Eversource Energy

Report on
Least Cost Integrated Resource Planning 2020

October 1, 2020

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1 EXECUTIVE SUMMARY

Public Service of New Hampshire d/b/a Eversource Energy ("Eversource" or the "Company") submits this 2020 Least Cost Integrated Resource Plan ("LCIRP") consistent with the requirements of RSA 378:38 and Order Nos. 26,362 (June 3, 2020) and 26,371 (June 22, 2020) in Docket No. DE 19-139.

As a public utility, Eversource has the responsibility to plan, construct and operate an electric distribution system that not only provides safe, reliable, cost effective service to all customers connected to the system today, but also that meets the needs of customers in the future. For today, Eversource is focused on constructing the overhead system in a sturdier, more resilient manner to reduce the frequency of customer interruptions during routine operations. The bulk of the Company's core investments are targeted at overhead equipment and facilities upgrades that will make the distribution system more durable and resilient in major weather events, while also preparing a platform for the integration of advanced technologies that have the potential to produce multiple benefit streams.

For the future, the vision for electric companies is changing rapidly with the development, deployment and application of new technologies that are changing the way the electric system is planned, designed, and operated. For example, distributed energy resource ("DER") technologies that capture the intermittent energy of the sun and wind are deployed in a distributed manner, reducing demand on the electric grid at various hours of the day. However, these technologies also cause power to flow in the reverse direction, i.e., from the customer's premise *into* the electric grid, as opposed to one-way power flowing from a centralized point to customer premises. The existing grid was not designed to accommodate these two-way, reverse power flows. Therefore, with the current design and construction of the system, the ability to integrate advanced energy solutions is limited in many areas. The Company is working to convert the system to a platform that is capable of enabling and interconnecting advanced energy solutions at virtually any point on the system. Upgrading to newer, stronger infrastructure helps build a strong foundation for the distribution system and will aid in the successful integration of higher amounts of advanced energy solutions.

Moreover, DER impacts create operational challenges not only under system intact (N-0) conditions, but also under contingency (N-1) conditions. There are instances in New Hampshire where DERs need to be accommodated through circuit tie closing operations in situations such as of the loss of single ended bulk stations, allowing for reliable integration of these resources through adjacent substation facilities. As a result, it is not just the normal, but also the *abnormal* – contingent conditions of the grid – that drive switching conditions to accommodate DERs, electric vehicles, and similar technologies.

In addition to increasing DER penetration, the changing nature of load is also affecting the grid in other profound, observable ways. For example, increased adoption of electric vehicles is changing the cycles of demand on grid resources; the proliferation of electronic loads is affecting power factor, harmonics and the relationship between voltage and demand; and increasing reliance on electricity by customers looking to charge their devices, heat and cool their homes and power their everyday lives has increased and shifted demand on the grid. The aggregate impact of these trends means that there needs to be a fundamental shift in the expectations and considerations of system planners.

Eversource's System Planning group also needs to consider the time-varying nature of load and DER output, as well as the likelihood of adoption of new load types in the future. Accordingly, the Company's distribution planning scenarios are changing from focusing on a single peak hour of the year to comprehensive time-series analyses of system performance over daily, seasonal and yearly (8760-hour) load cycles. The planning scenarios will incorporate forecasts of not just load growth, but also shifts in technology use, and penetration levels of DER, electric vehicles, and electrification alternatives to burning fossil fuels. Each of these technology trends offers opportunities and challenges to the Company's mission to not only provide reliable electric service but to also find ways to continue to improve upon that level of service.

The recent, and ongoing, experience with the Coronavirus pandemic has also provided a glimpse into a likely future with more people working from home, becoming even more reliant on a reliable, resilient electric distribution system. Although it is impossible to know with precision how long those changes will last or what the ultimate impacts will be, it is clear that a shift has occurred. Utilities must be ready to meet the demands of the shifting landscape, as well as those future challenges that cannot be fully anticipated today. Eversource has developed a new Distribution System Planning Guide that describes how the Company will be planning and designing the distribution system going forward. This guide establishes planning criteria and methods that ensure rational development of a safe, secure, reliable distribution system to support load growth and expansion of new technologies, and to meet the challenges of the future.

The Distribution System Planning Guide also describes how Eversource will make prudent investment decisions in the best interests of customers, considering "non-wires" solutions ("NWS") alongside traditional utility investments while ensuring that the electric distribution infrastructure is maintained and modernized to meet the needs of our customers for decades to come. Eversource has an obligation to incorporate advances in technology, material and construction standards into the design of the electric system to enhance reliability and resiliency. Energy efficiency, demand response, and DER of various types need to be in the tool box of options that utility system planners have at their disposal to develop the most cost-effective solutions to meet the reliability and resiliency needs of the distribution system while maintaining the ability of the utility to operate the system safely.

Eversource is committed to adapting to the evolving needs of the electric system and the customers relying on that system by developing scenario-based planning tools and processes that lead to prudent investment decisions. These tools and processes will improve grid resiliency and reliability during major events, as well as on blue sky days, and allow customers to apply new technologies without degrading the performance of the electric system.

Through this LCIRP submission, Eversource will demonstrate to the Commission how it performs its ongoing (and ever evolving) planning activities to assess the short-term and long-term requirements and capabilities of the electric distribution system. These activities include: probabilistic load and DER forecasting at granular levels incorporating the likelihood of adoption of new technologies; distribution system analysis to assess and predict the performance of distribution circuits and substations; integrated electric system planning to evaluate the interaction with the transmission system, and the myriad (and growing) supply points; demand-side resource planning, including the integration of energy efficiency and other demand-side resources; and incorporation of new methodologies and technologies to create a more modern and responsive grid.

The result of these activities is the development of a least-cost, integrated plan for Eversource's distribution system that demonstrates the data sources and methodologies used by the Company to meet customer needs and expectations. The following sections describe the various planning activities performed by Eversource. The attached appendices include planning studies, load forecasts, reliability planning, joint system planning and demand resource planning, as well as other supporting documentation. This document, together with the appendices, constitute Eversource's least-cost integrated transmission and distribution plan.

2. OVERVIEW OF LCIRP

The Company's distribution business consists primarily of the delivery of electricity to residential, commercial and industrial customers. As of August 31, 2019, Eversource furnished retail franchise electric service to approximately 530,000 retail customers, including approximately 441,450 residential customers, 75,000 commercial customers and 2,735 industrial customers. The Company provides distribution service in 211 cities and towns in New Hampshire, covering a service area of approximately 5,630 square miles. The Company's customer base represents approximately 70 percent of the total electric customers in the State of New Hampshire. The Company also provides wholesale delivery service to the New Hampshire Electric Cooperative, Inc. ("NHEC"), Unitil Energy Systems, Inc. ("UES") and several municipal electric companies.

The Eversource electric system in New Hampshire consists of approximately 1,040 miles of transmission lines, and 12,200 miles of overhead distribution circuits, including approximately 3,000 miles of roadside, three-phase distribution circuits and 600 miles of distribution lines within off-road rights-of-way. The Company also has approximately 1,800 miles of underground distribution lines. Approximately 17 percent of the distribution system is considered backbone and the remaining 83 percent of the system consists of overhead laterals stemming off backbone circuits. The longest, single circuit is 180 miles long and the shortest is just under one-tenth of a mile. Eversource has 139 distribution substations (including shared substations) in New Hampshire, and 184 substation transformers ranging from 1.5 MVA for a small 34-4 kV station to 140 MVA for the largest 345-34.5 kV stations. The Company maintains approximately 244,000 distribution poles on its distribution system and has facilities attached to more than 450,000 poles throughout the state.

Over the past 10 years as emerging technologies have entered the marketplace, Eversource has instituted changes that include organizational restructuring, processes improvements utilized in running the business, and utilization of technology with the sole focus of improving system reliability, system resiliency, operational efficiency and customer service. As stewards of the system, these foundational changes are designed to achieve maximum efficiency in operations and cost while improving the customer experience. Eversource continues to optimize its distribution business operations to capture the benefits of the following critical elements:

a. Implementing an organizational structure focused on operating, constructing and maintaining the system;

b. Making smart investments on the distribution system with technology and infrastructure to improve reliability, resiliency and operational efficiency;

c. Leveraging advanced technologies that promote situational awareness to improve restoration and reduce response time, along with increasing communications both internally and with customers; and

d. Improving planning and scheduling processes to execute the Company's work plan.

Under the Distribution System Planning section of this Plan, Eversource describes how it fulfills its responsibility to provide service that is reliable and resilient to all distribution customers, not only today, but into an uncertain future with increasing penetration of DER and electrification technologies.

The Transmission Planning and Investment section of the Plan describes how Eversource provides transmission service regulated by the Federal Energy Regulatory Commission ("FERC") and administered by ISO-New England ("ISO-NE"). The transmission section provides details regarding transmission planning and investment consistent with ISO-NE's Regional System Plan ("RSP").

The LCIRP also provides insight into energy efficiency and demand side management opportunities provided to Eversource customers; the benefits of grid modernization activities; and reliability improvements undertaken.

The appendices to this LCIRP provide perspective on how the plan will be implemented. Appendix A specifies the requirements applicable to Eversource's Plan. The Appendix refers the reader to the proper sections of the document or provides insight within the appendix. Additional appendices include guides, plans, process flows, and certain reports, as specified in the Plan.

3. TERMINOLOGY AND ACRONYMS

As used in this document, the following terms have the following meanings:

Bulk Distribution Substation – A collection of equipment and transformers used to step the Transmission source voltage (115 kV and higher) down to a Distribution voltage (usually 34.5 kV and below).

Non-bulk Distribution Substation – A collection of equipment and transformers used to step the Distribution source voltage (46 and 34.5 kV) down to a lower Distribution voltage (usually 12.47 kV and 4.16 kV).

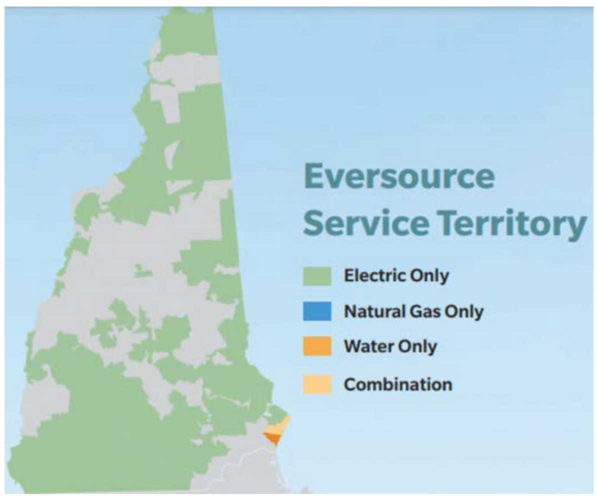
Commonly Used Acronyms

ABR	Automatic Bus Restoral scheme
ADR	Active Demand Response
AMI	Advanced Metering Infrastructure
C&I Customers	Commercial and Industrial Customers
CapEx	Capital Expense
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DES	State of NH's Department of Environmental Services
DG	Distributed Generation
DMS	Distribution Management System
DR	Demand Response
EE	Energy Efficiency
EERS	Energy Efficiency Resource Standard
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation and Service Restoration
GIS	Geographic Information System

IEEE	Institute of Electrical and Electronics Engineers
ISO-NE	Independent System Operator-New England or ISO-New England
LCC	Load Carrying Capability
LCIRP	Least Cost Integrated Resource Plan
LSP	Local System Plan/Planning
LTE	Long Term Emergency rating
NEPOOL	New England Power Pool
NHEC	New Hampshire Electric Cooperative
NWS	Non-Wires Solutions
OpEx	Operations Expense
PAC	Planning Advisory Committee
PTF	Pool Transmission Facilities
PTO	Participating Transmission Owners
PUC/NHPUC	State of New Hampshire Public Utilities Commission
PV	Photovoltaic (Solar)
ROW	Right of Way
RSP	Regional System Plan
SCADA	Supervisory Control and Data Acquisition
STE	Short Term Emergency Rating
TFRAT	Transformer Rating, used historically by legacy PSNH
TO	Transmission Owner
UES	Unitil Energy Systems
VVO	Volt VAr Optimization

4. SYSTEM OVERVIEW

Eversource's New Hampshire distribution system is comprised of 832 distribution circuits generally operating at primary voltages of 4.16, 12.47 and 34.5 kV. The system consists of approximately 12,300 miles of primary overhead facilities and 2,000 miles of primary underground facilities.



Most distribution bulk substations, which are sourced from the Eversource transmission system, supply distribution facilities from transformers which operate at 115 to 34.5 kV. There are three distribution substations that operate with 345 to 34.5 kV transformers, five that operate with 115 to 12.47 kV transformers, and one that operates with a 115 to 4.16 kV transformer.

Eversource has an extensive network of 34.5 kV lines in Rights of Way. These lines provide the sources for 75 distribution substations that serve customers at 12.47 or 4.16 kV. An approximate breakdown of the circuits by voltage is as follows:

- 4.16 kV – 80
- 12.72 kV – 125
- 34.5 kV – 620
  - 34.5 kV in ROW – 125
  - 34.5 kV Taps from Lines in ROW – 450

- 34.5 kV Street-side from Bulk Substations – 45

There are numerous independently owned and operated non-utility generating facilities connected to the Eversource system.

5. DISTRIBUTION SYSTEM PLANNING

The objective of the Eversource distribution planning process is to provide safe, reliable, cost effective electric service to customers. The planning methods and recommended solutions must be capable of adapting to customer expectations for a more resilient and reliable distribution system and accommodating changes in customer behavior regarding behind-the-meter DER, EV charging and other electrification technologies. Where the solution to asset condition, reliability, or capacity needs is determined to be an investment in traditional utility infrastructure, the Company will apply standard equipment and designs whenever possible consistent with the Distribution System Planning Guide.

5.1 Load Forecast

The load forecast is a critical component in the development of system models that are used to conduct distribution planning and identify planning criteria violations and the solution year of need. In 2016, Eversource transitioned from a methodology that relied upon regional historical trends and identified spot loads to a process that incorporated an econometric model and provided a load forecast at the bulk substation level.

The current forecasting process begins by forecasting the peak demand at the Eversource system level. The Eversource system level peak demand is forecasted using an econometric model that evaluates historical peak demand as a function of peak day weather conditions and the economy. The econometric model utilizes two different weather variables in forecasting summer peak demand: a three-day weighted temperature humidity index and cooling degree days. The forecast assumes normal weather conditions, which are based off the most recent 10-year period. Eversource produces a “50/50” and a “90/10” peak demand forecast. The 50/50 forecast is based off normal 10-year weather and has a 50 percent chance of being exceeded. The 90/10 forecast is the extreme weather scenario that has a 10 percent chance of being exceeded. The economic history and forecast are provided by Moody’s Analytics, an international economic consulting company.

Once the Eversource system level forecast is finalized, the bulk substation level forecasts are developed. Each bulk substation is forecasted using an econometric model that evaluates substation historical demand as a function of the Eversource system peak demand history and forecast. The substation econometric models measure how each substation performed relative to the Eversource system and then projects that relationship into the future.

After a trend forecast is produced for each substation, the forecast is adjusted for energy efficiency, DER, large customer projects, or other material changes in load or supply. Company-sponsored energy efficiency and behind-the-meter solar PV are proportionally applied to each substation in proportion to historical peak demand at each substation. Specifically identified large development projects or expected changes in system operations that could not otherwise be predicted by the econometric forecasts are applied to the affected substation. In addition, capacity reserves are held for customer owned co-generation units which hold Standby Delivery Service Contracts.

Figure 1 and Table 1, below, provide the historical peak load as well as the 50/50 and 90/10 forecast using this methodology. Detailed historical and forecasted loads at the regional and substation levels are included in Appendix B and Appendix C, respectively.

