric Vehicle Adoption Rate Forecasting for vehicle adoption by private residents, commercial fleets, and public transportation.

b. Electric Vehicle Travel Models to understand where electric vehicles will charge in addition to where they are being bought.

III. **Battery Storage Adoption Rate Forecasting**: Adoption rate forecasting for behind the meter and storage + solar facilities using economic and pay back models.

IV. **Sector Conversion Forecasting**: Potential for the adoption of electrification of heating applications.

Implementation of Modeling

As noted in Figure 7 above, a comprehensive 10-year plan that accounts for existing, queued and forecasted DER requires a multi-year-8760 planning model that accounts for:

- Updated system topology
- Inclusion of future planned work
- 8760 gross load profiles
- Location and customer-based load profiles
- Area growth curves
- Up-to-date equipment setting database adjusted for planned work

The existing configuration of the electric distribution system (or system topology) should be updated on a constant basis to ensure accurate results when analyzing new DER or load customer additions. Moreover, approved customers and DER additions should be added by expected in-service date in order to have a comprehensive picture of the next 10 years. Gross load profiles are added to the models for all the hours of the year (8760) to account for all possible system conditions. Location and customer-based profiles can be added to the model to account for: customer load type, EV, EE, PV, sector conversion, and electrification. Advance forecasting will be required to develop 8760 gross load profiles and customer-based profiles for years 1-10, refer to Implementation of Advance Forecasting Section below.

The Company proposes to accomplish the model developing process on a yearly basis divided into 3 phases: Maximum Load Model, Minimum Load Model, and Multi-Year-8760 Model. This will allow for easier integration into the utility yearly planning cycle. For example, prioritizing the maximum load model allows the utility to address distribution areas with capacity deficiencies identified during the summer peak load days. Reinforcements proposed as a result of the peak load flow analysis can be incorporated into the analysis in order to find more cost-effective solutions. The minimum load model is completed after the maximum load model to incorporate updates to the system topology, which typically includes all the reinforcements completed prior to June in preparation for summer months. The minimum load model is updated to include the latest generation customers.

With a completed minimum and maximum load model, a multi-year-8760 model is completed by adding the reinforcements, customers, and system changes that are proposed for years 1 to 10, in addition to developed forecasts and customer-based profiles.

Implementation of Planning Process

Upon completing of the initial efforts to prepare the Company's forecasting capabilities to meet the requirements outlined in the group study proposal and stakeholder engagement process, the Company will conduct the advanced adoption rate forecasts on a yearly basis to produce probabilistic models for all stations operated by Eversource in the Commonwealth. These steps, illustrated in Figure 7, will be aligned with the proposed stakeholder engagement timelines in Figure 9. The following provides a brief overview of the recurring steps conducted for the process for a given year (Year 1).

I. **Data Recording and Cleaning Year 1**: Data recording happens continuously and throughout the year. However, the important events for the low load model typically occur during Spring and Fall months. To provide a complete set for a given calendar year, recording should be completed at least until end of October.

   a. During this time, the company will be conducting the September Stakeholder meeting of the previous year (Year 0).

   b. Towards the end of the Data Recording and Cleaning for Year 1, the company will also start work on the final solution for the previous year (Year 0).

II. **High Level Evaluation Year 1**: The company will create the historic gross load models from the data recordings, create the minimum load models, and work on the assumptions that will be used to determine DER adoption rates across all Eversource stations in the commonwealth.

III. **January Stakeholder Meeting Year 1**: At this stakeholder meeting, Eversource proposes to present its Planning Scenarios and specific sub-regions included in the applicable year scope. It will also present associated modeling assumptions, forecasts and underlying data and methodologies for the Medium-Term Interconnection Forecast.

IV. **Preliminary Solution Year 1**: Based on stakeholder feedback on the forecasting assumptions, the company will then develop a preliminary solution for year 1.

V. **September Stakeholder Meeting Year 1**: At this stakeholder meeting, Eversource proposes to present preliminary study results – system constraints resulting from DER forecasts as well as its preliminary proposed mitigations.

VI. **Final Solution Year 1**: The company will develop a final solution based on the September Stakeholder Meeting, including high level costs.

a. In parallel, the company will be preparing the baseline assumptions for the Year 2 stakeholder engagement cycle.

VII. **January Stakeholder Meeting Year 1**: At this final Year 1 stakeholder meeting, Eversource proposes to present the final study results, full testing of its recommended mitigations to resolve all outstanding system constraints as well as cost estimates and appropriate allocation between CIP Fees and Reconciling Charge.

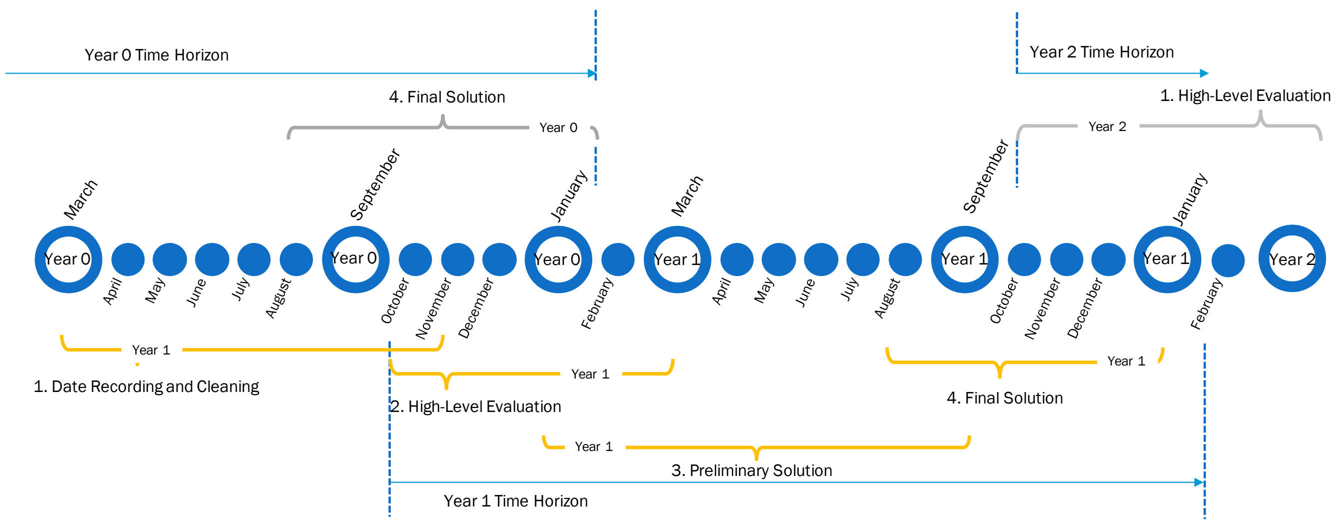

Figure 7: Recurring Timeline for Advanced Forecasting

Implementation of Approval Process

As discussed in the Company's initial comments on the Department's D.P.U. 20-75 straw proposal filed on December 23, 2020 and reiterated in the Scope of Analysis section of this proposal, the anticipated EPS upgrades, in addition to enabling renewable energy to fully support the Commonwealth's climate goals, also allow the Company to preserve and maintain safe, reliable operation of the EPS for all customers with high penetration of DER. As discussed, and illustrated with examples earlier, it becomes increasingly difficult for the Company to preserve reliability and operational flexibility under all operating scenarios as systems become more saturated with DG. Therefore, the capacity enabled by EPS upgrades allows the company to maintain its operational standards and provide safe reliable service despite these challenges.

Consequently, the Company recommends Department review and approval of proposed upgrades to be recovered through applicable fees and charges. The Company has proposed that Common System Modifications be substantially funded through the Reconciling Charge and Capital Investment Project costs be recovered through Capital Investment Project Fees. Development of upgrades covered by both mechanisms will be a substantial undertaking that will require certainty through regulatory support from the Department to protect the interests of customers, the Company, and other stakeholders throughout the deployment process. Anticipated upgrades will involve significant near-term expenditures that are in excess of distribution expenditures that the Company would not incur but for the growth of DER, and implementation of the planning process contemplated in the Straw Proposal. The Company supports the Department's engagement to review and approve upgrade plans and associated recovery of charges and fees to provide certainty in not just planning the necessary upgrades but also cost recovery. Department review will provide transparency for all interests involved and will facilitate efforts to track and review ongoing costs associated with DER interconnection, while at the same time allowing the Company to obtain timely and adequate recovery of expenditures.

Specifically, Eversource proposes that the Department review and pre-authorize system upgrade plans, similar to how the Department currently reviews and approves the prudence of estimated costs associated with the Company's grid modernization investment plan and energy efficiency investment plans. As discussed above, the Department should establish an annual process whereby the electric companies present a plan to the Department that would delineate the projects that need to be undertaken to accommodate DG penetration. In this filing, each company would present the list of potential projects; the estimated cost range and the proportion of costs that would be assigned to the developer versus the system. In this proceeding, the Department would review and approve the projects allowed for the program and the allocation of costs between the electric company's customers and the developers. The actual project costs would then be subject to a review for prudence (i.e., cost management and implementation) at a later date, once the project is complete. The final cost allowed by the Department would then be split between the Company's customers and the developers, but the split assigned in the initial phase would not be revisited.

In addition, in the course of preauthorizing system upgrades and estimated costs, the Company recommends the Department also review and approve the structure of Capital Investment Project Fees to be assessed to interconnecting facilities.

The Company supports the transparency that its recommended review of system upgrades provides, but also recognizes that prolonging the finalization of project fees and initiation of construction activity also presents challenges to development of DG facilities that may be dependent on the outcome of the Department's review. The Company proposes that the uncertainty and timelines for such a review could be expedited by establishing clear guidelines for the content of EDC filings and appropriately focusing the scope of the Department's review in such proceedings.

Implementation of Construction

The project approval/construction process to implement each successive DER Group Capital project, after approval from DPU on the project and associated cost recovery, as described in the Implementation of Approval Section above, is designed to ensure that the technical approach is sound, and resources are budgeted and allocated to ensure successful and timely execution of the projects. The overall process flow for DER group study projects is depicted in Figure 8.

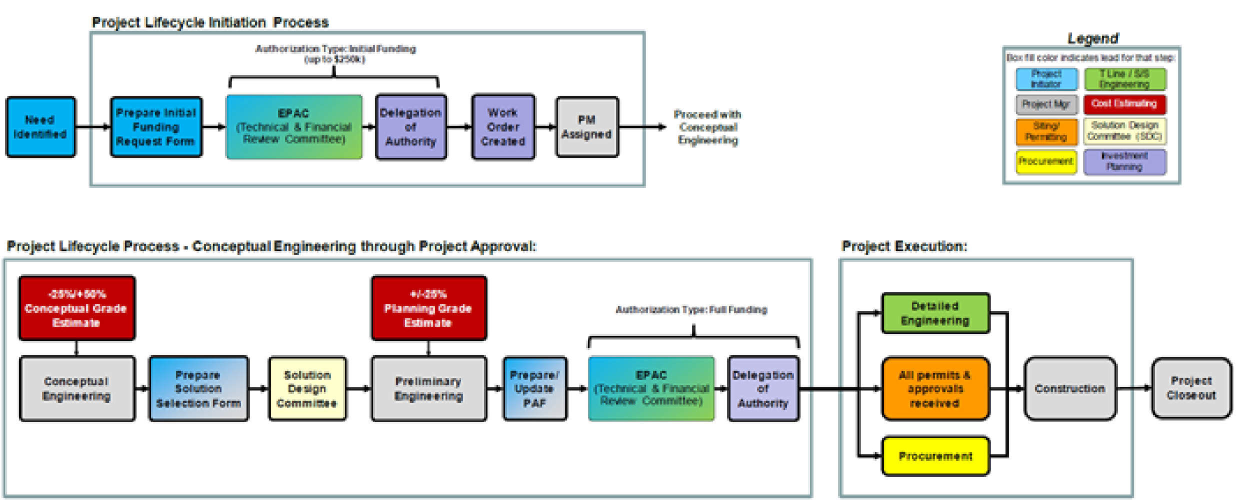

Figure 8: Schematic overview of the approval/construction process

As shown in the figure above, following the final approval of a project, the initiator will secure initial funding for preliminary engineering. The initiator will be required to document the project need, objectives and include an explanation of the funding request amount, including a budget for conceptual and preliminary engineering activities and a schedule for acquiring full project funding. Key process steps include:

- Project initiation
- Conceptual Engineering
- Solution vetting
- Preliminary Engineering
- Full Project authorization
- Detailed Engineering, Siting, and Permitting
- Construction and Construction Variance Monitoring.

The assigned project manager will track execution and construction by monitoring spend vs. authorized cost. The project manager will submit a revised supplemental request form if any of the following occur:

- The project cost exceeds approved tolerances
- Significant scope change such as added unit of property or change in technology
- Significant technical design change

All project documents will be closed, and associated databases updated upon project closeout in accordance with Project Management Process or applicable local project closeout process.

5. CONSIDERATION OF THE COMMONWEALTH'S POLICY OBJECTIVES

Eversource is in full support of the Commonwealth's clean energy and climate objectives[5, 6] and has committed itself to addressing these objectives in the Company's capital plans to ensure distribution and

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[5] The Global Warming Solutions Act (An Act Establishing the Global Warming Solutions Act ("GWSA")) requires a reduction of greenhouse gas ("GHG") emissions in Massachusetts of 25 percent below the 1990-statewide emissions level by 2020, and a reduction in GHG emissions of 80 percent below 1990 levels by 2050. G.L. c. 21N, § 3; St. 2008, c. 298.

[6] The Executive Office of Energy and Environmental Affairs is undertaking a planning process to identify cost-effective and equitable strategies to ensure Massachusetts meets the emissions reductions set for the in GWSA and achieves net zero emissions. See: https://www.mass.gov/info-details/ma-decarbonization-roadmap

transmission systems can enable these objectives. For this purpose, the Company has initiated several initiatives and process improvement activities as highlighted earlier in Section 4 to this proposal.

The Commonwealth's clean energy and climate policy objectives will be reflected as part of the Long-Term Adoption Rate Forecast as outlined in Section 4 where they inform total adoption rates for core decarbonization technologies. As the forecasts ultimately drive system impacts, they will be considered within the solutions developed for the group studies to ensure that capital investments in the EPS today are designed to accommodate future DER growth.

1. **Scenario Forecasting:** Eversource will be using the Commonwealth's clean energy and climate objectives to build a variety of scenarios for 2030 and 2050. With adoption of core DER technologies driven predominantly through policy decisions and incentives, Eversource believes it best to align the long-term adoption scenarios with the State's objectives to ensure that the Company's infrastructure investments are aligned with the Commonwealth's clean energy objectives. Eversource will develop a variety of scenarios based on the objectives that highlight different technologies being dominant in the transition, to enable visibility into cost drivers of the energy transition.
2. **Advanced Forecasting**: Eversource has, under the 2021 Grid Mod Plan, been granted funds to develop advanced, probabilistic forecasting capabilities. Eversource is currently reviewing vendor proposals for this project and anticipates that deployment will start in May of 2021. This project will provide Eversource with advanced capabilities to model adoption rate forecasts for core decarbonization technologies such as solar, storage, and electric vehicles (behind the meter, commercial, utility scale). Timelines for the adoption rates will be given as scenarios from the State's clean energy and climate policy objectives. These will then be broken down into localized adoption propensities by core technology because distribution and transmission planning require a clear understanding of when, where, and what will be interconnected to electric power system. As a result, the Company will use these technologies to model customer reference clusters (types) against sensitivities such as regional socio-economic or political impacts in a probabilistic model for the entire Eversource territory to identify those areas with high and fast technology adoption.

6. STAKEHOLDER PARTICIPATION

As noted in D.P.U. 20-75, the Company supports establishment of a stakeholder process specifically as it relates to development of distribution upgrades required for reliable integration of DER eligible for special ratemaking treatment with cost recovery through a Reconciling Charge. Enabling greater stakeholder participation in the EDC's rolling 10-year Distribution Planning assessment related to integration of DER that is the subject of this proceeding will support the achievement of the Commonwealth's clean energy and climate policy objectives. *It is important to note that the Company's Distribution upgrades that solely result from Eversource's base load forecast scenarios are otherwise included in the Company's Distribution Capital Plan and cannot be the subject of this stakeholder process, as decisions related to the base capital investments that are necessary to ensure the safe and reliable operation of the electric grid rest squarely with the EDCs*. The EDCs must ensure the timely execution of these projects and therefore cannot subject the review, approval, or prioritization of base Distribution Capital projects to a stakeholder process. This also applies to the final decision-making about the necessary investments that result from the base load forecasts.

As Eversource builds the Short-Term Interconnection Forecast and Long-Term Adoption Rate Forecast, the company is looking for stakeholder participation through the proposed stakeholder process over the course of three (3) annual meetings as shown in Figure 9. These stakeholder meetings are also shown in Figure 7 aligned with the model development process.

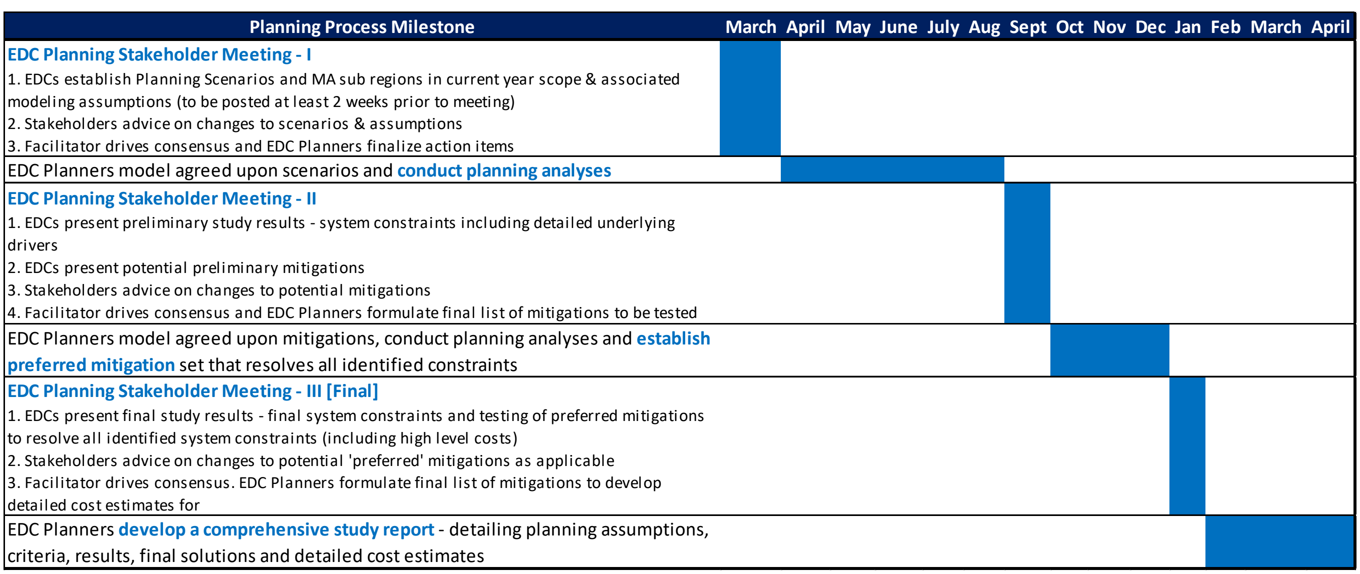

Figure 9: Proposed Outline of Stakeholder Process

I. **March Meeting**: At this stakeholder meeting, Eversource proposes to present its Planning Scenarios and specific sub-regions included in the applicable year scope. It will also present associated modeling assumptions, forecasts and underlying data and methodologies for the Medium-Term Interconnection Forecast. This stakeholder meeting provides an opportunity for all stakeholders to guide and inform forecasting assumptions – specifically as it relates to EDC assumptions of DG forecast at specific stations included in the applicable year scope and its alignment with the Commonwealth's Climate policy objectives.

II. **September Meeting**: At this stakeholder meeting, Eversource proposes to present preliminary study results – system constraints resulting from DER forecasts as well as its preliminary proposed mitigations. This stakeholder meeting provides an opportunity for all stakeholders to guide and inform distribution infrastructure solution development as well as any other applicable solutions that may be feasible and implementable in time to allow for DER integration.

III. **January Meeting**: At this stakeholder meeting, Eversource proposes to present the final study results, full testing of its recommended mitigations to resolve all outstanding system constraints as well as high level costs – and associated allocation among CIP Fees and Reconciling Charge.

The Stakeholder Input Process would provide important information and context to the DER community on DER system impacts and reliability considerations and also provide valuable feedback to the Company on the solutions and mitigation plans developed to address these impacts. The stakeholder process would provide a mechanism for developing consensus around the need to balance investments to accommodate DG growth with investments to promote safe, reliable operation for all customers. It is Eversource's objective to incorporate developer feedback on the scenarios and adoption rate forecasts produced. Eversource's key challenge in these forecasts is to determine factors driving adoption of core technologies in certain areas in the near term.

7. TIMELINE FOR IMPLEMENTATION

As outlined in Eversource's proposed stakeholder engagement process (Figure 9), the first meeting during the annual cycle is March during which Eversource kicks off the annual forecasting by facilitating input from stakeholders on assumptions made by the company on a variety of DER forecasts. Eversource expects to hold its first stakeholder meeting March 2022. At this point, Eversource will be presenting the first iterations of forecasting assumptions for the group study areas of importance which will be developed in the second half of 2021.

ATTACHMENT 1

DSPG 2020
(Revision 00)

1.

Distribution System Planning Guide

Approved: September 22nd, 2020

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Contents

ATTACHMENT 1

1. Overview

This Distribution Planning Guide has been developed to provide Eversource Energy ("the Company") with a consistent uniform approach to designing an efficient and reliable electric distribution system to provide the quality of service expected by our customers. The Planning Guide is aligned with applicable safety codes, regulatory requirements, and industry standards (referenced in Section 5) and provides uniform criteria and design standards across the Eversource Service Territory for all aspects of the System Planning Process.

The electric power industry is undergoing significant change with: increasing customer expectations for reliability and resiliency; widespread adoption of new, often disruptive, technologies including Distributed Energy Resources (DER), electric vehicles (EV), and smart homes; utility grid modernization initiatives; and a rapidly evolving regulatory landscape. These changes and other advancements have not altered the basic mission of the distribution system, but have impacted the way we way approach planning, the data sources and methods, scenarios and simulation cases, and the range of possible solutions considered for mitigation.

The Company's unique electric system, supplying both high density urban areas and rural areas across three states, affords planners a great degree of flexibility in adapting the system to meet customer needs in a cost-effective manner. However, due to the legacy standards and practices in different operating areas, there is pressing need to harmonize standards and practices across the Company and provide clear, uniform consistent guidelines for how and when to expand the system to meet load and DER growth. The application of these panning standards will provide long term improvements in system performance in response to recent challenges facing the electric utility industry.

1.1. General

The basic goal of distribution planning is to provide orderly, economic expansion of equipment and facilities to meet future system demand with acceptable system performance. The key planning objectives include:

- Build sufficient capacity to meet instantaneous demand
- Satisfy power quality/voltage requirements within applicable standards
- Provide adequate availability to meet customer requirements
- Deliver power with required frequency
- Reach all customers wherever they exist

Since the electric utility is often the provider of last resort, planning the system is delicate balance between performance and cost. Planning engineers must identify the goals for system performance, understand how differences in system design and equipment will affect achievement of the goals, and find the most suitable design solution to meet performance goals.

Balancing cost and performance to find the most suitable design solution is made more challenging by a number of factors, including performance pressures, cost escalation, aging infrastructure, DER/EV penetration, and state/regulatory mandates.

This Distribution Guide outlines the planning criteria, design and analysis methods and engineering rationale for effectively expanding the distribution system to meet demand. The planning criteria builds upon existing company standards, mainly the Distribution System Engineering Manual (DSEM) and the SYSPLAN standards, as well other legacy standards such as NH - ED3002.

1.2. Scope

The scope of the Distribution Planning Guide is comprehensive, including traditional planning considerations for expanding the system to avoid capacity, voltage and reliability violations as well as advanced planning concepts related to Non-Wires Solutions (NWS), Battery Energy Storage System (BESS) and other DER application, and integrated load/DER forecasting with EV adoption.

The foundation of the planning methodology is an advanced distribution analysis platform to enable key planning activities. The application can import system models from GIS, integrate demand and DER data from linked sources, and incorporate forecast and adoption models to build daily (24-hour) and yearly (8760-hour) planning scenarios.

2. Planning Criteria

2.1. Introduction

This guide defines the criteria Eversource uses to determine how to plan and design the system to avoid loading, voltage, and reliability violations during normal and emergency system operation, as defined is Reference Section 5.

2.2. Thermal Loading Criteria

The topics below define the application of thermal loading criteria for substation transformers and conductors used in the distribution system.

The methods for determining the normal and emergency rating of bulk distribution transformers is covered in Section 3 of this document. Eversource Distribution System Engineering Manuals (refer to Section 5 references) provide the methods for determining the normal and emergency rating for distribution lines and equipment. The criteria below define the safe and reliable utilization of rating limits, specified by Eversource Standards, under both normal and emergency conditions. They address the existing system design as well as future design changes planned for the distribution system.

When analyzing system load versus Normal, Emergency, LTE, and STE ratings, it is done with respect to the applicable seasonal ratings (e.g. winter and summer).

2.3. Substation Transformer

The design criteria noted below may be more restrictive than a transformer's Normal rating. This does not necessarily limit the actual operation of the transformer equipment, which may be utilized to the full extent of its normal rating, but it provides for pre-load conditions that will maintain the equipment below acceptable LTE and STE rating following emergency conditions.

Bulk Distribution Transformer loading is evaluated on a winding basis, that is the load carried by each individual winding is evaluated against that winding's rating(s). Bulk Distribution Transformer windings shall have ratings determined per the requirements of Eversource Procedure SYSPLAN 008, refer to Section 3.3, and shall be applied in the following manner.

Bulk Transformers, Normal Operation – CT/MA

Loading Up To 75% of The Normal Rating:
Bulk transformer winding loads (expressed in Amperes or MVA), should not exceed 75% of the normal rating, under normal (scheduled) operating conditions/configurations.

Notes:

- When determining LTE and STE ratings of a transformer winding, a 75% pre-load condition is assumed. Therefore, to protect the integrity of the emergency ratings, normal loads should be limited to 75% of the normal rating[1].
- Loading up to 100% of normal ratings can be used for single transformer substations, when that transformer is not relied upon to provide secondary supply to another bulk distribution supply bus.

Loading Between 75% of The Normal Rating and the Long-Term Emergency (LTE) Rating:
Bulk transformer winding loads above the normal rating, but below the LTE rating are allowed for one Event (24-hour load cycle). Transformer winding loads within this range result from contingency events in the distribution

[1] Applies to transformers that provide contingency (N-1) supply to load normally served by other transformers. Utilization at this level balances the maximization of the contingency STE rating with that of base capacity, ensuring that a substation has sufficient capacity to maintain continuity of service for customers in the event of loss of a transformer.

system or within substations (loads in this range may result from ABR operations).

Note:
Load transfers (within the distribution system) or installation of a mobile transformer should be available to lower winding loads to the normal rating (or below) for subsequent load cycles following the contingency, or until the system can be returned to normal conditions.

Loading Between the Long-Term Emergency (LTE) Rating and the Short- Term Emergency (STE)/ Drastic Action Limit (DAL) Rating:
Bulk transformer winding loads above the LTE rating, but below STE/DAL rating must be lowered to below the LTE rating within 30 minutes.

Loading Above the Short-Term Emergency (STE)/Drastic Action Limit (DAL) Rating:
Loading transformer windings above the STE/DAL rating is not acceptable under planning criteria for any duration. This is intended as an emergency operational practice only. Automatic protection schemes shall be applied when needed to prevent loading bulk substation transformer above the STE rating.

Note:
Operating a transformer, for any duration, at loading levels above the STE rating can result in loss of life or in extreme cases, increased risk of catastrophic internal failure of the transformer.

Bulk Transformers, Normal Operation – NH

For all transformers in New Hampshire, loading shall not exceed 95% of the Normal rating. Maintaining transformer loading at a higher threshold under normal (N-0) system conditions increases the risk of equipment failures and exposure to customer reliability interruptions under N-1 contingency conditions. This variation in design criteria, from the standard 75%, is to allow maximum utilization of the existing population of 34.5kV transformer that do not exhibit a significant reduction on STE rating when applying a 95% preload. For those transformers where STE performance impacts the ability to restore customers automatically (as per Section 2.8) the standard 75% preload should be maintained.

Non-Bulk, Normal Operation (N-0)

For all non-bulk transformers on the Eversource system, planned loading shall not exceed 100% of the Normal rating.

Non-Bulk, Contingency Operation (N-1)

With available load transfers, the loading on a transformer shall be reduced to below the LTE rating. Load levels can only be sustained above the Normal rating for one load cycle.

2.3.1. Loading Limits for Conductors used in the Distribution System:

The topics below define the application of thermal loading criteria for conductors used in the distribution system, calculated values for cable and wires thermal loading limits in Amps is provided in the DSEM Section 08.00 by conductor type.

Cables and Wires supplying underground and Overhead Areas:

Normal Operation (N-0)
During normal system conditions, load levels shall not exceed the Normal rating. The normal rating is the maximum loading without incurring loss of life above the design-loading limit.

Contingent Operation (N-1)

Cables
During contingent system conditions of the electric system, load levels may not exceed Normal Ratings for Cables[2]. System changes shall be developed when cable limits are expected to exceed 100% of Normal rating during contingency operations. Operating above the Normal rating may involve loss of life or loss of tensile strength for conductors, loading must be reduced after one load cycle (24-hour period)

Wires
During contingency system conditions of the electric system, load levels may not exceed the following criteria:

- NH – Wires shall not exceed emergency rating, as per Distribution System Planning and Design Criteria Guidelines (ED-3002)
- CT/MA – Wires shall not exceed normal rating[3]

2.3.2. Load Balance

Distribution feeders shall be arranged in order to give the best possible load balance on the system. In Distribution feeders where load imbalance exceeds 50 amps between phases, necessary improvements should be considered to reduce imbalance to less than 50 amps.

2.3.3. Feeders Supplying Underground Network System:

All network feeders are designed to operate within their normal rating at all times of the year. In addition, the feeders are designed to operate within their normal ratings in the event of the loss of any one (N-1) feeder in the grid. This is done in order to provide some level of protection against a double contingency. The feeders should also be designed to operate within their LTE rating in the event of a double (N-2) contingency.

2.3.4. Distribution Supply System (DSS) Lines

Under normal configuration the loads of all lines (in service) in the line group will be below the normal ratings at all times.

During a single contingency (N-1) condition, where one of the lines is out of service, the load on any one of the remaining lines should not exceed its long-term emergency (LTE) rating.

2.4. Voltage

Operating voltage limits allowed on Eversource Energy Distribution circuits, principally for residential or commercial services, are covered in the DSEM (refer to Sections 5 and 7). These voltage limits are also used as a reference when analyzing customer voltage problems and designing distribution circuits.

Upper and Lower Voltage Limits

State	Voltage Limits
CT	Connecticut upper and lower voltage limits are those prescribed in Section 16−11−115, Voltage Variations, of the Regulations of Connecticut State Agencies. Voltage excursions above the upper limit shall not exceed one minute. American National Standards Institute (ANSI) C84.1−2016 shall be used to determine the lowest temporary voltage excursions permissible.
MA	Massachusetts limits are based on voltage guidelines in ANSI C84.1−2016.

[2] In compliance with the Department’s guidance in Docket Number 17-12-03, PURA Investigation into Distribution System Planning of the Electrical Distribution Company
[3] In compliance with the Department’s guidance in Docket Number 17-12-03, PURA Investigation into Distribution System Planning of the Electrical Distribution Company

State	Voltage Limits
NH	New Hampshire limits are based on New Hampshire Code of Administrative Rules, Rule 304, Quality of Electric Service. These limits are based on voltage guidelines in ANSI C84.1.

Table 1- Upper and Lower Voltage Limits

Contingency Voltage Limits

CT, MA, and NH state regulations allow for temporary voltage excursions outside the normal range at the customer service entrance during contingency operating conditions. Some examples of temporary contingency conditions are listed below. For CT, temporary voltage below the lower limit should not exceed 24 hours where practical. Voltage excursions above the upper limit are not identified by magnitude but shall not exceed one minute. For WMA and NH, voltages above and below normal limits are based on ANSI C84.1 guideline and shall be limited in extent, frequency, and duration. When they occur, corrective measures shall be undertaken within a reasonable time to improve voltages to meet normal voltage range requirements.

Contingency operating conditions, when temporary voltage excursions are allowable, include (but are not limited to) the following:

- Autoloops when a circuit, or part of a circuit, is being supplied through a tie recloser
- Automatic transfer schemes when fed by the backup feeder
- Contingent, manually switched supply to load in response to an interruption of normal supply routes or as needed for line construction, not exceeding 24 hours in expected duration
- Secondary networks with one or more supply feeders out of service
- Secondary networks with one or more network transformers out of service
- Forced outages of bulk power transformers
- Forced outages of transmission lines

Additional information on voltage variation among phases and calculation of voltage unbalance is included in the Distribution System Engineering Manual Section 05.131 to 05.135 (refer to Section 7),

High and Low Normal and Contingency Limits Summary

The Tables below list the high and low normal and contingency service voltage limits for all three states in the Eversource system:

Nominal Voltage	Normal High Limit	Normal Low Limit	Contingency Low Limit
120	123.6	114.0	110.0
208	214.2	197.6	190.7
240	247.2	228.0	220.0
277	285.3	263.2	253.9
480	494.4	456.0	440.0
600	618.0	570.0	550.0

Table 2- Connecticut Service Voltage Limits (Volts)

Nominal Voltage	Normal High Limit	Contingency High Limit	Normal Low Limit	Contingency Low Limit
120	126	127	114	110
208	218	220	197	191
240	252	254	228	220
277	291	293	263	254
480	504	508	456	440

Nominal Voltage	Normal High Limit	Contingency High Limit	Normal Low Limit	Contingency Low Limit
600	630	635	570	550

Table 3- Massachusetts & New Hampshire Service Voltage Limits (Volts)

2.5. Power Quality

System Planning follows the latest approved version of the "Eversource DER Information and Technical Requirements for the Interconnection of the Distributed Energy Resources (DER)" to complete analysis of:

- Steady-state Thermal and Voltage Criteria
- DER Impact on Voltage Regulating Equipment
- Transformer Reverse Power Capability
- Rapid Voltage Change and Voltage Flicker
- 3V0 Assessment[4]

System Planning also follows the transient overvoltage curve in IEEE Std. 1547–2018, clause 7.4.2. limiting the transient overvoltage to less than 1.2pu. This is a critical section due to potential load rejection overvoltage (LROV) by the inverters, which can potentially cause damage to utility equipment, and/or nearby customer equipment.

2.6. Load Density

One important metric utilized by Planning Organizations, to determine the substation design and reliability criteria required to supply specific geographic areas is load density. This is defined by Distribution System Planning as MWh Energy Demand for a whole year over the Supply Area in square miles:

- High Load Density areas are those greater than 750MWh/square miles or comparable to Downton Boston, MA.
- Medium Load Density areas are those between 250MWh/sq-mi and 750MWh/sq-mi or comparable to Stamford, CT and Somerville Area, MA.
- Low Load Density areas are those less than 250MWh/sq-mi or comparable to Plymouth, SEMA.

MWh Energy Demand is calculated by using a sampling rate of 1 hour and actual MWh readings for an entire year (8760 hours) from all the distribution stations supplying the targeted geographic area. The Supply Area (square miles) is the geographic boundary of all the distribution circuits that normally supply load via the targeted stations. The distribution circuit boundary extends up to the last distribution or non-bulk transformer supplied by the targeted Substation and does not cover the length of additional tie lines to other stations. The geographic boundary includes all habitable land, including small parks and recreational areas, but not the areas covered by large green areas or water bodies (state forest, large parks, ocean, lake, ponds, and/or wetlands).

Based on the above definition:

- Area Work Centers (AWC) in the CT and NH service territory currently fall within the Low to Medium Load Density Criteria
- Somerville and Mass Ave AWC fall within Medium to High Load Density Criteria
- Metro Boston Network area falls within the High Load Density Criteria
- Other MA service territory (except for Somerville, Mass Ave and Metro Boston) currently fall within the Low to Medium Load Density Criteria.

2.7. Reliability

2.7.1. Bulk Distribution Substations:

[4] Eversource requires ground fault (zero sequence) overvoltage ("3V0") protective relaying package to be installed on the transformer high-voltage side to detect the ground fault overvoltage when the upstream transformer connection is delta and the DER is about 50% of minimum load.

Within its service territory, Eversource supplies a range rural and urban areas which often differ in electric supply characteristics and requirements. Electric distribution substations are scaled in size and redundancy as a proportion of the mix between rural and urban areas. To maintain adequate levels of reserve capacity, power quality, and reliability, that meet or exceed our Customer's increased expectations, Bulk Distribution Substations shall be designed to sustain any Single Contingency (N-1) with no Load Loss.

Transmission System Considerations:
Upholding the Bulk Distribution Substation N-1criteria starts at the transmission level, by observing the following:

- The transmission system supplying distribution bulk substations shall be designed so that the outcome of any single contingency event at the transmission side does not result in a condition greater than a Single Contingency (N-1) at the distribution bulk substation.

Distribution System Considerations:
Upholding the N-1 design standard also applies to the distribution system by observing the following:

- The distribution system shall be designed so that any feeder outage does not result in thermal or voltage violation above design criteria, as defined Sections 2.2 and 2.4.

2.7.2. Distribution System Reliability

Distribution Feeder design is intended to provide safe, reliable service within allowed voltage limits at a reasonable cost. Reliability generally addresses interruptions of service exceeding the targets specified by state regulators. Eversource uses three reliability measures adopted by the utility industry: SAIDI, SAFI and CAIDI, refer to DSEM 02.11. There are limits as to what degree of reliability is practical or achievable, depending on the investment cost and rates permitted by regulatory authorities. To evaluate the effectiveness of reliability projects and determine the most cost-effective solution Eversource follows DSEM 03.30.

To maintain approved regulatory reliability indices, the following solutions can be implemented in areas of the distribution system that required reliability improvement:

- Add automatic sectionalizing devices to limit exposure to 500 customers or less per switchable zone. Refer to DSEM 02.30, DSEM 06.51, and DSEM 10.42.
- Eliminate or reconfigure triple circuit pole lines to minimize customer exposure for single emergency events that result in more than 1000 customers out of service
- Reconfigure double circuit pole lines where both the normal and alternate source supply the same group of customers resulting in more than 1000 customers out of service.

2.8. Standard Substation Design

While it may not be possible to design, build, and operate substation facilities that are completely resilient to any event which could result in customer outages, there are economic designs and technologies that minimize the occurrence and/or impact of substation-based events to improve reliability. At the distribution level, it is Eversource's goal to have customer's electric service automatically restored upon loss of supply to Bulk Distribution Supply Buses.

In areas of High Load Density, a higher degree of reliability is required by maintaining supply, without the loss of power, to Bulk Distribution Buses following an N-1 Contingency Condition.

To accomplish this, certain technologies/designs are considered:

- Each distribution bus providing service to high load density areas shall have at least two means of supply connected in a parallel. In this context, the preferred primary supply is provided by connection to the secondary winding of a Bulk Distribution Transformer, and secondary supply is provided by connecting to a normally closed bus tie breaker that connects to another bus supplied by the secondary winding of a different Bulk Distribution Transformer.
- Each distribution bus providing service in low to medium load density areas, shall have at least two means of supply (primary and secondary). In this context, the preferred primary supply is provided by connection to the secondary winding of a Bulk Distribution Transformer.
    - Secondary supply for distribution buses is provided by a connection to bus tie breakers (either

normally open or normally closed) that connects to another bus that is supplied by the secondary winding of a different Bulk Distribution Transformer within the same substation.

For all Standard Substations, Automatic bus restoral schemes (ABR), on the transformer secondary side, are designed/intended to restore supply to distribution buses after loss of supply due to transmission and/or substation events that results in loss of the transformer that normally supplies that distribution bus. These schemes automatically isolate the secondary breaker of the primary transformer supply to the bus and then close a normally open tie breaker to another bus/transformer, restoring supply to the affected customers.

Secondary bus arrangement for Standard Bulk Substations shall consist of two or more standard size transformers connected at the secondary side via a Ring Bus or Double Bus Switchgear configuration, refer to Figure below:

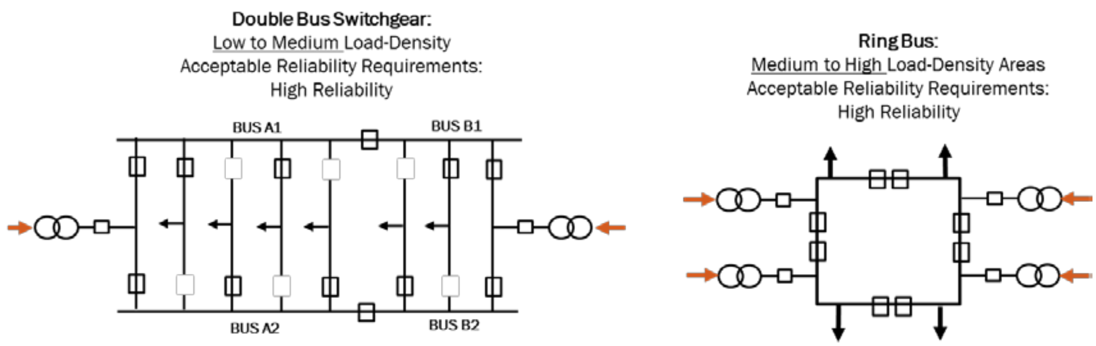


Figure 1 - Standard Substation Design

The preferred secondary bus arrangement design for new substations or substation upgrades shall be driven by the expected load density, based on long-term forecast of the area to be supplied. Low to Medium Load-Density areas shall be planned as Double Bus Switchgear configuration, and for areas with Medium to High Load-Density future substations shall be planned as a Ring Bus Configuration. In both substations arrangements, the system shall be design so that a bus fault does not result in loss load. In the Double Bus Switchgear this is accomplished by transferring the load to the non-faulted bus, in a Ring Bus Configuration the distribution system is designed to account for a bus fault.

Standard Bulk Distribution Substation shall be designed to meet the following criteria:

- Available short circuit currents shall not exceed the protection equipment's interrupting capabilities, both inside the substation and the distribution system:
- Short circuit currents that exceed protection equipment interrupting capability can result in equipment damage, widespread outage events, and concerns in maintaining personnel and/or public safety near such equipment. To minimize the risk, impact, and possibility of such events, simulations shall be conducted to evaluate the maximum short circuit current in a substation against the protection equipment's capability of interrupting it.
- The System Protection and Control department is responsible for this determination.
- Bulk Distribution Substations shall be designed such that the limiting element is the Substation Transformer(s).
- Capability to ensure Bulk Distribution Transformer winding loads can be maintained within the applicable rating during both normal and post-contingency conditions as per Section 2.2.
- Sufficient VAR support to maintain scheduled bus voltage values during normal and post-contingency (N-1) conditions.
- Capability and proper load balance between secondary buses to ensure:
    - Secondary bus loading is not exceeded during normal and post-contingency (N-1) emergency conditions.
    - Substation equipment and getaway cable loading is not exceeded during normal and post-contingency (N-1) emergency conditions.

2.9. Substation Upgrade Criteria

Bulk Distribution Substation designs should be in accordance with the design criteria specified in the Section 2.8 When existing substation designs do not conform to these criteria or future potential non-conformances are identified, as part of the Solution Development Process in Section 4.8, plans shall be developed to address identified violations. This section outlines the process for prioritizing needed upgrades required to mitigate capacity, power quality, and reliability violations.

To maximize the benefit of available funds and resources, the Eversource distribution bulk substations system improvement objective is to prioritize upgrades addressing violations based on the following priorities, in order:

1 - Highest to lowest overloads under normal and contingency (N-1) conditions
2 - Load loss under first contingency (N-1) conditions
3 - Highest to lowest number of customers impacted during contingency conditions
4 - Associated risk evaluation of substation based on individual components (Asset Condition).
    a - This Asset Condition criteria does not include equipment with asset conditions deemed a safety hazard, those should be prioritized and resolved under emergency conditions.

This objective ensures that violations addressing distribution substation overloads, both bulk and non-bulk, are prioritized due to the risk that equipment failure can pose to the public and employee safety. Moreover, violations that impact the reliability of the electric service we provide to our customers is also prioritized by addressing violations that result in a Single Contingency Load Loss. A reliable electric grid brings a host of benefits beyond reduced outage time to those affected by power outages (e.g., by providing greater assurance to businesses and emergency personnel that their activities will not be inconvenienced by electric outages). Lastly, by prioritizing reliability driven replacement of substation transformer and/or equipment as a factor of the load density, the number of customers affected by equipment failure is reduced (e.g., replacement of transformers that are over their useful life and are supplying high load density areas shall be prioritized when compared to similar transformers supplying low load density areas).

After the yearly distribution substation assessment process, Distribution System Planning shall identify all violations per individual substations and rank them by state based on the priority given in Table below.

Priority Number	Violation Type	Description
1.	Capacity	Bulk Distribution Substation Overloads
2.	Capacity	Non-Bulk Distribution Substation Overload
3.	Reliability	Single Contingency (N-1) load loss
4.	Reliability Power Quality	Substations with higher risk of equipment failure, due to asset condition or power quality violations, supplying High Load Density Areas
5.	Reliability Power Quality	Substations with higher risk of equipment failure, due to asset condition or power quality violations, supplying Low Load Density Areas
6.	Power Quality	Power quality Violations such as Harmonics, TOV, ROI
7.	Reliability	Non-Standard Substation Design

Table 4 - System Violation Ranking

Single Contingency Load Loss (SCLL)

SCLL is identified as complete or partial interruption of load served by a Substation for a sustained period due to the absence of automatic throw-over schemes on the transmission end or load swap schemes on the distribution end, (e.g. load supplied from radially fed circuits with no ties.)

Eversource System Operating Procedure (ESOP-28) - Single Contingency Load Loss for the respective state. supports the identification of events which result in customers being fed by a single transmission path, a loss of which would lead to complete or partial interruption of load served by a Substation for greater than 90 minutes due to the absence of automatic throw-over schemes on the transmission end or load swap schemes on the distribution end. Eversource has an established process to identify, review, and notify stakeholders of these SCLL situation to manage the risk of having these types of event occur. This process is specified in the ESOP-28 and applies to Eversource CT, MA, and NH electric transmission and distribution organizations. The process ensures involvement of stakeholders and management in reviewing, preparing for, and issuing any needed notification for outage work that creates a SCLL condition. Completion of the SCLL process in advance of the scheduled outage ensures that plans are in place to minimize risk exposure and mitigate customer load interruption.

Distribution System Planning should identify SCLL conditions due to substation transformer or switchgear outages that result in exposures exceeding the conditions cited in ESOP-28. When developing preferred and alternate solutions that will be implemented in the 5-year capital plan, as part of the solution development process in Section 4.8, Distribution System Planning will assess the severity of potential SCLL conditions and document these findings as part of the Solution Selection Form (SSF). Where SCLL risks are deemed to be severe, such risks would be considered in the design of the applicable solution.

For events that could potentially exceed the ESOP-28 criteria, the following information should be documented as part of the preferred solution:

- The next event (transformer or switchgear outage) that will result in the greater number of customers out of service.
- Identify transformer or switchgear equipment age and/or known asset conditions.

2.10.Feeder Upgrade

Feeder upgrades are required when one or more of the following design criteria is violated to ensure that any feeder cable/wire will not exceed Normal or Emergency Ratings, as per Section 3.1.

Cables and Wires Supplying Underground and Overhead Areas:
System modifications shall be developed and proposed when conductor limits are expected to exceed the following:

- 80% of normal feeder rating for cables
- 90% of normal feeder rating or emergency for wires

Feeder Supplying Underground Network Systems
System modifications shall be developed and proposed when conductor limits are expected to exceed the following:

- 80% of normal feeder rating

Distribution Supply System (DSS) Lines
System modifications shall be developed and proposed when DSS Lines are expected to exceed the following:

- 80% of normal or emergency rating for cables
- 90% of normal or emergency rating for wires

2.11.Battery Energy Storage System Design Criteria

Eversource defines the deployment of energy storage as a distribution grid solution, and the process for identifying scenarios where battery energy storage solutions would be most beneficial. Energy storage can be classified as a Non-Wires Solution (NWS) option or as a standalone technology that can be deployed at various scales.

Energy storage systems are uniquely capable of a variety of applications and uses. Like other NWS, energy storage can be used to defer distribution system upgrades and provide peak shaving benefits. In addition, can also provide demand charge reductions, and backup power in behind the meter applications.

Energy storage solutions can provide benefits to the distribution system in numerous ways, by providing multiple functions at different times of the day:

Active Power Functionality

Peak shaving - may be used to reduce exceptionally high load flows that likely occur only a handful of times per year and threaten to exceed thermal limits of lines or transformers either under all facilities in (N-0) or Contingency outage (N-1) conditions, as well as address voltage issues that might be caused at feeder ends.

Load Flattening Peak Shaving - may refer to the regular dispatch of energy during relative (typically daily) Substation of feeder load peaks. Operating the BESS in this way can:
Reduce the range of loading on a given feeder
Absorb energy during light-load periods

System Services – may be used to strategically dispatch the BESS to address (sub) transmission system needs
Provide energy and power when they are more valuable,
Limit ramp rates associated with the evening decrease of PV generation
provide frequency control services

Reactive Power Functionality

It could be beneficial year-round (management or peak shaving should still be set as priority) to regulate substation power factor to help minimize losses as well as reduce the amount of reactive power to be sourced or absorbed by transmission. With modern inverter technology, reactive power support can be provided even while active power functionality is idling.

- BESS's method of dispatching reactive power aid in system voltage regulation by absorbing or injecting reactive power or idling as necessary.
- The ability of control voltage can help mitigate issues caused by the high penetration of DER, such as light load voltage rise depending on the location of the storage asset.
- The ability of the BESS to control voltage can mitigate post-contingency high voltage issues on the Transmission system that may be identified by ISO-NE.
- The ability of the BESS to control power factor may permit more improved compliance with ISO-NE Operating Procedure #17(Annual Load Power survey)

Operational Responsibility

One of the chief potential values of energy storage is its ability to provide timely energy on demand to the grid. This requires the eligibility of Eversource Energy to own and operate energy storage as a flexible source of power. It is necessary to own and operate energy storage to provide distribution grid management services, such as discharging the storage to offset peak load on a circuit or to manage voltage on a circuit. It is the responsibility of Eversource to have the ability to control the energy storage under defined conditions or time periods—and that the energy storage be available (i.e., sufficiently charged) to meet the grid performance need.

Processes for Identifying BESS Opportunities

Through analysis and assessments, specific distribution grid needs/constraints can be identified and be considered and addressed by a BESS option. Distribution System planning can include a variety of analysis such as:

- Forecasting of load growth analysis
  - Seasonal peak loads at substation distribution transformers
  - Spot loads
- Distribution feeder loading analysis
- Distribution system modeling and scenarios simulations
- Reliability assessments
  - Worst performing circuit analysis
- Utilization of traditional reliability indices
- Equipment/asset loading analysis

A traditional solution must be identified to be compared with the BESS option.
The BESS will be implemented if it meets the "least cost" solution for a grid need. If applied as a capacity deferral,

the transformer/line remaining life time expectancy must be greater than 10 years. A preliminary BESS gross estimate can be calculated by using the latest version of the National Renewable Energy Laboratory (NREL) U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Cost Benchmark. Refer to most recent table of US Utility-Scale Lithium-ion Standalone Storage Cost for Durations of 0.5-4 hours. To the selected $/kWh value, the feeder position installation cost (if applicable), must be added. To this total cost the ES Indirect Costs and the AFUDC must also be applied. Contact the respective Cost Estimating Department to get these costs

Distribution Battery Energy Storage Suitability

Eversource owned Energy Storage can be used to meet System Planning Standards for normal and contingency operations. When the BESS is applied inside or in the substation vicinity, consideration should be given to future substations expansions. The BESS should not restrict expected long-term substation upgrades.

Eversource uses the following suitability criteria to identify opportunities for storage Implementation:

<table>
<tr><th>Criteria</th><th colspan="2">Potential Elements Addressed</th></tr>
<tr><td>Project Type Suitability</td><td colspan="2">Project types include Capacity, Power Quality, and/or Resiliency.</td></tr>
<tr><td rowspan="2">BESS</td><td colspan="2">Storage is the least cost solution compared with traditional option</td></tr>
<tr><td colspan="2">2-3 years Lead Time for small projects
3-5 years Lead Time for large projects</td></tr>
<tr><td rowspan="3">Time-Horizon Suitability</td><td>BESS Minimum Life</td><td>5-12 years</td></tr>
<tr><td>BESS Cycle Duration at nameplate power</td><td>1-4 hours</td></tr>
<tr><td>Asset Condition (being relieved) Remaining Life Expectancy</td><td>≥ 5-12 year</td></tr>
<tr><td rowspan="2">Demand Suitability</td><td>Large Project</td><td>3-20 MW</td></tr>
<tr><td>Small Project</td><td>1-2.5 MW</td></tr>
</table>

Table 5 - Opportunities for Storage Implementation Criteria

Note - For grid forming BESS applications short circuit ratio (short circuit of electric system at point of interconnection divided by size of BESS) should be greater than 1 at the minimum, optimal design is greater than 2. For grid following BESS applications short circuit ratio should be greater than 2, optimal design is greater than 3. BESS size solutions for Eversource areas with Low/Medium DER saturation and/or low peak shaving: 2.5MW/10MWh and 3.5MW/14MWh.

BESS distribution applications will consider utility system benefits such as:

- Avoided/Deferred distribution investments costs
    - Deferred distribution investment costs will be considered on a net present value basis
- Avoided energy and transmission costs
    - Yearly Capacity Peaks Reduction (Forward Capacity Market (FCM) costs
    - Monthly Regional and Local Network Services (RNS/LNS) Peak Reductions
- Clean Peaks Standards Certificates (MA only)

MA Only - Constructability of the BESS solution compared to the avoided conventional T&D upgrade.
If the BESS requires a substation expansion with extension of the fence line (which is an intensification of use), the BESS itself may trigger MDPU Chapter 40A review, whereas the conventional Substation upgrade (replacement of transformers in-kind with Larger banks) may not. This may be a factor that makes the conventional upgrade superior to the BESS implementation notwithstanding other apparent benefits.

Other components we need to consider for the Evaluation of a storage site vs. traditional upgrade.

- Aside from CapEx cost, BESS have significantly higher OpEx, so we should include expected maintenance and upkeep for the BESS over the study horizon as a net present value stream
- BESS energy losses, not sure where we account for those, but a 10MWh system that cycles once a day with an 80% roundtrip efficiency has a total annual energy consumption of 730 MWH. That needs to be paid for an accounted somehow
- Decommission and recycling. If it's not already baked into the upfront project contract that can be a major cost factor.

Inverters Functions Applied to Eversource Options:

A three-phase inverter transforms the dc input into three-phase ac output. Inverters rely on their internal control logic to achieve the targeted functions and to support the grid stability. Inverters equipped with advanced functionality can provide grid support services such as frequency/voltage regulation (Volt-var, Volt-watt, Fixed power factor (watt-var), hertz-watt, etc.)

<u>Reactive power applications</u> including Volt/VAR, independent reactive power (Q) dispatched output, and PF control

- The goal is to use inverters as a resource in distribution circuit voltage profile management, power quality, and power factor management
- Both autonomous and centrally controlled applications are of interest
- Implementations may include an inverter Q response to a local and/or remote measurement
- With modern inverters and dependent on the control option, Q response is not limited to times of active power activity.

Islanding

- The goal is to provide enhanced resiliency to customers by providing a back-up power supply during a loss of the normal electrical service
- Near-term anticipated islanding use cases have the following characteristics:
    - The ESS will island a 3-phase portion of a distribution circuit
    - Phase imbalance may be significant
    - The ESS inverter is required to provide grid-forming functions including voltage and frequency regulation
    - The island will not include other sources of generation, load control, or a central microgrid controller
    - The ESS will coordinate with circuit management devices such as reclosers and with a distribution control center
    - May be implemented as seamless transfer, or may require picking up cold load
- Future islanding applications, in addition to the above, have the following characteristics:
    - Require coordination with central microgrid controller
    - Require coordination with diverse other resources including solar, cogeneration facilities, diesel generators, flexible load
    - May involve significant phase imbalance of load and other generation resources

- Frequency response
    - The goal is to explore ability of inverters to participate in autonomous frequency response

- Inverter should have an autonomous response to locally measured frequency Phase Balancing operation
    - 3 phase inverters are typically set up as three single phase inverters with a joint DC bank allowing theoretical, and practical control of each phase individually.
    - Charging and discharging of active power to balance phases
    - Generation or consumption of reactive power to balance power factor and support individual phase voltages

- Eversource-owned utility scale BESS can also:
    - Participate in ISO-NE System Blackstart
    - Participate in other ISO-NE markets such as frequency regulation.