Figure 1: Historical Peak Loads and Planning Forecast

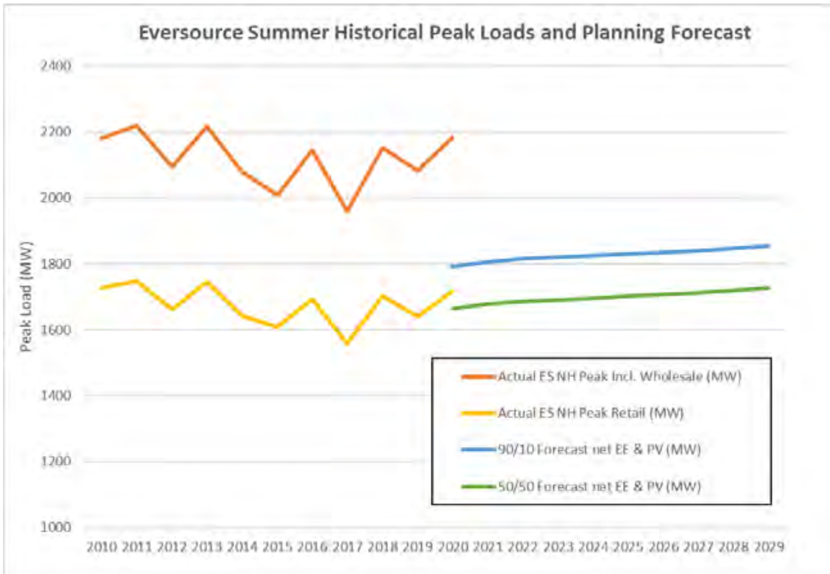


Table 1: Eversource 50/50 and 90/10 Peak and Design Load Forecasts

Year	Eversource New Hampshire	
	Average (50/50) Peak Load (MW)	Peak (90/10) Design Load (MW)
2020	1663	1792
2021	1679	1807
2022	1686	1815
2023	1692	1820
2024	1696	1824
2025	1702	1830
2026	1707	1835
2027	1712	1840
2028	1719	1847
2029	1726	1854

The detailed load forecasting methodology is documented within Section 4.4 of the Distribution System Planning Guide (Appendix D). In addition to the process described above, Eversource will be adding adoption-rate forecasts for specific technologies, such as Electric

Vehicles, Distributed Generation, fossil fuel conversion technologies and other DER, to the forecast model throughout 2020 and 2021. Alongside those forecasts, Eversource will be developing new probabilistic models to account for the uncertainty in those forecasts and to better evaluate alternative technologies such as NWS. These probabilistic adoption-rate forecasts will be developed using a bottoms-up approach and aggregated at the substation level using socio-economic data on a zip-code by zip-code basis.

Through the use of probabilistic adoption-rate forecasts, Eversource is able to conduct scenario-based planning specific to individual bulk substations to ensure reliability at a granular level. In addition to customized scenarios based on locational specifics, two base case scenarios will be developed and applied in each study, as documented in Section 4.5 of the Distribution System Planning Guide:

1. High Load Scenario based on the Peak Gross Load Model
2. High DG Scenario based on the Minimum Gross Load Model

These two base scenarios will especially be applicable in areas with increased distributed generation adoption to better plan for system conditions when generation outpaces load.

5.2 Equipment Ratings

Thermal ratings of the conductors and equipment in the distribution system are identified to determine safe and efficient utilization of distribution system capacity while also protecting the useful life and asset condition of the relevant assets. The most limiting series equipment is identified within each modeled segment when modeling and determining system capacity.

Bulk substation transformers have three ratings: Normal, Long-Term Emergency (LTE), and Short-Term Emergency (STE). Presently, non-bulk substation transformers have only one rating for both continuous and contingency conditions – the Long-Term Emergency (formerly TFRAT). With the publication of the Distribution System Planning Guide, Eversource will be utilizing a Normal, LTE and STE ratings for these transformers as well. The rating process for substation transformers is described in SYSPLAN 008 with conditions specified in the Distribution System Planning Guide.

Line equipment (conductors, regulators, step transformers, switches, etc.) is provided one or two ratings: a nameplate or Normal rating, and an Emergency rating. Ratings for this equipment are presented in the Distribution System Engineering Manual[1]. Protective devices are provided a third rating that reflects the trip setting of the respective device developed by Protection & Control Engineering.

5.3 Bulk Distribution Substations & Associated Interconnected Feeders

Modeling and power flow simulations of the bulk distribution substations and the interconnected 34.5 kV and 12.47 kV distribution systems they supply are currently performed using Siemens PTI PSS/E power flow software. The effects of hot weather conditions on demand and the lower seasonal thermal ratings during summer months present the greatest thermal constraints on Eversource's equipment. Historically, most of Eversource's New Hampshire bulk substations peak in the summer. As a result, a steady-state load flow study is performed at summer peak conditions, with winter peak feeders reviewed as necessary.

The three-phase, balanced distribution model lies under a model of the transmission system created by ISO-New England. The model mimics the actual conditions during their most recent summer peak hour, including substation feeder flows, generation output and device status/configuration. Details of the line impedance, capacitor bank sizes and locations, transformer ratings, etc. are updated as projects are completed and when System Operations announces a configuration change. During the annual model creation, bus loads are scaled to match feeder loading. Bus-by-bus load updates on feeders are performed as needed, with load data originating from the PI historical database. Large customers expecting incremental growth or that account for a significant proportion of the load of a feeder are modeled as a separate bus load. This customer-specific spot load enables forecast study models to capture customer projected growth or maintain a consistent load level year-to-year, allowing the remainder of the substation load to grow at the forecasted level. Sections 4.3 to 4.5 of the Distribution System Planning Guide document the forecasting and model-building process System Planning will adopt going forward.

During Eversource's study process, the interconnected 34.5 kV distribution model is the starting point for forecast model development. System improvements, configuration changes, and known individual customer load adjustments are made. Once all planned projects expected to be

[1] A copy of the Distribution System Engineering Manual was provided to PUC Staff in September 2019. Changes have been made to Section 19 Distributed Generation Policies. A complete, updated Section 19 is included in Appendix E of this filing.

in-service in a particular year are modeled in the base case of that year, the model is then grown so that the bus loads per substation and respective system losses match bulk substation peak forecasted load levels for each year of the study. Non-utility generators are left at their output levels from the base model, but during analysis the largest generator in an area under review is modeled offline. Due to their intermittent nature (river flows and wind patterns), hydroelectric and wind generators are modeled with no output. Section 4.4. of the Distribution System Planning Guide addresses the treatment of PV in the planning models. For future years, System Planning uses the study year model to identify violations and operating constraints, and to develop associated solutions to ensure safe, reliable operation under the loading conditions.

In the future, Eversource will continue to maintain the PSS/E model for joint planning studies and use by System Operations, but almost all planning studies will be performed within Synergi Electric power flow software. Synergi models are generated from multiple internal company databases that provide connectivity, loads, circuit topology, equipment ratings, control types, etc., providing a detailed single-phase (per-phase), unbalanced distribution model of the entire Eversource distribution system. The model development for base study models and simulations are described in detail in the Distribution System Planning Guide. Once the base models are developed, two probabilistic forecasts are to be applied; a peak load driven forecast (low DG impact) and a generation driven minimum load forecast (high DG impact). From this, Eversource then performs its analyses to determine substation and feeder capacity, reliability, and power quality deficiencies.

In both power-flow programs, normal system configuration and all design contingencies are reviewed at the forecasted load levels for each year of the study. System deficiencies identified in accordance with the system design criteria in the Distribution System Planning Guide are documented. The solution options are determined through a detailed solution study and follow the project technical review and approval process presented in the process flow narrative and diagram provided as Appendix F. During this process, various Eversource departments contribute to the development of appropriate cost-effective solution options.

5.4 Non-Bulk Distribution Substations

Non-bulk distribution substation loads are projected by Distribution System Planning based on the forecasts (both Average and Peak) of the respective supply bulk substation. Load projections are based on the recent summer peak and forecasted 10 years, mirroring the time span of the bulk substation forecast available. New customer load that is very likely to appear on the system beyond each non-bulk transformer is identified and added to the non-bulk forecast. This forecasted load is analyzed to ensure load will not exceed the capacity of the transformer. Capacity deficiencies based on the criteria in the Distribution System Planning Guide are identified.

Solutions to the capacity violations are developed through a detailed solution study and follow the project technical review and approval process presented in the process flow narrative and diagram provided as Appendix F. The retirement of 4 kV substations through a voltage conversion to a higher standard distribution voltage is considered when developing the solution alternatives.

5.5 Distribution Circuit Planning

As noted earlier, all 34.5 kV and 12.47 kV distribution feeders that provide a potential path between bulk substations using SCADA controlled devices (i.e. that contribute to the Load Carrying Capability of a substation) are modelled in PSS/E and are reviewed annually by the Distribution System Planning department. The remaining distribution circuits are the responsibility of the Distribution Engineering Department.

5.5.1 Distribution Circuit Load Projections

Distribution Engineering does not prepare load forecasts for every individual distribution circuit. Actual demand on the circuits is highly dependent on the addition or removal of spot loads. Regional field engineers use their local circuit knowledge and historical peak load data collected from equipment on the circuits to identify those circuits where load growth is a concern and conduct analyses as needed based on those projections.

5.5.2 Distribution Circuit Element Loading and Voltage Criteria

Design criteria limits conductor, recloser, and regulator loading to 100% of the normal rating. Step transformers are of significant interest since a failure of such a device would lead to a lengthy outage. Individual assessments are made for step transformers that exceed 100% of nameplate. Peak loading of up to 120% of the nameplate is typically accepted on step transformers installed as a single unit per phase. Step transformers configured with parallel 333 kVA or 500 kVA per phase are limited to 100% to account for differences in impedance and the significant number of customers served.

The primary voltage must be maintained between 97.5% and 105% of the nominal voltage.

5.5.3 Circuit Models

Circuit models are currently created in DistriView using an extract from the GIS to ensure the most recent circuit information. Models are created on an as-needed basis for specific studies. The Field Engineers typically prepare the circuit models for the following reasons:

- To perform coordination studies to improve reliability or when load growth requires changes in the sizes or placement of protective devices.
- In response to potential low voltage conditions identified by an Eversource employee, a Company owned piece of equipment, or a customer voltage concern.
- An element of the circuit has exceeded, or is expected to exceed, its rating.
- A new residential or commercial development or individual customer load addition is proposed which the Field Engineer determines warrants further study.

Eversource is in the process of adopting Synergi as the enterprise distribution circuit modeling tool. New Hampshire is expected to transition from DistriView to Synergi in 2021. Once Synergi is deployed, all primary distribution circuits will be completely modeled in Synergi, as described in the Distribution System Planning Guide.

5.5.4 Distribution Circuit Study Results

Distribution Engineering conducts specific circuit studies to address reliability, voltage concerns, and the addition of customer load throughout the year. Upgrades needed to address protective device coordination, add protective devices or to address voltage regulation are typically inexpensive and time sensitive for the customer. Therefore, upgrades are identified, designed, and completed in a short time frame. Upgrades necessary to serve specific customer load additions are identified, designed and completed based on the customer’s identified need date.

Eversource analyzes a variety of reliability metrics and reports to assess the performance of the distribution system and to identify opportunities for improvement. The annual review of the worst performing circuits and the monthly review of customers experiencing multiple interruptions are just two examples. The Company also conducts program improvements each year. Examples include constructing circuit ties to large radial circuits, adding pole-top SCADA controlled devices to reduce the number of customers impacted by an event and to provide situational awareness to the system operators, and replacing fuses with devices that have reclosing functionality to avoid permanent outages for temporary faults. A report discussing the reliability analyses and improvement efforts is attached as Appendix G.

Each summer, the Distribution Engineering department reviews peak circuit equipment loading to identify violations or predicted violations of the loading criteria. Low cost solutions, such as increasing the size of a step transformer, are identified to be engineered and completed before the following summer. Criteria violations requiring larger investments are reviewed to determine alternatives.

Recommended system enhancements to address circuit loading and/or reliability that are estimated at greater than $100,000 are presented at the Distribution Capital Review (Challenge Session) meeting where the recommended solutions, as well as alternatives, are reviewed by New Hampshire Leadership. The proposed projects generally require less than a year to engineer and construct. Load forecasts at the distribution circuit level are driven by relatively small spot loads that are generally not known with any degree of certainty until months before they are added to the circuit. Therefore, circuit upgrades to address loading are constructed to be put in service at the time of need, thereby allowing the most prudent use of capital investment.

5.6 Distribution System Planning Criteria Revisions

In 2018, Eversource adopted company-wide procedures for the Calculation and Documentation of Bulk Distribution Transformer Ratings (SYSPLAN 008) and the Bulk Distribution Substation Assessment Procedure (SYSPLAN 010). These two procedures superseded elements of the PSNH Distribution System Planning and Design Criteria Guidelines (ED3002).

The most significant change in calculating bulk distribution transformer ratings with the adoption of SYSPLAN 008 was the methodology used to calculate long-term and short-term emergency ratings. The methodology changed from a calculated loss of life method using a 24-hour load curve (referred to as TFRAT by Eversource) to a method that determined the rating by using a constant load for a fixed loading period (i.e. 12 hours summer, 4 hours winter for LTE) while limiting the hottest spot winding temperature to 140 degrees C. Eversource adopted this methodology based on guidance provided in the IEEE standard for IEEE Guide for Loading Mineral-Oil-Immersed Transformers. Section 8.2.1 of C57.91 (2011) includes the following note:

"*Operation at hottest-spot temperatures above 140 °C may cause gassing in the solid insulation and the oil. Gassing may produce a potential risk to the dielectric strength integrity of the transformer or voltage regulator and this risk should be considered when the guide is applied*." The SYSPLAN 008 procedure remains active.

The newly developed Distribution System Planning Guide supersedes SYSPLAN 010 and is attached as Appendix D. This document, rather than SYSPLAN 010 will be the basis for distribution system planning at Eversource going forward. No projects were initiated solely as a result of the adoption of SYSPLAN 010 from 2018 through 2020. The changes to system planning resulting from the adoption of the Distribution System Planning Guide are presented here.

5.6.1 Bulk Transformer Loading (Transmission Level to Distribution Level Voltage)

The peak loading under the normal system configuration (base case) is limited to 95% of the highest nameplate value associated with the transformer's level of cooling. Under ED3002, the transformer peak loading under base case was allowed to exceed the nameplate rating, limited by a long-term emergency rating which was referred to as the TFRAT. This TFRAT value was typically 115% - 150% of the nameplate value. Loading critical equipment such as substation power transformers above their nameplate value under base case conditions is not an acceptable practice because it accelerates aging, potentially leading to premature failure. The 95% of nameplate limitation for bulk substation transformers has been selected as the base case criteria. The uncertainty associated with load forecasting and the penetration and performance of distributed energy resources are related reasons for utilizing the 95% value. This also provides additional capacity under contingency to aid in the restoration of customers and allows for unforeseen delays in executing a solution to a system need.

5.6.2 Non-Bulk Transformer Loading (Distribution Level to Distribution Level Voltage)

The peak loading under base case is limited to 100% of the highest nameplate value associated with the transformer's level of cooling. Under ED 3002, the transformer peak loading under base case was allowed to exceed the nameplate rating as explained above.

5.6.3 Bulk Substation Contingency Planning

An event that results in the loss of any single piece of equipment located within a bulk substation will not result in a permanent outage to customers. The loss of one transformer in a two-transformer substation will utilize an Automatic Bus Restoral (ABR) scheme to restore customers automatically. Under ED3002, the planning criteria allowed the permanent interruption of up to 30 MW for up to 24 hours for a transformer failure. For all of Eversource's electric operating affiliates, the distribution design is such that a single transformer contingency event in a bulk substation does not cause loss of load for customers.

5.6.4 Non-Bulk Substation Contingency Planning

There is no change from the ED3002. The loss of a transformer in a non-bulk substation relies upon a mobile transformer to be installed within 24 hours when adequate circuit ties are not available.

5.7 Incorporating Non-Wires Solutions in the Planning Processes

Eversource understands that the DER technology landscape is ever evolving and that there is the potential for some of these technologies to defer capital investments under the right circumstances. However, a diligent, comprehensive analysis of near- and long-term system needs, as well as solution characteristics, is required to ensure continuity of service quality and reliability while assuring that the most cost-effective solution is applied for the customers.

As discussed in the Distribution System Planning Guide, NWS applicability to a planning problem 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 outlined in the Guide include:

- 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.
- 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.

With an emphasis on finding the most technically and economically viable alternatives, Eversource is currently developing a Non-Wires Solutions Screening Tool ("The NWS Screening Tool") to provide a company-wide standardized methodology for reviewing the feasibility and applicability of a broad spectrum of NWS technologies. Until the NWS Screening Tool goes live in first quarter of 2021 as expected, the criteria and methodologies for NWS evaluation are codified as part of the Eversource standard distribution planning process outlined in the Distribution System Planning Guide and discussed above. The NWS Screening Tool and the underlying considerations described in the Distribution System Planning Guide Section 4.8.3 are part of the solution development process for capital projects. This ensures that traditional capital projects will be screened against NWS opportunities to determine if NWS is a viable alternative. The NWS Screening Tool will aim to evaluate pure NWS or hybrid (traditional + NWS) solutions considering, among other things, the total cost of ownership (CapEx and OpEx), safety, reliability, potential revenue streams from the NWS, and deployment timelines.

Both the standardized Distribution System Planning Guide and the NWS Screening Tool will utilize bulk substation-level ten-year forecasts to determine: when system investment is needed; whether NWS can avoid or defer that investment; the respective cash flow over the planning horizon; and the net present value of savings. Lastly, it is important to note that the NWS Screening Tool and the underlying screening criteria for NWS will not only apply to the capital plan projects but will also apply to DER interconnection projects that would require capital investments.