Distribution System Potential Benefits from the BESS/Smart Inverter

- Capacity Deferral—Storage can help delay a capacity investment to reduce expected present value costs or gather additional information and preserve options regarding the timing, nature, and scale of the required investment.
- Backup Supply—Storage can enable a Customer or group of Customers to maintain some or all electric service when power is not available from the grid.
- Remote Loads—Storage can be deployed in locations where significant investment would be required to provide service to the Customer and/or meet reliability requirements. This may include support for various remote EV charging scenarios (e.g., fast charging, fleet charging, transit charging) to smooth spikes in demand.
- Buffering—Storage can continuously and automatically offset and smooth changes in real power demand and supply from other DERs.
- CVO—Storage can assist in actively controlling distribution voltage, in most circumstances, to achieve energy and demand savings/reductions.
- Island—In an Island mode, zones, or circuits are capable of operating autonomously or collaboratively to optimize their operation based on system conditions. Storage can help balance demand and supply in a specific zone/circuit when disconnected from other portions of the grid system.
- Power Quality—Storage can help maintain the wave form in an alternating current (AC) power system that is necessary to ensure reliable and efficient operation of the grid and Customer equipment.
- Congestion Relief—Storage can help mitigate distribution congestion and enable more efficient power transfer by increasing demand upstream of a constraint or by supplying energy downstream of a constraint.
- Ramping—Storage can help address rapid changes in supply and/or demand over various time periods, from several dispatch intervals to several hours.
- System Efficiency—Storage can make load factor improvements by shifting demand from peak to off-peak periods.
- Topology Optimization—Storage can provide power or reserves such that the system can be reconfigured while continuing to meet reliability requirements.

System	***Capacity***	***Grid/Ancillary Services***	***Reliability***
Distribution System	Capacity Deferral Backup Supply Remote Loads Buffering CVO Congestion Relief Topology Optimization Backup Supply	Power Quality System Efficiency	Island
Bulk System	Capacity Deferral Buffering Congestion Relief Backup Supply	Power Quality System Efficiency	Ramping

2.12.Network Criteria

Downton areas of large cities are characterized by high power demands and increased customer density. Additionally, since most of the financial and commercial businesses are typically located in downtown areas, there are often strict requirements for uninterruptable power supply and power quality.

Full Secondary Network load areas, which are typically High Load Density, are defined as those in which both the low voltage secondary grid and customer spot networks installations are supplied by distribution underground network feeders that are connected to network bulk distribution substations. By this definition, both the supply feeders and the substations are designed and operated to meet the Reliability Requirements of the Secondary Network System.

Partial Secondary Network load areas are defined as those in which the low voltage secondary grid and individual customers spot networks installations are supplied by a combination of underground and overhead network feeders, but both the feeders and/or the substations are not designed to meet the reliability requirements of the Secondary Network System. Low and Medium load density areas are typically supplied via Partial Secondary Network systems.

Full Secondary Network System Reliability Requirements:

The objective of a secondary network is to interconnect feeders and transformers to form a consistent and well-diversified intermesh through the impedance of the low-voltage grid of mains and transformers. Feeders are connected to network transformers whose low voltage cables connect to a low-voltage secondary grid via network protector devices. The Eversource Full Secondary Network Systems is designed for N-1 Contingency Criteria at the substation level. The system is designed so that the loss of one distribution feeder does not result in customer interruptions, unsatisfactory customer voltages, or secondary cable overloads.

To maintain this level of reliability, the following design practices are implemented in Secondary Network load areas:

- At the secondary low voltage grid level, it is necessary to install a diversified intermesh with proper number, size, and capacity of transformers and secondary mains. This ensures that secondary equipment load levels remain under the required normal and emergency threshold for any combination of N-1 contingency.
- At the feeder level, it is necessary to use proper diversity when supply network transformers so that a single contingency N-1 event or transformer outage will have the minimum impact on secondary mains and nearby transformer loading.
- At the network level, to maintain proper feeder diversity only a certain number and combination of feeders are installed in the same conduit system and allowed to supply the same local areas or spot network installations. This prevents a single manhole or conduit section failure to result in secondary main overloads, transformer overloads, and/or customer outages.
- At the substation level, to maintain proper bus diversity feeder bus arrangement in network stations should be designed so that a bus section outage will have minimum impact on feeder loading. When designing or arranging distribution network feeders, it is recommended to connect unrelated feeders to each bus sections. This ensures that feeders supplying the same local areas a supplied from different bus sections.

Network Substation Supplying Full Secondary Network Load Areas:

Distribution Bulk Substation supplying network areas shall be designed so that each distribution bus has a minimum of two means of supply that are always connected in a parallel. In this context, the primary supply is provided by connection to the secondary winding of a bulk distribution transformer, and secondary supply is provided by connecting to a normally closed bus tie breaker that connects to another bus supplied by the secondary winding of a different Bulk Distribution Transformer.

For a Standard Substation Ring Bus configuration, each distribution bus has three means of supply that are always connected in parallel. The primary supply is provided by connection to the secondary winding of a bulk distribution transformer, and secondary supply is provided by connecting to normally closed bus tie breaker that connects to another bus supplied by the secondary winding of a different bulk distribution transformer.

Substations supplying Full Secondary Networks are operate with all transformers in service and all transformers connected in parallel so that the loss of transformers resulting from a Single Contingency event (loss of transmission or transformer) does not result in interrupted customers service.

The responsibility for determining and ensuring that network transformers, secondary mains, and network feeder loadings are within the design criteria for normal and emergency conditions rests with Distribution Engineering. The responsibility for determining and ensuring that the substation, inside plant distribution equipment, and inside plant cable as well as Distribution feeder is within design criteria for normal and emergency conditions rests with Distribution System Planning.

2.13. Distributed Energy Resources Criteria.

Detailed requirements relative to the safety, performance, reliability, operation, design, protection, testing and maintenance of the DER's interconnecting facility are provided under reference document "Information and Technical Requirements for the Interconnection of DER".

Eversource has established administrative processes for interconnecting all types and sizes of DER installations. As the level of customer and developer interest advances beyond the initial inquiry phase, a formal review process takes place in which the potential impact of a given site on the Eversource EPS is reviewed. This review may include the execution of formal study agreements and may result in general and specific requirements for certain design aspects of the DER. These requirements typically include electrical protection and control design and configuration, interface transformer configuration, required modifications to local Eversource facilities, metering and supervisory control and data acquisition ("SCADA") requirements, and in some cases operating constraints for the proposed DER.

3. Rating Criteria

3.1. Feeder Rating

The Eversource distribution feeder ratings are determined by the Synergi power flow program. The method outlined in this specification is incorporated into the Synergi program.

Distribution Feeder Rating

- The normal rating of a distribution feeder is the load in amperes that the feeder can carry for a 24-hour load cycle under system intact (N-0) conditions without exceeding the normal rating for Substation getaway cable, underground cable, aerial cable, overhead wire or any equipment in series on the feeder.
- The emergency rating of a distribution feeder is the maximum load in amperes that the feeder can carry under contingency (N-1) conditions without exceeding the emergency ratings for Substation getaway, underground cable, aerial cable, overhead wire or equipment in series for 24 hours.

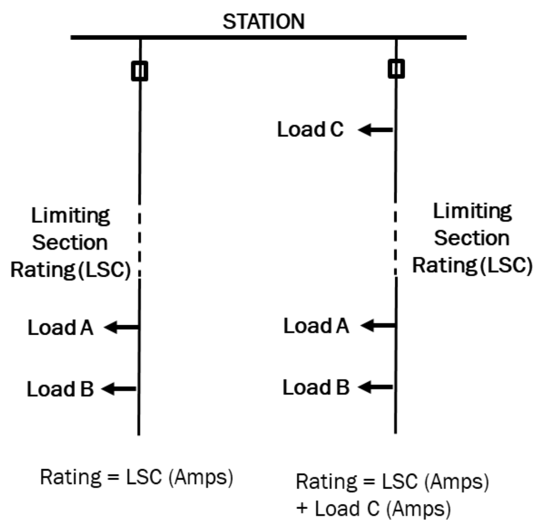


Figure 2 - Feeder Ratings and Limiting Section

Procedure for Rating Distribution Feeders:
The procedure for rating distribution feeders at the source involves 3 steps
1 - Determine the feeder rating as limited by Substation getaway cables, by using an Eversource approved rating program, and the feeder trip set point calculated by the Protection Department, which should include the rating of the Substation feeder breaker.
2 - Calculate the feeder rating as determined by the most limited section of underground cable, aerial cable or overhead wire, using the cable and wire thermal loading criteria provided in Section 2.3.1.
3 - Establish the feeder rating as the values of 1 and 2 whichever is lower.

Distribution Normal Rating

Radial Feeder

The normal rating is the normal rating of the cable or wire ahead of all load, or it is the normal rating of a limiting cable or wire section plus all the load that is normally supplied ahead of the limiting section, whichever is lower. The emergency rating is the emergency rating of the cable or wire ahead of all load, or it is the emergency rating of a limiting cable or wire section plus the total of an appropriate combination of emergency and normal loads ahead of the limiting section, whichever is lower. The appropriate combination of emergency and normal loads ahead of the limiting section that gives the lowest emergency rating is used.

Loop Feeders

The normal rating of each side of the loop is determined as for Distribution Radial Feeder above by considering all normal loads from the source end of the loop to the electrical midpoint of the loop. The emergency rating of each side of the loop is the emergency rating of the cable or wire between the source and the first load, or it is the emergency rating determined by a limiting cable or wire section on the basis that the loop is open at one end between the source and the first load.

Feeders with co-Generation

Cogeneration customers supply a portion of their total load with their own generators. Co-generation installed on a distribution feeder reduces the apparent load on the respective feeder. When determining the rating on a feeder with co-generation, any load supplied by co-generation should be added to the monitored load on the feeder. The reason for this policy is that co-generation possibly may not be connected to the feeder during the summer peak period and the company must supply all the load of the co-generation customer from existing facilities. Additional assessments of historic operational history, as well as contractual commitments from the Generation Owner to Eversource, are conducted where large co-generation (relative to the identified thermal overload) may sufficiently mitigate thermal constraints.

Distribution Emergency Ratings

Radial Feeder

The emergency rating is the emergency rating of the cable or wire ahead of all load, or of a limiting cable or wire section plus all load that is normally supplied ahead of the limiting cable or wire section plus load that has been identified as Required Emergency Switching ahead of the limiting section, whichever is lower. Required Emergency Switching shall be identified for every radial circuit by Engineering and Operations. It includes the largest load transfer expected on a radial feeder to support other connected feeders during emergency operations.

Loop Feeders with Automatic/Manual Ties

The emergency rating of each feeder is determined for each single loop feeder by assuming the automatic midpoint field switch is closed and the entire normal load on the two feeders is supplied from one substation. Consider the possibility that the loop feeder, with the automatic field switch open, also supplies load to one or more emergency tie points (Required Emergency Switching), or feeds load through to another substation. The emergency rating that is calculated by accounting for the largest emergency tie in the feeders should be used.

3.2. Rating of Feeder Supplying Secondary Networks

Network feeder cables have Normal and Long-Term Emergency ratings for both summer winter months. The ratings are contained in a table of cable ratings compiled for use in rating 15kV and 25kV cables, and they take into account the cable size and the number of ducts occupied in a given duct bank. In the network area, the ratings are applied conservatively to account for the proximity of other facilities in the street, including non-electric facilities that can contribute additional heat to the network feeder cables.

3.3. Transformer Rating

Bulk Distribution Transformers are integral to the electric distribution system and are large capital investments with long lead time. The cost of premature/unexpected failure of these assets can amount to several times the initial cost of the transformer. The cost of failure not only includes refurbishment or replacement of the transformer, but also costs associated with clean-up, loss of revenue and possible deterioration in the quality of service to customers. It is important to Eversource that the ratings for bulk distribution transformers are calculated accurately and that the results are well documented.

Eversource follows the methodology in SYSPLAN 008 for calculating Bulk Distribution Transformers. This procedure is based on IEEE C57.91-2011 and IEEE C57.12.00-2015.

The process in SYSPLAN 008 was developed in a collaborative effort between the Eversource System Planning, Substation Design Engineering, and Substation Technical Engineering Departments and relies on input from Industry Standards, ISO-NE Planning Procedures, and Eversource operating experience.

Transformer Rating Categories

ISO-NE PP-7 section 2.3 requires transmission owners in New England to provide four categories of load carrying ratings: Normal, Long Time Emergency (LTE), Short-Time Emergency (STE) and Drastic Action Limit (DAL). Per ISO-NE PP-7 Appendix D, since operation of load-serving transformers does not impact the high voltage transmission system, the transformer owner may determine the criteria for rating a load-serving transformer. Also, the duration associated with LTE, STE and DAL limits may vary from the durations in PP7 Section 2.3. Therefore, Eversource utilizes the following time durations for these four categories of ratings:

- Normal Ratings – Continuous
- Winter LTE (W LTE) - 4 hours
- Summer LTE (S LTE) - 12 hours
- Winter STE (W STE) - *30 minutes
- Summer STE (S STE) - *30 minutes
- Drastic Action Limits – *DAL is equal to the STE for Summer and Winter ratings)

*Note - For operational practicality purposes, there is not enough time for an operator to respond when a transformer is loaded at or above STE. Hence, Eversource generally sets the STE as a 30-minute rating as opposed to the guideline of 15-minutes and sets the DAL equal to the STE rating.

Substation Rating:

To maximize the substation output, the Standard Bulk Distribution Substation shall be designed such that the limiting element is the substation transformer. Therefore, the Substation Normal and Emergency Ratings shall be defined by the Normal, LTE and STE ratings of the smallest transformer(s).

For a Substation where the transformer(s) is not the limiting element, the rating of the substation as a whole should be calculated based on the limiting factor which includes but is not limited to: gateway duct bank cable, switchgear/bus, breakers, disconnect switches, and transmission lines. Distribution System Planning should verify the Substation limiting element against the NX-9B form supplied by Substation Engineering.

Substation Firm and Load Carrying Capability:

In calculating the rating of a bulk distribution substations, it is important to consider the loss of the largest element during an N-1 contingency condition in addition to the load that can be transferred out of the station post contingency. Firm and Load Carrying Capability (LCC) ratings are used to account for both of these limits:

- Firm Capacity is defined as the total LTE rating of the remaining transformer(s) after the loss of the largest transformer, refer to Section 6.1 for full definition.
- LCC is defined as the Firm Capacity plus Distribution Transfer Switching Capacity
    - Distribution Transfer Switching Capacity is calculated by assuming successful transfers of load to other stations is completed within 30 minutes

The 30-minute limit used for Distribution Transfer Capacity is driven by constraints under various operational scenarios. Below is a list of steps to be considered following a contingency:

NOTE: Dispatcher initiated load transfers (using distribution automation capabilities, manual switching is not used for this purpose) must be available to lower transformer winding loads to below the LTE rating, within the time frame given below.

When distribution load transfers are credited for reducing transformer winding loads to below the LTE rating, the following time frames shall be used:

- The initial post-event assessment period for Dispatchers to identify/assess the event shall be 10 minutes.
- The time to implement each load transfer is 5 minutes.
- All load transfers are sequential, when more than one is needed:
    - Two transfers take 10 minutes
    - Three transfers take 15 minutes
    - Etc.
- Where possible, there shall be at least one extra load transfer available for Dispatchers to use. This shall be available for use in the event that one of the primary load transfers cannot be accomplished.

Bulk Distribution Transformer(s) that provide secondary supply to other transformers under contingency conditions, shall be within LTE loading criteria for the first load cycle following an event. Additional distribution switching (remotely controlled) and/or a mobile transformer shall be available to lower transformer winding loads to the normal rating or below.

Additional distribution switching via loop scheme used in lowering the transformer to below normal rating shall be limited to those that can be restored to normal configuration within 24 hours or a mobile position connection shall be installed at the substation. A mobile installation will be implemented when problems will require multiple load cycles to be resolved. Substations with space or connection constraints that prohibit the installation of a mobile transformers shall be rated up to the nameplate of the remaining transformers after the loss of the largest transformer.

Substations Serving Major Secondary Network Systems

Because of the nature of secondary network loads, there is no transfer switching capability with other substations. This results in the substation capability being equal to the LTE rating of the smallest remaining transformer(s) and that STE/DAL ratings cannot be applied because there is no transfer capability to relieve transformer winding loads.

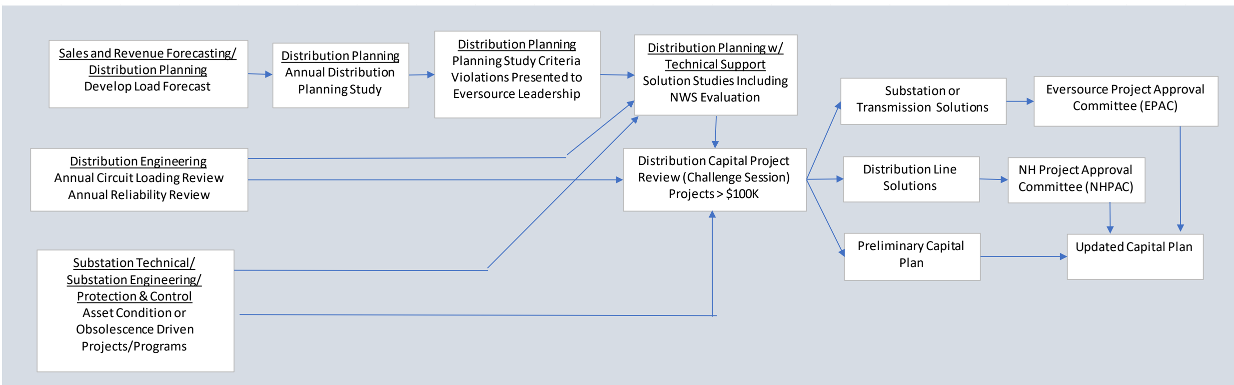
4. Planning Methodology

4.1. Introduction

Distributions System Planning is a fundamental function of the utility to provide reliable and cost-effective electric service to our customers. System Planning objective is centered around the goal of providing safe and reliable service to our customers. Eversource is at the forefront of integrating System Planning with a comprehensive modeling and Probabilistic Forecast process that integrates new technologies as they mature, and penetration levels increase. The goal is to integrate new technologies in a manner that enhances or maintains grid reliability. Although traditional system upgrade solutions have proven effective, as DER penetration levels increase, consideration should be given in the evaluation of solutions to avoid compromising safety, cost effectiveness, and reliability.

4.2. Process Map

Project Initiation Process



4.3. Model Development

Distribution System Planning develops regional planning models which are used to perform capacity, reliability, and power quality studies for bulk distribution substations, including 10-year substation capacity plans. This section describes the model development process applicable to all distribution planning departments using the Synergi Electric software.

The yearly model development process starts after the summer period with the first October of the Observed Year. Seasonal 24-hour load profiles are extracted from PI and analyzed for accuracy. Hereby two peak conditions can be identified:

I - Peak Net Load Day: The day with the highest peak net load measured at the substation. Because this load is measured from the substation meters it includes the impact (load reduction) of generation that is in service during that day.
II - Peak Gross Load Day: The day representing the highest gross demand at the substation. This load is calculated by using the measurement at the substation and adding the contribution of generation output (front of the meter) and estimates (behind the meter).

NOTE: The Peak Gross Load Day is important for the 10-year system plan. As a result, when defining that day, it cannot simply be done by finding the highest loading day measured at the substation. A more comprehensive search must be conducted in correlation with generation (including Distributed Energy Resource – DER). When insufficient load/generation data is available to determine the Peak Gross Load Day for the year, a good workaround is to use the Peak Net Load Day data and add the generation output (front of the meter) and estimated generation (behind the meter) to obtain the Summer Peak Gross Load Day.

The same analysis is to be done for

I - Minimum Net Load Day: The day with minimum net load measured at the substation.
II - Minimum Gross Load Day: The day representing the minimum gross demand at the substation.

Based on the substation load profile measured for the Observed Year and the trend in historical peak load, Distribution System Planning determines which ones should be analyzed as non-coincident or coincident with the ISO NE system peak, the official peak substation day, and the actual peak time. When possible, a peak day (or time) with normal system conditions is selected, and days with outages of substation transformers, multiple distribution feeders, or transmission lines should be avoided. The final Peak Gross Load for each Substation is recorded and provided to the Forecasting group to start the development of the company's 10-year load forecast. When required, the load profile is adjusted to account for abnormal conditions, including but not limited to: emergency load transfers, system reconfiguration, contingency conditions, and generation status. This yields the system model and load condition that are expected under normal configuration.

In parallel with the effort of reviewing the Peak 24-hour load profile for each substation, distribution system data extraction/import into the Synergi application is completed using the established **Peak Gross Load Day** as a framework. Ideally, the connectivity model that closely matches the actual circuit configuration during the peak day shall be extracted from GIS and made available in Synergi, ensuring a more accurate planning model.

Based on the availability and accuracy of the extracted GIS and Synergi data, distribution Substation capacity analysis is completed using one of the following methods:

- For substations with limited data that result in a non-converging model or load flow results not reflecting real peak load conditions, as a comparison of actual substation measured data during the peak load day, a 10-year capacity analysis based on hand calculation of capacity is acceptable.
- If data extraction results in a converging load flow model reflecting real peak-time conditions but not accurate 24-hour load conditions, complete and use only the peak-time load data and model for completing the substation 10-year capacity analysis.
- If data extraction results in a converging 24-hour load data model, complete and use a 24-hour model for completing the substation 10-year capacity analysis.

When developing 10-year substation capacity plans, each substation <u>can</u> be considered under a total of two (2), or where applicable, four (4) different planning models. These planning models should align with the studies conducted for DER interconnection studies by the DER Planning Group.

I - Summer or Shoulder
a - Minimum Load Planning Models
b - Peak Load Planning Models
II - Winter Planning Models:
a - Winter Peak Load Planning Model
b - Winter Minimum Load Planning Model

NOTE: Distribution System Planning will determine the scenario(s), Summer, Shoulder, and/or Winter, to be analyzed for each station depending on the station historical load profile.

To expedite the yearly distribution system model building process and account for substation normal and N-1 conditions, Distribution System Planning will define and maintain a list of models and the substations included in each model. At the minimum, a complete planning model shall include:

- All the distribution bulk transformers in each substation
- Transmission source impedance at the high side of the substation transformers based on the normal configuration of the Transmission System.
- Station bus with associated bus tie breakers and feeder breakers
- Full representation of all distribution feeder backbone sections that are used to provide load carrying capability (LCC)
- Non-bulk substations may be modeled as needed up to the secondary side of the transformers, including the distribution ties between substations, to provide additional details.

4.4. Gross Load Model and DER Forecast

With Eversource's Service Territory experiencing a large increase in DER adoption the development of Gross Load Models is extremely importance.

$$P_{Gross}(t) = P_{net}(t) + P_{DER}(t)$$

Hereby $P_{net}(t)$ represents the 15 min time series values (where available) in MW measured at the substation and collected from the PI database.

NOTE: Where 15 min data is not available, hourly interval simulations are acceptable

CAUTION: In a multi transformer station ensure that that DERs are accurately assigned to the circuit, and transformer, that is feeding them.

The following figure highlights the difference between a clear sky irradiance profile and the actual measured profile during a peak day sample.

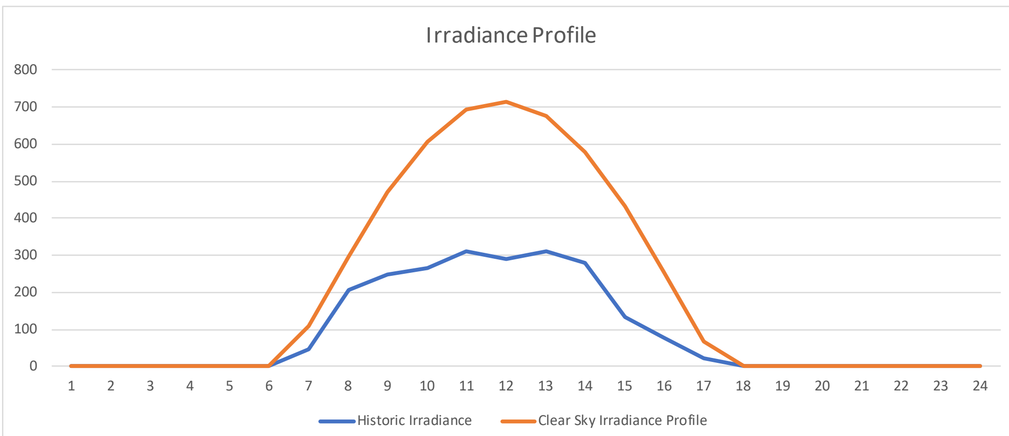


Figure 3: Clear sky and actual irradiance profile

NOTE: Irradiance data is given in W/m2. Solar ratings are typically given at 1000W/m2. As a result, the actual output is:

$$P_{Output} = P_{Rating} * \frac{\epsilon_{irradiance}}{1000\,\frac{W}{m^2}}$$

$P_{DER}(t)$ represents the power generated by the DER the at time point.

Type of DER	Methodology
Behind-The-Meter solar (BTM)	Multiply the installed DER nameplate capacity by the historic irradiance data to receive the estimated output at the specific data and time. If no irradiance data is available, use the nearby PI reading of a large solar installation.
In front of the meter solar	Utilize the PI recorded data if available, otherwise apply same process as for BTM solar.

Table 6: Solar Methodology

The following highlights an example for a net and gross load model with solar generation. This gross load model allows the identification of the Gross Load Peak and Gross Load Minimum day.

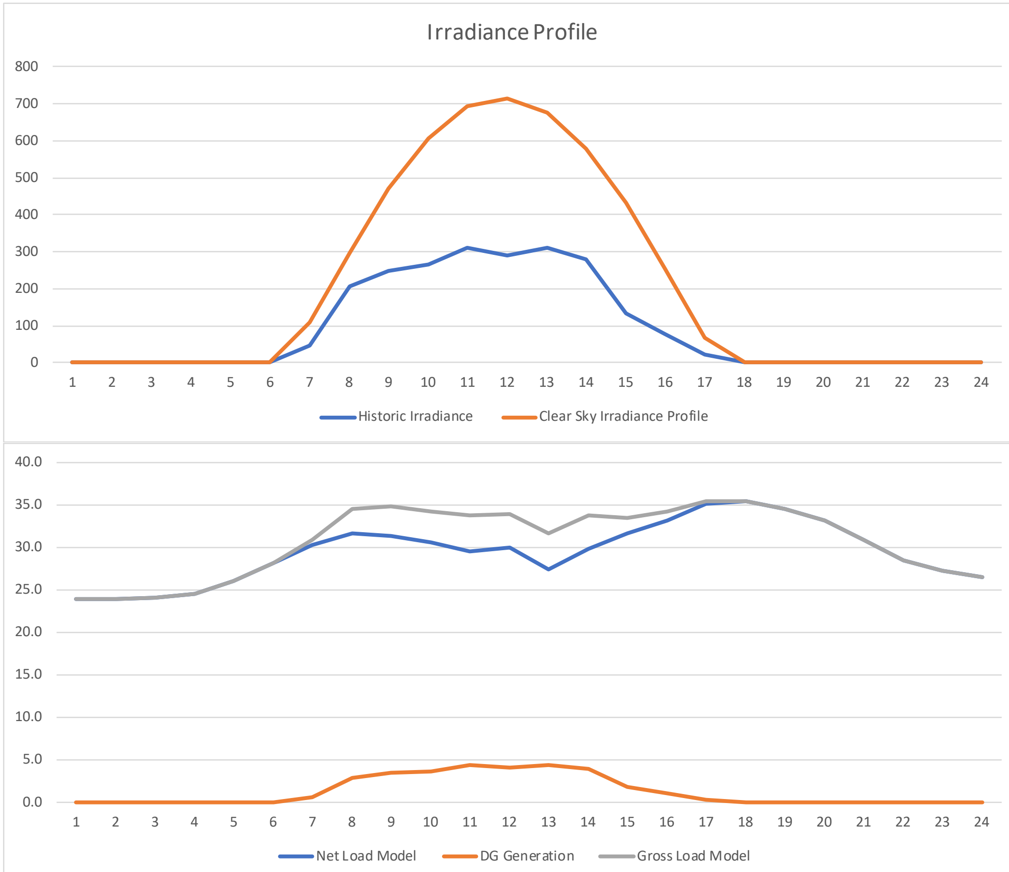


Figure 4: Gross and Net Load Profiles with DER output

Once the DG is backed out of the net readings and the gross load time series determined, the peak gross day can be evaluated. When applying forecasts to any gross model, the following steps are to be taken.

When reapplying the forecast data to the Gross Model, two observations can be made depending on if the forecasts are applied to the gross peak or gross minimum:

1) - Peak Forecast Load Model

When forecasting with the peak load model, the objective is to scale and build the system for heavy load conditions. This model finds application in all systems where there is not enough DG to be driving capacity investments. As such, high load conditions and low DG conditions are assumed.

$$P_{Peak\_forecast}(t) = P_{gross\_max}(t) - \left[P_{Installed}(t) + P_{Forecasted_{10th}}(t)\right] * \varepsilon_{10\%}$$

Where

P_{gross_max} = Gross maximum load
$P_{Installed} * \varepsilon_{10\%}$ = 10% of seasonal clear sky profile
$P_{Forecasted} * \varepsilon_{10\%}$ = 10th percentile of solar adoption

Steps

1 - Determine the gross peak load day (e.g. August 4th
2 - Determine the corresponding clear sky profile
3 - Determine the 10% profile of the corresponding clear sky profile
4 - Apply the 10% profile to all installed DG
5 - Add in 10th percentile DG adoption

6 - Apply the 10% profile to all newly adopted DG

2) - Minimum Forecast Model

The minimum model serves as the planning model for high DG impact systems where the largest concern is around low load conditions meeting high DG output. As such, it is forecasted with low load growth and high DG adoption and output.

$$P_{Min\_forecast}(t) = P_{gross\_min}(t) - \left[P_{Installed}(t) + P_{Forecasted_{90th}}(t)\right] * \varepsilon_{100\%}$$

Where

P_{gross_max} = Gross minimum load
$P_{Installed} * \varepsilon_{10\%}$ = 10% of seasonal clear sky profile
$P_{Forecasted} * \varepsilon_{10\%}$ = 10^{th} percentile of solar adoption

Steps

1 - Determine the gross minimum load day (e.g. March 4^{th}
2 - Determine the corresponding clear sky profile
3 - Apply the clear sky profile to all installed DG
4 - Add in 10^{th} percentile DG adoption
5 - Apply the clear sky profile to all newly adopted DG

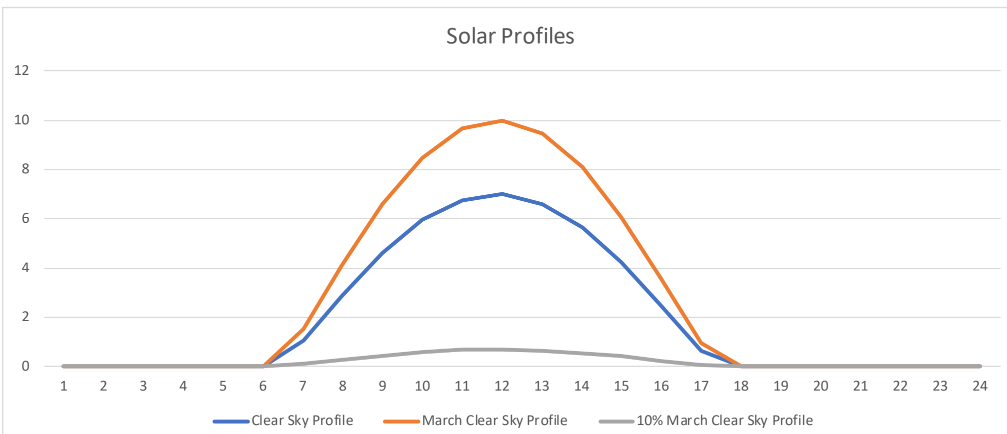


Figure 5: Scaled Forecast Profiles

4.4.1. Scenario Forecasts

Eversource historically produces both a 'normal' and an 'extreme' peak load forecast for each operating company. The normal peak load is based on average historical weather data, and the extreme peak is based on the 90th percentile of that historical weather data. The extreme peak is also referred to as a 90/10 forecast and it assumes a 10% chance that the peak load would be exceeded. Put another way, the forecast will be exceeded on average only once every 10 years.

As part of the Company's substation planning process, the Company develops Probabilistic Based Forecasts for the purposes of testing and evaluating the performance of the system and assessing the need for substation capacity upgrades. Hereby an individual set of forecasts can be generated for each substation to reflect locational specific factors.

Forecast Component	Description	Responsibility	Type
Trend ε_{Trend}	Historical and forecast economic data are procured by an international economic	Revenue Forecasting	Proportional Scaling Forecast: Scales existing loads proportionally with forecasted trend. Applies to all 24-hour time intervals

Forecast Component	Description	Responsibility	Type
	consulting company.		Capacity Data **%** of last peak day
DG Adoption $P_{DG_{Adoption}}$	Produces a probability distribution of total DG adoption on the studied station. Depending on forecast type, certain percentiles are selected	System Planning	Probabilistic Forecast: Capacity Data in **MW** by type of DG
DG Queue $P_{DG_{Queue}}$	All previously known DG interconnections that have been requested	DER Planning	Capacity Data in **MW** by unit including location
DG Output $\varepsilon_{DG_{Output}}(t)$	Firm contribution of DG assets to peak. Using a probabilistic model, the firm contribution of any form of DG to system peak is calculated and later applied to forecasted, in queue, and presently available installed DG capacity	System Planning	Probabilistic Forecast: Produces percentiles of forecasted correlation between load peak and DG output. Time Series Data in **%** of installed by type of DG
EV Adoption $P_{EV_{Adoption}}$	Produces a probability distribution of total EV charging capacity adoption on the studied station. Depending on forecast type, certain percentiles are selected	System Planning	Probabilistic Forecast: Number of EV charging stations Capacity Data in **MW**
EV Profile $\varepsilon_{EV_{Profile}}(t)$	Produces a probabilistic load shape for EV charging based on expected travel patterns, charging durations, vehicle types and available charging infrastructure.	System Planning	Probabilistic Forecast: Load shapes can be selected based on observed percentile. Requires a forecast on number of electric vehicles Time Series Data in **%** of installed
Energy Efficiency EE	EE Trend forecast showing the annual and cumulative reduction expected through energy efficiency measures	Energy Efficiency Group	Proportionally Scaling Forecast: Reduces all loads proportionally to peak hour at any time point of the scenario Capacity Data in **MW** (applied proportionally)
Sector Conversion $P_{Conversion}(t)$	Linear forecast based on assumptions of gas to electricity conversion. Time series load profile derived from gas profiles	System Planning	Time Series Data in **MW**
New Business Growth Queue $P_{Step_{Queue}}(t)$	All previously known New Business Growth interconnections that have been requested	System Planning	Capacity Data in **MW** by unit including location
New Business Growth Development $P_{Step}(t)$	Probabilistic forecast predicting the probability of total new New Business Growth additions in MW during peak load hour.	System Planning	Proportionally Scaling Forecast: Increases all loads proportionally to peak hour at any time point of the scenario Capacity Data in **MW** (applied proportionally)

Forecast Component	Description	Responsibility	Type
Capacity Reserves $P_{Reserve}(t)$	Represents known co-generation units that run continuously. Customer or utility sited. Accounts for failure of the largest of such units on the observed station[5]	System Planning	Time Series Data in **MW**

Table 7- Forecast Components

Hereby $P_{PeakLoad}(t)$ represents last year's season peak load day (24 hours, 15 min intervals) and $P_{DG_{Installed}}$ represents all currently installed capacity (by type of DG) on the studied station.

$$P_{PeakForecast} = \left[P_{PeakLoad} * \varepsilon_{Trend} * \left[1 + \frac{\left(P_{Step} + P_{Step_{Queue}} + EE \right)}{\max[P_{PeakLoad}]} \right] \right] + P_{Reserve} - \left[\sum_{All\ DG} \left(P_{DG_{Installed}} + P_{DG_{Adoption}} + P_{DG_{Queue}} \right) * \varepsilon_{DG_{Output}} \right] + \left(P_{EV_{Adoption}} * \varepsilon_{EV_{Profile}} \right) + P_{Conversion}$$

As well as $P_{MinLoad}$ represents last year's season minim load day (24 hours, 15 min intervals)

$$P_{MinForecast} = \left[P_{MinLoad} * \varepsilon_{Trend} * \left[1 + \frac{\left(P_{Step} + P_{Step_{Queue}} + EE \right)}{\max[P_{MinLoad}]} \right] \right] + P_{Reserve} - \left[\sum_{All\ DG} \left(P_{DG_{Installed}} + P_{DG_{Adoption}} + P_{DG_{Queue}} \right) * \varepsilon_{DG_{Output}} \right] + \left(P_{EV_{Adoption}} * \varepsilon_{EV_{Profile}} \right) + P_{Conversion}$$

NOTE: If specific forecasts are not available for a substation, they can be assumed to be not relevant to the study.

Each forecast that is impacted by seasonality (Sector Conversion, EV Profile, DG Output, and Trend) are provided by season to allow planners to select the corresponding forecast depending on the scenario he/she is studying for a specific station.

The following shows an example of two scenario forecasts and their respective extreme versions.

[5] In compliance with the Department's guidance in D.P.U. 13-86, the Company has amended its load forecasting methodology both to align with ISO-NE and to change how it reconstitutes loads for distributed generation. The Company no longer reconstitutes loads for distributed generation units larger than 5 MW, unless those customers are on Standby Delivery Service (also called Reserve Capacity in CT). For Customers on Standby Delivery Service, the company is obligated to be: "standing ready to provide delivery of electricity supply to replace the portion of the Customer's internal electric load normally supplied by the Generation Units be unable to provide all, or a portion of, the expected electricity supply." It is the Company's obligation to provide service to these customers regardless of whether the Generation Units that can serve a portion of the customer's load are operating or not. To reflect this obligation, forecasted loads have been reconstituted for the portion of load that was served by the Generation Units.

Forecast Component	Load Driven Forecast Model (Extreme)	Generation Driven Forecast Model (Extreme)
Baseline	Peak Gross Load Model	Minimum Gross Load Model
Trend ε_{Trend}	Baseline (90th percentile)	Baseline (10th percentile)
DG Queue $P_{DG_{Queue}}$	As Reported	As Reported
DG Adoption $P_{DG_{Adoption}}$	10th percentile (-2-Sigma)	90th percentile (2 Sigma)
DG Output $\varepsilon_{DG_{Output}}(t)$	10% of clear sky	100% of clear sky
EV Adoption $P_{EV_{Adoption}}$	90th percentile (2-Sigma)	10th percentile (-2 Sigma)
EV Profile $\varepsilon_{EV_{Profile}}(t)$	90th percentile (2-Sigma)	10th percentile (-2 Sigma)
Energy Efficiency EE	10th percentile (-2-Sigma)	90th percentile (2 Sigma)
Sector Conversion $P_{Conversion}(t)$	90th percentile (2-Sigma)	10th percentile (-2 Sigma)
New Business Growth Development P_{Step}	90th percentile (2-Sigma)	10th percentile (-2 Sigma)
New Business Growth Queue $P_{Step_{Queue}}(t)$	As Reported	As Reported
Capacity Reserves $P_{Reserve}(t)$	As Reported	As Reported

Table 8- Forecast Scenario Extreme Versions

NOTE: The distribution planner may use multiple scenarios from the available forecast data in addition to the above-mentioned scenario forecasts. Additional scenarios can be created by mixing the respective forecast components based on local knowledge.

4.4.2. Modeling Forecasts

When modeling the Probabilistic forecasts in the Approved Distribution Model, some forecast projections are applied at the substation level and equally distributed to all line segments using load allocation and some forecast projections are applied at individual feeder locations.

Forecasted Resource	Approach in Synergi
New Business Growth Forecast	Equally distributed load increase across all line segments
New Business Growth Queue	Placed at reported location
DG Forecast	Equally distributed load decrease by profile
DG Queue	Placed at reported location
EV	Equally distributed load increase across all line segments with charging profile
DG Output	Applied to the respective DG clear sky profiles
Sector Conversion	Equally distributed load increase across all line segments
Energy Efficiency	Equally distributed load decrease across all line segments

Table 9- Forecast Resources

For load allocation, allocation by annual consumption data is the preferred method where the data supports such an approach. Otherwise, allocation by installed capacity is to be used.

4.5. Planning Model

4.5.1. Base Case Planning Model

Base Case Planning models are validated against the actual measured station load of the Observed Year. Based on the configuration of the distribution system, load transfer capability, and distributed generation size and location, a Based Case Planning Model could be defined as just one station, or multiple stations could be combined as one model. Combining interconnected stations, that depend on each other during contingency conditions, into one model facilitates the analysis of N-1 contingencies in the distribution system and the impact that these contingencies have on system operation.

Due to the validation requirements, Base Case Planning Models are finalized after the peak summer day is established. Once validated, the 10-year probabilistic load forecast can be integrated, and capital projects can be studied and proposed for the next 10 years. Projects not meeting a required 12 months minimum timeline from the completion of the model shall be analyzed using the prior year Base Case Models.

4.5.2. Peak and Minimum Load Planning Models

These are developed from the Base Case to represent the peak and minimum load day conditions for the specific station or group of stations that make up the model. These models include the 10-Year Load Forecast, planned DER, and Planned Reinforcements in the 5-year capital plan.

Probabilistic Forecast
If a 10-year Probabilistic Forecast will be made available in the future, it is integrated into the model to analyze the peak load conditions for the next 10 years.

By adjusting the individual Forecast Components that make up the Probabilistic Forecast it is possible to account for existing business-as-usual planning scenarios, as well as future local and/or state policy and technologies changes with the potential to alter the electric load forecast.

Standard Forecast
The Standard Forecast considers the possibility of different growth rates based on historical trend and penetration of new technologies, but it does not consider consumer behavior or local/state policies and technology changes driving the use and adoption of these technologies, which should be studied using a Probabilistic Planning Approach. Nevertheless, if insufficient data is available to develop a Probabilistic Forecast, the Peak and Minimum Load Planning Models shall be analyzed using a Standard Forecast and existing scenario forecast.

Peak and Minimum Load Planning Model should be developed, at the minimum, using the data sources below as input:

Forecast Component	Load Driven Forecast Model	Generation Driven Forecast Model
Baseline	Peak Gross Load Model + Installed DG at 10% of clear sky profile	Minimum Gross Load Model + Installed DG at 100% of clear sky profile
Trend ε_{Trend}	Baseline	Baseline
DER Adoption $P_{DG_{Adoption}}$	In Queue	In Queue
DER Output $\varepsilon_{DG_{Output}}(t)$	10%	100%
Energy Efficiency EE	In Queue (not included in base forecast)	In Queue (not included in base forecast)
New Business Growth Development P_{Step}	In Queue	In Queue
Capacity Reserves $P_{Reserve}(t)$	As Reported	As Reported

Table 10 - Standard Forecast Components

Substations with minimal load and or DG growth and sufficient long-term capacity (both forward, reverse, and contingency) can be modeled without the DG Adoption and DG Output Forecast Components noted in table above.

Substations with medium/high load growth that are not expected to be overloaded in the next 10 years shall include, in addition to the Forecast Component in the above table:

- New Business Growth Queue Forecast Component for years 5 to 10 that is based on recent historical new business growth
- DER Adoption and DER Output Forecast Components

This should result in a more representative new business trend after year 5.

Stations with medium/high load growth (based on Trend and in queue forecast components) that are expected to be overloaded in the next 10 years shall be scaled in load for the following 10 years using the Peak Load Planning Case and a Scenario Based Planning load allocation approach which includes:

- Business-as-usual process for developing the 10-year forecast and peak demand. This is based directly on the prevailing DG interconnection queue and load growth queue that has existing work order factoring in average attrition rates. This will provide an adequate planning goal for years 1-3 since the new business load and DER are well defined, but not as well defined after year 4.
- Accounting for region specific economy, policy, and technology changes. This scenario reflects what local and/or state policies will consider ambitious but achievable goals. Additionally, DER adoption and new business loads are forecasted based on previous historical growth over 10 years at a local level. In general, this Scenario provides adequate planning goals for years 4-10.

4.5.3. Winter Planning Models

Developed to represent the Winter peak and minimum load day conditions for the specific station or group of stations that make up the model. It is also developed from the Base Case, but it includes the 10-Year Winter Load Forecast and Planned Reinforcements already included in the 5-year capital plan.

Stations with significant Winter load growth that can equal or exceed summer Peak Load, resulting from zero carbon emission policies and/or consumer behavior, should be studied using a winter high load case to reflect capacity concerns in areas with expected gas/oil to electric conversion.

The Winter Planning Model process is the same as the Peak and Minimum Load Planning Model process with the only difference being that a Winter 10-year Load Forecast is required for both the Probabilistic and Standard Forecast.

4.5.4. Modeling Yearly Increase

For all cases the first step is to determine all the Possible Planning Models that are to be considered for the 10-year forecast horizon.

NOTE: This results in a maximum of 2 or 4 Probabilistic or Standard Forecasts, depending on whether the shoulder periods are studied as one, or two separate scenarios.

Any station that has a violation for the 10-year forecast is subject to further study. Hereby the objective is to determine the first year by which a need arises:

- For substations with sufficient 10-year capacity that are not expected to be overloaded in the next 10 years (both forward and reverse) the study can be focused on year 10 to determine if there are violation and study the prior years as necessary.
- Stations with medium/high load growth that are expected to be overloaded in the next 10 years shall be scaled in load by year (using the process in Section 4.5 above) in the Synergi model

Identified violations shall be in accordance to the steps in Section 4.6

4.6. Study Methodology

4.6.1. Periodic Assessments

The Eversource Distribution System Planning Group performs periodic assessments/studies of Bulk Distribution Substation facilities to ensure continued compliance with the performance criteria outlined in this document. Studies may also be performed for any of the reasons given below:

- Studies required by State Regulators, such as;
  - The Annual Reliability Report to the Massachusetts Department of Public Utilities (DPU).
  - The Massachusetts Annual Loss Study
  - Other state regulatory mandates
- Eversource initiated studies to investigate deficiencies in the performance of the electric supply system and to identify potential plans for system reinforcements or mitigating measures
- System Planning initiated studies to investigate pre-existing power quality events, resulting from DER penetration, affecting the distribution substation. These include: Transient Overvoltage, 3VO Assessment, DER Impact on Voltage Regulating Equipment, Rapid Voltage Change and Voltage Flicker.

4.6.2. Annual Studies

System Planning Engineers should perform annual assessments of all distribution substations. These assessments are intended to ensure that distribution substations meet or exceed Eversource’s Distribution Substation Planning Criteria, refer to Section 2.

Appropriate Base Case Model:
Distribution System Planning will assess **capacity**, **power quality (voltage)**, and **reliability** performance using the appropriate model.

- The Summer/Shoulder Peak Load model together with the 10-year forecast is used to determine potential Substation capacity, reliability, and/or power quality needs during peak load conditions.

- The Minimum Load model together with the 10-year forecast is used to determine potential Substation capacity (mostly due to DER-driven reverse flow), reliability, and/or power quality needs during minimum load conditions.
- If a second system peak is observed during winter months that equals or exceeds the Summer Peak Load, a Winter Peak model together with the 10-year Winter Peak forecast is used to determine potential capacity, reliability, and/or power quality needs.

Substation Normal and Contingency Conditions:
Distribution System Planning will use the Appropriate model to identify violations affecting Distribution Bulk Substations and backbone feeder sections involved in the calculation of the Substation LCC:

- To identify violations under Normal (N-0) system conditions the Planning Base Case models will be used to verify that all substation transformers and backbone feeder sections operate under normal thermal ratings, voltage limits, and acceptable load phase balance, as per Section 2.2 below.
- To identify violations under Contingency (N-1) conditions the Planning Base Case models will be used, together with the guidance provided in Section 4.6 below to verify that all substation transformers and backbone feeders sections operate under the appropriate Thermal Loading criteria specified in Section 2.2 below.

Substation LCC Capability:
Distribution load transfer schemes used in the calculation of the LCC, will be modeled and verified by Distribution System Planning for Bulk Distribution Substations that fall within the following criteria:

- Above 75% of nameplate under normal (N-0) conditions within the next 5 years
- Above 90% of LCC under emergency (N-1) conditions within the next 5 years

Contingency Conditions (N-1) Operational Assessment:

The following criteria apply to all situations where bulk distribution transformers are relied upon for N-1 contingencies to restore electric service to customers, and should be considered during studies:

To determine whether Bulk Distribution Transformers provide an adequate secondary source for the bulk distribution bus loads, the substation bus restoration scheme operation shall be modeled and the following performance criteria under the projected operating loads shall be demonstrated:

- The Bulk Distribution Transformer(s) that provides the alternate supply shall be within the LTE loading criteria for the first load cycle following the ABR scheme operation.
- Additional distribution switching (remotely controlled) shall be available to lower transformer winding loads to the normal rating or below. This additional switching will be implemented when problems will require multiple load cycles to be resolved.
- Distribution bus voltages should be able to be maintained within normal scheduled limits (as per Section 2.4) using transformer load tap changers and/or distribution capacitor banks (substation distribution capacitors banks should be in service under these circumstances to supply increased reactive losses resulting from the loss of a transformer).
- Bulk Distribution Transformer winding loading should be below the Long- Term Emergency Rating and shall not exceed the Short-Term Emergency/Drastic Action Limit Rating.

The following criteria apply to all situations where distribution feeders and remote bulk transformers are relied upon for N-1 contingencies to restore electric service to customers:

To determine that distribution feeders provide an adequate secondary source for the bulk distribution bus loads, the distribution feeders shall be modeled and the following performance criteria under the projected operating loads shall be demonstrated:

- Bulk Distribution Transformer(s) that provide the alternate supply, shall be within LTE loading criteria for the first load cycle following loss of the primary supply. Additional distribution switching (remotely controlled) shall be available to lower transformer winding loads to the normal rating or below. This additional switching will be implemented when problems will require multiple load cycles to be resolved.

- Distribution feeders providing the alternate supply to bulk distribution supply buses, shall not exceed their ratings as per Section 3.1
- To provide acceptable voltage levels at customer service points, distribution feeder primary voltage levels must also be at acceptable levels as per Section 2.4

4.6.3. Contingency Analysis

The following guidance should be used to analyze N-1 Contingency Condition thermal limitations in Bulk Distribution Substations. This guidance is in line with the calculation of Substation Firm Capacity rating.

For Distribution Station in which LCC is equal to Firm:
For distribution stations where a single event at the transmission level corresponds to a single event at the distribution station, not exceeding N-1 conditions:

- An N-1 contingency can be modeled at the distribution station by taking the <u>largest transformer out of service and</u> closing the appropriate bus breaker to transfer the load to the remaining transformers.

For distribution stations where a single event at the transmission level corresponds to an event at the distribution station that exceeds N-1 conditions:

- The Distribution station contingency shall be modeled based on the transmission contingency that results in the worst contingency condition for the Distribution Station.

For Distribution Station in which LCC is <u>not</u> equal to Firm:
For distribution stations where a single event at the transmission level corresponds to a single event at the distribution station, not exceeding N-1 conditions:

- A distribution model containing the station to be studied in addition to the stations providing Distribution Transfer Switching (DTS) and backbone feeders Capacity shall use for contingency analysis
- N-1 contingency can be modeled at the distribution station by taking the largest transformer out of service and closing the appropriate bus breaker to transfer the load to the remaining transformers.
- The analysis should include transferring load to the station providing DTS capacity

For distribution stations where a single event at the transmission level corresponds to an event at the distribution station that exceeds N-1 conditions:

- The Distribution station contingency shall be modeled based on the transmission contingency that results in the worst contingency condition for the Distribution Station
- The analysis should include transferring load to the station providing DTS capacity

4.6.4. Allowed System Adjustments to Mitigate Capacity and Power Quality Violations:

This section describes mitigation measure that are used in the models to address system violations during Annual and Periodic Assessments of the Distribution System.

The following violations are accounted for during the Annual Studies:
- Thermal violations
- Phase load imbalance
- Voltage violation at the substation bus and feeder backbone as per Section 2.4

System adjustments to mitigate violations include:
- <u>Thermal violations:</u>
    - Reduce load by load transfers or non-wires solution (as per Section 4.8).
    - Increase system capacity by upgrading existing equipment or installing new equipment.
- <u>Phase load imbalance:</u> reduce phase loading by distribution circuit reconfiguration
- <u>Substation Secondary bus load thermal violations:</u> reduce load by load transfer, or increase equipment

capacity
- Voltage Violation:
    - Reduce load by load transfers or non-wires solutions
    - Applying capacitor or voltage regulation.
    - Upgrading or installing new equipment

System Periodic Assessment Review:
As the power system evolves, with increasing DER penetration and electronic loads, the need to study power quality violations more accurately become critical. Electromagnetic Transients (EMT) simulation tools such as PSCAD should be used to analyze transient voltage violations due to switching and load rejection overvoltage events that exceed the limits in Section 2.5 below.

4.7. Documentation of System Constraints

Study Reports:
A report summarizing the results of the Annual Study should be produced by the responsible System Planning Engineer. The report should consider:
- The substation current configuration/capacity along with transformer ratings
- The historical peak and actual loads, actual/planned load transfers and most recent 10-year load forecast
- Assessment of DG connected to each transformer's feeders and any load adjustments made because of these facilities
- System Review Summary, including:
    - Identification of Non-Standard Bulk Distribution Substations and associated violations
    - Non-Bulk Distribution Substation configuration/capacity and potential violations
    - System reinforcements or mitigating measures to plan or investigate further

Based on the violation type (Capacity, Power Quality, and Reliability) the System Planning report should include:
- Substation name
- Substation Summary
- Description of Problem (if applicable)
- Description of Violation (if applicable)
- Substation Equipment Rating and Limit
- Actual Peak Load (Observed year)
- System Review Summary
- Possible Mitigation Actions

4.8. Solution Development

When the system capability does not meet forecasted loads, Planning Engineers must resolve projected violations prior to the violation year as per Section 4.8. Once a list of violations is compiled, Distribution System Planning engineers will identify potential solutions to address those violations affecting:
- Bulk Distribution Substations
- Non-Bulk Distribution Substation
- Feeder Backbone Sections required for substation LCC capacity.

The solution development method adopted by Distribution System Planning is a complex and iterative process which addresses the system needs in conjunction with the capital budget. This approach balances the safe and reliable service provided by the utility with the need to control cost for our customers.

4.8.1. Distribution Bulk Substation Solution Development

Projected violations that are not within the planning design criteria for substation and distribution assets are not tolerated. The planning design criteria (see Section 2) are intended to maintain safe, reliable operation of the power system. When these criteria are violated, the system must be reinforced, reconfigured, or upgraded to eliminate the constraints by the forecasted violation year.

An identified violation can be resolved in different ways. To develop the most viable and cost-effective solutions, Distribution Planning, in conjunction with other engineering disciplines and internal groups, will evaluate several alternatives for cost-effectiveness and technical feasibility.

The most viable and cost-effective solution is presented in the System Planning proposal along with alternative solutions considered. Solutions to resolve potential system violations could include a combination of reinforcement, load reduction, and/or system reconfiguration recommendations. Reinforcement or reconfiguration options that increase capacity include:

- Add transformer cooling
- Replace limiting substation equipment
- Add Reactive Power sources
- Add new transformer or expand substation
- Add new substation

Load Reduction options include:

- Permanent Load Transfer
- Increase load transfer capability (LCC)
- Implement Non-Wires Solutions

4.8.2. Distribution Feeder and Non-Bulk Substation Solution Development

The planning design criteria (see Section 2) are intended to maintain safe, reliable operation of the power system. Projected violations that are not within the planning design criteria are not tolerated. When these criteria are violated, the system must be reinforced, reconfigured, or upgraded to eliminate the constraints by the forecasted violation year. This requires violations to be identified, solutions compared, and projects implemented in an appropriate timeframe (refer to Section 4.9). Overloads can be driven by either new business load growth, load transfer under contingency condition, and baseline growth.

Distribution System Planning should review backbone feeder sections that provide LCC capability and Non-Bulk Distribution Substation Transformers. The traditional solutions that are typically used to address load relief at the distribution level include:

- Upgrade limiting conductor sections
- Add new feeder
- Reduce feeder Load by:
  - Load transfer
  - Implementation of Non-Wires Solutions

Non-Bulk Distribution Substations:

- Add transformer cooling
- Replace limiting substation equipment
- Transfer load
- Add reactive power sources
- Substation elimination/voltage conversion
- Add new transformer or expand substation

4.8.3. Application of Non-Wires Solutions

When evaluating distribution system improvements, Engineers should consider the use of Non-Wires Solutions

(NWS)[6] as an option to defer or avoid distribution system investments. Non-wires solutions are defined as grid investments or programs that use non-traditional solutions to achieve one or more of the following:

- Defer or eliminate the need for distribution grid capacity standard equipment or material upgrade (e.g., distribution lines, transformers)
- Increase distribution grid reliability and/or resilience
- Increase operational efficiency and optimization of the distribution grid (e.g., volt-var optimization)

The primary objective for considering NWS options is to identify solutions with the potential to mitigate system violations (capacity, reliability and resilience) or that enable grid-operating efficiency at a lower total cost to the rate payer, as compared to traditional grid solutions. The Eversource NWS Screening Toolset (ENST) provides a standardized basis for a go-no-go decision for an NWS. When considering NWS alternatives, attention is given to asset health condition and age. The benefit of deferring T&D equipment, with known asset health conditions and/or that are near end-of-life, by using NWS methods should be weighed against the expected remaining useful equipment life.