6. JOINT SYSTEM PLANNING

Eversource participates in an annual joint system planning process with UES and NHEC. UES provided the following description of the Joint Planning Process in its 2016 LCIRP filing and included discussion about its objectives, guidelines and design criteria. Eversource and UES have agreed that this description remains accurate today and, UES has agreed that it is appropriate for Eversource to include in this submission. Eversource's planning process with NHEC is similar to that described for UES.

6.1 Eversource-UES Joint Planning Objectives

The UES 2016 LCIRP Filing states the following:

> The goal of the Joint System Planning between UES and Eversource is to develop the most cost-effective alternatives for the combined UES and Eversource system. Absent this process, UES and Eversource customers may be subject to more expensive system enhancements due to duplication of facilities between UES and Eversource. This process is intended to promote coordinated planning efforts between Unitil and Eversource to develop a single "best for all" plan that potentially affects both companies. The objective is to provide a consistent approach for the planning of safe, reliable, cost effective, and efficient expansion and enhancements to each other's local area systems while meeting regulatory and contractual requirements.
>
> By agreement, this process establishes a Joint Planning Committee of Eversource and UES representatives. This committee meets several times on an annual schedule to bring all parties together to coordinate each company's individual plans. The committee considers the application of consistent planning criteria using agreed upon system data; the total cost of planned additions, including internal costs of each utility; the reliability impact of planned additions and modifications; operational considerations, system losses, and maintenance costs; technical considerations for standardized designs and equipment; and the intent of the wholesale supply contract.

6.2 Guidelines and Design Criteria

The UES 2016 LCIRP Filing states as follows:

Each company uses its own guidelines and design criteria for their own individual planning. For joint planning, utility-specific criteria are applied for planning of Dedicated Use Facilities – those facilities which provide electric service to a single company. The design criteria of the affected system is applied for the planning of Dual Use Facilities – those facilities which provide both retail and wholesale service to more than one company. If there is a discrepancy between design criteria, the companies mutually agree on the solution.

Financial models for comparison of options employ a Net Present Value methodology, identifying capital expenditures on an annual basis. An annual return on equity shall be used in the Net Present Value calculations and is subject to review and agreement by each party annually.

System operating constraints and appropriate methods of evaluation are employed to determine preferred options. This includes but not be limited to: operation and maintenance costs, system losses, environment, reliability, and power quality. These criteria are mutually agreed upon.

Technical preference is often considered when evaluating alternatives. Technical preferences may include standard versus non-standard design. It may also refer to concerns such as age and condition of facilities, availability of spare parts, ease of maintenance, ability to accommodate future expansion, or ability to implement. These criteria are mutually agreed upon.

6.3 Joint Planning Report

A joint planning report documents the contingency evaluation, system improvement options, and additional items that were discussed during the joint effort of the two affected utilities. The Eversource/UES 2020 Joint Planning Report is attached as Appendix H. The Eversource/NHEC 2020 Joint Planning Report is attached as Appendix I.

7. TRANSMISSION PLANNING AND INVESTMENT

7.1 Regional Transmission System Planning

Ten-year transmission system planning is performed to develop a regionally coordinated plan to reliably meet customer demands for electricity in addition to supporting the delivery of power across the region. New Hampshire transmission facilities are needed for reliability and to support the expansion of the New Hampshire economy. As noted by the Commission in Order No. 25,459 (January 29, 2013), Eversource's transmission requirements are considered within the purview of the ISO-NE regional transmission planning process. Eversource actively participates in the development of the ISO-NE Regional System Plan (RSP).

The regional transmission system planning process is performed in compliance with applicable planning standards of the North American Electric Reliability Corporation and the Northeast Power Coordinating Council Inc. The Federal Energy Regulatory Commission (FERC) has given authority to ISO-NE to operate and perform regional system planning of the transmission system in New England. The ISO-NE regional transmission planning process for the New England pool transmission facilities (PTF) is performed in accordance with the ISO-NE Transmission, Markets, and Services Tariff (ISO-NE Tariff) Attachment K. This planning process is coordinated with transmission-owning entities, other entities interconnected to the New England transmission system, and the owners and planning authorities of neighboring systems to ensure the reliability of the New England transmission system and ensure compliance with national and regional planning standards and criteria. As described in Appendix 1 to Attachment K of the ISO-NE Tariff - Local System Planning Process, the Participating Transmission Owners (PTOs) are responsible for the Local System Planning (LSP) process for the Non-PTF of the New England Transmission System.

As part of the regional planning process, stakeholder input is provided to ISO-NE by the Planning Advisory Committee (PAC). Specifically, the PAC reviews and provides input on: (i) the development of the RSP; (ii) assumptions for studies; (iii) the results of Needs Assessments and Solutions Studies; and (iv) potential market responses to the needs identified by ISO-NE in a Needs Assessment or the RSP. ISO-NE and New England Transmission Owners (TOs) conduct periodic assessment studies (Needs Assessments) of the New England transmission system. These assessments are performed to identify system needs over a long-term planning horizon. ISO-NE incorporates market responses, including utility-scale generation, distributed generation, and energy efficiency, as the first step in meeting needs identified in the Needs Assessments. If market responses do not eliminate or address the needs identified in Needs Assessments, ISO-NE develops and evaluates regulated transmission solutions in response to the needs identified by ISO-NE.

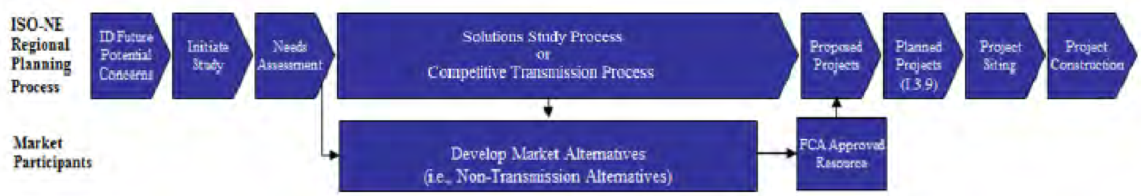
When a system reliability need is identified from a Needs Assessment, ISO-NE begins a process to address the need. Starting May 18, 2015, ISO-NE decides whether it must conduct a competitive process to determine the transmission solution. This process is used if the reliability problem is not expected to materialize within three years of the date of completion of the Needs Assessment and any qualified developer, including incumbent providers such as Eversource, can participate. If the reliability problem is expected to materialize within three years, ISO-NE and the TO(s) affected by the reliability problem develop transmission system alternatives to resolve the reliability need and ensure compliance with the national and regional reliability standards. No matter which process is used, the transmission system alternatives are evaluated by ISO-NE and presented to PAC. In all cases, transmission system solution options are further evaluated to determine their feasibility of construction, potential for environmental impacts, estimated costs, longevity, operational differences, etc. When analysis of the options is complete, ISO-NE recommends a proposed transmission project to the PAC.

The centerpiece of the regional planning process is the development of the RSP. The RSP is typically published on a biennial basis and contains the assumptions, methods and needs for the New England regional transmission system. ISO-NE develops the RSP for approval by the ISO Board of Directors following stakeholder input through PAC. The RSP also provides information on a broad variety of power system requirements that serve as inputs for assessing the reliability of the New England transmission system, reviewing the design of the markets, and assessing the overall economic performance of the system. The RSP also describes the coordination of ISO-NE's regional system plans with regional, local, and inter-area planning activities.

ISO-NE also develops, maintains and posts on its website cumulative lists reflecting the regulated transmission solutions selected by ISO-NE to meet reliability needs identified in response to Needs Assessments (RSP Project List). The RSP Project List is a cumulative representation of the regional transmission planning expansion efforts ongoing in New England. The project listing is periodically updated by ISO-NE to follow the progression of a project, from the initial selection of a project by ISO-NE, through construction, and until a project is placed in-service. The planned project status changes when the project is under construction. ISO-NE maintains a similar list (the Asset Condition List) reflecting projects developed by the TOs to address asset condition issues identified by the TOs on their existing transmission facilities.

Another part of the stakeholder process is the review of project plans by the New England Power Pool (NEPOOL). Once the preferred transmission solution has been reviewed by PAC, the project is then analyzed in accordance with section I.3.9 of the ISO-NE Tariff. The project sponsor performs detailed engineering and power flow analyses that is the basis of a Proposed Plan Application (PPA) that is submitted to ISO-NE for review by NEPOOL and final approval by ISO-NE. This review is needed to ensure that a preferred project will have a no significant adverse effect on the stability, reliability, or operating characteristics of the TO's transmission facilities, the transmission facilities of another TO, or the system of a Market Participant in New England.

The transmission planning process is shown below.



ISO-NE Transmission Planning Process

To comply with applicable regulatory requirements, Eversource's local transmission planning process employs methodologies similar to the ISO-NE regional planning process. The consideration and evaluation of multiple alternatives to address local reliability needs and the final development of a recommended local system plan are coordinated with ISO-NE as part of the overall regional planning process and the development of the annual ISO-NE RSP. This information is identified in the Eversource Local System Plan (LSP) as presented to PAC on an annual basis.

7.2 New Hampshire Transmission Planning

The New Hampshire transmission plan is discussed in detail at the following web site:

https://www.iso-ne.com/system-planning/key-study-areas/vt-nh/

The RSP notes that ISO-NE is taking action to address transmission system reliability issues in all six New England states and has developed preferred solutions to serve customer needs. A number of studies of the New Hampshire system have been conducted. Most recently, ISO-NE completed the New Hampshire 2029 Needs Assessment, and the companion New Hampshire 2029 Solutions Study is underway. This study has identified the need for 115 kV transmission support in the central and western portions of the State and 345 kV or 115 kV transmission support in the southern portion of the State.

Because Eversource's transmission requirements are within the purview of ISO-NE, the RSP should be consulted for a complete understanding of the New England transmission planning process.

8. RELIABILITY PERFORMANCE

For Eversource, reliability performance is more than a key performance indicator. Eversource embeds reliability performance and analysis into all of its operations for the direct, long-term benefit of customers. Eversource views that customer demands for an increasing level of reliability are important and reflect a change in how customers rely on electric service for their daily lives. Reliability performance is the focus of daily conference calls for both the Operations and Engineering organizations. Analyses of outage causes, number of customers affected, frequency, and duration are the cornerstone of distribution project proposals and investments.

The distribution system is inherently vulnerable to adverse weather conditions and customers are becoming increasingly reliant on uninterrupted electric service. The Reliability Enhancement Program, integration of Geographical Information and Outage Management Systems, and extensive expansion of Distribution Automation have advanced the capabilities of the Eversource system and built resiliency on behalf of its customers. Eversource's construction standards have also been updated over recent years to reinforce the distribution system, hardening it against such adverse conditions. Eversource's standards now specify Class 2 poles, covered wire, composite crossarms, and more.

Engineering and Operations Teams continually investigate options to maintain and improve reliability performance and resiliency. In addition to the Distribution Planning and Smart Grid discussions in Sections 5 and 10, additional details about Eversource's reliability performance and its programs are included in Appendix G.

In addition, the fundamental purpose and design of the Company's distribution planning and investment plan is to establish the foundation for enhanced reliability, resilience, operational efficiency and the incorporation of grid-modernization investments, which is a necessary precursor to grid modernization. This was acknowledged in Commission Order No. 25,877 (April 1, 2016) in Docket No. IR 15-296, where the Commission stated that it expects the benefits of grid modernization to include the improving the reliability, resiliency, and operational efficiency of the grid; reducing generation, transmission, and distribution costs; empowering customers to use electricity more efficiently and to lower their electricity bills; and facilitating the integration of distributed energy resources.

The Company's grid modernization plan will encompass some of the same objectives of the Commission (i.e., reliability, resiliency and operational efficiency), but will also encompass the steps necessary to allow for the integration of DER. Advanced energy solutions may be defined as technologies, both established and emerging, that are and will deliver a clean, secure, and affordable energy system for the future. Existing examples of these are DER (solar, wind, fuel cells, etc.) and energy storage devices. Future technology advances are expected to introduce new devices, not yet conceived. Among other challenges involved in installing these technologies to the distribution system, the integration of these technologies creates an urgent need for more granular visibility and monitoring of the distribution system on a near-time and real-time basis. Successful integration of these technologies requires continued focus on the condition and integrity of the distribution system.

9. DISTRIBUTED ENERGY RESOURCES INTERCONNECTIONS

DER Planning manages the interconnection to Eversource's distribution system of: (1) Eversource-owned generation and storage; (2) customer-owned generation and storage (behind a retail meter); and (3) independently owned generation and storage (i.e., merchant generators). All requests to interconnect generation follow an application review process administered by the DER Planning group, which is part of the Eversource engineering organization.

Eversource-owned generation and storage are subject to the same interconnection requirements as independently owned resources. These resources could be used to defer capital investments, are directly under the control of Eversource system operations, and would be evaluated along with other potential non-wires solutions to deliver the lowest cost solution with the greatest electric system benefit.

Customer-owned generation consists of small-scale renewables, such as solar photovoltaic (PV) and wind, as well as a few natural gas, methane gas, and biomass fueled generation and co-generation units. There has been a modest but growing amount of customer-owned solar installed in Eversource's New Hampshire territory. These resources primarily participate in the net metering program in accordance with the Commission's Puc 900 rules. The small scale and intermittent nature of these systems results in a minimal impact to the planning process. The treatment of behind-the-meter resources in the Eversource load forecast is described in the Distribution System Planning Guide (Appendix D). A summary of net-metered generation is provided to the Commission each month in the form of the US Department of Energy form EIA-826.

Independently owned merchant generation interconnections to the distribution system primarily consist of hydro, landfill gas, biomass, and wind generation. In recent years, the majority of applications for interconnection have been proposals for large-scale solar generation.

Eversource DER Planning, in conjunction with ISO-NE, is currently processing a number of interconnection requests from large-scale merchant solar developers. These projects range in size from 10 MW to 20 MW. Eversource cannot be certain which, if any, of these resources will ultimately achieve commercial operation status.

DER impact is accounted for in the distribution planning process in several ways as described in the Distribution System Planning Guide, from inclusion in the forecast model, to representation in Synergi simulations, to consideration as mitigation options in NWS.

10. SMART GRID

Eversource recognizes that the future economic well-being of New Hampshire will continue to be fostered by a resilient, modern and integrated grid. Eversource's customers expect to take service from an electric grid that is resilient and reliable, allows for more options to reduce energy costs and enable opportunities to explore emerging customer-side energy solutions like solar, storage and electric vehicles. Smart grid technologies have the potential to transform the grid into a customer-centric platform that enables a cleaner energy future while continuously improving the safety, security, reliability, resiliency and cost effectiveness of the electric power system in New Hampshire. Smart grid technologies and associated programs can be assessed in three categories: visibility, automation and optimization. The costs of smart grid technologies and programs will vary based on the nature and extent of the programs. The associated benefits, in terms of improved reliability and resiliency and support for clean energy objectives, can be characterized based on specific investment types within the three smart grid categories. Appendix J details the benefits associated with specific smart grid investment types.

11. DEMAND SIDE ENERGY MANAGEMENT PROGRAMS

Eversource is recognized as a national leader in providing comprehensive energy efficiency programs to our customers. The Company places a strong emphasis on planning and executing on impactful and cost-effective energy efficiency programs. Eversource continuously evaluates programs and collaborates with regulators, stakeholders, vendors and customers to improve energy efficiency offerings and is committed to continued efforts towards achieving all-cost effective efficiency.

In New Hampshire, Eversource has been providing energy efficiency services for more than 20 years. Since 2002, Eversource has collaborated with the other New Hampshire utilities to deliver coordinated energy efficiency solutions to customers, residential, municipal, commercial and industrial throughout the state. These innovative and cost-effective programs are offered under the NHSaves™ Programs ("NHSaves Programs") brand. In 2016, Eversource was a party to a settlement agreement filed with the Commission that lead to establishment of the state's Energy Efficiency Resource Standard ("EERS"). The EERS is the framework within which the NHSaves Programs have been implemented since 2018. Under the EERS framework, Eversource and the other New Hampshire utilities are required to file triennial plans, to pursue annual savings goals, and to work toward the long-term objective of achieving all cost-effective energy efficiency. Eversource participates fully in all stakeholder discussions related to energy efficiency program planning, in quarterly reporting and quarterly meetings on program results, and annual reporting. The programs are audited yearly by the Commission's Audit Division.

Under the EERS, Eversource has increased energy savings from energy efficiency each year. The next triennial plan, if approved by the Commission, will continue the trajectory of increased energy savings.

Energy Savings as a Percent of Sales Under EERS

Year	2018 Actual	2019 Actual	2020 Planned	2021 Filed	2022 Filed	2023 Filed
Energy Savings as a % of 2014 sales	0.97%	1.18%	1.35%	N/A	N/A	N/A
Energy Savings as a % of 2019 sales	0.99%	1.21%	1.39%	1.44%	1.70%	2.09%

11.1 Energy Efficiency Program Offerings

From 2002 to 2019, Eversource electric customers have saved over 12.7 billion lifetime kilowatt-hours. When compared to average retail prices, this translates into customer cost savings of more than $1.8 billion. The energy efficiency programs are designed to achieve cost-effective energy savings and provide accessible avenues to participation for a wide variety of customer types and needs.