The NWS options include a broad set of technologies as well as approaches to their integration to increase the range of suitable opportunities. Adopting a broader definition of NWS increases the range of suitable opportunities and enables adoption of emerging technologies, maximizing potential benefits. Some NWS technology examples may be deployed individually or concurrently and may be either in front of or behind the meter; these include, but are not limited to, the following:

- Utility controlled Energy Storage Systems (BESS)
- Solar Installations (Utility or 3rd Party Owned)
- Energy efficiency (EE)
- Demand response (DR)
- Conservation Voltage Reduction (CVR)
- Fuel Cells or CHP (Utility or 3rd Party Owned)
- Conventional Generators (Utility Controlled)

NWS technologies can be combined and integrated with the distribution grid and integrated:

- **Automatic—**Some technologies may provide NWS functions simply through their inherent characteristics. These could include energy efficiency end uses or non-dispatchable DER.
- **Autonomous—**Some technologies (e.g., intelligent end-use devices) may respond to local conditions or follow schemes that are based on programmed set points that can be adjusted according to grid needs. These could include Demand Response, BESS and/or DERs.
- **Dispatch**—Some technologies enable an operator to dynamically specify or direct quantities of supply or demand reduction from specific resources. This could include Demand Response, Battery Storage, DERs and virtual power plants.

Development of NWS Suitability Criteria

Distribution System Planning will develop a list of planned capital projects that may be candidates for avoidance and/or deferral through deployment of non-wires solutions (NWS) ("NWS Candidates"). Each of the capital projects on said list will be evaluated using the ENTS.

The ENTS builds its screening process on the following screening criteria. Until the ENTS is fully operations (Expected End of Q1-2021), planners are to evaluate NWS using the same criteria. NWS suitability can be guided by criteria related to the type of project, the timeline of the need, and the size of the solution (in MW and/or dollar cost). General considerations are provided below. State-specific regulations, settlements, and/or other guidance will be used to develop more specific screening criteria.

Existing Asset Considerations: If assets are part of the proposed capital projects that through their age or asset health index pose a reliability risk, a traditional system upgrade is to be prioritized.

System Obsolescence: For aging and/or obsolete systems traditional system upgrades should be prioritized.

[6] Sometimes refer to as Non-Wires Alternatives or Non-Transmission Alternatives

Project Type Suitability: Looking at categories of traditional projects that might share similar attributes can help identify projects most suitable for NWS solicitation.

Timing Criteria: NWS should only be considered where they can be deployed in time to address a need. Recognizing that it takes time to procure NWS, a timing screen can be used to exclude consideration of particular types of NWS for grid needs that are expected to develop within a certain time frame.

Project Cost Criteria: The proposed capital project is to be compared from a cost perspective to identify which NWS would pose the least cost solution to the rate payer, and if that solution provides a lower cost to the rate payer than the traditional capital project. Hereby capital cost, maintenance, energy, or replacement cost over the planning horizon are considered. The standard planning time frame of 10 years is applied. For NWS that can provide additional revenue streams or value adds, those are to be considered in the Total Cost of Ownership of the NWS to the benefit of the ratepayer. This screening category uses cost thresholds to exclude certain types of NWS from consideration for minor, inexpensive projects in which high transaction costs could disproportionately disadvantage them.

Project Size Criteria: Initial procurements can screen for non-wires solution opportunities that are below a certain size threshold to limit potential reliability impacts from NWS non-performance or outage. Size thresholds would be established upon review of the system planning assessment and the range of associated load at risk, as well as the number of contingent events driving system constraints. Project size thresholds can be used as a guide to ensure that any non-wires solution project failure would be manageable from a reliability perspective.

NWS Technology Screening

Historically, the Least Cost Technically Acceptable (LCTA) transmission and distribution solution, has typically been considered as the only accepted options for replacement/addition of equipment. Given the new opportunities provided by non-wires solutions, an LCTA must be defined as the best option between traditional solutions, NWS or a hybrid (combination) of both. The following suitability criteria establishes guidelines for consideration of NWS:

- Estimate the cost of preferred traditional LCTA solution
- Assess asset condition and life expectancy of the equipment being addressed/studied and compare with the life time duration of the solutions being considered.
- Contact Strategy & Business Development (CSBD) about existing company-owned PV program opportunities in the area.
- Obtain a feasibility assessment from the respective Energy Efficiency (EE) Department about Demand Response (DR), EE programs and Behind the meter Storage. The EE Department will obtain information for outside customers on non-utility programs only. A timeframe of 1-2 months is required by the EE department to obtain an estimated MW saving.
- Concurrent with the review completed by the CSBD and EE Departments, analyze company-owned BESS feasibility. Obtain the respective load curve profile of the substation that needs load relief, including the profile of individual feeders. Establish the following, to address capacity and or power quality deficiencies:
    - The capacity need (MW)
    - Duration of the capacity need (hours)
    - Calculation of the Energy MWh = (MW) x (hours)
    - Yearly frequency of the events
    - Calculation of the battery cost (gross estimate value)

A preliminary BESS gross estimate can be calculated by using the latest version of the National Renewable Energy Laboratory (NREL) U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Cost Benchmark. Refer to most recent table of US Utility-Scale Lithium-ion Standalone Storage Cost for Durations of 0.5-4 hours.

To the selected $/kWh value, the feeder position installation cost (if applicable), must be added. To this total cost the Eversource Indirect Costs and the Allowance for Funds During Construction AFUDC must also be applied. Contact the respective Cost Estimating Department to get these costs.

- Determine the availability of utility-owned and/or controlled DER that is connected to the system with the identified deficiencies.

- Table 1 below can be used as a preliminary review for determining the applicable NWS solution to be implemented standalone or as a combination:

NWS Type	Minimum Years for Solution review prior to implementation	Solution Size Considerations	Duration of Solution	Yearly Incentive Cost
PV-Utility	1-2	Note 1		
BESS-Utility	2-5	Note 2, 3	< 4hr	N/A
DR-WIFI controlled	1-2	0.5-1kW – Residential 200kW – C&I	3hr / 10 times per year	$200/kW-Residential $50/KW-Commercial Note 4
BTM-Storage (existing installation)	1-2	7kW – Residential 100 – 1000kW – Commercial	3hr / 60 times per year	$300/kW-Residential $250/KW-Commercial Note 4
Energy Efficiency	1-2	3-10% of target Substation/feeder load	Permanent	N/A

Note 1 – When applied to an ES feeder, the line section aggregated DER must be less than or equal to 33 percent of minimum load, regardless of DER type mix to minimize the risk of islanding.

Note 2- For grid forming BESS applications short circuit ratio (short circuit of electric system at point of interconnection divided by size of BESS) should be greater than a ratio of 1 at the minimum, optimal design is greater than 2. For grid following BESS applications short circuit ratio should be greater than 2, optimal design is greater than 3. BESS size solutions for Eversource areas with Low/Medium DER saturation and/or low peak shaving: 2.5MW/10MWh and 3.5MW/14MWh.If the solution does not pass the short circuit ratio screen, a detailed study is required an informed go-no-go.

Note 3 - When the BESS is applied inside or in the substation vicinity, consideration should be given to future substations expansions. The BESS should not restrict expected long-term substation upgrades.

Note 4 – Numbers are subject to change

After tabulating all potential NWS that could address the identified system deficiencies, based on Table 1, the preferred traditional LCTA solution should be compared with the implementation of one or a combination of the NWS. The most cost-effective solution should be proposed as the preferred solution and additional least cost-effective solutions should be included as alternatives for the initial funding request (IFR) and through the Solution Design Committee (SDC) process.

4.9. Planned and Proposed Upgrades

During the annual development of the transmission and distribution capacity and power quality plans, System Planning shall design long term solutions (Traditional and NWS) that will address capacity and resiliency needs of all distribution substations. Planned projects, identified in the Low Load and Medium Load Planning Scenarios, that address immediate substation capacity and resiliency needs shall designed and prioritized to be included in the 5-year capital plan as approved projects. Proposed projects, identified in the Long-Term Planning Scenario, that address long term capacity and resilience needs shall be developed but not submitted for approval.

The table below provides a high-level breakdown of the ideal project planning schedule:

Constraint Type	Timeframe	Status	Planning Scenario
Planned	1-5 years	Full development & approval	Low and Medium Load Growth
Planned	5 -10 years	Partially developed	Medium and High Load Growth

Constraint Type	Timeframe	Status	Planning Scenario
Proposed	10 years and above	Conceptual Design	Medium and High Load Growth

Table 11- Ideal Planning Scenarios

Projects that are required within the next 6 years of the Observed Year should be fully developed and approved using the latest version of the Capital Project Approval Process, refer to Section 7.1. A Distribution System Planning Substation Review form should be completed by the responsible System Planning Engineer.

The Form should consider:

- The substation current configuration/capacity along with transformer ratings
- The historical peak and actual loads, actual/planned load transfers and most recent 10-year load forecast
- Assessment of DG connected to each transformer's feeders and any load adjustments made because of these facilities
- System Review Summary, including:
  - Identification of Non-Standard Bulk Distribution Substations and associated violations
  - Non-Bulk Distribution Substation configuration/capacity and potential violations
  - System reinforcements or mitigating measures to plan or investigate further

Based on the violation type (Capacity, Power Quality, and Reliability) the Final form should include:

- Substation name
- Substation Summary
- Substation Equipment Rating and Limit
- Actual Peak Load (Observed year)
- 5 Year Projected Forecast
- System Review Summary
- Possible Mitigation Actions
- In-Service due date
- System Planning Timeline for IFR, SSF, and PAF

Refer to Section 7.3 for a sample template and Section 7.2 for the Capital Project Approval Process.

5. References

The following referenced documents are indispensable for the application of this document:

- ANSI C84.1, Electric Power Systems and Equipment—Voltage Ratings (60 Hz).
- NERC Standard FAC-008-3 – Facility Ratings Methodology
- System Planning Procedure No. 8 (SYSPLAN-008) Calculation and Documentation of Bulk
- IEEE 1547 – 2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resource with Associated Electric Power Systems Interfaces
- IEEE Standard C57.91-2011, "IEEE guide for Loading Mineral-Oil-Immersed Transformers and Step Voltage Regulators"

Distribution Transformer Ratings
SYS PLAN 006 – Determining Transmission System Facility Ratings (EMA)
SYS PLAN 007 - Auto Transformer Ratings Calculation Procedure and Documentation (EMA)

Eversource Information and Technical Requirements for the Interconnection of Distribution Energy Resources (DER) – Jan 21st 2020

IEEE Standard C57.12.00-2015 "IEEE Standard for General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers"

EPRI PTLOAD Version 6.2 Software Manual

DSEM - Distribution System Engineering Manual – T & D Engineering Standard Bookshelf Procedure:

- DSEM 03.30 - Reliability Project Cost Effectiveness is used to evaluate project alternatives.
- DSEM 02.11. – Reliability Indices
- DSEM 02.30 - Automatic Sectionalizing Device Guideline
- DSEM 06.51 - Circuit Zones
- DSEM 10.42 Smart Switches.

Distribution System Planning and Design Criteria Guidelines (ED-3002)

Eversource System Operating Procedure ESOP-28- Single Contingency Load Loss

6. Definitions and acronyms

6.1. Definitions

bulk power system (BPS): Any electric generation resources, transmission lines, interconnections with neighboring systems, and associated equipment.

distributed energy resource (DER): A source of electric power that is not directly connected to a bulk power system. DER includes both generators and energy storage technologies capable of exporting active power to an EPS. An interconnection system or a supplemental DER device that is necessary for compliance with this standard is part of a DER.

DER include any non-BES resource (e.g. generating unit, multiple generating units at a single location, energy storage facility, micro-grid, etc.) located solely within the boundary of any distribution utility, Distribution Provider, or Distribution Provider-UFLS Only, including the following[7]: •

- Distribution Generation (DG): Any non-BES generating unit or multiple generating units at a single location owned and/or operated by 1) the distribution utility, or 2) a merchant entity. •
- Behind The Meter Generation (BTMG): A generating unit or multiple generating units at a single location (regardless of ownership), of any nameplate size, on the customer's side of the retail meter that serve all or part of the customer's retail load with electric energy. All electrical equipment from and including the generation set up to the metering point is considered to be behind the meter. This definition does not include BTMG resources that are directly interconnected to BES transmission. •
- Energy Storage Facility (ES): An energy storage device or multiple devices at a single location (regardless of ownership), on either the utility side or the customer's side of the retail meter. May be any of various technology types, including electric vehicle (EV) charging stations. •
- DER aggregation (DERA): A virtual resource formed by aggregating multiple DG, BTMG, or ES devices at different points of interconnection on the distribution system. The BES may model a DERA as a single resource at its "virtual" point of interconnection at a particular T-D interface even though individual DER comprising the DERA may be located at multiple T-D interfaces. •
- Micro-grid (MG): An aggregation of multiple DER types behind the customer meter at a single point of interconnection that has the capability to island. May range in size and complexity from a single "smart" building to a larger system such as a university campus or industrial/commercial park. •
- Cogeneration: Production of electricity from steam, heat, or other forms of energy produced as a byproduct of another process
- Emergency, Stand-by, or Back-Up generation (BUG): A generating unit, regardless of size, that serves in times of emergency at locations and by providing the customer or distribution system needs. This definition only applies to resources on the utility side of the customer retail meter.

electric power system (EPS): Facilities that deliver electric power to a load.

flicker: The subjective impression of fluctuating luminance caused by voltage fluctuations. NOTE—Above a certain threshold, flicker becomes annoying. The annoyance grows very rapidly with the amplitude of the fluctuation. At certain repetition rates even very small amplitudes can be annoying (refer to IEEE Std 1453).

inverter: A machine, device, or system that changes direct-current power to alternating-current power.

load: Devices and processes in a local EPS that use electrical energy for utilization, exclusive of devices or processes that store energy but can return some or all of the energy to the local EPS or Area EPS in the future.

nameplate ratings: Nominal voltage (V), current (A), maximum active power (kW), apparent power (kVA), and reactive power (kvar) at which a DER or transformer is capable of sustained operation. NOTE—For Local EPS with multiple DER units, the aggregate DER nameplate rating is equal to the sum of all DERs nameplate rating in the Local EPS, not including aggregate capacity limiting mechanisms such as coincidence factors, plant controller limits, etc., that may be applicable for specific cases.

[7] NERC – Distributed Energy Resources – February 2017

Summer Peak Gross Load Day: Peak Net Load Day plus generation output (front of the meter) and estimated generation (behind the meter)

New Business Growth: Also called Step Loads in MA or Spot Loads in NH, refers to the new large customer load additions. It includes load additions greater than 500kW and it could be one large customer or a group of customers in a similar area (e.g. large residential developments)

Bulk Distribution Supply Bus: A bus, within a substation that supplies multiple distribution feeder breakers. Nominal voltage shall be below the 69kV level.

Contingency: An event, usually involving the loss of one or more Elements, which interrupts the flow of power on the power system.

Standard Bulk Distribution Substation: Preferred configuration Based on a Double Bus Switchgear or Ring Bus design configuration, refer to Section 2.8.

Single Contingency (N-1): For Standard Bulk Distribution Substation is defined as loss of one bus section, one bus tie breaker, or one Transformer per Event. For Non-Standard Bulk Distribution Substation is based on the Contingency that result in the loss of the largest MVA supply per Event. Distribution System N-1 contingency is defined as the loss of one distribution feeder from a common bus, per event.

Event: Defined as a Single Contingency (N-1) condition lasting one cycle (24 hours)

Distribution Transfer Switching: Load that can be moved from one distribution feeder to another using remotely controlled switches (manual switching operations are not acceptable) within the distribution system. This switching transfers the load from its original bulk transformer supply to a different bulk transformer supply

Element: Any electric device with terminals that may be connected to other electric devices. (e.g.; a transformer, circuit, circuit breaker, getaway cable)

Emergency: Any abnormal system condition that requires automatic or manual action to prevent or limit the loss of substations, or distribution that could adversely affect the electric system.

Observed Year: Or Base Year, is the year for when the Maximum and Minimum Loads are measured/calculated at the substation in preparation for the next 10 years.

Firm Capacity (of a substation):

- Single Transformer Substations: The Firm Capacity of a substation equipped with a single transformer is equal to zero.
- Double Transformer Substations: The Firm Capacity of a substation equipped with two transformers is equal to the smallest LTE (Long Term Emergency) rating of the transformers.
- Three (or more) Transformer Substations: The Firm Capacity of a substation equipped with three (or more) transformers is equal to the total substation supply capability (typically limited by transformer LTE ratings) after loss of a single element, assuming proper operation of automatic transfer/restoral schemes.

Long Term Emergency (LTE) Rating: The rating based on the operational limit of an Element under a set of specified conditions. The conditions consider the prior and post contingency load levels and load cycle durations for the Element, the maintenance history and the calculated capacity that is available in the Element based on the life expectancy of the Element.

Load Carrying Capacity (LCC): The capacity of a Substation is equal to the Firm Capacity plus available Distribution Transfer Switching capacity to adjacent Substations, limited by the Short-Term Emergency Rating of the transformer being relieved by the Distribution Transfer Switching and the transfer capability limit of the affected distribution system elements.

Normal Rating: The rating that specifies the level of electrical loading, usually expressed in mega-volt amperes

(MVA) or other appropriate units that a system, facility, or Element can support or withstand under continuous loading conditions.

Short Circuit Interrupting Rating: The rating of system protection equipment designed to interrupt service under short circuit conditions. The rating is expressed as the amount of short circuit power or current the device can safely interrupt under fault conditions.

Short Term Emergency (STE) Rating: The rating based on the operational limit of an Element under a set of specified conditions. The conditions consider the prior and post contingency load levels and load cycle durations for the Element, and the calculated capacity that is available in the Element based on the life expectancy of the Element.

Distribution System Supply (DSS) Elements: Distribution System Supply (DSS) elements are distribution lines or cables that have similar characteristics and function to transmission supply lines since they feed bulk area load but are designed and operated at lower voltages. DSS elements can supply bulk distribution area loads either through downstream Eversource distribution facilities or directly to customer stations. These reside predominantly in the Eastern Massachusetts portion of the Eversource System. For the purposes of this procedure, DSS elements shall be treated the same as bulk distribution transformers where the system is assessed for the loss of a single DSS element.

3V0: - 59N scheme fed by Potential Transformers on the high (utility) side of the GSU required to sense over voltages on the un-faulted phases during single phase-to-ground faults upstream the GSU.

6.2. Acronyms

DER	distributed energy resources
EPS	electric power system
BESS	battery energy storage system
PV	photovoltaic
STE	Short-Term Emergency Rating
LTE	Long-Term Emergency Rating
DAL	Drastic Action Limit
GSU	Generator Step-up transformer

7. Annex A (informative)

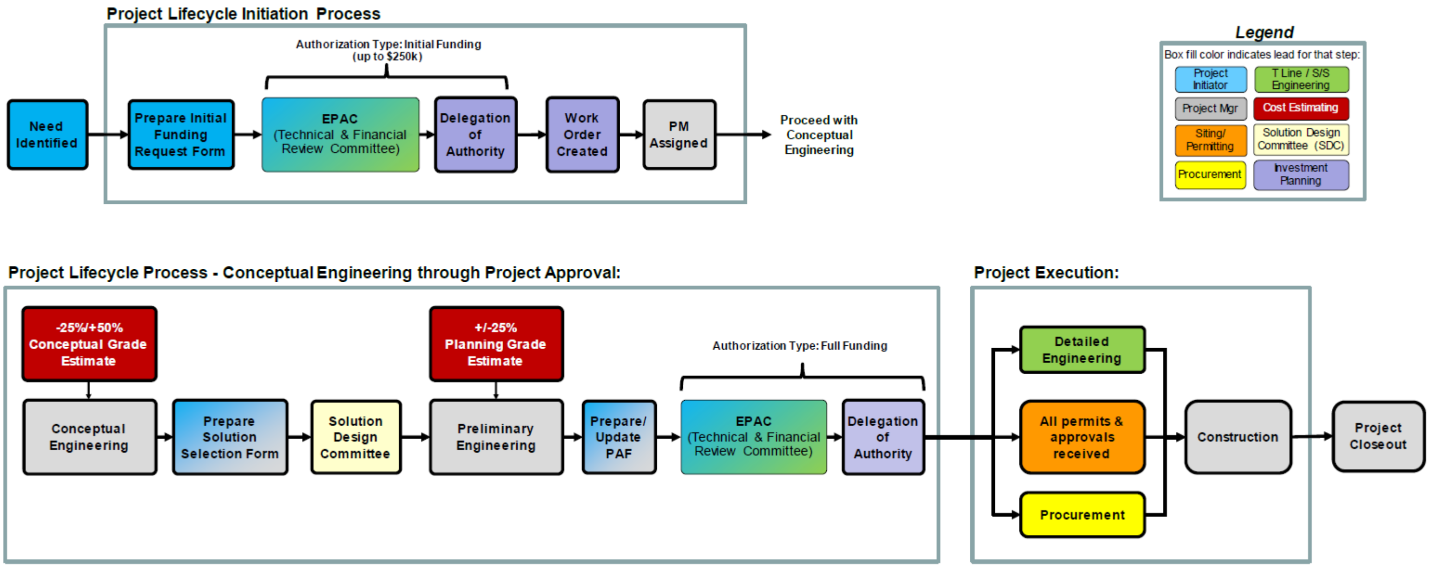
7.1. Reference Documents

SYSPLAN 010 – Bulk Distribution Substation Assessment Procedure	Link to NSTAR Standard
SYSPLAN 008 – Calculation and Documentation of Bulk Distribution Transformer Ratings	Link to NSTAR Standard
DSEM 03.30 – Reliability Project Cost Effectiveness	Link to DSEM Standard
DSEM 02.11 – Reliability Indices	Link to DSEM Standard
DSEM 05.131 – Voltage Limits	Link to DSEM Standard
IEEE 1547 – 2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resource with Associated Electric Power Systems Interfaces	IEEE 1547-2018.pdf
IEEE Standard C57.12.00-2015 "IEEE Standard for General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers"	C57.91-2011 Transformer Loading
Distribution System Planning and Design Criteria Guidelines (ED-3002)	ED-3002 Distribution Plannin
Distribution System Planning Substation Project Template	Planning Project Template.docx
Capital Project Approval Process Revision 5	JA-AM-2001-A, Rev 5, Capital Project Ap

Table 12 - Reference Documents[8]

[8] In order to determine whether a given document is the current edition and whether it has been amended, visit the standard Bookshelf Site or contact System Planning.

7.2. Attachment D of Capital Project Approval Process



7.3. Distribution System Planning Substation Review Template

Project Type: Capacity, Power Quality, Reliability

Level: Proposed, Planned

Substation Name:

Summary

<u>Substation Ratings:</u>

Transformer	Nameplate	Cyclic Rating (LTE)

<u>Station Capabilities:</u>

Total Station Capacity (N)	Station Firm Capacity (LTE)	Remote Control Transfer	Manual Transfer	Total LCC

<u>2020 Actual Peak Load: MW</u>

2020-2024 Projected load (MW):

2020	2021	2022	2023	2024

Summary of System Review:

Possible Mitigation Actions

Timeline for Long-Term Solution:	
Initial Funding Request (IFR)	*Expected Date*
Solution Selection Form (SSF)	*Expected Date*
Project Authorization Form (PAF)	*Expected Date*

2021

EVERSOURCE

Non-Wires Alternative Framework

VERSION 2.0

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CONTENTS

1. TABLES AND FIGURES

2. ABBREVIATIONS

BESS:	Battery Energy Storage System
BTM:	Behind the Meter
CHP:	Combined Heat and Power
CPR:	Clean Power Research
CVR:	Conservation Voltage Reduction
DER:	Distributed Energy Resource
DG:	Distributed Generation
DR:	Demand Response
EE:	Energy Efficiency
EG:	Emergency Generation
ENST:	Eversource NWA Screening Tool
EV:	Electric Vehicle
FC:	Fuel Cell
LR:	Load Reducer
MARCS:	Modified Accelerated Cost Recovery System
MG:	Modelled Generation
NWA:	Non-Wires Alternative
PV:	Photovoltaics
SOG:	Settlement Only Generation

3. INTRODUCTION

As part of Docket No. 17-12-03RE07[1], PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Non-Wires Alternative, Eversource submitted a Written Comments outlining a Non-Wires Alternatives (NWA) Screening Process. Within this process, Eversource identified three (3) main Phases;

a. Technology Screening and Approval
b. NWA Screening Process Per Identified Need
c. Vendor Qualification and Solution Deployment

In Phase II, Eversource calls for a system wide screening of NWA opportunities based on an NWA Screening Tool. This NWA Screening Tool is an Eversource internal development which allows Eversource System Planning to screen capacity project needs at specific locations for potential application of NWA solutions. The intention being, that only sites that are suitable and viable for NWA solutions will move to a more detailed, engineering analysis stage.

The Eversource NWA Screening Tool is designed to enable rapid initial screening of NWA options against traditional system upgrade projects. The NWA Screening Tool will also provide appropriate sizing of such solutions. The objective of the tool is not to provide detailed and accurate costing or technical solution design, but rather to provide a quick, repeatable, scalable process for initial screening of NWA options using levelized cost estimates and basic technical assumptions. To enable this rapid screening, the NWA Screening Tool uses levelized values and standard assumptions for costing of solutions. Furthermore, the NWA Screening Tool only focuses on deferring station capital upgrades and does not incorporate a power flow engine, but rather uses substation load forecasts. Once an NWA solution passes the NWA Screening Tool as a viable solution, Eversource System Planning will still need to perform detailed steady-state and transient analysis studies as well as develop engineering designs and cost estimates for the identified solution at a specific location. And this stage, it is still possible that an NWA solution fails to proceed due to technical issues or cost constraints.

To guide a successfully development of the NWA Screening Tool and screening analysis, Eversource developed this NWA Framework. The NWA Framework describes all the assumptions applicable to the NWA Screening Process. This document represents the Eversource NWA Framework. Within the NWA Framework the following key topics are discussed:

a. **General Assumptions**: Provides an overview of the general assumptions made in the screening process
b. **Reliability Model**: Details how the reliability of NWAs is modeled within the NWA Screening Tool.
c. **Dispatch Model**: Describes dispatch and technical modeling of DERs within an NWA Solution
d. **Cost Model**: Highlights the cost parameters that are used to determine cost of solutions
e. **Revenue Requirements Model**: Provides information on revenue requirements calculations conducted
f. **Revenue Estimation Model**: identifies revenue streams that could be captured by DERs in NWA Solutions

[1]

4. STAKEHOLDERS

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5. INITIAL NWA SCREENING

The NWA Framework calls for an initial screening to ensure that from a practical and company policy standpoint the project does not pose any insurmountable obstacles for an NWA Solution before further analysis has been conducted.

A. CRITICAL SUITABILITY CRITERIA

The Critical Suitability Criteria pose a go-no-go decision point in the NWA Screening Process.

a. **Asset Health Index < 0.5**: Any station with a transformer's asset health index above 0.5 will not be considered as an NWA candidate. A health index greater than 0.5 equals a turn insulation drop below 400. (new transformers are at ~1000). Industry/literature[2] accepted practice is that <400 is a replacement candidate.
b. **Year of First Violation ≥ 2**: Any constraint that appears with 2 or less years from the base year will not be considered for an NWA option, as the timeframes for solution design and procurement would not suffice. A standard, out of the box traditional solution provides a faster, and safer alternative to address the issues.

Any project site that does not pass all three criteria will be disqualified from further NWA considerations and Eversource will move forward with developing a traditional solution.

B. ADDITIONAL CONSIDERATIONS

The additional screening considerations are intended to help guide a discussion in case the final cost benefit is close to 1. If any of the additional considerations is answered with a "No", a decision against the NWA solution might be made, but needs to be evaluated on a case by case basis.

a. Is it reasonable to assume at this time that a Non-Wires Alternative can be physically sited in the area?
b. Is it reasonable to assume at this time that there are no environmental concerns with Non-Wires Alternatives in the area?
c. Is it reasonable to assume at this time that local residents would accept a Non-Wires Alternative Solution in the area?
d. Is there no other capital project already approved in the same station?

[2] EPRI 3002019254 Analysis Assessment and Comparison

6. GENERAL FRAMEWORK

The following Chapter outlines the general NWA Framework, including which distributed energy resources (DER) are considered, how reliability is considered, and how forecasts and financial planning horizons are applied.

A. CONSIDERED RESOURCES

The NWA Framework is designed to consider both in front of and behind the meter (FTM / BTM) DER technologies in the NWA Evaluation Process. BTM DERs are assumed to be 3rd party owned and operated through a utility program. Table 1 outlines the DER technologies which are considered in the NWA Framework as options for deferring capital investments.

Table 1: DER Technologies Considered as NWAs

NWA	Definition	Capabilities
Energy Efficiency (EE)	Reduction of load through energy efficiency initiatives in addition to naturally occurring and already planned for energy efficiency.	Reduces load profile overall but limited by availability that is defined by customer makeup
Demand Response (DR)	Temporary reduction of consumption through demand response programs ▪ Commercial DR ▪ Residential DR	Reduces load for a fixed time with pre-conditioning and snap back effects
Photovoltaic (PV)	Solar PV installations ▪ Utility Scale Solar PV ▪ BTM Solar PV	Non-dispatchable output that is dictated by solar irradiance profiles
Battery Energy Storage System (BESS)	Lithium Ion Battery Systems ▪ Utility Scale BESS (Infront of meter) ▪ BTM BESS	System needs to provide enough capacity to recharge during cycles, can provide both active and reactive power
Combined Heat and Power (CHP)	Customer Program CHP solutions incentivized by the Utility Energy Efficiency Program	Modeled to run continuously and generates revenue from electricity and heat. Dispatch capability assumed through Enbala DR Platform
Conservation Voltage Reduction (CVR)	Voltage modification scheme that reduces system voltage to lower system load	Very limited impact which is highly dependent of the feeder makeup and types of loads, typically below 3%
Fuel Cell (FC)	Customer Program FC solutions incentivized by the Utility Energy Efficiency Program	Modeled to run continuously and generates revenue from electricity and heat. Dispatch capability assumed through Enbala DR Platform
Emergency Generation (EG)	Contracted generators (Diesel, Gas, etc.) that can be called upon by the utility	On-call resources with high reliability and flexibility; not renewable, could be noisy and have high emissions; typically, expensive to maintain.

B. FORECASTING AND PLANNING HORIZONS

To allow a technical and economic comparison on a level playing field, solutions are compared not simply with their initial capital need, but over longer time horizons to ensure that they

a. Can meet future capacity needs in a reliable manner
b. Can maintain economic feasibility over longer time spans

As a result, the NWA Framework considers two-time frames, the System Forecast and the Financial Planning Horizon.

SYSTEM FORECAST HORIZON

The System Forecast Horizon describes the timeline over which the EDC can forecast load and generation growth on their system. The NWA Framework assumes a 10-year System Forecast Horizon. Within that 10-year horizon the utility can provide a load growth and DER adoption forecast which allows determination of the expected system peaks. Capacity deficits can only be determined within that 10-year forecasting horizon. As a result, traditional and DER investments can only be made within those ten years. The NWA Framework does not concern itself with the forecasting methodologies but takes a completed forecast as an input for each of the ten (10) years.

The System Forecast Horizon is set at the Base Year + 10 years. The Base Year describes the last year with a complete annual timeseries data set using 15-min interval data.

FINANCIAL PLANNING HORIZON

The Financial Planning Horizon defines the time horizon over which the NWA solution is assumed to be active. Within the Financial Planning Horizon, the tool will automatically track replacement of components, such as battery cells, as needed and O&M costs. The Financial Planning Horizon hereby needs to be larger than

$$\mathrm{FirstConstraintYear} + \mathrm{DeferalYears} - \mathrm{BaseYear} \qquad \text{06.B.01}$$

This is to ensure that the cost of the NWA is considered for the entire time span over which it needs to defer the traditional solution.

The NWA Framework suggests following approach to setting up the Financial Planning Horizon: **Shortest Expected Lifespan**. Using the shortest asset lifespan in addition to the year of construction yields the total financial planning horizon. E.g. with the inclusion of a battery storage system, the shortest expected lifespan is 12 years for the battery cells. The financial planning horizon can now be 12 to 22 years from the base year, depending on when the battery asset is constructed. E.g., the Battery Solution is to be constructed in year 8 of the System Forecast, as a result the Financial Planning Horizon is 8 + 12 = 20 years from the Base Year.

Note: The financial planning horizon needs to reach further at all times than the date to which the traditional solution is deferred.

TERMINAL COST

With a varying Financial Planning Horizon all assets are considered with their entire lifetime revenue requirements impact. For this purpose, the Framework requires revenue requirements up to the financial planning horizon, which includes 1) new investments such as asset replacements as well as O&M, and 2) the terminal cost after the planning horizon which no longer includes O&M or new investments and simply sums the remaining cumulative net present value revenue requirements.

DEFERRING CAPACITY NEED

a. **Deferral within the System Forecast Horizon**: If an NWA solution defers the capacity only so much that the need arises again within the 10-year System Forecast Horizon, a simple value of deferral is calculated using the applicable inflation rate, technology cost reduction, and discount rate to create a change in NPV revenue requirements. Therefore, the NPV of the cost of the NWA solution plus the NPV of the cost of the deferred traditional solution must be less than the NPV of the cost of the traditional solution alone. This is shown in the equation below:

$$\mathrm{NWA}(t)_{\mathrm{NPV}} + \mathrm{Traditional}(t+n)_{\mathrm{NPV}} \leq \mathrm{Traditional}(t)_{\mathrm{NPV}} \qquad \text{06.B.02}$$

where the traditional solution is depreciated over 40 years.

b. **Deferral past the System Forecast Horizon**: With a ten (10) year forecasting horizon, it may happen that an NWA solution is capable of deferring the capacity need past the horizon. In this case, the capacity need is deferred to the first year after the forecast. With a 10-year forecast, the maximum possible deferral is ten (10) years. This limits the value an NWA can produce by deferring capital investments by no more than 10 years, as the assumption is that in year eleven (11) the capital project would be needed.
   - **Situational**: Based on the forecast trends and the chosen NWA solution, a decision can be made to declare the deferral to be ≥ 10 years. E.g. if forecasts show a decline

Figure 1 illustrates an example of the application of different timelines in the financial planning model. Hereby, a capacity need at year five (5) is deferred by five (5) years.

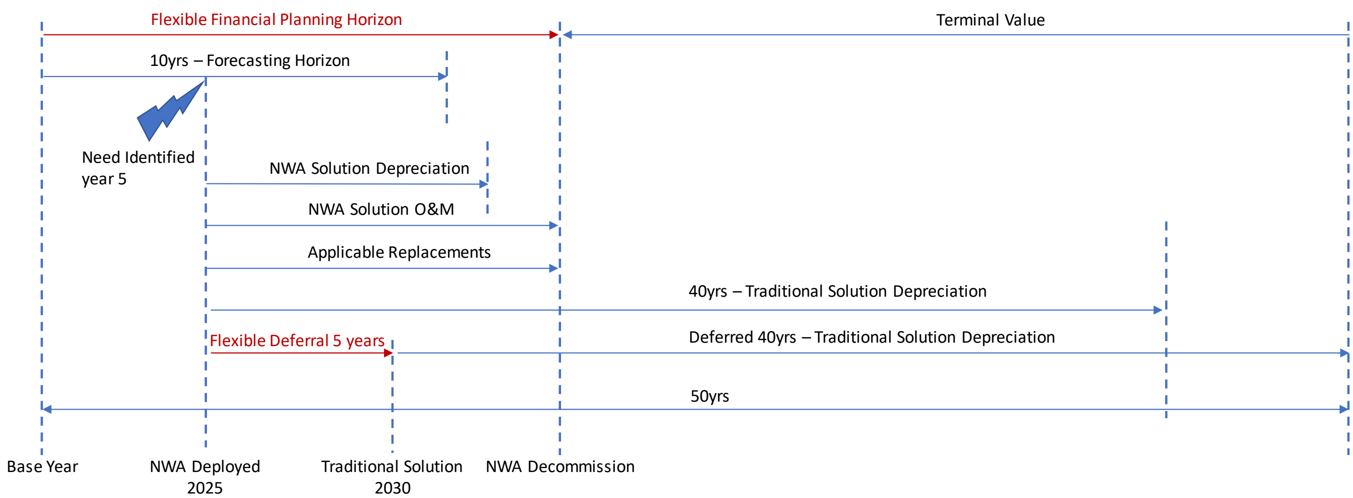

Figure 1: Financial Timelines in NWA Framework

C. NWA DISPATCH OPTIONS

For EDCs to consider DERs as NWAs they need to provide the same level of availability as traditional solutions. While, in most cases, the EDC will be able to forecast high load conditions and the associated dispatch need, unforeseen conditions need to be taken into consideration as well. Such conditions can include storm impacts or other events of natural or human cause that interrupt or disable capacity carrying parts of the system. In such an event, much like the traditional solution counterpart, load might need to be transferred to the NWA on very short notice.

In conclusion, there are two dispatch options

a. **Planned Dispatch**: up to 48-hours ahead, the EDC can determine peak load events and provide dispatch schedules for the NWA to mitigate such situations. This time frame allows the NWA to get “ready” for the dispatch if it is in non-ideal conditions.
b. **Unplanned Dispatch**: the EDC calls upon an NWA within seconds of the actual dispatch due to an unforeseen event of natural or human origin. The NWA does not have time to get “ready” for its dispatch but still needs to provide the full service.

Note: Dispatch option b. is the more limiting for NWA technologies but cannot be excluded from the evaluation criteria, as without it, the EDC needs to provide a contingency for the unplanned dispatch, which would likely be the traditional solution upgrade that the NWA was aiming at deferring in the first place. As a result, several market participation options will not be considered by the Framework specifically because they do not meet this asset readiness standard.

7. RELIABILITY MODEL

In order to assume availability of DERs that are used as an NWA, the company needs to ensure sufficient reserve margin, especially for assets that are controlled through utility owned programs. With NWA assets being part of the electric distribution grid's supply capability, the same N-1 approaches apply as they would to transformers and other hardware.

This section describes the NWA Framework for reliability rules around DERs used for NWA purposes.

A. EXEMPTIONS FROM THE N-1 RELIABILITY DESIGN STANDARD

a. **Energy Efficiency** programs replace existing hardware with newer, more efficient hardware. Once replaced, the new hardware permanently consumes less energy than its predecessor. As a result, Energy Efficiency measures can be exempted from an N-1 design criterion.

b. **Conservation Voltage Reduction** includes the installation of new voltage regulating equipment at the station and along feeder lines. This equipment is not typically designed to N-1 standards, and for the purpose of the NWA Framework, CVR will therefore not be part of any N-1 design criterion.

B. RELIABILITY ASSUMPTIONS FOR CUSTOMER PROGRAMS

For residential customer sited DR, Battery Storage, and Solar assets which are controlled through customer programs an assumption on participation is made. The following equations are utilized to calculate the minimal customer behavior adjusted reliable capacity where the number of assets under contract is (n)

a. Residential Solar

$$P_{PVReliable\_BTM} = \left(\sum P_{PVInstalled\_BTM}\right) * \varepsilon_{capPV}\left(1 - \frac{1}{n}\right) \qquad 7.B.01$$

b. Residential Demand Response

$$P_{DR_{Reliable}} = \left(\sum P_{DRInstalled\_BTM}\right) * \varepsilon_{capDR}\left(1 - \frac{1}{n}\right) \qquad 7.B.02$$

c. BTM Battery Storage

$$P_{BES_{Reliable}} = \left(\sum P_{BESInstalled\_BTM}\right) * \varepsilon_{capBES}\left(1 - \frac{1}{n}\right) \qquad 7.B.03$$

d. **Commercial Demand Response** is treated slightly differently and functions similar to a normal N-1 approach where the largest asset is removed from the overall observation.

$$P_{DRCom_{Firm}} = \left(\sum P_{DRCom_{Reliable}}\right) - \max(P_{DRCom_{Reliable}}) \qquad 7.B.04$$

ε_{cap} represents the saturation limit of distributed DR and PV. For example, if $\varepsilon_{cap} = 0.8$ then no more than 80% of installed assets will ever be accounted for. The following values are used based on historic observations by the Eversource Energy Efficiency Group.

Table 2 shows the respective saturation factor for reliability calculations with

$$\varepsilon = \lim_{n\to\infty} \frac{P_{Available}}{P_{Installed}} \qquad 7.B.05$$

Table 2: Saturated Reliability Factor for Utility Programs

$\boldsymbol{\varepsilon_{capPV}}$	$\boldsymbol{\varepsilon_{capDR}}$	$\boldsymbol{\varepsilon_{capBES}}$
0.95	0.80	0.80

C. RELIABILITY ASSUMPTIONS FOR GRID SCALE BATTERIES

Utility owned and operated grid-scale batteries are considered to be in the same N-1 reliability group as the station's transformers. The resulting capacity which will be considered for grid scale-batteries is therefore calculated as follows

$$P_{Bat_{Firm}} = \begin{cases} (\sum P_{Bat}); & \max(P_{Bat}) \le \max\,(P_{Transformer}) \\ (\sum P_{Bat}) - \max(P_{Bat})\,; & \max(P_{Bat}) > \max\,(P_{Transformer}) \end{cases} \qquad 7.C.01$$

Note: It is therefore advisable that no single BESS exceeds the size of the largest station transformer as it would be entirely removed for the firm capacity calculation.

D. RELIABILITY ASSUMPTIONS FOR DG

All DG NWA solutions (Solar, Fuel Cell, CHP, Emergency Generators) are considered to be in a separate reliability group. The largest DG is excluded in the NWA Framework to calculate the Reliable DG Capacity $P_{DG_{Reliable}}$ analogous to the transformer + large scale BESS group.

$$P_{DG_{Reliable}} = (\sum P_{DG}) - \max(P_{DG}) \qquad 7.D.01$$

DER assets included in P_{DG} are

a. **Solar DG**: For solar DG, $P_{DG_{Solar}}$ represents the installed capacity adjusted for minimal certain weather adjusted output. See Solar Generation for details.
b. **Fuel Cells**: $P_{DG_{FC}}$ represents the nameplate installed capacity
c. **CHP**: $P_{DG_{CHP}}$ represents the nameplate installed capacity
d. **Emergency Generators**: $P_{DG_{EG}}$ represents the nameplate installed capacity

8. DISPATCH MODEL

In order to determine their ability to solve technical issues, the dispatch, especially of flexible resources such as BESS, needs to be accurately modeled. The NWA Framework makes assumptions on DER dispatch modes and capabilities as outlined in the following Chapter

A. PRIORITIZATION OF DER DISPATCH

The NWA Framework assumes that in a multi-solution NWA portfolio, the dispatch priorities are as follows:

a. **Permanently Altering Assets**: These technologies permanently alter the load of the system and are therefore always available and do not require an active dispatch to produce their benefit. The tool will use their contribution first to determine if any remaining dispatch is required.
   - Energy Efficiency

b. **Continuously Running Assets**: Assets that are assumed to be continuously running are considered next. Given the nature of the resources, curtailment of their output would not make fiscal sense. Their contribution is set to nominal throughout the day which is observed. Any remaining capacity need is handled by dispatchable assets.
   - Solar: Has no variable cost and generates revenue when running
   - CHP: Installed through program funding with an assumed dispatch capability through DR system
   - Fuel Cell: Installed through program funding with an assumed dispatch capability through DR system

c. **Dispatchable Assets**: Dispatchable assets can change their dispatch characteristics to the extent that their technical limitations allow them to.
   - **CVR:** Dispatch of tap changers at transformers, capacitors, and in-line voltage regulators with no marginal cost of dispatch
   - **Utility Program Dispatch**: Any utility program, such as DR management, fall under this category
     i. DR (Commercial and Residential DR), limited to one dispatch a day
   - **Utility Owned Asset Optimization and Battery Programs**: Remaining capacity need can be managed by storage. Storage is prioritized before emergency generation assets from an ecological standpoint. This includes the use of Battery Storage DR Programs.
     i. Utility Scale Battery Storage
     ii. BTM Storage Control Programs
   - **Contracted Emergency Assets**: As a last resort emergency generation asset can be dispatched to fill any remaining capacity gap. Their environmental impacts and associated costs make them the least desirable solution.
     i. Emergency Generator

B. SOLAR GENERATION

For consideration of solar distributed generation as an NWA the technology's technical capabilities are defined as follows by the NWA Framework (these apply to both utility scale and BTM installations, their different considerations by the NWA Framework on reliability can be reviewed in 7.D. Reliability Assumptions for DG; any values considered in this section are the result of those reliability assumptions).

a. **Time Variant Output**: Solar PV installations can only generate power during the hours when the sun is shining (typically daytime hours in the U.S.), therefore, any capacity deficits which occur outside those hours cannot be addressed through solar. Solar generation potential is defined through clear sky irradiance profiles[3]. These clear sky irradiance profiles represent ideal weather conditions and change with the day of the year. The following simplified equation is used to determine the P_{DC} panel output over time.

$$P_{DC}(t) = \frac{I_{ClearSky}(t)}{1000\frac{W}{m^2}} * P_{DC_{Rated}} \qquad 8.B.01$$

The Framework does not consider losses or orientation of the solar array and rather assumes ideal conditions for both.

b. **Minimal Weather Adjusted Output (MWAC)**: In order to account for weather conditions and the chance of non-ideal conditions for solar generation, a Minimal Weather Adjusted Relative Irradiance $\varepsilon_{Irr_{MWAC}}$ has been evaluated through data analytics on historic irradiance data sets. A Minimal Weather Adjusted Relative Irradiance shall be used for all three seasons using the 10th percentile on the event distribution.

- **Summer:** Jun, Jul, Aug — 16.6%
- **Transition:** Mar, Apr, May, Sept, Oct, Nov — 18.1%
- **Winter:** Dec, Jan, Feb — 24.1%

The resulting Minimal Weather Adjusted Clear Sky Irradiance Profile can therefore be determined by

$$I_{ClearSky_{MWAC}}(t) = I_{ClearSky}(t) * \varepsilon_{Irr_{MWAC}} \qquad 8.B.02$$

Resulting in a Minimal Weather Adjusted DC Capacity of

$$P_{DC_{MWAC}}(t) = \frac{I_{ClearSky_{MWAC}}(t)}{1000\frac{W}{m^2}} * P_{DC_{Rated}} \qquad 8.B.03$$

No conversion losses are modeled for solar distributed generation, and the $P_{DC_{MWAC}}(t)$ results can be directly converted to the resulting $P_{AC_{MWAC}}(t)$ values as follows. If $P_{DC_{MWAC}} > P_{AC_{Rated}}$, $P_{AC_{MWAC}}$ is capped at $P_{AC_{Rated}}$.

$$P_{AC_{MWAC}}(t) = \max_{P_{AC_{Rated}}} P_{DC_{MWAC}}(t) \qquad 8.B.04$$

c. **Degradation**: The NWA Framework does not account for panel degradation over time but assumes a replacement of panels every 20 years.

Note: The NWA Framework defaults the P_{DC} to P_{AC} ration as 1.2.[4]

Figure 2 shows an application of solar distributed generation to reduce a capacity deficit. Using the evaluation framework for solar distributed generation, this capacity curve was calculated as follows:

a. The plan calls for four (4) systems at $P_{AC_{Rated}} = 2$ MW each; no other DERs are considered
b. The systems are defined as having an $\frac{P_{DC_{Rated}}}{P_{AC_{Rated}}} = 1.5$ ratio
c. The reliability framework accounts for only three (3) of the four (4) systems at 2 MW each, assuming the loss of the largest asset
d. The clear sky irradiance profile is converted to the Minimal Weather Adjusted clear sky irradiance profile and applied to $P_{DC_{MWAC}}$ to calculate $P_{DC_{MWAC}}(t)$ using summer profiles

[3] The NWA Framework bases its Clear Sky Irradiance data off Clean Power Research's SolarAnywhere® Datasets

[4] Data based on historic trend analysis of large-scale solar system installations in CT

e. In no instance does $P_{DC_{MWAC}}(t)$ exceed $P_{AC_{Rated}}$, therefore there is no capping of the expected output

f. The resulting Minimal Weather Adjusted capacity curve peaks at 3.15 MW, or 39.3% of $P_{AC_{Rated}}$, or 26.3% of $P_{DC_{Rated}}$

g. Due to the time of peak, very little contribution is made by solar to the capacity deficit shown in the example below.

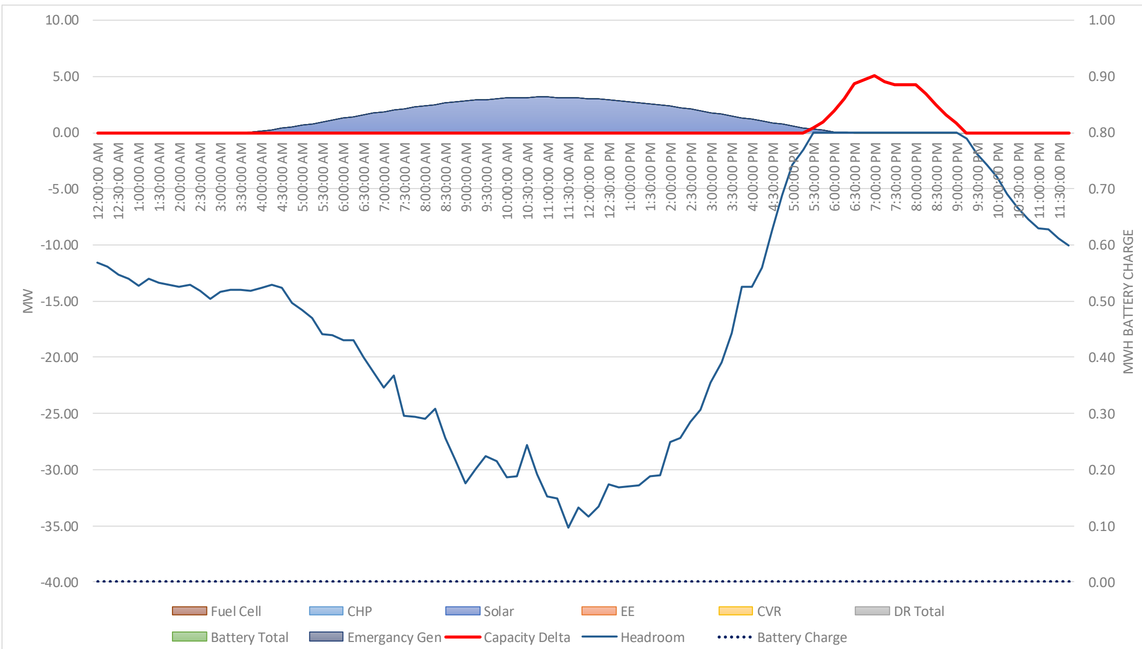

Figure 2: Application of Minimal Weather Adjusted Solar Generation Capacity to a Capacity Deficit

C. ENERGY EFFICIENCY

Energy Efficiency is modeled as a permanent dispatch from the year of installation. This means, that the Energy Efficiency impacts will be modeled as continuously on, regardless of whether there is a capacity deficit or not. Energy Efficiency is modeled for four (4) distinct applications as well as a generic application, each with different profiles. Energy Efficiency is calculated as follows over the course of a day, with $\varepsilon_{Type}(t)$ the Energy Efficiency specific profile type. The Energy Efficiency profiles listed below are based on internal experience of the EE-Team.

$$P_{EE} = \sum_{Type} \left(P_{EE_{Type}} * \varepsilon_{Type}(t) \right) \qquad 8.C.01$$

a. **Lighting**: Lighting Energy Efficiency is assumed to mostly target commercial and industrial lighting, as a result, Energy Efficiency savings will manifest themselves during working hours. Commercial and industrial lighting-based Energy Efficiency will take effect starting at 7am and stop at after 6pm. No seasonal dependency is assumed for Lighting Energy Efficiency measures.

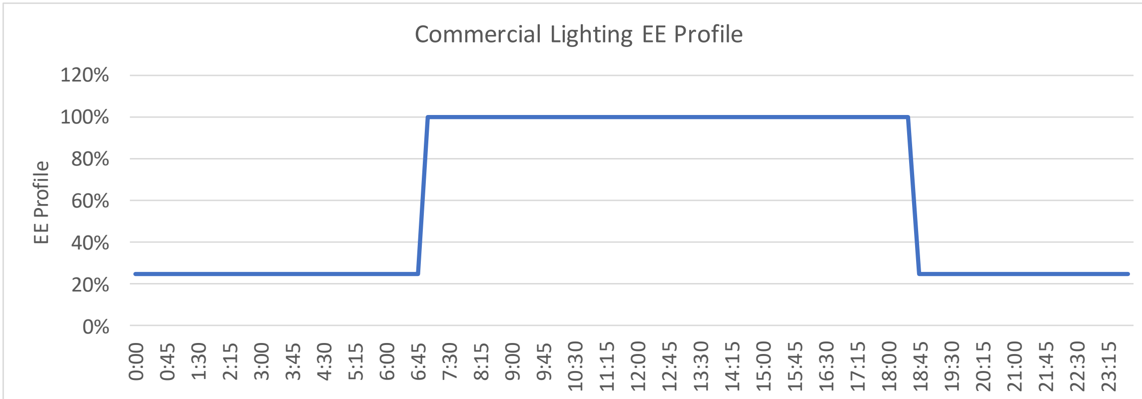

Figure 3: Daily Lighting EE Profile

b. **Residential Lighting**: Residential Lighting is assumed to provide the most impact in the evening hours after 7pm.

c. **HVAC Commercial**: Commercial HVAC is assumed to mostly be active during the day, with minimal activity at night. It is also dependent on the time of year. The underlying assumption is that HVAC load will be the highest during summer months, the lowest during spring and fall, with a minor peak during winter.

To determine the day of year dependency of potential commercial HVAC savings, the following equation applied in the NWA Framework:

$$\varepsilon_{\mathrm{HVAC_{Comm}Yearly}}(t) = 1 + \cos\left(\frac{\text{15 min Interval of the Year}}{\text{Total number of15 min Intervals per Year}} * 4\pi\right) + \frac{1}{3}\sin\left(\frac{\text{15 min Interval of the Year}}{\text{Total number of15 min Intervals per Year}} * \pi\right)$$

8.C.02

which results in the annual curve for HVAC below.