11.1.1 Commercial, Industrial and Municipal Programs

Small Business Energy Solutions Program. This retrofit and new equipment and construction initiative offers technical expertise and incentives to small business customers who lack the dedicated staff, time, or resources to address energy costs.

Municipal Program. This energy efficiency solution provides technical assistance and incentives to municipalities and school districts to help them identify energy-saving opportunities and implement projects.

Large Business Energy Solutions (Retrofit and New Equipment & Construction) Program. The program offers technical services and incentives to assist large C&I customers who are retrofitting existing facilities or equipment, adding or replacing equipment that is at the end of its useful life, or constructing new facilities or additions.

Large Business Energy Rewards RFP ("Energy Rewards") Program. The Energy Rewards program encourages customers to propose energy efficiency projects through a competitive solicitation process.

11.1.2 Residential Programs

ENERGY STAR Homes Program. This residential single-family and multifamily new construction program provides incentives and contractor support through two pathways: (1) Drive to ENERGY STAR and (2) ENERGY STAR 3.1.

ENERGY STAR Products Program. This high-volume program with broad reach is designed to help residential customers overcome the extra expense of purchasing and installing ENERGY STAR-certified appliances, electronics, HVAC equipment and systems, hot water-saving equipment, and lighting.

Home Energy Assistance Program. The program serves New Hampshire's income-eligible homeowners and renters to help reduce their energy costs, optimize their home's energy performance, and make their homes safer, healthier, and more comfortable.

Home Performance with ENERGY STAR. This energy efficiency solution provides comprehensive energy-saving services at significantly reduced cost to customers' existing homes, and covers lighting improvements, space heating and hot water equipment upgrades, weatherization measures, and appliance replacements.

11.2 Impact of Eversource Energy Efficiency Programs on Energy Consumption

The table below summarizes Eversource's actual expenditures, lifetime kilowatt-hour savings, annual kilowatt-hour savings and customer participation during the 2019 program year by customer sector and program. Based on the 2019 results, Eversource saved kilowatt-hours at an average cost of 3.33 cents per lifetime kilowatt-hour as compared to the June 2019 average retail price per kilowatt-hour of $16.88 cents[2].

[2] US Energy Information Administration, Electric Power Monthly, Table 5.6.A. Average Price of Electricity to Ultimate Customers by End-Use Sector, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a

Eversource 2019 Energy Efficiency Program Results

2019 Eversource Energy	**Expenditures (in $000s)**	**Annual kWh Savings**	**Lifetime kWh Savings**	**Customer Participation**
Residential Programs				
Home Energy Assistance	$ 7,295.4	1,371,331	17,245,196	1,220
Energy Star Homes	$ 1,259.2	894,233	19,612,979	402
Home Performance with Energy Star	$ 2,869.8	736,533	12,816,238	1,224
Energy Star Products	$ 4,148.9	14,715,501	104,823,377	199,274
Home Energy Reports	$ 722.3	4,420,562	12,124,554	79,120
Customer Engagement Platform	$ 193.1	-	-	
ISO-NE Forward Capacity Market	$ 12.5	-	-	
Subtotal Residential	$ 16,501.3	22,138,159	166,622,345	281,240
Commercial/Industrial Programs				
Large Business Energy Solutions	$ 9,179.3	40,199,700	27,741,168	493
Small Business Energy Solutions	$ 6,674.6	23,655,091	09,379,852	753
Municipal Energy Solutions	$ 1,304.5	3,365,248	44,033,687	127
C&I Customer Partnerships	$ 17.2	-	-	-
Energy Rewards RFP Program	$ 528.2	3,625,832	2,201,712	8
Customer Engagement Platform	$ 289.9	-	-	-
Education	$ 277.5	-	-	-
ISO-NE Forward Capacity Market	$ 29.3	-	-	-
Large Business DR Initiative	$ 332.1			
Subtotal C&I	$ 18,632.5	70,845,870	923,356,419	1,381
Smart Start	$ 24.5			
Total	**$ 35,158.2**	**92,984,030**	**1,089,978,764**	**282,621**

11.3 Impact of Eversource Energy Efficiency Programs on Capacity or Peak Reduction

In addition to kilowatt-hour energy savings, Eversource's programs also provide capacity or peak demand reductions. Installation of energy efficiency measures to reduce kilowatt-hours typically also result in a reduction of kilowatts coincident with the New England Peak. Such peak demand reductions can be referred to as "passive" demand reduction because they occur as a secondary result of the energy efficiency measure.

Eversource 2019 kW Savings from Energy Efficiency Measures

2019 Eversource Energy	Summer kW	Winter kW
Residential Programs		
Home Energy Assistance	145.7	322.0
Energy Star Homes	197.3	110.3
Home Performance with Energy Star	151.4	75.6
Energy Star Products	1,800.5	3,962.2
Home Energy Reports	368.4	504.6
Subtotal Residential	2,663.3	4,974.7
Commercial/Industrial Programs		
Large Business Energy Solutions	4,495.1	4,586.3
Small Business Energy Solutions	3,653.7	3,188.4
Municipal Energy Solutions	421.9	367.0
Energy Rewards RFP Program	349.4	238.7
Subtotal C&I	8,920.0	8,380.4
Total	**11,583.31**	**13,355.08**

In 2019 and 2020, Eversource began offering a pilot Active Demand Response ("ADR") Initiative through the energy efficiency programs. The goals of ADR programs are to flatten peak loads, improve system load factors, and reduce long-term system costs for all grid-tied New Hampshire customers. Active Demand savings (kW) are realized by dispatching resources during the ISO-NE peak demand period. Reducing load during ISO-NE peak hours also has the effect of reducing New Hampshire's share of the installed capacity ("ICAP") cost allocation. Successful pilot results and evaluation information have led Eversource to propose moving ADR from a pilot phase to a full program in the 2021-2023 Term.

Eversource 2019 and 2020 ADR Pilot

Eversource Energy	2019 Actual Active kW*	2020 Planned Active kW
Residential		
Wi-Fi Thermostat Direct Load Control	N/A	500
Battery Storage	N/A	100
Subtotal Residential	N/A	600
Commercial/Industrial Programs		
C&I Interruptible Load Curtailment	3,933	6,500
Subtotal C&I	3,933	6,500
Total	**3,933**	**7,100**
* Because 2019 is a pilot offering Eversource did not claim Active kW savings as part of the Energy Efficiency Program performance incentive calculation.		

11.4 Demand Side Energy Management and Non-Wires Solutions

Demand side energy management such as energy efficiency and active demand reduction can contribute to non-wires solutions in particular locations. There are two avenues for incorporating efficiency and ADR in a non-wires effort. The first would be to utilize existing energy efficiency and demand reduction program offerings and market them in a targeted way to the area of desired impact. Expected energy reductions as a result of the offerings would depend on the types of customers in the location, the potential for reduction at those customer sites, and the willingness of those customers to engage with the energy efficiency or ADR program to achieve savings. The existing energy efficiency and ADR offerings are already designed and approved as part of the Company's cost-effective program offerings.

The second avenue for incorporating efficiency and ADR in a NWS would be to design a set of specific offerings for the particular location of interest, rather than relying on existing programs. New or modified offerings could potentially incorporate higher incentives levels to increase the likelihood of customer participation or otherwise be targeted to the particular needs of the customers in the area of desired impact. If these new or modified offerings did not meet the existing energy efficiency program parameters, additional benefit-cost testing and/or funding sources may be needed. The overall potential for usage reduction in the location would still be depended on the customer mix, the potential for reduction at individual customer sites and the willingness of the customers to participate and achieve energy reductions.

Review of locations for potential inclusion of energy efficiency and ADR measures as part of a NWS should take into account the following factors:

- Number of residential, commercial, industrial and residential space heating customers in the area.
- The relative demand from each customer segment.
- The potential for energy use reductions within each customer segment and the potential for energy use reductions from individual higher-use customer sites.
- How many customers from each segment have already participated in energy efficiency or ADR programs.
- Which higher-use customers have already participated in energy efficiency or ADR programs.

As part of its planning process outlined in the Distribution System Planning Guide, Eversource has incorporated energy efficiency and active demand response in the range of possible solutions for resolving bulk station capacity violations. The enhanced probabilistic forecast methodology will, in the future, also include the trend in EE growth by substation area, projected down to a granular level. In addition, the NWS Screening Tool includes an assessment of both the technical and financial viability of EE and ADR for reducing violations.

12. CONCLUSION

In Eversource's view, the approaches to planning laid out in this submission reflect a prudent balance of traditional investments alongside the application of advanced tools and techniques to integrate and support a more dynamic and distributed electric grid. As an example of advanced tools and techniques, the Company is working to develop a Non-Wires Solution Screening Tool, which will be integral to developing and applying alternative, non-traditional solutions at the lowest reasonable cost to our customers, while protecting and enhancing the safe, secure and reliable operation of the Eversource electric system. This tool and many others will be continually adapted to help Eversource meet future challenges.

Considering the new and rapidly evolving demands being placed on modern electric systems, System Planning must adapt to keep pace with customer needs and to anticipate changes in technology and customer expectations. Eversource has taken steps, as demonstrated in this LCIRP and the attached Distribution System Planning Guide, to analyze, understand, and plan for these future challenges while providing required system performance and reliability. In Eversource's assessment, this submission is consistent with the requirements of the New Hampshire statutes governing the scope and purpose of the LCIRP, as well as Commission directives.

APPENDICES

APPENDICES

COMPLIANCE WITH LCIRP REQUIREMENTS

Eversource has committed to meeting the objectives of the LCIRP filing by addressing both statutory requirements and commitments made in prior LCIRP filings.

1. STATUTORY ITEMS

The following requirements are set in RSA 378:38. Eversource has described below how each requirement is addressed and/or where additional discussion is located within the filing.

I. A forecast of future demand for the utility's service area.

This forecast is addressed in Section 5 of this filing.

II. An assessment of demand-side energy management programs, including conservation, efficiency, and load management programs.

This assessment is addressed in Section 11 of this filing.

III. An assessment of supply options including owned capacity, market procurements, renewable energy, and distributed energy resources.

To the extent Eversource provides energy supply to its customers through its default Energy Service, Eversource does so by soliciting that supply through RFPs to wholesale market participants. Following the completion of divestiture in 2018, Eversource has no owned capacity.

With respect to renewable energy and distributed energy resources, Eversource accommodates the development of such projects and installations by customers as part of its distribution system planning process as described in Section 5 of this filing. Eversource does not own or operate such facilities in New Hampshire, and does not dictate or prescribe their development.[1] Nevertheless, Eversource expects the development of such facilities to continue and expand in New Hampshire and, consistent with Section 10, will continue to plan for a system that can accommodate such development.

IV. An assessment of distribution and transmission requirements, including an assessment of the benefits and costs of "smart grid" technologies, and the institution or extension of electric utility programs designed to ensure a more reliable and resilient grid to prevent or minimize power outages, including but not limited to, infrastructure automation and technologies.

This assessment is addressed in Section 10 of this filing.

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[1] In 2019, Eversource did file with the Commission a petition relating to the development of an Eversource-owned battery storage project. *See* Docket No. DE 19-133. On February 28, 2020, that project proposal was withdrawn, without prejudice, following discussions with the Commission Staff and others. At present, there are no proposals for Eversource to own or develop distributed energy resources.

V. An assessment of plan integration and impact on state compliance with the Clean Air Act of 1990, as amended, and other environmental laws that may impact a utility's assets or customers.

Pursuant to RSA 378:38, V, an LCIRP is to include, if applicable, "*an assessment of plan integration and impact on state compliance with the Clean Air Act of 1990, as amended, and other environmental laws that may impact a utility's assets or customers*." Following the restructuring of the electric industry, and the completion of Eversource's divestiture of generating assets in 2018, Eversource no longer owns generation, and therefore is not subject to Section 112 compliance requirements of the Clean Air Act on electric generating facilities (i.e., "stationary sources").

Moreover, to the degree that Eversource provides default Energy Service to customers, it does so through RFPs for electricity supply which is provided from the wholesale market. In the ISO-NE area, the wholesale market for electric generation is presently dominated by natural gas, but that resource mix is continuing a shift toward less carbon-intensive sources. The electricity supply mix for Eversource's customers is consistent with the regional resource mix and Eversource anticipates that the supply mix will continue to shift away from carbon-intensive sources driven by states\ and regional policy goals.

VI. An assessment of the plan's long- and short-term environmental, economic, and energy price and supply impact on the state.

Pursuant to RSA 378:38, VI, an LCIRP is to include, if applicable, "*An assessment of the plan's long- and short-term environmental, economic, and energy price and supply impact on the state*." In that Eversource does not have any owned capacity and does not currently have distributed energy resources under development, the direct impact on energy price or supply in the State from Eversource's planning is limited.

Previously, with the attempted development of the Northern Pass Transmission project, Eversource (through its affiliate companies) envisioned potential impacts on the environmental, economic, and energy price and supply. With the termination of that proposed project, Eversource's plans pertaining to the development of its distribution and transmission facilities does not have a direct impact on energy price and supply in New Hampshire.

As part of its new distribution planning process documented in the Distribution System Planning Guide, Eversource will seek to incorporate NWS where economically and technically feasible into its solution portfolio, which has the potential to support environmental goals in the State.

VII. An assessment of plan integration and consistency with the state energy strategy under RSA 4-E:1.

This assessment is addressed throughout this filing. Pursuant to RSA 4-E:1, "*the Office of Strategic Initiatives, in consultation with the state energy advisory council established in RSA 4-E:2, with assistance from an independent consultant and with input from the public and interested parties, shall prepare a 10-year energy strategy for the state*." The most recent version of the State Energy Strategy was released by the Office of Strategic Initiatives in 2018.[2] As noted in that version of the Strategy, its purpose is to highlight various "*policy goals. . . that will steer the development and evolution of energy policies*" in New Hampshire. 2018 State Energy Strategy at 5**.**

Some of the goals outlined in the Strategy are largely policy decisions belonging to State leaders rather than matters to be solely managed within the planning or operation of the electric distribution system. However, among the goals described in the 2018 Strategy, perhaps the first five are the most relevant to the considerations in this document. Specifically, they are:

1. Prioritize cost-effective energy policies.
2. Ensure a secure, reliable, and resilient energy system.
3. Adopt all-resource energy strategies and minimize government barriers to innovation.
4. Maximize cost-effective energy savings.
5. Achieve environmental protection that is cost-effective and enables economic growth.

2018 State Energy Strategy at 12.

Through its planning functions and the forward-looking analyses, including those relating to planning for energy efficiency and grid modernization, as described in Sections 5, 10 and 11 of this document, Eversource is ensuring that we will continue to provide a reliable and resilient electric system now and in the future. That system will be capable of enabling the State's energy strategy, and will be better positioned to integrate demand response, energy efficiency, and DER – all of which will, collectively, help maximize energy savings while supporting environmental goals.

Further, as the State has adopted an "all-resource" strategy, Eversource must build and operate a system capable of accommodating large and small generation sources, as well as traditional "base load" sources alongside intermittent output from solar and wind resources. Using its new Distribution System Planning Guide, discussed in Section 5 and included in Appendix D, Eversource is committed to planning and designing a system capable of safely integrating all such resources, while

[2] The State Energy Strategy is available here: https://www.nh.gov/osi/energy/programs/documents/2018-10-year-state-energy-strategy.pdf.

incorporating, where appropriate, non-wires solutions to help lower energy costs while meeting performance goals.

Viewed as a whole, and through the issues identified in the sections above, Eversource's LCIRP is consistent with the State Energy Strategy.

2. SETTLEMENT AGREEMENT IN DOCKET NO. DE 19-139

Non-Wires Solutions (NWS)

Among the elements of the Settlement Agreement in Docket No. DE 19-139 pertaining to Eversource's prior LCIRP filing is the following:

Assessment of Demand Side Management Programs. *Consistent with RSA 378:38, II, an assessment of demand side energy management programs, including the potential of such programs to defer or avoid the need for capacity-related investments. The Company will provide in its initial LCIRP filing a list planned capital projects that may be candidates for avoidance and/or deferral through deployment of non-wire solutions (NWS) ("NWS candidates"), a detailed analysis of the non-wire potential of one chosen candidate, and further details on how NWS are incorporated into utility planning.*

NWS Candidates. *The list of NWS candidates provided in Eversource's LCIRP will identify capacity-related distribution infrastructure investments that may be candidates for: (1) deferral or avoidance via deployment of non-wires solutions (NWS); or, (2) a combined deployment of NWS paired with a traditional system solution. Specifically, Eversource will identify projects that: (1) are capacity-related; (2) require no more than 30MW of peak load relief within seven years of the LCIRP filing; (3) have a projected cost of at least $1 million; and (4) and have a planned in-service date at least 3 years after the date of the 2020 LCIRP filing.*

Detailed NWS Potential Analysis. *Prior to the filing of the LCIRP, and once the NWS candidates are initially identified by the Eversource, the Company agrees to meet with the Settling Parties to identify an NWS candidate that should be the focus of a more detailed analysis provided within the LCIRP filing. This analysis of NWS should consider utility system benefits other than avoided distribution capacity costs and include, but not be limited to, avoided energy and transmission costs. The analysis shall include an evaluation of the demand reduction potential associated with energy efficiency and large C&I load curtailment, as well as other NWSs.*

Consistent with this requirement, Eversource developed a list of potential NWS solution candidates that was shared with the Staff and OCA in August 2020. A meeting on those candidates was held in early September, and the Staff issued discovery on those candidates, to which Eversource responded in mid-September.