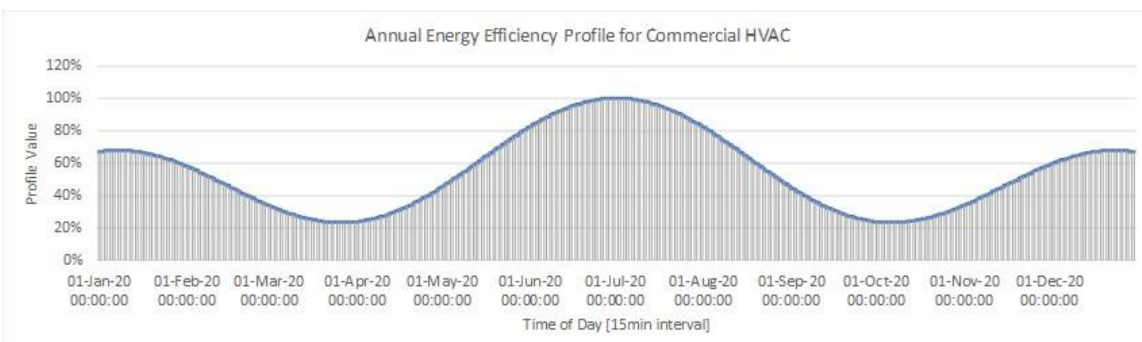

Figure 4: Annual Commercial HVAC EE Profile

For daily profile of commercial HVAC Energy Efficiency,

$$\varepsilon_{\mathrm{HVAC_{Comm}Daily}}(t) = \frac{1}{2}\left(1 + \sin\left(\pi * \frac{\text{15 min Interal of the Day} - 10}{\text{Total number of15 min Intervals per Day}}\right)\right) * \varepsilon_{\mathrm{HVAC_{Comm}Yearly}}(t)$$ 8.C.03

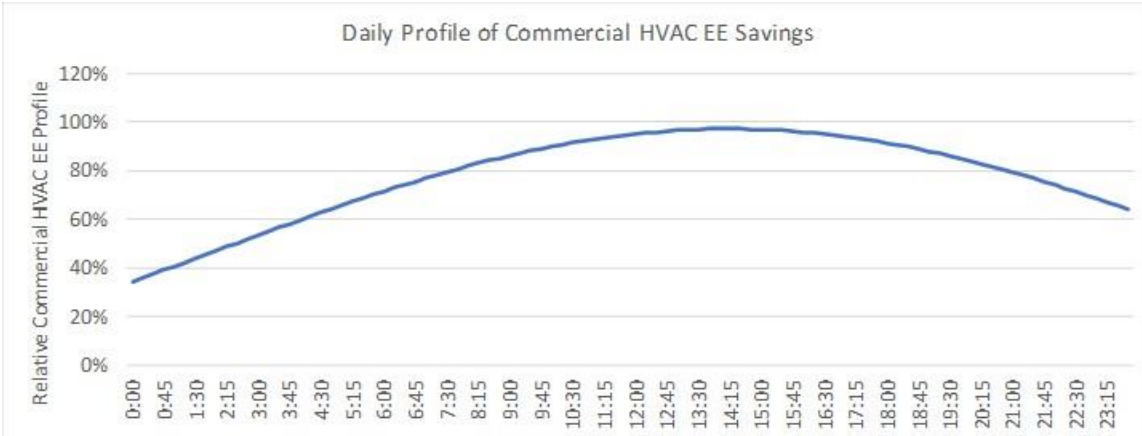

Figure 5: Daily Profile for Commercial HVAC EE

d. **HVAC Residential**: The HVAC residential follows the same yearly distribution as the HVAC commercial application, see above Equation 8.C.02.

$$\varepsilon_{\mathrm{HVAC_{Res}Yearly}}(\mathrm{t}) = \varepsilon_{\mathrm{HVAC_{Com}Yearly}}(\mathrm{t}) \qquad 8.C.04$$

However, given that residential HVAC applications typically have a higher yield in the evening hours and at night as opposed to the commercial HVAC which typically operates during the day, the profile has been adjusted. For the daily profile of residential HVAC, the following profile function is applied.

$$\varepsilon_{\mathrm{HVAC_{Res}Daily}}(\mathrm{t}) = \left(0.7 + \frac{3}{10}\sin\left(2\pi * \frac{\text{15 min Interval of the Day+30}}{\text{otal number of15 min Intervals per Day}}\right)\right) * \varepsilon_{\mathrm{HVAC_{Res}Yearly}}(\mathrm{t}) \qquad 8.C.05$$

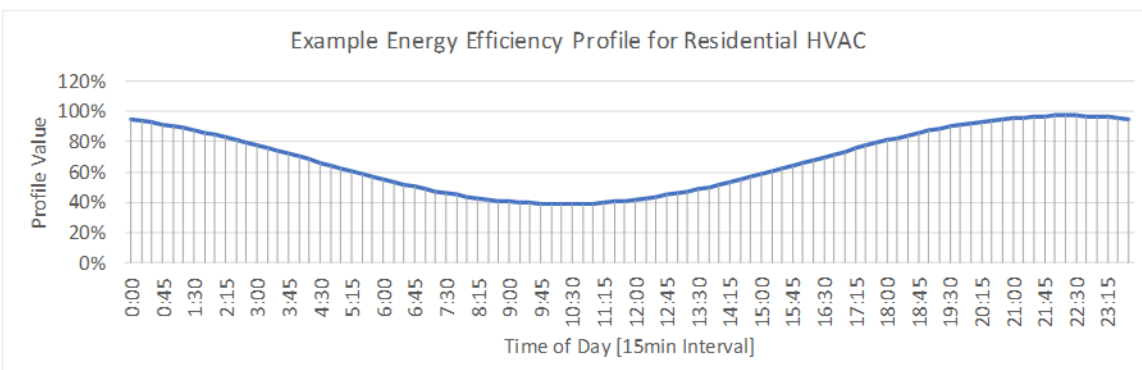

Figure 6: HVAC Residential HVAC EE Profile

D. DEMAND RESPONSE

Demand Response (DR) is classified into two types, commercial and residential DR. Both types of DR will dispatch automatically if there is a modeled capacity delta. The dispatch is modeled as a binary function, activating all of the resources or none.

DR contracts provide for a 3-hour dispatch minimum window. Longer dispatch windows can be simulated, but an adjustment to the overall DR volume needs to be made, as the EDC would then stagger the DR resources to achieve such an effect.

SNAP BACK AND PRE-CONDITIONING

Both DR resource types are modeled with pre-conditioning (e.g. through precooling before an event) and a snap back (e.g. through re-cooling after an event).

a. **Pre-Cooling** lasts 30 min and is defaulted to 60% of the total DR impact and is user adjustable depending on local conditions
b. **Snap Back** lasts for 2 hours after the event and is defaulted to 60% of the total DR impact and is user adjustable depending on local conditions

Figure 7 shows a modeled DR event with 2 MW of commercial, and 0.5 MW of residential DR capacity. Clearly visible, the pre-conditioning and snap back, before and after the event respectively.

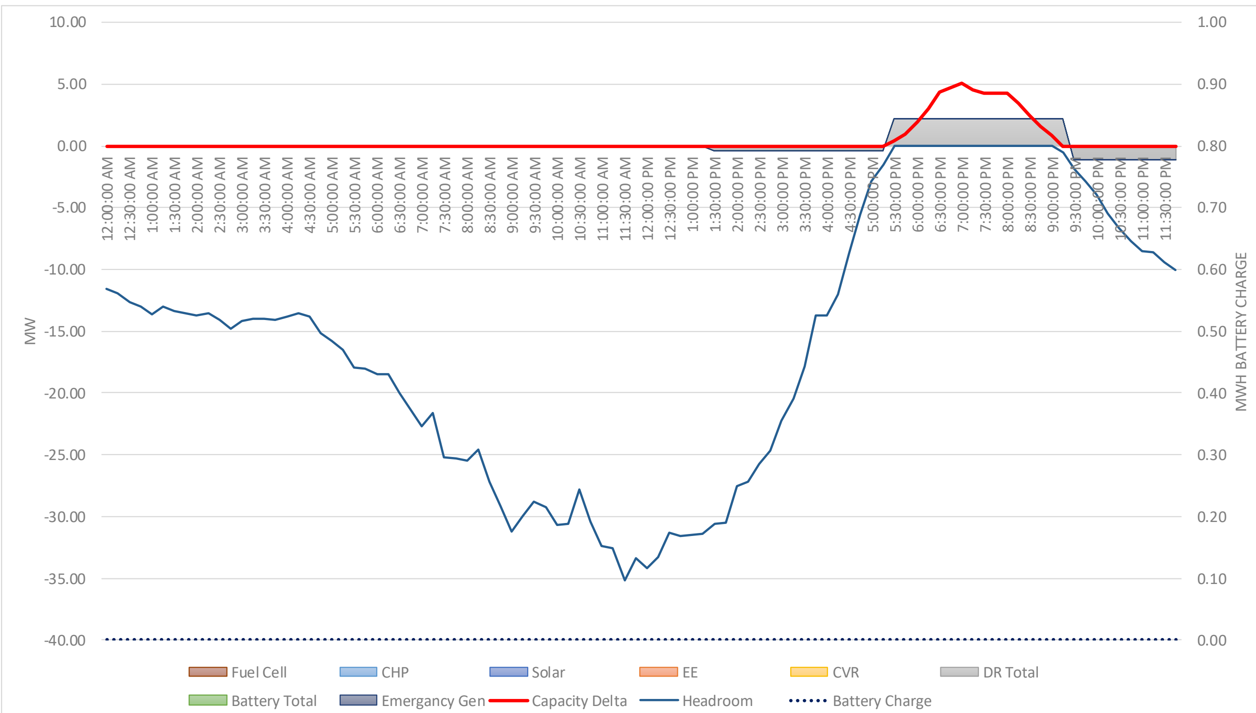

Figure 7: Example DR Event with Pre-Conditioning and Snap Back

AVAILABILITY OF DR RESOURCES

DR resources, much like EE, are only available if the underlying load is actually being used. For EE, the Framework models this approach with a seasonal and intra-day dependency. For commercial and residential DR, the NWA Framework provides a similar approach. As both forms of DR (excluding BTM storage) are typically based on HVAC applications, their highest impact will be achieved during peak summer month during afternoon hours. Figure 8 highlights the peak availability of DR resources throughout the year assumed in the NWA Framework.

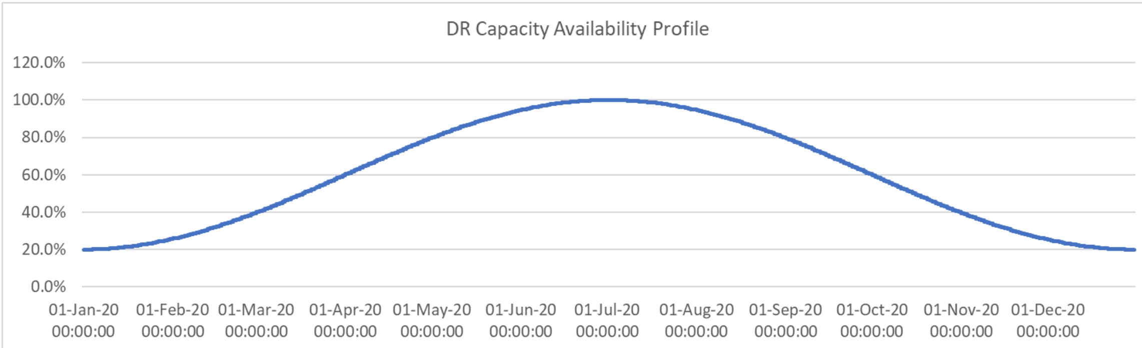

Figure 8: Annual DR Capacity Availability Profile

For each individual day, the Annual DR Capacity Availability Profile provides the peak DR response that can be expected based on the contracted volume. All contracted volume is given at 100% Annual DR Capacity. For each individual day, the value is then scaled to a daily profile to match actual resource usage. Figure 9 shows the Framework's availability profile for commercial and residential DR resources.

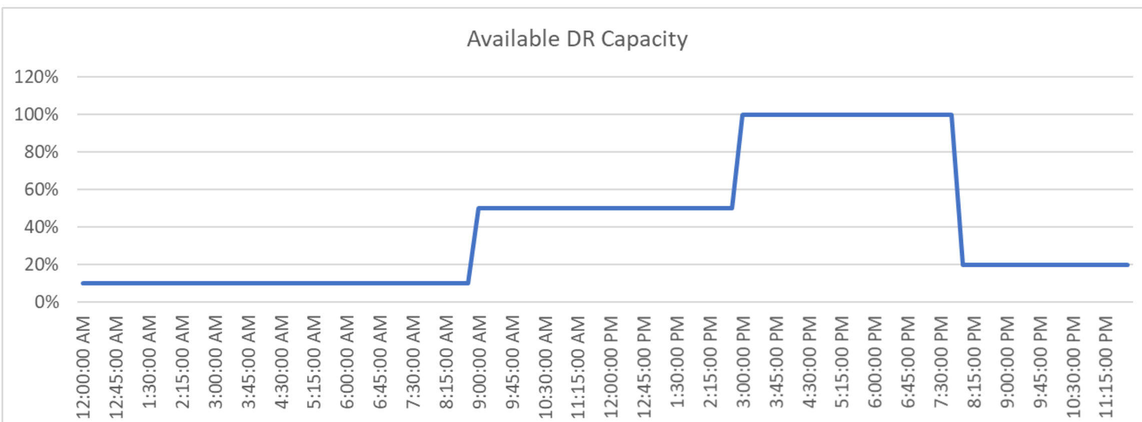

Figure 9: Available DR Capacity Profile

E. CONSERVATION VOLTAGE REDUCTION

Conservation Voltage Reduction (CVR) is given as a percentage of feeder load and as such varies over time. During a low load situation CVR will consequently reduce the load less in absolute numbers, than it does during a high load situation. The default assumed maximum reduction value is 1.8%, which is lower than the 2.34[5] reported by EPRI (only report with more constant impedance loads), but the number can be changed depending on the feeder topology and load constellation. The 1.8% represents values evaluated by the Company on its own circuits and requires a high-level evaluation for each region to ensure that such targets can be reached.

F. BATTERY STORAGE

For the purpose of technical evaluation all available battery resources are dispatched in the same manner. Hereby no distinction is made between grid scale battery systems and BTM solutions. Further, only battery resources that are under direct control of the utility are considered as NWA options, both utility scale and behind the meter.

Battery dispatch is constrained by:

a. **Maximum Charging/Discharging Power**: It is assumed that a battery has a symmetric dispatch and can achieve its full rated power both when charging or discharging and is limited only by the inverter capabilities. No reactive power dispatch will be taken into consideration.
b. **Available Headroom**: The battery will <u>not</u> (dis)charge in a fashion that introduces new capacity violations, therefore, recharge limitations are in place and a battery might find itself in a situation where it cannot recharge fast enough to support a new capacity constraint. It will take into consideration any additional capacity from Permanently Altering and Continuously Running Assets (See Section 8.A.)
c. **Capacity Deficit**: The battery will <u>not</u> (dis)charge more than is required to eliminate a capacity deficit. This means, only the absolute required minimum usage of the battery is assumed, which would equal ideal conditions.
d. **State of Charge**: The battery cannot charge, or discharge more than its state of charge allows. Batteries are assumed to be able to charge between 0% and 100% of their nameplate capacity. All the batteries are given an initial state of charge for the peak day simulation. That initial state of charge can be freely chosen[6] by the user. The dispatch simulation requires the batteries to return to the same SOC at the end of the simulated day, to ensure same initial condition should the following day also require battery dispatch for NWA purpose. The default setting here is 50%, stating that the battery starts, and ends, each day at 50% state of charge.
    a. **IMPORTANT**: If the battery is unable to attain at least the same SOC at the end of the peak day that it started the day with, it is at <u>high risk of not being able to perform two consecutive event days</u>. This means that the station does not have enough headroom to allow adequate recharging of the BESS.
e. **Degradation**: No degradation of storage capacity is applied in the NWA Framework
f. **Round Trip Efficiency**: A round trip efficiency is defined in the NWA Framework, which is applied equally to the charging and discharging cycles with

$$\sqrt[2]{\%_{\text{roundtrip}}} \qquad \text{8.F.01}$$

[5] https://www.epri.com/research/products/1024482

The charge and discharge efficiency are taken into consideration for SOC modeling, energy loss calculations, and when determining the ideal system size.

If any capacity deficit cannot be met by the battery, either because it does not have sufficient power, or because it has run empty, this will be highlighted.

G. FUEL CELL

Fuel Cell units are assumed to be must run assets and are modeled as continuously running. See Chapter 6.A and 9.K. The NWA Framework assumes that, outside of reliability considerations, any downtime for Fuel Cells will be maintenance-related and scheduled outside of possible event days.

H. COMBINED HEAT AND POWER

Combined Heat and Power (CHP) units are assumed to be must run assets and are modeled as continuously running. The NWA Framework assumes that, outside or reliability considerations, any downtime for CHPs will be maintenance-related and scheduled outside of possible event days.

I. EMERGANCY GENERATION

Emergency Generation units are dispatched to compensate any capacity deficits. Their dispatched is modeled as binary, either on or off. They are not modeled to require warm up or spool down times as the resolution of the NWA Framework is 15 min, which provides adequate time for a generator to reach operational output. Aside from N-1 considerations, Emergency Generators are modeled at name plate rating.

9. COST MODEL

For the NWA Framework, the Cost Model describes how costs of all types of solutions, NWA and traditional are modeled. For all NWA solutions, the same cost model is applied (with the exception of CVR). Where an NWA solution does not have a cost factor, the values are considered null.

A. TRADITIONAL SOLUTION

Traditional Solution cost is provided in the NWA Framework in three categories

a. **CapEx**: Capital Expenses for traditional solutions are provided for a single year of expense; the NWA Framework assumes for simplicity reasons that all cost can be allocated to a single year. The Framework provides for entries in the following fields, which are all summed up to be included in the total CapEx of the project:
    a. Labor and Equipment
    b. Engineering
    c. Material
    d. PM Support / Permitting
    e. Removal
    f. Contingency
    g. Escalation
    h. Indirects
    i. AFUDC

b. **OpEx**: Operational Expenses are provided starting the year of the project and represent any <u>increase or decrease</u> in OpEx due to the new solution. A decrease in OpEx due to a new traditional solution can also be included as a negative value. Any change in OpEx will be extrapolated forward over the full financial planning horizon.

c. **Real-Estate Cost**: Any property purchases required are recorded separately. An annual addition to the revenue requirements is made through multiplication of the sum of all property purchases made to that point in time, multiplied by the WACC

$$\mathrm{WACC} * \sum_1^t \$_{\mathrm{PropertyPurchase}}(t) \qquad 9.A.01$$

B. NWA COST TYPES

The NWA Framework accounts for four (4) types of cost when it comes to DERs under consideration for NWA opportunities.

a. **CapEx Cost:** Capital Expenses (CapEx) are treated as expensed in a single year for any DER project. E.g., the installation of a battery system carries $5.5 Million CapEx cost. Even if the project to build said battery system might, in reality take more than a year, the Framework assumes those costs occur in the year the solution is deployed.
    - CapEx costs are increased on a yearly basis using a general inflation rate
    - CapEx costs have a book depreciation over the asset's life span (12, 20, or 40 years)
    - CapEx costs have a tax depreciation over either 5, 7, or 20 years
    - CapEx costs for specific asset types have a technology cost reduction, such as solar panels

    CapEx Cost includes the following line items in the cost model for each type of NWA

- **Equipment Cost:** Includes all NWA asset equipment, such as generators, panels, or inverters. Reappears for an asset replacement. Given in $^{\$}/_{\mathrm{MW}}$. For accounting purposes (see Chapter 10.A. Accounts), these costs are split between the following positions where applicable
  - **Distribution Hardware**
  - **Inverters**
  - **Generators/Motors/CHP/Fuel Cells**
  - **Battery Cells**
- **Interconnection Equipment:** Includes all equipment required to interconnect the asset. Does not re-appear for an asset replacement. Given in $^{\$}/_{\mathrm{MW}}$
- **Replacement Cost:** For NWA solutions with a lower life span than financial planning horizon, a replacement of the Equipment cost is considered in addition to a labor factor. Given in $^{\$}/_{\mathrm{MW}}$
  - **Battery Cells** are replaced after 12 years
  - **Inverters** are replaced after 20 years
  - **Solar Panels** are replaced after 20 years
  - **Generators, CHP, and Fuel Cells** are replaced after 20 years
  - **All Other Hardware** is replaced after 40 years
- **Engineering, Installation, and Commissioning:** All labor associated with the installation of the Equipment and the Interconnection. This includes labor, EPC overhead, and any interconnection costs with the utility. Given in $^{\$}/_{\mathrm{MW}}$
- **Overhead:** Project management and internal overhead for projects. Given in % of other CapEx cost where *x* represents the respective CapEx cost components as (for battery systems, the includes the battery cell component cost)

$$\sum\left(\mathrm{P_{inst}} * \mathrm{x}\frac{\$}{\mathrm{MW}}\right) \tag{9.B.01}$$

b. **OpEx Cost:** Operational Expenses (OpEx) are treated as expenses reoccurring every year. Reoccurring cost, program or OpEx, are calculated on a yearly basis.
- OpEx costs are increased on a yearly basis using a general inflation rate
- OpEx costs are treated as a direct passthrough to revenue requirements without additional earnings add on

OpEx Cost include the following line items in the cost model for each type of NWA
- **Fixed O&M**: Includes all maintenance and minor replacement activities, in addition to any running cost that are not dependent on utilization.
- **Variable O&M**: Includes all fuel and other variable cost that is dependent on either the energy produced or the Full Load Hours of operation per year.
- **Full Load Hours**: For variable O&M this represents the assume ratio of $\frac{\frac{\mathrm{Energy}}{\mathrm{Year}}}{\mathrm{P_{inst}}}$

c. Real-estate Cost: Real-estate cost can come into consideration for traditional solutions, grid scale solar DG and storage systems. Investments into properties cannot be depreciated, but will be accounted for with WACC
- Real-estate costs are increased with the yearly inflation rate

d. Program Costs: There are two types of Program Costs, reoccurring, such as costs created through Demand Response Programs, and one-time program costs, such as for the deployment of energy efficiency measures
- **One Time Program Cost:** Added to the OpEx costs the year they are incurred with an earnings multiplier
- **Reoccurring Program Cost:** Added to the OpEx cost every year they are incurred with an earning multiplier
- Program Costs are <u>not</u> increased on a yearly basis using a general inflation rate

C. ANNUAL RATES OF CHANGE

All values in the NWA Framework are provided in nominal values. To account for inflation, and the reduction in cost for certain technologies, the NWA Framework provisions for annual rates of change for the following

a. **Inflation Rate**: The inflation rate is defaulted to 2% an applies to all hardware, labor, real estate and O&M costs. Program costs are excluded from inflation

b. **Discount Rate**: The discount rate is given as a nominal discount rate and defaulted to -3.37%[7]. The effective discount rate is calculated, depending on the year the expense happens as

$$(100\% + \varepsilon_{\text{Discount Rate}} + \varepsilon_{\text{Inflation Rate}})^{\text{t}-\text{Base Year}} \qquad \text{9.C.01}$$

c. **Cost Rate PV Panels[8]**: The cost rate for PV Panels provides a projection of cost development of PV Panels <u>instead</u> of the inflation rate. PV Panels are not subject to the inflation rate but adhere to changes based on the Cost Rate for PV Panels. The NWA Framework defaults this value at -4.0%

d. **Cost Rate Battery Cells[9]**: The cost rate for Battery Cells provides a projection of cost development of Battery Cells <u>instead</u> of the inflation rate. Battery Cells are not subject to the inflation rate but adhere to changes based on the Cost Rate for Battery Cells. The NWA Framework defaults this value at -5.0%

e. **Cost Rate Inverters[10]**: The cost rate for Inverters provides a projection of cost development of Inverters <u>instead</u> of the inflation rate. Inverters are not subject to the inflation rate but adhere to changes based on the Cost Rate for Inverters. The NWA Framework defaults this value at 6%. This value applies to both Battery and Solar inverters. While the NREL report highlights a 2019 price increase of 20% for utility scale central inverters, that number will most likely not be sustainable.

Table 3: Application of Annual Change Rates Based on Cost Component

Component	Inflation Rate	Discount Rate	Cost Rate Panels	Cost Rate Cells	Cost Rate Invert.
Real Estate	X	X			
Traditional	X	X			
Int. Hardware	X	X			
Any O&M	X	X			
Inverters	X	X			X
Battery Cells	X	X		X	
Solar Panels	X	X	X		
Gen., FCs, CHP	X	X			
Program Costs		X			
Electricity Cost	X	X			

[7] https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf

[8] NREL Q4 2019/Q1 2020 Solar Industry Update Page 39

[9] NREL Cost Projections for Utility-Scale

[10] NREL Q4 2019/Q1 2020 Solar Industry Update Page 64

Note: All technology rates of change can be edited within the NWA Screening Tool to adjust to the ever-changing landscape. To provide a unified source of information, the NWA Framework uses NREL's publications[11]

D. EARNING FACTORS UTILITY PROGRAMS

For energy efficiency and demand management expenditures, the Company has the ability to earn a performance incentive averaging 5% of total program expenditures. Therefore, for purposes of modeling within the NWA solution the following rates are applied by state.

Note: Historic assumption is based on the level of generated benefits as a percentage of spend and depending on jurisdiction.

Table 4: Program Performance Incentive

State	MA	CT	NH
Assumed Performance Incentive	5.0%	5.0%	5.0%

These values are applied to:

a. Demand Response Programs, <u>annually</u>
    a. Commercial
    b. Residential
    c. Battery Storage
b. Energy Efficiency Programs, <u>once</u>
c. Behind the Meter Solar Programs, <u>annually</u>

E. LIFE CYCLE ASSUMPTIONS

For the cost calculation, the NWA Framework makes assumptions on the useful life of an asset. This is achieved within the NWA Framework by clustering assets into three (3) expected useful life spans

Table 5: Life Cycle Assumptions by Asset Type

Asset Type	12-Year Assets	20-Year Assets	40-Year Assets
Traditional Solution			X
Interconnection Hardware			X
Inverters		X	
Battery Cells	X		
Solar Panels		X	
Generators, FCs, CHP		X	

The Life Cycle Assumptions will inform the calculation of the Revenue Requirements through the tax and book depreciation, as well as MACRS values.

[11] NREL Annual Technology Baseline

If, within the financial planning horizon selected, an asset reaches the end of its useful lifespan, it is assumed replaced by the NWA Framework with an addition investment happening in the last year of its expected lifespan. This process can, depending on the asset and the Financial Planning Horizon, happen more than once.

F. SOLAR GENERATION

For the NWA Framework, cost assumptions have been made for the cost of solar systems to supply default values.

UTILITY SCALE SOLAR GENERATION[12][13]

a. CapEx Cost

- Equipment Cost:
  - i. Panels $\$340{,}000/_{\mathrm{MW}}$
  - ii. Solar Inverter (2 Quadrant) $\$62{,}000/_{\mathrm{MW}}.$
- Interconnection Equipment: $\$330{,}000/_{\mathrm{MW}}$
- Replacement Cost: The default labor rate factor is at $\varepsilon_{\mathrm{Replace}} = 20\%$
- Engineering, Installation, and Commissioning: $\$240{,}000/_{\mathrm{MW}}$
- Overhead: 50%

b. OpEx Cost

- Fixed O&M: Fixed O&M cost is defaulted at $\$50{,}000/_{\mathrm{a}}$
- Variable O&M: $\$0.00/_{\mathrm{MWh}}$
- Full Load Hours: $1400\mathrm{h}/_{\mathrm{a}}$

c. Real-Estate Cost: $0.00

d. Program Costs

- One Time Program Cost $\$0/_{\mathrm{MW}}$
- Reoccurring Program Cost $\$0/_{\mathrm{a} * \mathrm{MW}}$

With different sizes between inverters and panels, the cost model accounts for the Equipment Cost as follows

$$\$470{,}000/_{\mathrm{MW}} * \mathrm{P}_{\mathrm{inst}_{\mathrm{DC}}} + \$50{,}000/_{\mathrm{MW}} * \mathrm{P}_{\mathrm{inst}_{\mathrm{AC}}} \qquad 9.F.01$$

Where. For the NWA Framework, a default overclocking rate $\varepsilon_{\mathrm{OC}}$ is assumed for all solar generation, this value is defaulted to

$$\varepsilon_{\mathrm{OC}} = 1.2 \qquad 9.F.02$$

[12] https://atb.nrel.gov/electricity/2019/index.html?t=su

[13] Solar Energy Industries Association, US Solar Market Insight, Full Report, Q4 2020

BEHIND THE METER SOLAR GENERATION:

The NWA Framework considers that behind the meter solar generation could provide an NWA to traditional utility investments in certain situations as part of a utility-managed program. However, current incentive structures available to behind the meter solar applications generally do not incentivize solar installations on a location-specific basis in order to ensure that installation would provide a benefit to the distribution system as an NWA.

a. CapEx Cost
- Equipment Cost: $\$0.00/_{\mathrm{MW}}.$
- Interconnection Equipment: $\$0.00/_{\mathrm{MW}}$
- Replacement Cost: The default labor rate factor is at $\mathrm{N/A}$
- Engineering, Installation, and Commissioning: $\$0.00/_{\mathrm{MW}}$
- Overhead: $\mathrm{N/A}$

b. OpEx Cost
- Fixed O&M: Fixed O&M cost is defaulted at $\$0.00/_{\mathrm{a*MW}}$
- Variable O&M: $\$0.00/_{\mathrm{MWh}}$
- Full Load Hours: $1400\mathrm{h}/_{\mathrm{a}}$

c. Real-Estate Cost: $\$0.00$

d. Program Costs
- One Time Program Cost $\$0/_{\mathrm{MW}}$
- Reoccurring Program Cost $\$35/_{\mathrm{a*MW}}$

G. ENERGY EFFICIENCY

Energy Efficiency is conducted as a utility program with the assumption that all expenses happen in a single year, and that no continuous expenses are required.

a. CapEx Cost
- Equipment Cost: $\$0.00/_{\mathrm{MW}}.$
- Interconnection Equipment: $\$0.00/_{\mathrm{MW}}$
- Replacement Cost: The default labor rate factor is at $\mathrm{N/A}$
- Engineering, Installation, and Commissioning: $\$0.00/_{\mathrm{MW}}$
- Overhead: $\mathrm{N/A}$

b. OpEx Cost
- Fixed O&M: Fixed O&M cost is defaulted at $\$0.00/_{\mathrm{a*MW}}$
- Variable O&M: $\$0.00/_{\mathrm{MWh}}$
- Full Load Hours: $\mathrm{N/A}$

c. Real-Estate Cost: $\$0.00$

d. Program Costs
- One Time Program Cost $\$50/_{\mathrm{10a*MWh}}$
- Reoccurring Program Cost $\$0/_{\mathrm{a*MW}}$

The cost of energy efficiency programs is determined by through a \$/kWh saved metric $\varepsilon_{\mathrm{EE}}$, with

$$\varepsilon_{\mathrm{EE}} = 50 \frac{\$}{\mathrm{MWh} * 10\mathrm{a}} \qquad \text{9.G.01}$$

To calculate the cost of the total Energy Efficiency program, the savings over a ten (10) year time span are considered in the NWA Framework, resulting in an Energy Efficiency program cost of

$$\mathrm{EE}_{\mathrm{cost}} = \varepsilon_{\mathrm{EE}} * 10\mathrm{a} * \int_0^{365} \mathrm{EE}_{\mathrm{kWh}} \mathrm{dd} \qquad \text{9.G.02}$$

Where the savings are calculated over all days of the year using the Energy Efficiency Profiles.