Given the additional discovery from the Staff, and other considerations pertaining to the NWS candidates, as of the date of this submission, the Company, Staff and OCA have not yet identified the candidate that would be the focus of the more detailed analysis. Eversource remains committed to identifying the candidate and completing the more detailed analysis and will supplement this filing with additional information once the candidate has been identified and the analysis performed.

Incorporation of NWS into Utility Planning. *The LCIRP will also include a description of the planning process employed to assess NWS as part of the Company's broader planning processes and the steps taken to incorporate NWS into its planning decisions as well as revised internal policy documentation reflecting an increased emphasis on incorporating NWS to reduce or defer traditional infrastructure investments.*

This process is described in Section 5 of this filing.

Planning Criteria Revisions

Planning Criteria Revisions. *The LCIRP will address issues pertaining to the adoption and implementation of the planning criteria in SYSPLAN-008 and SYSPLAN-010. In particular, Eversource will: (1) explain and describe the changes from its prior planning criteria and will explain the justification for the changes in those criteria; and (2) describe any projects proposed through 2021 that may be impacted by the changes from the prior planning criteria to SYSPLAN-008 and SYSPLAN-010, the degree to which the new criteria are factors in those projects, and any incremental costs or benefits relating to those projects as a result of applying the new criteria.*

Planning criteria revisions are described in Section 5 of this filing.

3. SETTLEMENT AGREEMENT IN DOCKET NO. DE 17-136

Grid Needs Assessment. *The grid needs assessment shall describe all forecasted grid needs related to distribution system capital investments of $250,000 or more over a five-year planning horizon at the circuit level. The grid needs assessment shall be available in spreadsheet format and shall include the following attribute-based columns and content: (1) Substation, Circuit, and/or Facility ID: identify the location and system granularity of grid need; (2) Distribution service required: capacity, reliability, and resiliency; (3) Anticipated season or date by which distribution upgrade must be installed; (4) Existing facility/equipment rating: MW, kVA, or other; and (5) Forecasted percentage deficiency above the existing facility/equipment rating over five years. Upon filing of the LCIRP and associated grid needs assessment, Commission Staff, the OCA, and Liberty will review planned capital investments to identify candidates that may be appropriate for NWA opportunities.*

This assessment is addressed in Appendix K of this filing.

Appendix L includes a series of approved Solution Selection Forms and Project Authorization Forms for projects planned by Eversource.

Coincident 50/50 Regional Summer Peak Forecast (MW)

Year	Northern	Southern	Western	Central	Eastern	System Total[1]
2006	156.0	331.7	49.7	234.3	148.6	0.0
2007	174.1	256.2	130.7	367.4	296.4	0.0
2008	184.1	395.7	176.8	377.1	318.7	0.0
2009	238.0	403.2	169.4	357.5	326.3	0.0
2010	270.7	423.1	187.5	382.4	349.8	0.0
2011	264.3	463.8	190.0	381.9	357.2	0.0
2012	270.2	434.8	157.8	363.6	337.0	0.0
2013	268.9	530.2	194.2	376.9	357.5	0.0
2014	284.6	495.1	176.4	355.0	358.2	0.0
2015	262.2	485.2	170.2	356.4	361.0	0.0
2016	354.1	507.9	184.8	436.9	401.5	0.0
2017	301.1	477.2	160.4	403.5	363.3	0.0
2018	348.8	515.1	185.5	437.9	398.8	1703.0
2019	345.8	499.2	174.5	425.5	384.3	1639.9
2020	*348.6*	*507.6*	*176.7*	*431.7*	*403.9*	*1663.4*
2021	*351.1*	*512.2*	*178.5*	*434.2*	*408.4*	*1678.8*
2022	*353.0*	*513.7*	*179.7*	*435.9*	*410.4*	*1686.4*
2023	*354.5*	*514.8*	*180.6*	*437.1*	*411.6*	*1691.6*
2024	*355.8*	*515.7*	*181.4*	*438.2*	*412.7*	*1696.3*
2025	*357.5*	*516.9*	*182.4*	*439.6*	*413.3*	*1701.7*
2026	*359.1*	*518.1*	*183.4*	*440.9*	*413.8*	*1706.7*
2027	*360.8*	*519.3*	*184.3*	*442.3*	*414.3*	*1711.8*
2028	*362.8*	*520.9*	*185.6*	*444.1*	*415.1*	*1718.6*
2029	*365.1*	*522.7*	*186.9*	*446.0*	*416.0*	*1726.0*
20-29 CAGR	0.51%	0.32%	0.63%	0.36%	0.33%	0.41%

Northern Region - Coincident 50/50 Summer Peak Forecast (MW)

Year	Ashland	Beebe River	Berlin	Laconia	Lost Nation	No. Woodstock	Pemigew asset	Saco Valley	Webster	White Lake	Whitefield	Oak Hill	Total Northern
2006	0.0	22.7	0.0	62.5	12.6	8.8	0.0	16.4	33.0	0.0	0.0	0.0	156.0
2007	0.0	0.0	0.0	59.7	10.4	9.2	0.0	17.4	34.0	43.4	0.0	0.0	174.1
2008	37.3	19.7	0.0	57.1	10.1	6.9	0.0	16.1	0.0	36.9	0.0	0.0	184.1
2009	31.5	19.3	0.0	54.5	0.0	8.4	18.2	16.3	29.7	38.8	21.3	0.0	238.0
2010	29.7	22.7	0.0	58.9	10.9	8.7	21.8	17.6	34.1	43.6	22.8	0.0	270.7
2011	33.7	21.1	16.1	62.6	0.0	8.7	22.4	19.7	36.0	44.1	0.0	0.0	264.3
2012	27.2	22.6	14.8	54.4	9.6	7.8	20.3	18.7	34.6	40.2	19.9	0.0	270.2
2013	35.5	17.9	11.6	59.5	10.5	8.9	22.8	20.1	31.3	34.2	16.5	0.0	268.9
2014	34.0	19.4	15.3	58.6	9.9	8.6	22.0	19.9	34.2	42.4	20.2	0.0	284.6
2015	31.2	16.3	15.6	55.7	7.7	8.2	20.9	17.2	32.5	39.1	17.8	0.0	262.2
2016	35.3	17.7	17.5	61.3	8.2	8.9	22.7	18.6	36.7	43.7	22.0	61.5	354.1
2017	26.9	15.3	14.6	51.3	8.5	7.2	19.7	16.7	33.1	33.5	18.2	56.2	301.1
2018	33.5	17.1	18.3	59.0	10.4	8.5	21.5	18.7	38.8	40.7	20.5	61.7	348.8
2019	32.2	17.5	18.1	59.6	9.5	9.4	21.5	19.5	36.6	43.5	19.9	58.6	345.8
2020	*32.9*	*17.3*	*18.0*	*60.1*	*9.4*	*9.5*	*21.0*	*19.7*	*36.4*	*43.9*	*21.4*	*59.1*	*348.6*
2021	*33.1*	*17.5*	*18.1*	*60.4*	*9.5*	*9.6*	*21.2*	*19.8*	*36.7*	*44.1*	*21.6*	*59.4*	*351.1*
2022	*33.3*	*17.6*	*18.2*	*60.7*	*9.6*	*9.7*	*21.3*	*20.0*	*36.9*	*44.4*	*21.7*	*59.7*	*353.0*
2023	*33.4*	*17.7*	*18.3*	*60.9*	*9.7*	*9.8*	*21.4*	*20.1*	*37.0*	*44.5*	*21.8*	*59.9*	*354.5*
2024	*33.5*	*17.8*	*18.4*	*61.1*	*9.7*	*9.8*	*21.5*	*20.1*	*37.1*	*44.7*	*21.9*	*60.1*	*355.8*
2025	*33.7*	*17.9*	*18.5*	*61.4*	*9.8*	*9.9*	*21.7*	*20.3*	*37.3*	*44.8*	*22.0*	*60.3*	*357.5*
2026	*33.9*	*18.0*	*18.6*	*61.6*	*9.9*	*10.0*	*21.8*	*20.4*	*37.4*	*45.0*	*22.1*	*60.6*	*359.1*
2027	*34.0*	*18.1*	*18.7*	*61.8*	*10.0*	*10.0*	*21.9*	*20.5*	*37.6*	*45.2*	*22.2*	*60.8*	*360.8*
2028	*34.2*	*18.2*	*18.8*	*62.1*	*10.1*	*10.1*	*22.0*	*20.6*	*37.8*	*45.4*	*22.4*	*61.1*	*362.8*
2029	*34.4*	*18.4*	*18.9*	*62.5*	*10.2*	*10.2*	*22.2*	*20.7*	*38.0*	*45.7*	*22.5*	*61.4*	*365.1*
20-29 CAGR	0.52%	0.64%	0.56%	0.43%	0.85%	0.78%	0.60%	0.57%	0.47%	0.45%	0.57%	0.43%	0.51%

Southern Region - Coincident 50/50 Summer Peak Forecast (MW)

Year	Amherst	Bridge St. 4kv	Bridge St. 34.5kv	Busch	Chester	Hudson	Kingston	Lawrence Road	Long Hill	Scobie Pond	South Milford	Thorton	Mammoth	Total Southern
2006	112.6	0.0	54.8	0.0	41.5	0.0	13.8	0.0	51.4	0.0	41.1	16.3	0.0	331.7
2007	104.5	0.0	0.0	0.0	34.3	0.0	11.4	0.0	54.1	0.0	36.8	15.2	0.0	256.2
2008	108.2	0.0	72.7	0.0	36.9	46.6	12.3	0.0	58.8	0.0	42.3	17.9	0.0	395.7
2009	98.3	0.0	59.3	0.0	31.5	43.6	10.5	44.8	59.2	0.0	37.6	18.5	0.0	403.2
2010	103.6	0.0	60.6	0.0	34.9	44.1	11.6	46.6	64.4	0.0	41.0	16.5	0.0	423.1
2011	106.3	0.0	56.9	0.0	38.0	42.8	12.7	46.4	72.7	24.9	42.9	20.3	0.0	463.8
2012	102.2	7.2	55.0	0.0	37.5	42.8	12.5	45.8	67.5	23.5	40.8	0.0	0.0	434.8
2013	108.0	6.9	58.2	5.5	40.0	43.5	13.3	44.8	71.0	24.9	41.5	21.8	50.7	530.2
2014	98.6	7.5	55.2	6.0	35.5	43.6	11.8	43.6	62.6	28.9	37.8	22.3	41.6	495.1
2015	97.9	6.4	51.1	5.3	38.0	39.1	12.0	42.8	64.2	27.7	38.2	20.1	42.4	485.2
2016	104.2	6.6	55.8	4.7	38.2	43.1	13.0	41.6	66.4	30.9	39.7	19.1	44.7	507.9
2017	96.5	6.2	46.7	4.6	37.4	39.3	11.9	42.2	63.7	28.7	38.7	17.9	43.3	477.2
2018	103.8	7.4	52.8	5.6	41.7	41.4	12.7	44.0	67.0	31.1	43.9	17.4	46.3	515.1
2019	101.3	7.3	52.3	5.8	38.2	41.1	12.7	44.0	64.3	29.6	41.1	16.2	45.3	499.2
2020	*101.0*	*7.3*	*52.6*	*5.3*	*39.5*	*43.1*	*12.3*	*43.6*	*64.8*	*29.6*	*44.0*	*17.8*	*46.2*	*507.6*
2021	*101.6*	*7.3*	*52.9*	*5.6*	*39.7*	*43.3*	*12.4*	*43.8*	*65.2*	*29.7*	*46.2*	*17.9*	*46.5*	*512.2*
2022	*102.0*	*7.4*	*53.0*	*5.6*	*39.8*	*43.4*	*12.3*	*43.9*	*65.4*	*29.8*	*46.3*	*17.9*	*46.6*	*513.7*
2023	*102.2*	*7.4*	*53.2*	*5.5*	*39.9*	*43.5*	*12.3*	*44.0*	*65.6*	*29.9*	*46.4*	*17.9*	*46.8*	*514.8*
2024	*102.5*	*7.4*	*53.3*	*5.5*	*39.9*	*43.6*	*12.3*	*44.1*	*65.7*	*29.9*	*46.4*	*17.9*	*46.8*	*515.7*
2025	*102.8*	*7.4*	*53.4*	*5.5*	*40.0*	*43.7*	*12.3*	*44.2*	*65.9*	*30.0*	*46.5*	*18.0*	*47.0*	*516.9*
2026	*103.1*	*7.4*	*53.6*	*5.5*	*40.1*	*43.8*	*12.3*	*44.3*	*66.1*	*30.0*	*46.6*	*18.0*	*47.1*	*518.1*
2027	*103.4*	*7.5*	*53.7*	*5.5*	*40.2*	*43.9*	*12.3*	*44.4*	*66.3*	*30.1*	*46.6*	*18.0*	*47.2*	*519.3*
2028	*103.8*	*7.5*	*53.9*	*5.5*	*40.3*	*44.0*	*12.3*	*44.5*	*66.5*	*30.1*	*46.7*	*18.1*	*47.4*	*520.9*
2029	*104.2*	*7.5*	*54.1*	*5.5*	*40.4*	*44.1*	*12.3*	*44.7*	*66.8*	*30.2*	*46.9*	*18.1*	*47.6*	*522.7*
20-29 CAG	0.34%	0.32%	0.32%	0.38%	0.24%	0.26%	0.01%	0.28%	0.33%	0.23%	0.70%	0.21%	0.31%	0.32%

* Busch is only 1 customer and is based off 3 yr average

Western Region - Coincident 50/50 Summer Peak Forecast (MW)

Year	Chestnut Hill	Keene	Monadnock	North Keene	North Road	Swanzey	Jackman	Total Western
2006	15.4	0.0	0.0	0.0	0.0	0.0	34.3	49.7
2007	14.6	38.6	29.1	20.5	0.0	0.0	27.9	130.7
2008	14.8	39.1	32.6	20.8	35.3	0.0	34.3	176.8
2009	13.2	34.9	33.0	18.6	37.1	0.0	32.6	169.4
2010	15.0	37.3	34.4	19.8	35.0	7.1	39.0	187.5
2011	15.6	38.7	35.6	20.6	35.6	7.5	36.5	190.0
2012	15.4	35.8	43.0	19.1	0.0	7.2	37.4	157.8
2013	15.8	38.3	38.0	20.4	38.9	7.1	35.7	194.2
2014	13.5	35.2	34.3	18.7	35.6	6.5	32.6	176.4
2015	14.5	33.2	33.1	17.6	32.5	6.7	32.7	170.2
2016	15.1	34.7	39.1	18.4	38.4	6.4	32.6	184.8
2017	13.8	31.4	29.2	16.4	34.3	6.0	29.3	160.4
2018	15.7	35.0	36.8	19.1	38.8	7.1	32.9	185.5
2019	14.6	32.9	33.7	18.1	37.2	6.6	31.5	174.5
2020	*14.6*	*33.7*	*34.1*	*18.6*	*37.4*	*6.6*	*31.8*	*176.7*
2021	*14.7*	*34.4*	*34.3*	*18.8*	*37.6*	*6.6*	*32.0*	*178.5*
2022	*14.8*	*34.7*	*34.5*	*18.9*	*37.9*	*6.7*	*32.2*	*179.7*
2023	*14.9*	*34.8*	*34.7*	*19.0*	*38.0*	*6.7*	*32.4*	*180.6*
2024	*15.0*	*35.0*	*34.8*	*19.1*	*38.2*	*6.8*	*32.5*	*181.4*
2025	*15.1*	*35.1*	*35.0*	*19.2*	*38.3*	*6.8*	*32.7*	*182.4*
2026	*15.2*	*35.3*	*35.2*	*19.4*	*38.5*	*6.9*	*32.9*	*183.4*
2027	*15.3*	*35.5*	*35.4*	*19.5*	*38.7*	*6.9*	*33.0*	*184.3*
2028	*15.5*	*35.7*	*35.6*	*19.6*	*38.9*	*7.0*	*33.3*	*185.6*
2029	*15.6*	*36.0*	*35.8*	*19.8*	*39.2*	*7.0*	*33.5*	*186.9*
20-29 CAG	0.76%	0.73%	0.56%	0.68%	0.52%	0.76%	0.59%	0.63%

Central Region - Coincident 50/50 Summer Peak Forecast (MW)

Year	Bedford	Eddy	Garvins	Greggs	Huse Rd	Pine Hill	Reeds Ferry	Rimmon	Weare	Total Central
2006	62.9	0.0	0.0	0.0	81.6	54.2	35.6	0.0	0.0	234.3
2007	60.4	67.7	0.0	10.9	82.5	46.6	34.4	64.8	0.0	367.4
2008	63.3	67.3	0.0	12.0	85.5	49.0	36.6	63.4	0.0	377.1
2009	58.3	62.6	0.0	9.4	80.5	43.9	31.8	58.9	12.1	357.5
2010	60.5	66.5	0.0	11.0	76.4	54.9	36.5	63.6	13.1	382.4
2011	62.2	69.3	0.0	10.8	74.1	55.3	34.2	62.3	13.7	381.9
2012	58.9	63.8	0.0	11.1	71.0	54.1	31.7	58.0	15.0	363.6
2013	60.2	68.0	0.0	11.1	72.4	55.3	34.4	60.9	14.7	376.9
2014	59.8	64.3	0.0	9.9	70.5	51.0	31.2	55.3	13.0	355.0
2015	64.2	60.8	0.0	10.8	67.6	52.3	30.8	55.6	14.3	356.4
2016	57.7	65.2	66.9	10.9	71.9	54.8	32.0	63.1	14.3	436.9
2017	54.7	54.3	62.8	10.8	64.5	51.5	30.7	61.1	13.1	403.5
2018	59.0	65.1	67.7	10.9	69.5	56.1	32.1	62.2	15.2	437.9
2019	58.5	64.9	67.4	10.9	66.9	54.9	29.0	59.1	13.9	425.5
2020	*58.3*	*65.2*	*66.5*	*0.0*	*71.5*	*54.7*	*31.0*	*59.9*	*24.5*	*431.7*
2021	*58.6*	*65.6*	*66.9*	*0.0*	*71.9*	*55.0*	*31.2*	*60.3*	*24.6*	*434.2*
2022	*58.9*	*65.9*	*67.2*	*0.0*	*72.2*	*55.2*	*31.3*	*60.5*	*24.7*	*435.9*
2023	*59.0*	*66.0*	*67.4*	*0.0*	*72.4*	*55.4*	*31.4*	*60.7*	*24.8*	*437.1*
2024	*59.2*	*66.2*	*67.5*	*0.0*	*72.5*	*55.5*	*31.5*	*60.8*	*24.8*	*438.2*
2025	*59.4*	*66.4*	*67.8*	*0.0*	*72.8*	*55.7*	*31.6*	*61.1*	*24.9*	*439.6*
2026	*59.5*	*66.6*	*68.0*	*0.0*	*73.0*	*55.8*	*31.7*	*61.3*	*25.0*	*440.9*
2027	*59.7*	*66.8*	*68.2*	*0.0*	*73.2*	*56.0*	*31.8*	*61.5*	*25.1*	*442.3*
2028	*60.0*	*67.1*	*68.5*	*0.0*	*73.5*	*56.2*	*32.0*	*61.7*	*25.2*	*444.1*
2029	*60.2*	*67.4*	*68.8*	*0.0*	*73.8*	*56.4*	*32.1*	*62.0*	*25.3*	*446.0*
20-29 CAG	0.36%	0.36%	0.37%		0.36%	0.34%	0.38%	0.38%	0.37%	0.36%

Eastern Region - Coincident 50/50 Summer Peak Forecast (MW)

Year	Brentwood	Dover	Madbury	Mill Pond	Ocean Road	Portsmouth	Resistance	Rochester	Tasker Farm	Timber Swamp	Total Eastern
2006	0.0	69.7	0.0	0.0	0.0	0.0	25.6	53.4	0.0	0.0	148.6
2007	21.3	66.4	66.6	0.0	33.1	0.0	24.6	53.1	0.0	31.4	296.4
2008	21.2	65.9	72.9	0.0	30.3	33.8	20.0	49.8	0.0	24.8	318.7
2009	19.6	67.3	63.3	0.0	35.0	36.9	22.2	52.0	0.0	29.9	326.3
2010	23.4	72.1	73.7	0.0	37.0	34.9	23.2	54.8	0.0	30.7	349.8
2011	22.3	74.3	71.9	0.0	37.5	35.9	22.5	59.1	0.0	33.9	357.2
2012	22.0	67.7	72.9	0.0	36.4	34.3	20.7	54.1	0.0	29.0	337.0
2013	22.7	75.8	69.7	0.0	38.2	36.2	24.4	58.2	0.0	32.3	357.5
2014	21.2	70.7	69.0	0.0	37.9	36.3	23.1	60.1	12.7	27.2	358.2
2015	21.8	71.4	61.7	3.3	33.6	34.5	19.5	57.4	28.5	29.3	361.0
2016	23.6	74.9	71.8	9.2	39.2	38.3	19.1	61.2	30.9	33.3	401.5
2017	22.3	70.5	65.9	8.6	30.9	35.5	20.6	52.6	26.1	30.1	363.3
2018	24.6	79.0	77.7	10.3	31.3	36.9	21.3	58.5	28.6	30.7	398.8
2019	23.7	75.2	67.5	9.7	29.6	38.4	20.8	59.5	27.5	32.3	384.3
2020	*23.9*	*75.4*	*76.2*	*11.5*	*34.9*	*40.9*	*21.3*	*59.7*	*27.6*	*32.6*	*403.9*
2021	*24.0*	*76.3*	*76.4*	*12.0*	*35.0*	*42.3*	*21.3*	*60.0*	*27.7*	*33.2*	*408.4*
2022	*24.0*	*76.5*	*76.5*	*12.1*	*35.1*	*43.1*	*21.3*	*60.2*	*27.8*	*33.8*	*410.4*
2023	*24.0*	*76.7*	*76.5*	*12.1*	*35.2*	*43.9*	*21.4*	*60.3*	*27.9*	*33.8*	*411.6*
2024	*24.0*	*76.8*	*76.5*	*12.1*	*35.2*	*44.7*	*21.4*	*60.4*	*27.9*	*33.8*	*412.7*
2025	*24.0*	*77.0*	*76.5*	*12.1*	*35.3*	*44.7*	*21.4*	*60.5*	*28.0*	*33.8*	*413.3*
2026	*24.0*	*77.1*	*76.5*	*12.1*	*35.3*	*44.8*	*21.4*	*60.6*	*28.0*	*33.9*	*413.8*
2027	*24.0*	*77.3*	*76.6*	*12.1*	*35.4*	*44.8*	*21.4*	*60.7*	*28.1*	*33.9*	*414.3*
2028	*24.1*	*77.5*	*76.6*	*12.2*	*35.4*	*44.9*	*21.4*	*60.9*	*28.2*	*33.9*	*415.1*
2029	*24.1*	*77.8*	*76.7*	*12.2*	*35.5*	*44.9*	*21.4*	*61.1*	*28.3*	*34.0*	*416.0*
19-28 CAG	0.08%	0.34%	0.07%	0.67%	0.21%	1.05%	0.09%	0.26%	0.26%	0.48%	0.33%

Coincident 90/10 Regional Summer Peak Forecast (MW)

Year	Northern	Southern	Western	Central	Eastern	System Total
2006	156.0	331.7	49.7	234.3	148.6	0.0
2007	174.1	256.2	130.7	367.4	296.4	0.0
2008	184.1	395.7	176.8	377.1	318.7	0.0
2009	238.0	403.2	169.4	357.5	326.3	0.0
2010	270.7	423.1	187.5	382.4	349.8	0.0
2011	264.3	463.8	190.0	381.9	357.2	0.0
2012	270.2	434.8	157.8	363.6	337.0	0.0
2013	268.9	530.2	194.2	376.9	357.5	0.0
2014	284.6	495.1	176.4	355.0	358.2	0.0
2015	262.2	485.2	170.2	356.4	361.0	0.0
2016	354.1	507.9	184.8	436.9	401.5	0.0
2017	301.1	477.2	160.4	403.5	363.3	0.0
2018	348.8	515.1	185.5	437.9	398.8	1703.0
2019	345.8	499.2	174.5	425.5	384.3	1639.9
2020	*381.8*	*539.6*	*195.5*	*463.8*	*424.0*	*1791.5*
2021	*384.2*	*544.2*	*197.4*	*466.3*	*428.5*	*1806.9*
2022	*386.2*	*545.7*	*198.6*	*468.0*	*430.5*	*1814.5*
2023	*387.6*	*546.8*	*199.4*	*469.2*	*431.7*	*1819.8*
2024	*388.9*	*547.7*	*200.2*	*470.2*	*432.8*	*1824.5*
2025	*390.6*	*549.0*	*201.2*	*471.7*	*433.4*	*1829.8*
2026	*392.2*	*550.1*	*202.2*	*473.0*	*433.9*	*1834.8*
2027	*393.8*	*551.3*	*203.2*	*474.4*	*434.5*	*1839.9*
2028	*395.9*	*553.0*	*204.4*	*476.2*	*435.3*	*1846.7*
2029	*398.1*	*554.7*	*205.7*	*478.1*	*436.2*	*1854.1*
20-29 CAGR	0.47%	0.31%	0.56%	0.34%	0.32%	0.38%

Northern Region - Coincident 90/10 Summer Peak Forecast (MW)

Year	Ashland	Beebe River	Berlin	Laconia	Lost Nation	No. Woodstock	Pemigewasset	Saco Valley	Webster	White Lake	Whitefield	Oak Hill	Total Northern
2006	0.0	22.7	0.0	62.5	12.6	8.8	0.0	16.4	33.0	0.0	0.0	0.0	156.0
2007	0.0	0.0	0.0	59.7	10.4	9.2	0.0	17.4	34.0	43.4	0.0	0.0	174.1
2008	37.3	19.7	0.0	57.1	10.1	6.9	0.0	16.1	0.0	36.9	0.0	0.0	184.1
2009	31.5	19.3	0.0	54.5	0.0	8.4	18.2	16.3	29.7	38.8	21.3	0.0	238.0
2010	29.7	22.7	0.0	58.9	10.9	8.7	21.8	17.6	34.1	43.6	22.8	0.0	270.7
2011	33.7	21.1	16.1	62.6	0.0	8.7	22.4	19.7	36.0	44.1	0.0	0.0	264.3
2012	27.2	22.6	14.8	54.4	9.6	7.8	20.3	18.7	34.6	40.2	19.9	0.0	270.2
2013	35.5	17.9	11.6	59.5	10.5	8.9	22.8	20.1	31.3	34.2	16.5	0.0	268.9
2014	34.0	19.4	15.3	58.6	9.9	8.6	22.0	19.9	34.2	42.4	20.2	0.0	284.6
2015	31.2	16.3	15.6	55.7	7.7	8.2	20.9	17.2	32.5	39.1	17.8	0.0	262.2
2016	35.3	17.7	17.5	61.3	8.2	8.9	22.7	18.6	36.7	43.7	22.0	61.5	354.1
2017	26.9	15.3	14.6	51.3	8.5	7.2	19.7	16.7	33.1	33.5	18.2	56.2	301.1
2018	33.5	17.1	18.3	59.0	10.4	8.5	21.5	18.7	38.8	40.7	20.5	61.7	348.8
2019	32.2	17.5	18.1	59.6	9.5	9.4	21.5	19.5	36.6	43.5	19.9	58.6	345.8
2020	*36.0*	*19.3*	*19.8*	*65.1*	*10.8*	*10.8*	*23.3*	*21.7*	*39.7*	*47.7*	*23.6*	*64.0*	*381.8*
2021	*36.3*	*19.4*	*19.9*	*65.5*	*10.9*	*10.9*	*23.5*	*21.9*	*39.9*	*47.9*	*23.8*	*64.4*	*384.2*
2022	*36.4*	*19.6*	*20.0*	*65.8*	*10.9*	*10.9*	*23.6*	*22.0*	*40.1*	*48.2*	*23.9*	*64.7*	*386.2*
2023	*36.6*	*19.6*	*20.1*	*66.0*	*11.0*	*11.0*	*23.7*	*22.1*	*40.3*	*48.3*	*24.0*	*64.9*	*387.6*
2024	*36.7*	*19.7*	*20.2*	*66.2*	*11.1*	*11.1*	*23.8*	*22.2*	*40.4*	*48.5*	*24.1*	*65.1*	*388.9*
2025	*36.9*	*19.8*	*20.3*	*66.4*	*11.2*	*11.1*	*23.9*	*22.3*	*40.5*	*48.6*	*24.2*	*65.3*	*390.6*
2026	*37.0*	*19.9*	*20.4*	*66.6*	*11.2*	*11.2*	*24.0*	*22.4*	*40.7*	*48.8*	*24.3*	*65.5*	*392.2*
2027	*37.2*	*20.0*	*20.5*	*66.9*	*11.3*	*11.3*	*24.1*	*22.5*	*40.9*	*49.0*	*24.4*	*65.8*	*393.8*
2028	*37.4*	*20.2*	*20.6*	*67.2*	*11.4*	*11.4*	*24.3*	*22.6*	*41.1*	*49.2*	*24.6*	*66.1*	*395.9*
2029	*37.6*	*20.3*	*20.7*	*67.5*	*11.5*	*11.5*	*24.4*	*22.7*	*41.3*	*49.5*	*24.7*	*66.4*	*398.1*
20-29 CAG	0.47%	0.57%	0.51%	0.40%	0.74%	0.68%	0.54%	0.51%	0.43%	0.41%	0.51%	0.40%	0.47%

Southern Region - Coincident 90/10 Summer Peak Forecast (MW)

Year	Amherst	Bridge St. 4kv	Bridge St. 34.5kv	Busch	Chester	Hudson	Kingston	Lawrence Road	Long Hill	Scobie Pond	South Milford	Thorton	Mammoth	Total Southern
2006	112.6	0.0	54.8	0.0	41.5	0.0	13.8	0.0	51.4	0.0	41.1	16.3	0.0	331.7
2007	104.5	0.0	0.0	0.0	34.3	0.0	11.4	0.0	54.1	0.0	36.8	15.2	0.0	256.2
2008	108.2	0.0	72.7	0.0	36.9	46.6	12.3	0.0	58.8	0.0	42.3	17.9	0.0	395.7
2009	98.3	0.0	59.3	0.0	31.5	43.6	10.5	44.8	59.2	0.0	37.6	18.5	0.0	403.2
2010	103.6	0.0	60.6	0.0	34.9	44.1	11.6	46.6	64.4	0.0	41.0	16.5	0.0	423.1
2011	106.3	0.0	56.9	0.0	38.0	42.8	12.7	46.4	72.7	24.9	42.9	20.3	0.0	463.8
2012	102.2	7.2	55.0	0.0	37.5	42.8	12.5	45.8	67.5	23.5	40.8	0.0	0.0	434.8
2013	108.0	6.9	58.2	5.5	40.0	43.5	13.3	44.8	71.0	24.9	41.5	21.8	50.7	530.2
2014	98.6	7.5	55.2	6.0	35.5	43.6	11.8	43.6	62.6	28.9	37.8	22.3	41.6	495.1
2015	97.9	6.4	51.1	5.3	38.0	39.1	12.0	42.8	64.2	27.7	38.2	20.1	42.4	485.2
2016	104.2	6.6	55.8	4.7	38.2	43.1	13.0	41.6	66.4	30.9	39.7	19.1	44.7	507.9
2017	96.5	6.2	46.7	4.6	37.4	39.3	11.9	42.2	63.7	28.7	38.7	17.9	43.3	477.2
2018	103.8	7.4	52.8	5.6	41.7	41.4	12.7	44.0	67.0	31.1	43.9	17.4	46.3	515.1
2019	101.3	7.3	52.3	5.8	38.2	41.1	12.7	44.0	64.3	29.6	41.1	16.2	45.3	499.2
2020	*108.3*	*7.8*	*56.2*	*5.8*	*41.8*	*45.7*	*12.6*	*46.3*	*69.4*	*31.3*	*46.4*	*18.7*	*49.4*	*539.6*
2021	*108.8*	*7.8*	*56.5*	*5.8*	*42.0*	*45.9*	*12.7*	*46.5*	*69.8*	*31.4*	*48.6*	*18.8*	*49.6*	*544.2*
2022	*109.2*	*7.9*	*56.6*	*5.8*	*42.1*	*46.0*	*12.7*	*46.7*	*70.0*	*31.5*	*48.7*	*18.8*	*49.8*	*545.7*
2023	*109.4*	*7.9*	*56.8*	*5.8*	*42.1*	*46.1*	*12.7*	*46.8*	*70.1*	*31.5*	*48.8*	*18.9*	*49.9*	*546.8*
2024	*109.7*	*7.9*	*56.9*	*5.8*	*42.2*	*46.2*	*12.7*	*46.8*	*70.3*	*31.6*	*48.9*	*18.9*	*50.0*	*547.7*
2025	*110.0*	*7.9*	*57.0*	*5.8*	*42.3*	*46.3*	*12.7*	*46.9*	*70.5*	*31.6*	*48.9*	*18.9*	*50.1*	*549.0*
2026	*110.3*	*7.9*	*57.2*	*5.8*	*42.4*	*46.4*	*12.7*	*47.0*	*70.7*	*31.7*	*49.0*	*18.9*	*50.2*	*550.1*
2027	*110.6*	*8.0*	*57.3*	*5.8*	*42.4*	*46.5*	*12.7*	*47.1*	*70.9*	*31.7*	*49.1*	*19.0*	*50.3*	*551.3*
2028	*111.0*	*8.0*	*57.5*	*5.8*	*42.5*	*46.6*	*12.7*	*47.3*	*71.1*	*31.8*	*49.2*	*19.0*	*50.5*	*553.0*
2029	*111.4*	*8.0*	*57.7*	*5.8*	*42.7*	*46.7*	*12.7*	*47.4*	*71.4*	*31.9*	*49.3*	*19.1*	*50.7*	*554.7*
20-29 CAG	0.32%	0.30%	0.30%	0.00%	0.23%	0.25%	0.02%	0.27%	0.31%	0.22%	0.67%	0.20%	0.29%	0.31%