All Energy Efficiency cost is incurred at the year on inception with no running cost. In addition, a Utility Earnings Factor, see Chapter 9.D. is applied to the cost.

$$\mathrm{EE}_{\mathrm{RevReq}} = \mathrm{EE}_{\mathrm{cost}} * (1 + \varepsilon_{\mathrm{Earning}}) \qquad \text{9.G.03}$$

There is no inflation assumed for the cost of Energy Efficiency programs

H. DEMAND RESONSE

Demand Response Programs are, as part of the NWA Framework, modeled with a cost per kW. In reality, there is a performance factor applied, with some assets no performing at all events, or not to full specification. However, for the NWA Framework, some assumptions have been made to simplify the modeling

a. The assumption is that the assets are fully able to perform. As a result, the cost for DR programs can be reduced to an annual capacity payment without a performance component.
b. Unlike Energy Efficiency, DR costs are annual costs that continue to present over the course of the financial planning horizon.
c. Demand Response program costs are excluded from an inflation rate in the NWA Framework
d. Programs working with storage do not account for replacement of cells or batteries. That cost is covered by the owner and accounted for in the annual payments.

COMMERICAL

For commercial DR, the capacity payments are set at

a. CapEx Cost

- Equipment Cost: $\$0.00/_{\mathrm{MW}}$.
- Interconnection Equipment: $\$0.00/_{\mathrm{MW}}$
- Replacement Cost: The default labor rate factor is at N/A
- Engineering, Installation, and Commissioning: $\$0.00/_{\mathrm{MW}}$
- Overhead: 0%

b. OpEx Cost

- Fixed O&M: Fixed O&M cost is defaulted at $\$0.00/_{\mathrm{a} * \mathrm{MW}}$
- Variable O&M: $\$0.00/_{\mathrm{MWh}}$
- Full Load Hours: N/A

c. **Real-Estate Cost**: $0.00

d. **Program Costs**

- One Time Program Cost $\$0/_{\text{MW}}$
- Reoccurring Program Cost $\$50{,}000/_{\text{a} * \text{MW}}$

Commercial DR contracts are limited to <u>eight (8) events a year</u> and can be expanded to include more events per year at an additional cost per kW. The event limit numbers are based on DR contracts as they are currently used by the company. To compute additional costs for larger DR contracts, the Framework defaults to an assumed surcharge of 50%.

$$\text{Total Events} - \text{Maximum Contract Events} \geq 0 \quad \text{9.H.01}$$

$$\varepsilon_{\text{DR}_{\text{Com}}} * \left(1 + 50\% * \frac{\text{Total Events} - \text{Maximum Contract Events}}{\text{Maximum Contract Events}}\right) \quad \text{9.H.02}$$

Resulting in a cost of

$$50{,}000 \frac{\$}{\text{kW}} * \left(1 + 50\% * \frac{16-8}{8}\right) = 75{,}000 \frac{\$}{\text{kW}} \quad \text{9.H.03}$$

The program is scaled to the year with the largest number of events in the forecasting horizon

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RESIDENTIAL

For residential DR, the capacity payments are set at

a. **CapEx Cost:**

- Equipment Cost: $\$0.00/_{\text{MW}}$·
- Interconnection Equipment: $\$0.00/_{\text{MW}}$
- Replacement Cost: The default labor rate factor is at N/A
- Engineering, Installation, and Commissioning: $\$0.00/_{\text{MW}}$
- Overhead: 0%

b. **OpEx Cost:**

- Fixed O&M: Fixed O&M cost is defaulted at $\$0.00/_{\text{a} * \text{MW}}$
- Variable O&M: $\$0.00/_{\text{MWh}}$
- Full Load Hours: N/A

c. **Real-Estate Cost**: $0.00

d. **Program Costs:**

- One Time Program Cost $\$0/_{\text{MW}}$
- Reoccurring Program Cost $\$120{,}000/_{\text{a} * \text{MW}}$

Residential DR contracts are limited to <u>16 events a year</u> and can be expanded at a cost rate of 50% using the same methodology as the commercial DR contracts, see Equation 9.H.03

The program is scaled to the year with the largest number of events in the forecasting horizon

STORAGE

For storage DR, the capacity payments are set at

a. CapEx Cost:

- Equipment Cost: $\$0.00/_{\mathrm{MW}}$
- Interconnection Equipment: $\$0.00/_{\mathrm{MW}}$
- Replacement Cost: The default labor rate factor is at N/A
- Engineering, Installation, and Commissioning: $\$0.00/_{\mathrm{MW}}$
- Overhead: 0%

b. OpEx Cost:

- Fixed O&M: Fixed O&M cost is defaulted at $\$0.00/_{\mathrm{a*MW}}$
- Variable O&M: $\$0.00/_{\mathrm{MWh}}$
- Full Load Hours: N/A

c. Real-Estate Cost: $0.00

d. Program Costs:

- One Time Program Cost $\$0/_{\mathrm{MW}}$
- Reoccurring Program Cost $\$250{,}000/_{\mathrm{a*MW}}$

Battery DR contracts are limited to <u>60 events a year</u> and can be expanded at a cost rate of 50% using the same methodology as the commercial DR contracts, see Equation 9.H.03

The program is scaled to the year with the largest number of events in the forecasting horizon

I. CONSERVATION VOLTAGE REDUCTION

CVR programs provide for a slightly altered cost structure. Based on the Company's experience, the cost to implement a CVR program at a Substation is highly variable based on present equipment, but is defaulted to

$$\varepsilon_{\mathrm{CVR}_{\mathrm{Install}}} = 2{,}500{,}000 \frac{\$}{\mathrm{Substation}} \qquad 9.\mathrm{I}.01$$

And takes an average of 12-man hours a week to operate, which results in an annual cost of

$$\varepsilon_{\mathrm{CVR}_{\mathrm{O\&M}}} = 78{,}000 \frac{\$}{\mathrm{Substation}*\mathrm{a}} \qquad 9.\mathrm{I}.02$$

J. BATTERY STORAGE

For battery storage solutions, the cost assumptions are based on NREL publications[14].

a. CapEx Cost:

- Equipment Cost: The default value Battery Storage is at

[14] https://atb.nrel.gov/electricity/2019/index.html?t=st based on 2-hour storage systems

i. Battery Cells $\$209{,}000/_{\mathrm{MWh}}$

ii. Battery Inverter (4 Quadrant) $\$70{,}000/_{\mathrm{MW}}$

- Interconnection Equipment: $\$100{,}000/_{\mathrm{MW}}$
- Replacement Cost: The default labor rate factor is at $\varepsilon_{\mathrm{Replace}} = 20\%$
- Engineering, Installation, and Commissioning: $\$62{,}500/_{\mathrm{MW}}$
- Overhead: 50%

b. OpEx Cost:

- Fixed O&M: Fixed O&M cost is defaulted at $\$50{,}000/_{\mathrm{a}}$
- Full Load Cycles N/A

c. Real-Estate Cost: $0.00

d. Program Costs:

- One Time Program Cost $\$0/_{\mathrm{MW}}$
- Reoccurring Program Cost $\$0/_{\mathrm{a} * \mathrm{MWh}}$

Note: Variable O&M for BESS is based on energy losses and cost of energy

K. FUEL CELL

Fuel Cells are modeled as Commercial Fuel Cells with the following cost components in the NWA Framework. For the NWA Framework, they will be considered as part of the Energy Efficiency portfolio. The following outlines the default values assumed in the cost model.

a. CapEx Cost

- Equipment Cost: $\$0.00/_{\mathrm{MW}}.$
- Interconnection Equipment: $\$0.00/_{\mathrm{MW}}$
- Replacement Cost: The default labor rate factor is at N/A
- Engineering, Installation, and Commissioning: $\$0.00/_{\mathrm{MW}}$
- Overhead: N/A

b. OpEx Cost

- Fixed O&M: Fixed O&M cost is defaulted at $\$0.00/_{\mathrm{a} * \mathrm{MW}}$
- Variable O&M: $\$0.00/_{\mathrm{MWh}}$
- Full Load Hours: $6000\mathrm{h}/_{\mathrm{a}}$

c. Real-Estate Cost: $0.00

d. Program Costs

- One Time Program Cost $\$700\ 000/_{\mathrm{MW}}$
- Reoccurring Program Cost $\$0/_{\mathrm{a} * \mathrm{MW}}$

L. COMBINED HEAT AND POWER

CHPs are modeled as Commercial – Natural Gas Microturbines with the following cost components in the NWA Framework. They are deployed through incentive programs managed under the Energy Efficiency portfolio.

e. CapEx Cost

- Equipment Cost: $\$0.00/_{\mathrm{MW}}$.
- Interconnection Equipment: $\$0.00/_{\mathrm{MW}}$
- Replacement Cost: The default labor rate factor is at N/A
- Engineering, Installation, and Commissioning: $\$0.00/_{\mathrm{MW}}$
- Overhead: N/A

f. OpEx Cost

- Fixed O&M: Fixed O&M cost is defaulted at $\$0.00/_{\mathrm{a} * \mathrm{MW}}$
- Variable O&M: $\$0.00/_{\mathrm{MWh}}$
- Full Load Hours: $6000\mathrm{h}/_{\mathrm{a}}$

g. Real-Estate Cost: $\$0.00$

h. Program Costs

- One Time Program Cost $\$1\,000\,000/_{\mathrm{MW}}$
- Reoccurring Program Cost $\$0/_{\mathrm{a} * \mathrm{MW}}$

M. EMERGENCY GENERATION

Emergency Generation typically represents 3rd party owned and operated Diesel or Natural Gas Generators which an EDC secures under contractual obligation. These contracts include annual capacity payments as well as variable payments depending on the rate of utilization.

a. CapEx Cost:

- Equipment Cost: The default value for Fuel Cells is at $\$0/_{\mathrm{MW}}$
- Interconnection Equipment: $\$0/_{\mathrm{MW}}$
- Replacement Cost: The default labor rate factor is at N/A
- Engineering, Installation, and Commissioning: $\$0/_{\mathrm{MW}}$
- Overhead: N/A

b. OpEx Cost:

- Fixed O&M: Fixed O&M cost is defaulted at $\$270{,}000/_{\mathrm{a} * \mathrm{MW}}$
- Variable O&M: $\$400/_{\mathrm{MWh}}$
- Full Load Hours N/A

c. Real-Estate Cost: $\$0.00$

d. Program Costs:

- One Time Program Cost $\$0/_{\mathrm{MW}}$
- Reoccurring Program Cost $\$0/_{\mathrm{a} * \mathrm{MWh}}$

10. REVENUE REQUIREMENTS

The NWA framework includes representative revenue requirement calculations in order to compare the potential ultimate cost to customers of NWA and traditional solutions. Further detailed financial analysis would be conducted prior to the Company implementing any solution and amounts sought for recovery by the Company would also be based upon more detailed revenue requirement calculations.

A. GENERAL ASSUMPTIONS

For the NWA Framework, a simplified approach was chosen to evaluate the revenue requirements stemming from certain investments.

ACCOUNTS

The following accounts and Modified Accelerated Cost Recovery System (MACRS) depreciations are considered:

a. **345** Inverters — 5 Years
b. **344** Solar Panels/Generators — 5 Years
c. **362** Distribution Station Equipment — 20 Years
d. **363** Storage Battery Equipment — 7 Years

For the book depreciation, the following equipment lifespans are considered

a. Battery Cells — 12 Years
b. Solar Panels, Inverters, Generators, Fuel Cells, CHP — 20 Years
c. All traditional hardware — 40 Years

The resulting combinations for assets are

a. **7/12** Battery Cells
b. **5/20** Solar Panels, Inverters, Generators, Fuel Cells, CHP
c. **20/40** All traditional hardware

DEPRECIATION ACCRUAL RATE

The Framework provisions the accrual rate as

$$\frac{1}{\text{Asset Useful Life (years)}} \quad \text{10.A.01}$$

PRE-TAX WACC

The Pre-Tax Weighted Average Cost of Capital (WACC) are calculated as follows

a. Using a Federal Tax Rate of 21% and a state rate per selected state the Effective State Rate is calculated as
$$\text{State Rate} * (1 - \text{Federal Rate}) \quad \text{10.A.02}$$
b. The Effective State and Federal Tax Rate is the calculated by
$$\text{Federal Rate} + \text{Effective State Rate} \quad \text{10.A.03}$$

c. The Net Income After Taxes on Income is

$$1 - \text{Effective State and Federal Tax Rate} \tag{10.A.04}$$

d. The Pre-Tax WACC will be calculated based on the weighted costs of debt and equity, as approved in base distribution rate cases from time to time.

PROPERTY PURCHASES

Any property purchases are reflected in the revenue requirements on a yearly basis with

$$\text{Cost of Property} * \text{WACC} \tag{10.A.05}$$

and are not inflation adjusted over time

PROGRAM COST

Program costs (yearly and one-time) are added to the revenue requirements of the year they are incurred and include potentially applicable utility incentive amounts.

$$\text{Yearly Program Cost} * (1 + \text{State Specific Earnings Rate}) \tag{10.A.06}$$

Program costs are not inflation adjusted over time

O&M COST

O&M (or OpEx) costs to the company are a direct pass through to the revenue requirements, they do however increase by the inflation rate on a yearly basis.

ASSET REVENUE

If the NWA solution provides a revenue stream that can be set against its cost, the annual revenue will be subtracted from the annual O&M cost.

B. MACRS

MACRS 7 YEARS (363 - STORAGE BATTERY EQUIPMENT)

Table 6: 7 Year MARCS

Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
14.29%	24.49%	17.49%	12.49%	8.93%	8.92%	8.93%	4.46%

MACRS 5 YEARS (344/345 - SOLAR PANELS, INVERTERS, GENERATORS)

Table 7: 5 Year MARCS

Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
20.00%	32.00%	19.20%	11.52%	11.52%	5.76%

MACRS 20 YEARS (344/345 - SOLAR PANELS, INVERTERS, GENERATORS)

Table 8: 20 Year MARCS

Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21
3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	2.23%

C. ASSUMPTIONS BY ENTITY

The NWA Framework will incorporate entity-specific values, where appropriate, for inputs into the revenue requirement calculation including property tax expense, state income tax expense, capital structure, cost of debt, equity, and preferred stock, and Energy Efficiency performance incentive levels.

11. REVENUE ESTIMATION MODEL

As part of the NWA Framework, potential revenue streams which can be generated through DER resources can be considered.

A. REGIONAL NETWORK SERVICE (RNS) AND LOCAL NETWORK SERVICE (LNS)[15]:

The RNS Rate is the rate applicable to Regional Network Service to affect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

LNS is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

As part of the NWA Framework and Tool, the RNS and LNS values will <u>not</u> be considered as an input when evaluating NWAs only, due to the following considerations:

a. The total volume of RNS and LNS cost on the transmission system remains the same, any reduction of those costs at one specific utility will result in an uptake of cost with all other utilities. From a regulatory standpoint, this favoring of one customer base over another is in the eyes of the EDCs not conducive to achieving the most cost-effective solution for all ratepayers
b. The Framework and Tool base their cost benefit analysis on the impact on Revenue Requirements, both the LNS and RNS values cannot be realized as an impact on the Revenue Requirements for a specific solution, therefore should not be considered.
c. In the medium and long term, Eversource expects a large-scale uptake of storage on the ISO-NE System. With large quantities of flexible resources, it is to be expected that most, if not all utilities will optimize dispatch against LNS/RNS cost, effectively flattening peak loads. As a result, any benefit that might have been had in the early days will disappear overtime.
d. For BESS, dispatch is solely reserved for managing distribution grid constraints, as such resources need to be held at ready state and can therefore not be used to address these value streams.

B. ISO REGISTRATION MODEL[16][17][18]

DERs have several options for registering with the ISO New England. However, not all options are acceptable/feasible for DERs listed as NWAs as it significantly limits their ability to act on distribution grid needs. The following options are available.

a. **SOG:** A generating unit may register and participate in the wholesale market as a Settlement Only Generator if it has capability of less than five MW connected below transmission per OP-14. A SOG does not participate in the day ahead energy market, participated in the real time energy market but without submitting priced energy offers, thus not dispatched by operations and is not monitored in real time. An SOG can participate in the capacity market, in the regulation market as an alternative technology regulation resource, ATRR, and not in the reserve market.

[15] https://www.iso-ne.com/static-assets/documents/2019/10/transmission_planning_improvements.pdf

[16] https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op14/op14_rto_final.pdf

[17] https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op18/op18_rto_final.pdf

[18] https://www.iso-ne.com/participate/support/glossary-acronyms/

b. **MG:** Modelled Generation is any generating unit participating in the wholesale market whose capability is greater than 5 MW connected at any voltage level or below 5 MW connected to transmission must register as a Modeled Generation. A MG may participate in the day ahead energy market (must if it has a capacity supply obligation from the capacity market), must make priced energy offers in the real time energy market, and have appropriate telemetry per OP-18 so operations can dispatch and monitor output. A MG can participate in the capacity, reserve and regulation markets provided the unit meets applicable technical requirements.
c. **LR:** A Load Reducer is any operating generating unit not registered as a generating unit to participate in the wholesale energy, reserves or regulation markets. A load reducer may participate in the regulation market as an ATRR.

Note: For a DER to be considered as an NWA, the EDC's NWA dispatch always takes precedent over the ISO's dispatch for two reasons:

a. The ISO has a larger pool of resources to draw upon with a statistical assumption of compliance allowing it to address issues with a level of non-response from assets whereas the EDC with its limited NWA resources behind a single constraint relies on the asset's participation.
b. Failure to comply with the EDC's NWA dispatch can result in a localized power system failure resulting in customer outages and the DER being offline for either one purpose.

The NWA Framework therefore applies the following considerations

a. In general, **for all NWA assets**, the preferred mode to register with the ISO is SOG or LR. While registration as MG provides more access to market value streams, it requires strict dispatch schedules and steep penalties for non-compliance of those schedules. With the primary objective of the asset being distribution system reliability and ISO and distribution system needs not always aligning, this would cause a conflict of interest with potentially critical amounts of penalties incurred as the distribution system dispatch would always take precedence. The associated risk with such a participation cannot be modeled precisely and therefore does <u>not</u> lend itself as a reliable revenue stream.
b. In the event that storage is used as a grid resource and while owned by an EDC cannot participate in energy markets, it could be treated as a load reducer. In this case, the Framework looks only at the energy losses in the charging and discharging cycle as the battery would charge at retail and discharge at retail, not being allowed to make any revenue. (all SOG registered storage assets charge and discharge at wholesale cost)

Note: This limits the asset size to 5MW as any assets above this threshold are required to be a MG

C. ISO MARKET PARTICIPATION

In order to estimate any applicable revenue streams from different NWA resources which can be taken into consideration for offsetting revenue requirements to the customer, the NWA Framework assumes the following Table 9 highlighting how each resource type, depending on its registration model, will can participate.

Table 9: Applicable Energy Market Revenue Models by Type of DER

NWA	ISO Registration Model	Day Ahead Energy Markets	Real Time Energy Markets	Forward Capacity Markets
Large Scale Solar DG	SOG	NA	Applies	Applies
	MG	Applies	Applies	Applies
	LR	NA	NA	NA
Large Scale Storage	SOG	NA	Applies	Applies
	MG	Applies	Applies	Applies
	LR	NA	NA	NA
Energy Efficiency	on peak demand	NA	NA	Applies
	seasonal peak demand	NA	NA	Applies
Fuel Cell & CHP	SOG	NA	Applies	Applies
	MG	Applies	Applies	Applies
	LR	NA	NA	NA

Note: Due to limitations on the dispatch of NWA contracted DER, MG is not being considered.

D. ISO MARKET ASSUMPTIONS

The following Chapter provides a brief overview of the markets assumed accessible by the NWA Framework for DERs (excludes markets accessible through MG market participation)

REAL-TIME AND DAY AHEAD MARKET (WHOLESALE ENERGY)

The NWA Framework assumes a levelized wholesale energy price for all transactions and calculations over the financial planning horizon including annual inflation.

For simplicity reasons, the NWA Framework bundles the Real-Time and Day-Ahead Energy Markets into a single wholesale energy value for both MG and SOG registered DERs.

The NWA Framework defaults the levelized wholesale energy price to $40 \frac{\$}{\mathrm{MWh}}$

FORWARD CAPACITY MARKET (FCM)[19]

Due to various policy and market drivers, future supply and demand projections in New England and associated capacity market price formation is continuously evolving. We therefore believe using any forward projection of capacity prices provides a false sense of precision. But for purposes of accounting for some capacity market value, the NWA Framework applies the last FCM clearing price of $2.61 per kW-mo as a forward projection, subject to inflation.

E. DER REVENUE TIMELINES

As outlined early on, the NWA Framework requires DERs participating as NWA's to be under the EDC's dispatch control to ensure reliable operations at any point in time, if they are not EDC owned. During the duration of the NWA contract from the time of the NWA Solution goes live until the deployment of the traditional solution at the end of the deferral horizon, any NWA DERs are assumed to be under EDC dispatch. As a result, they might lose market revenues. This will specifically be the case with storage systems. However, especially for storage assets, DERs can be freed from this responsibility at the point the deferral of the traditional investment is completed. Once the traditional upgrade is in place to no further require NWA services, the battery could be utilized for bulk services.

[19] https://www.iso-ne.com/static-assets/documents/2021/02/20210211_pr_fca15_initial_results.pdf

F. DER REVENUE

The NWA Framework allows consideration of multiple NWA revenue streams. Even with several of the NWA solutions modeled as utility owned and operated, it is assumed that these resources can produce a revenue stream through e.g. generation of electric energy.

SOLAR PV

The NWA Framework allows for the following revenue streams from solar PV resources:

a. **Wholesale Energy Revenue**: Applicable to SOG registered solar plants as well during and after the NWA dispatch, revenue from the wholesale energy market is calculated in the tool using the assumption of an annual generation of

$$\int \left[\varepsilon * \frac{I_{\text{Clear Sky Irr}}(t)}{1000\frac{W}{m^2}} * \lim_{P_{\substack{\max \\ AC}}} \left(P_{\substack{\max \\ DC}} \right) \right] dt \qquad 11.E.01$$

Where kW_{DC} represents the installed DC Panel Power. The Framework assumes a uniform reduction of solar irradiance by ε over the entire year

b. **Net Metering**: Similar to wholesale revenue, the annual generation is calculated and applied to retail prices for net metered assets, which are registered as LR.

c. **State Sponsored Generation Credits**: Applicable depending on the state. To account for government funding of generation sites, the NWA Framework accounts for the presence of a generation credit in $\frac{\$}{kWh}$. The generation credit is applied to the revenue estimation as a cap for what PV solar resources can earn on their energy. Therefore, the additional value generated equals the difference of the generation credit and what was already earned through wholesale energy market revenue.

$$\min_{=0}\left(\$_{\text{Gen Credit}} - \$_{\text{Wholesale Energy}}\right) \qquad 11.E.02$$

d. **Forward Capacity Market Revenue**: Applicable to SOG registered solar plants. Revenue from the forward capacity market is calculated using the default assumption that solar is issued a capacity credit of 18% of the installed AC power.

Note: BTM solar is <u>not</u> attributed any revenue streams in the NWA Framework as the approach provides for the EDC paying a kWh-based subsidy to residents to install solar. Therefore, any revenue streams from the solar installation end up with the customer, and the per kWh payments remain directly impactful on the EDC's revenue requirements.

ENERGY EFFICIENCY[20]

The NWA Framework provides an FCM revenue for Energy Efficiency. Hereby, an Energy Efficiency measure that has been completed can generate FCM revenue for 1 to 25 years (averaging 8 years, given the current measure mix).

a. **Forward Capacity Market Revenue:** Energy Efficiency measures can be registered with the FCM while providing a capacity value for two windows throughout a year
    - April to November (Summer)
    - December to March (Winter)

   The capacity values accounted for in each window are based on one of two methods of calculation
    - On-Peak:

[20] https://www.iso-ne.com/markets-operations/markets/demand-resources/about

i. To calculate the summer on-peak value, the energy efficiency capacity impact on an hourly basis for all non-holiday weekdays from June to August between 1 and 5 pm are added up and divided by the total number of hours.

ii. To calculate the winter on-peak value, the energy efficiency capacity impact on an hourly basis for all non-holiday weekdays from December to January between 5 and 7pm are added up and divided by the total number of hours.

- Seasonal Peak:
  i. To calculate the summer seasonal peak value, the energy efficiency capacity impact is assessed on non-holiday weekdays in hours when the real-time system hourly load is equal to or greater than 90% of the system peak-load forecast during June – August timeframe.

  ii. To calculate the winter seasonal peak value, the energy efficiency capacity impact is assessed on non-holiday weekdays in hours when the real-time system hourly load is equal to or greater than 90% of the system peak-load forecast during December – January timeframe.

DEMAND RESPONSE

Demand Response is not considered for ISO based revenue streams in the NWA Framework.

CONSERVATION VOLTAGE REDUCTION

Conservation Voltage Reduction is not considered for ISO based revenue streams in the NWA Framework.

BATTERY STORAGE

a. **Wholesale Energy Revenue**:

  a. **During NWA Dispatch**

    i. **LR:** An LR Storage charges and discharges at retail rate, which is constant, and can therefore not generate any revenue.

    ii. **SOG:** An SOG Storage charges and discharges at wholesale energy cost. Since the Framework assumes a levelized wholesale energy cost, no value is yielded. Therefore, the Framework assumes an arbitrage value which is defaulted to 40$/MWh. The number of yearly constraint events yields to amount of energy discharged.

    $$\sum_{\text{Events/year}} t * Q_{\text{Discharged}} * \frac{\$_{\text{Arbitrage}}}{\text{MWh}} \qquad 11.E.03$$

  b. **After NWA Dispatch** Applicable SOG, battery storage systems charge at wholesale energy rates, and discharge at wholesale energy rates. Using 11.E.03 the tool provides inputs for assumed annual cycles after the NWA dispatch contract is completed with a default value of 365.

b. **State Sponsored Generation Credits**: Applicable depending on state. To account for government funding of storage sites, the NWA Framework accounts for the presence of a generation credit in $\frac{\$}{\text{kWh}}$. The generation credit is applied to the revenue estimation as a cap for what resources can earn on their energy. Therefore, the additional value generated equals the difference of the generation credit and what was already earned through wholesale energy market revenue.

$$\min_{=0}\left(\$_{\text{Gen Credit}} - \$_{\text{Energy Revenue}}\right) \qquad 11.E.04$$

c. **Forward Capacity Market Revenue**: Applicable for SOG resources after the completion of an NWA contract.

Note: BTM battery installations managed through a utility program will not be considered for additional ISO based revenue streams as any revenue from the assets stays with the customer and the EDC is not acting as a virtual power plant (VPP) but rather has contracts only for the NWA dispatch requirements.

Note: If the Battery is operated as a LR it cannot participate in wholesale energy markets and therefore will charge and discharge at retail rates making it impossible to yield an arbitrage, as those rates are not time dependent. Cost of operating the battery therefore is defined by the energy losses and the retail cost of energy.

FUEL CELL & CHP

As Fuel Cells and CHP are part of targeted energy efficiency programs, any revenue generated through heat or electric generation flows directly to the customer.

EMERGANCY GENERATION

a. **Wholesale Energy Revenue**: The only revenue option assumed for emergency generators is the wholesale value of the energy produced during dispatch. Hence, the total assumed revenue from emergency generation equals

$$\sum_{\text{Events/year}} t * P_{\text{installed}} * \frac{\$_{\text{wholesale}}}{\text{MWh}} \tag{11.E.05}$$