* Busch is only 1 customer and is based off 1 yr average

Western Region - Coincident 90/10 Summer Peak Forecast (MW)

Year	Chestnut Hill	Keene	Monadnock	North Keene	North Road	Swanzey	Jackman	Total Western
2006	15.4	0.0	0.0	0.0	0.0	0.0	34.3	49.7
2007	14.6	38.6	29.1	20.5	0.0	0.0	27.9	130.7
2008	14.8	39.1	32.6	20.8	35.3	0.0	34.3	176.8
2009	13.2	34.9	33.0	18.6	37.1	0.0	32.6	169.4
2010	15.0	37.3	34.4	19.8	35.0	7.1	39.0	187.5
2011	15.6	38.7	35.6	20.6	35.6	7.5	36.5	190.0
2012	15.4	35.8	43.0	19.1	0.0	7.2	37.4	157.8
2013	15.8	38.3	38.0	20.4	38.9	7.1	35.7	194.2
2014	13.5	35.2	34.3	18.7	35.6	6.5	32.6	176.4
2015	14.5	33.2	33.1	17.6	32.5	6.7	32.7	170.2
2016	15.1	34.7	39.1	18.4	38.4	6.4	32.6	184.8
2017	13.8	31.4	29.2	16.4	34.3	6.0	29.3	160.4
2018	15.7	35.0	36.8	19.1	38.8	7.1	32.9	185.5
2019	14.6	32.9	33.7	18.1	37.2	6.6	31.5	174.5
2020	*16.5*	*37.2*	*37.5*	*20.8*	*41.0*	*7.4*	*35.1*	*195.5*
2021	*16.6*	*38.0*	*37.8*	*21.0*	*41.2*	*7.5*	*35.4*	*197.4*
2022	*16.7*	*38.2*	*38.0*	*21.1*	*41.4*	*7.5*	*35.6*	*198.6*
2023	*16.8*	*38.3*	*38.2*	*21.2*	*41.6*	*7.6*	*35.7*	*199.4*
2024	*16.9*	*38.5*	*38.3*	*21.3*	*41.7*	*7.6*	*35.9*	*200.2*
2025	*17.0*	*38.7*	*38.5*	*21.4*	*41.9*	*7.7*	*36.1*	*201.2*
2026	*17.1*	*38.8*	*38.7*	*21.5*	*42.1*	*7.7*	*36.2*	*202.2*
2027	*17.2*	*39.0*	*38.8*	*21.7*	*42.3*	*7.8*	*36.4*	*203.2*
2028	*17.4*	*39.2*	*39.1*	*21.8*	*42.5*	*7.8*	*36.6*	*204.4*
2029	*17.5*	*39.5*	*39.3*	*22.0*	*42.7*	*7.9*	*36.8*	*205.7*
20-29 CAG	0.67%	0.66%	0.50%	0.60%	0.47%	0.67%	0.53%	0.56%

Central Region - Coincident 90/10 Summer Peak Forecast (MW)

Year	Bedford	Eddy	Garvins	Greggs	Huse Rd	Pine Hill	Reeds Ferry	Rimmon	Weare	Total Central
2006	62.9	0.0	0.0	0.0	81.6	54.2	35.6	0.0	0.0	234.3
2007	60.4	67.7	0.0	10.9	82.5	46.6	34.4	64.8	0.0	367.4
2008	63.3	67.3	0.0	12.0	85.5	49.0	36.6	63.4	0.0	377.1
2009	58.3	62.6	0.0	9.4	80.5	43.9	31.8	58.9	12.1	357.5
2010	60.5	66.5	0.0	11.0	76.4	54.9	36.5	63.6	13.1	382.4
2011	62.2	69.3	0.0	10.8	74.1	55.3	34.2	62.3	13.7	381.9
2012	58.9	63.8	0.0	11.1	71.0	54.1	31.7	58.0	15.0	363.6
2013	60.2	68.0	0.0	11.1	72.4	55.3	34.4	60.9	14.7	376.9
2014	59.8	64.3	0.0	9.9	70.5	51.0	31.2	55.3	13.0	355.0
2015	64.2	60.8	0.0	10.8	67.6	52.3	30.8	55.6	14.3	356.4
2016	57.7	65.2	66.9	10.9	71.9	54.8	32.0	63.1	14.3	436.9
2017	54.7	54.3	62.8	10.8	64.5	51.5	30.7	61.1	13.1	403.5
2018	59.0	65.1	67.7	10.9	69.5	56.1	32.1	62.2	15.2	437.9
2019	58.5	64.9	67.4	10.9	66.9	54.9	29.0	59.1	13.9	425.5
2020	*62.6*	*70.0*	*71.5*	*0.0*	*76.7*	*58.6*	*33.4*	*64.5*	*26.3*	*463.8*
2021	*63.0*	*70.4*	*71.9*	*0.0*	*77.1*	*59.0*	*33.6*	*64.9*	*26.4*	*466.3*
2022	*63.2*	*70.6*	*72.2*	*0.0*	*77.4*	*59.2*	*33.7*	*65.1*	*26.5*	*468.0*
2023	*63.4*	*70.8*	*72.4*	*0.0*	*77.6*	*59.3*	*33.8*	*65.3*	*26.6*	*469.2*
2024	*63.5*	*71.0*	*72.5*	*0.0*	*77.8*	*59.4*	*33.9*	*65.4*	*26.7*	*470.2*
2025	*63.7*	*71.2*	*72.7*	*0.0*	*78.0*	*59.6*	*34.0*	*65.7*	*26.7*	*471.7*
2026	*63.9*	*71.4*	*73.0*	*0.0*	*78.2*	*59.8*	*34.1*	*65.9*	*26.8*	*473.0*
2027	*64.1*	*71.6*	*73.2*	*0.0*	*78.5*	*59.9*	*34.2*	*66.1*	*26.9*	*474.4*
2028	*64.3*	*71.9*	*73.4*	*0.0*	*78.8*	*60.1*	*34.3*	*66.3*	*27.0*	*476.2*
2029	*64.6*	*72.1*	*73.7*	*0.0*	*79.1*	*60.4*	*34.5*	*66.6*	*27.1*	*478.1*
20 -29 CA(	0.34%	0.33%	0.34%		0.33%	0.32%	0.35%	0.35%	0.34%	0.34%

Eastern Region - Coincident 90/10 Summer Peak Forecast (MW)

Year	Brentwood	Dover	Madbury	Mill Pond	Ocean Road	Portsmouth	Resistance	Rochester	Tasker Farm	Timber Swamp	Total Eastern
2006	0.0	69.7	0.0	0.0	0.0	0.0	25.6	53.4	0.0	0.0	148.6
2007	21.3	66.4	66.6	0.0	33.1	0.0	24.6	53.1	0.0	31.4	296.4
2008	21.2	65.9	72.9	0.0	30.3	33.8	20.0	49.8	0.0	24.8	318.7
2009	19.6	67.3	63.3	0.0	35.0	36.9	22.2	52.0	0.0	29.9	326.3
2010	23.4	72.1	73.7	0.0	37.0	34.9	23.2	54.8	0.0	30.7	349.8
2011	22.3	74.3	71.9	0.0	37.5	35.9	22.5	59.1	0.0	33.9	357.2
2012	22.0	67.7	72.9	0.0	36.4	34.3	20.7	54.1	0.0	29.0	337.0
2013	22.7	75.8	69.7	0.0	38.2	36.2	24.4	58.2	0.0	32.3	357.5
2014	21.2	70.7	69.0	0.0	37.9	36.3	23.1	60.1	12.7	27.2	358.2
2015	21.8	71.4	61.7	3.3	33.6	34.5	19.5	57.4	28.5	29.3	361.0
2016	23.6	74.9	71.8	9.2	39.2	38.3	19.1	61.2	30.9	33.3	401.5
2017	22.3	70.5	65.9	8.6	30.9	35.5	20.6	52.6	26.1	30.1	363.3
2018	24.6	79.0	77.7	10.3	31.3	36.9	21.3	58.5	28.6	30.7	398.8
2019	23.7	75.2	67.5	9.7	29.6	38.4	20.8	59.5	27.5	32.3	384.3
2020	*24.8*	*80.1*	*78.9*	*12.1*	*36.7*	*42.8*	*22.1*	*63.3*	*29.3*	*34.0*	*424.0*
2021	*24.8*	*81.0*	*79.1*	*12.6*	*36.9*	*44.2*	*22.1*	*63.6*	*29.4*	*34.7*	*428.5*
2022	*24.9*	*81.2*	*79.2*	*12.7*	*37.0*	*45.0*	*22.1*	*63.7*	*29.5*	*35.2*	*430.5*
2023	*24.9*	*81.3*	*79.2*	*12.7*	*37.0*	*45.8*	*22.2*	*63.9*	*29.5*	*35.2*	*431.7*
2024	*24.9*	*81.5*	*79.2*	*12.7*	*37.1*	*46.6*	*22.2*	*63.9*	*29.6*	*35.3*	*432.8*
2025	*24.9*	*81.6*	*79.2*	*12.7*	*37.1*	*46.6*	*22.2*	*64.1*	*29.6*	*35.3*	*433.4*
2026	*24.9*	*81.8*	*79.2*	*12.7*	*37.2*	*46.7*	*22.2*	*64.2*	*29.7*	*35.3*	*433.9*
2027	*24.9*	*82.0*	*79.3*	*12.8*	*37.2*	*46.7*	*22.2*	*64.3*	*29.8*	*35.4*	*434.5*
2028	*24.9*	*82.2*	*79.3*	*12.8*	*37.3*	*46.8*	*22.2*	*64.5*	*29.8*	*35.4*	*435.3*
2029	*24.9*	*82.5*	*79.4*	*12.8*	*37.4*	*46.9*	*22.2*	*64.7*	*29.9*	*35.5*	*436.2*
19-28 CAGR	0.08%	0.33%	0.08%	0.64%	0.20%	1.01%	0.10%	0.25%	0.25%	0.46%	0.32%

DSPG 2020
(Revision 00)

Distribution System Planning Guide

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Contents

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

[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.

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.
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

[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

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
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:

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:

[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.

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. <u>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.</u>

In areas of High Load Density, a higher degree of reliability is required by <u>maintaining</u> 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:

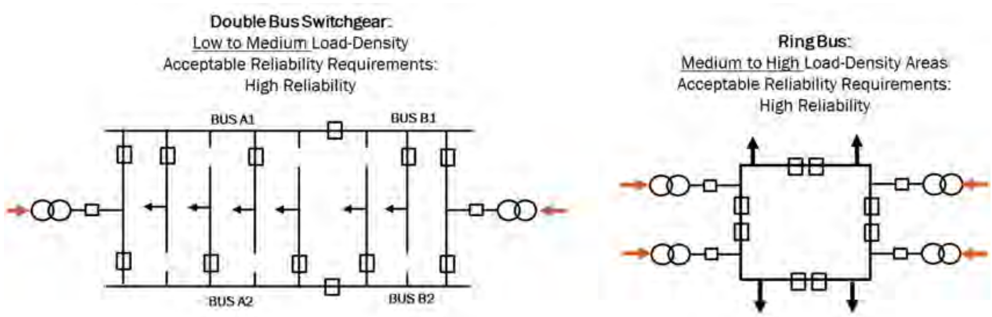


Figure 1 - Standard Substation Design

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:

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

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.)

Reactive power applications 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.

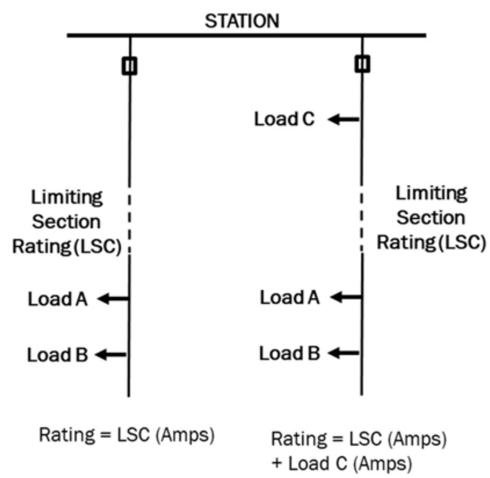


Figure 2 - Feeder Ratings and Limiting Section

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.

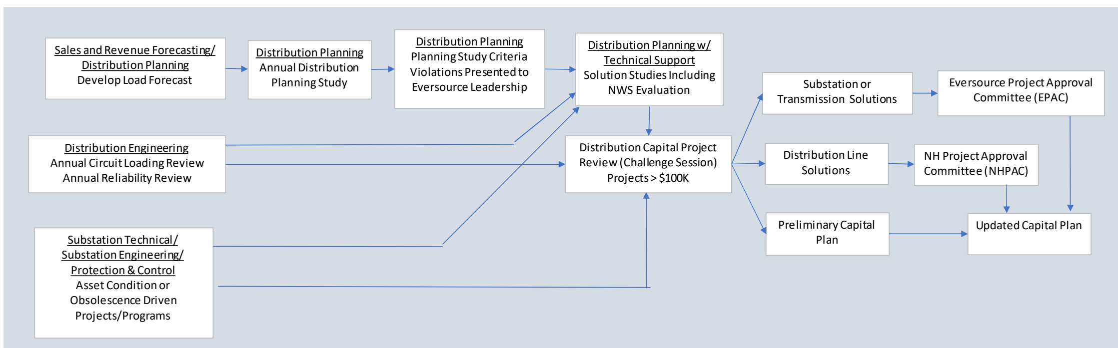
4. Planning Methodology

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 can 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.

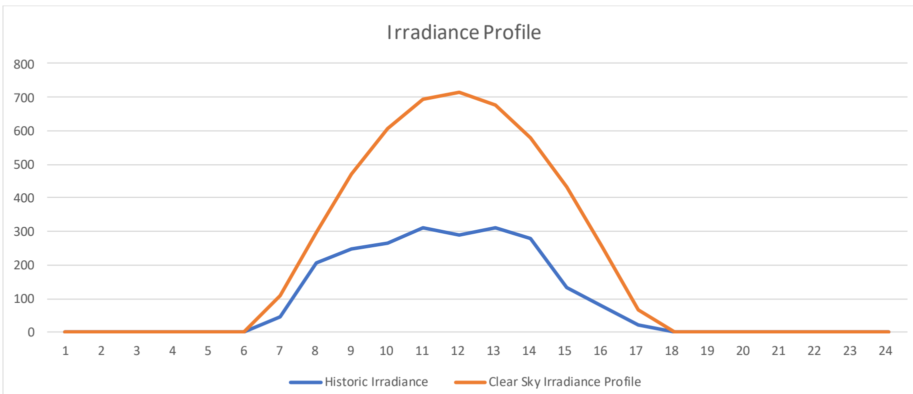


Figure 3: Clear sky and actual irradiance profile

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.

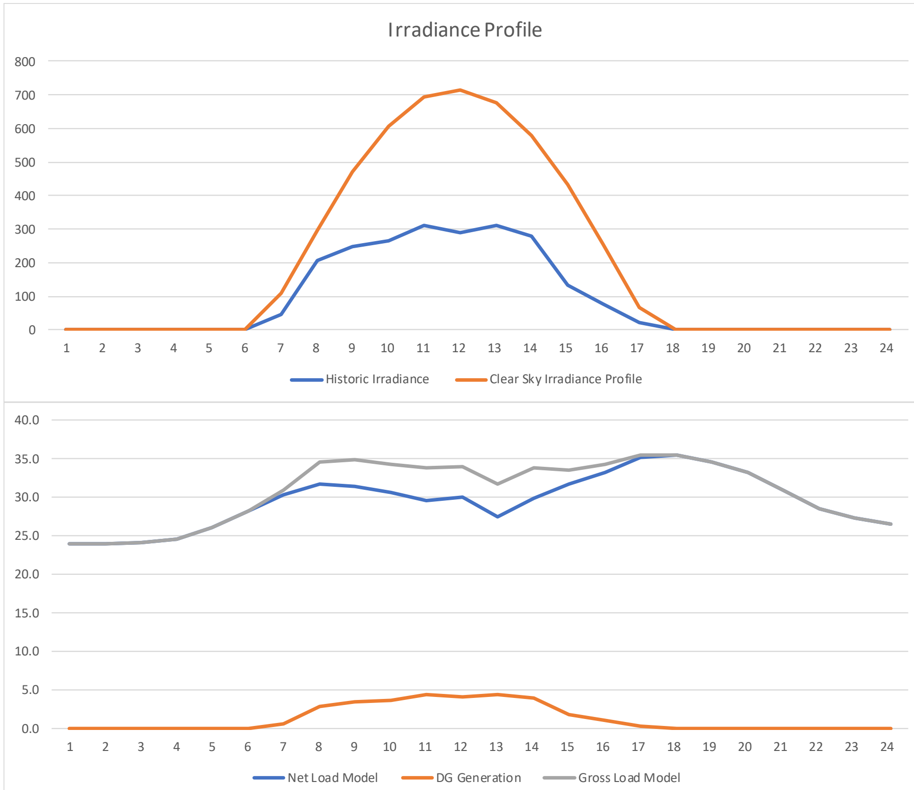


Figure 4: Gross and Net Load Profiles with DER output

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
$P_{Forecasted} * \varepsilon_{10\%}$ = 10^{th} percentile of solar adoption

Steps

1 - Determine the gross peak load day (e.g. August 4^{th}
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 10^{th} 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.

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

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

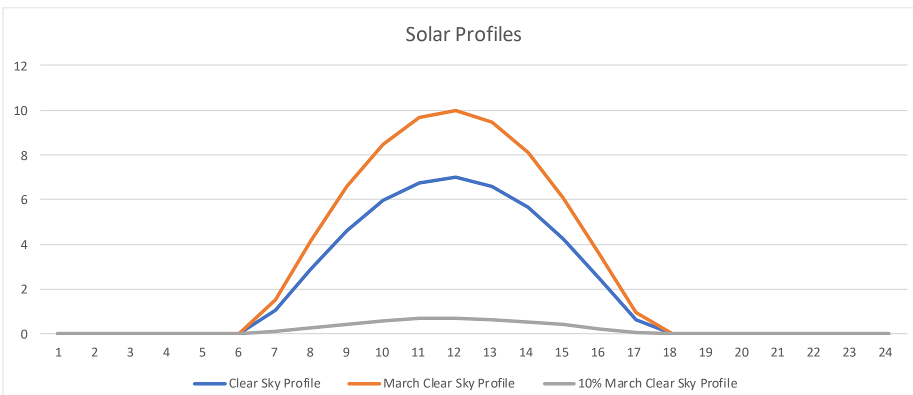


Figure 5: Scaled Forecast Profiles

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 largest transformer out of service and 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 not 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:

- Thermal violations:
  - 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.
- Phase load imbalance: reduce phase loading by distribution circuit reconfiguration
- Substation Secondary bus load thermal violations: 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

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

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.

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
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)

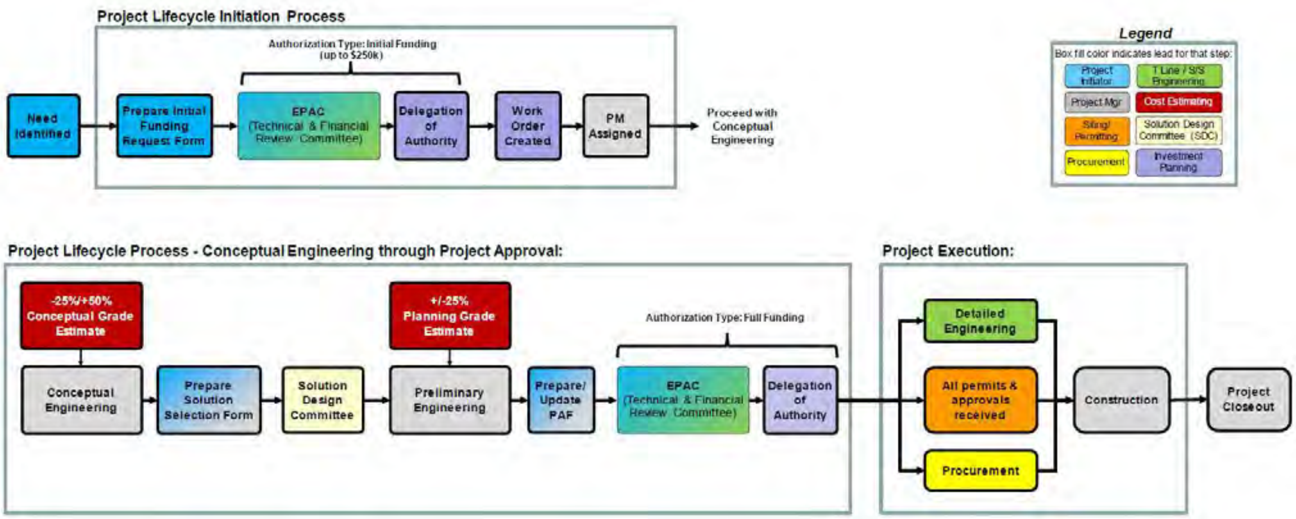
7.1. Reference Documents

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	PDF IEEE 1547-2018.pdf
IEEE Standard C57.12.00-2015 "IEEE Standard for General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers"	PDF C57.91-2011 Transformer Loading
Distribution System Planning and Design Criteria Guidelines (ED-3002)	PDF ED-3002 Distribution Plannin
Distribution System Planning Substation Project Template	W Planning Project Template.docx
Capital Project Approval Process Revision 5	PDF JA-AM-2001-A, Rev 5, Capital Project Ap

Table 12 - Reference Documents[8]

7.2. Attachment D of Capital Project Approval Process

[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.



7.3. 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*

Distributed Energy Resources Policies **Section 19**

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19.001

Approved By: JH Date: 04/2020

Eversource Technical Specifications for Distributed Generation Interconnection
CT/UI Guidelines for Generator Interconnection

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GENERAL – The Effective Grounding policy articulated here is only applicable to Distributed Generation (DG) connecting at Transmission, Subtransmission, or Primary Distribution Voltages. All DG connected at secondary voltage shall only be subject to NEC grounding requirements unless otherwise specified by Eversource Engineering.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

Effective grounding shall be required for all DG interconnections where any of the following is true:

1. The fault current at the point of common coupling (PCC) is caused to increase to a value 10 percent of the existing value.
2. Areas where fault current may already be deemed excessive.
3. DG interconnections larger than 1MW.
4. Anywhere there may exist a potential Islanding concern in regards to generation to load ratio.

To achieve effective grounding, the customer shall design and install an interconnection system where the ratio of the DG's reactance parameters meets the following criteria:

$2<X0/X1<3$ (X0 = zero sequence reactance and X1 = positive sequence reactance) at the PCC

Also, the DG shall have a generator step up transformer (GSU) with a reactively grounded neutral on the high (utility) side for any installation meeting the criteria listed in the following paragraph. Reactor sizing calculations confirming conformance to Eversource design requirements shall be submitted by the customer prior to scheduling of the witness test. The customer shall also supply specifications and ratings for all equipment as it pertains to all reactor sizing calculations.

Where DG connections do not meet the criteria required for effective grounding, delta windings shall be used on the high (utility) side of the GSU, provided they are neither connected at secondary voltage nor inverter based below 100 kW. For this type of interconnection or installations with existing delta connected transformers on the utility side which are serving as a GSU, a customer provided 59N (3V0) scheme fed by three, broken−delta connected PTs on the high (utility) side of the GSU shall also be required to sense over voltages on the unfaulted phases during single phase–to−ground faults upstream of the GSU. The 59N requirement is in addition to normal protection requirements specified for DG installations at Eversource.

Eversource reserves the right to specify any aspect of the customers grounding scheme if deemed necessary by Eversource Engineering. This may include GSU winding configuration and neutral grounding method.

Please see the **Eversource DER Briefing Sheet – Effective Grounding** for additional background information.

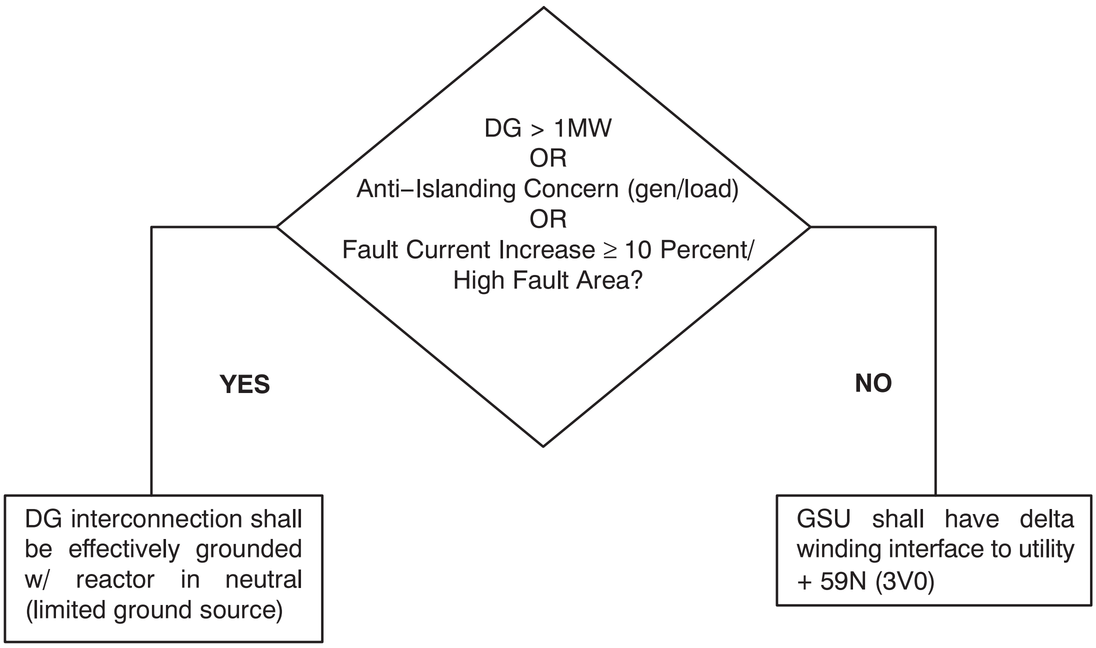


Figure 1 − Effective Grounding and GSU Winding Configuration Screening Tool

Flicker Evaluation

GENERAL – The criteria to be used for voltage flicker are based on the "GE flicker curve" as listed in IEEE 519. The calculated maximum flicker shall not exceed the values listed below, unless Engineering judgment establishes alternate limits in special situations that include, but are not limited to, tap changer and capacitor operation, and the type and number of customers on the circuit.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

1. The rate of change for a voltage dip should be assumed to be instant, from full 100 percent to 5 percent output, and vice versa.
2. Simultaneous dips on other DG sites on the circuit should be considered for the analysis if they are the same type, since a common event could affect more than one site. If the circuit occupies a large geographic area, engineering judgment may be used to determine volatility of generation output.
3. The maximum flicker should be based upon the type of generation as follows:
   a. PV – 2 percent
   b. Wind – 3 percent
   c. Hydro – 3.5 percent

Please see the **Eversource DER Briefing Sheet – Flicker Evaluation Criteria** for additional background information.

Transformer Reverse Power Capability

GENERAL

Any proposed DG that has the potential to cause reverse power flow through an Eversource substation transformer will require a System Impact Study (SIS). The SIS will specifically address the ability of the transformer to accommodate reverse power flow. The following items will be evaluated:

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

SYSTEM VOLTAGE CONTROL

A precursor to transformer excitation problems is the loss of the ability to control voltage due to various factors such as system configuration, generator location, system impedances, transformer impedance, customer load, reactive power flows, and generation output. The system impact study shall determine if system voltage control can be maintained at various boundary conditions.

In addition, the nature of the generation source shall be evaluated for impact on system voltage and transformer Load Tap Changer (LTC) operation. For example, large photovoltaic sources whose outputs can vary significantly and rapidly will impact the ability to control distribution customer voltage, and can cause excessive LTC operations. Sudden large changes in DG output that are faster than the LTC's capability to maintain voltage within the allowable range can also result in overexcitation.

LTC DESIGN

1. Reactive Type use a preventive autotransformer to limit circulating current when on bridging tap positions. This type of LTC can handle reverse power with no restrictions.
2. Resistive Type use one or two resistors to limit circulating current when bridging tap positions.
   a. Single resistor types cannot handle reverse power because of the manner in which load and circulating currents and voltages (recovery voltage) sum at the main arcing contacts – in one direction of operation. Single resistor type LTC's are unsuitable for DG / reverse power application. At a minimum, replacement of the LTC is required. Typically, however, the entire transformer must be replaced, as retrofit of another LTC type is a large involved job that requires input from both the transformer manufacturer and LTC manufacturer, and major modification to the transformer.
   b. Two resistor type LTCs can handle reverse power with no restrictions.

LTC CONTROLLER TYPE

The controller will be evaluated for the ability to recognize reverse flow and to respond with appropriate control strategies.

Voltage and current inputs must be available to the LTC controller.

LTC controllers are to be designed to sense the reverse power/positive feedback condition, and react appropriately.

Any LTC controller configuration that is not appropriate for reverse power must be replaced with a suitable controller with both voltage and current inputs.

LTC CONTROL SETTINGS

The choice of proper control strategy will depend on whether the aggregate of DG's connected to an individual transformer can "push" the transformer secondary voltage around under light load conditions that result in reverse power flow back to the transmission system (i.e., supply of VAR's by DG's).

Controllers shall have a variety of settings that can be used to “tune” LTC operation to the conditions encountered at a particular location. Such settings can be used to make location specific adjustments to LTC controller operation. The establishment of these settings will be dependent on case−by−case analysis of DG type and penetration.

CAPACITY LIMIT

Unless constrained by other more limiting DG policies, intermittent reverse power flow will be permitted up to 95 percent of the transformer’s top nameplate ampere rating with maximum cooling operational. The reverse power flow limit is based strictly on the transformer nameplate, with no consideration given to any forward power load on the transformer.

A possible consequence of allowing reverse power flow at a high percentage of the transformer nameplate rating is that the thermal aging rate of the transformer insulation will be increased, which may impact the lifespan of the transformer. Transformer insulation thermal aging is dependent on a combination of insulation temperature and time, as described in *IEEE Std. C57.91*, “IEEE Guide for Loading Mineral−Oil−Immersed Transformers and Step−Voltage Regulators.” Reverse power flow that will significantly add to the transformer insulation loss of life on a routine basis, based on the transformer specification and the insulation aging description in the latest version of *IEEE Std. C57.91*, must be evaluated. This evaluation will consider the calculated transformer insulation loss of life based on site specific ambient temperature and maximum aggregate DG power generation coincident with minimum distribution customer load on the distribution bus. Calculated loss of life that exceeds one percent per year will require further investigation of methods to mitigate the increased loss of life.

DG sources must supply a balanced three−phase output such that there would never be a situation where a substation transformer could experience forward power flow on one or more phases while experiencing reverse power flow on the other phase(s).

Please see the **Eversource DER Briefing Sheet – Transformer Reverse Power Capability** for additional background information.

Note: This section only addresses static DG power factor and does not address voltage schedules or other dynamic DG power factor control.

GENERAL

One of the potentially lowest cost methods for a DG applicant to mitigate certain voltage issues caused by their interconnection with the Eversource distribution system is to operate at a static off−unity power factor. DG applicants may be required to install equipment that can be set to operate at a power factor between 0.90 lagging (VARs to the Eversource distribution system) and 0.90 leading (VARs from the Eversource distribution system). The applicant will typically be told to operate at a power factor of 1.0, unless application review or subsequent evaluations of circuit evolutions determine that voltage rise or excessive operation of voltage control equipment (e.g. LTC's, regulators and capacitors) is an issue. It must also be verified that any DG static off−unity power factor operation will not cause the bulk power substation to violate the latest ISO−NE, NPCC, or other local regional planning criteria. The overall project power factor requirements shall be mutually agreed between the Generator−Owner and the Company.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

METHODOLOGY FOR STUDYING THE DG IMPACT ON THE SYSTEM'S POWER FACTOR

Transmission operators are concerned about the system's power factor at the point of interconnection to the transmission system. The scope of the impact study should encompass all the load and DG interconnected to the system bus for the bulk transformer which normally feeds the DG interconnection being studied.

1. Determining the Base Cases

   The system should be studied at light and peak loading conditions in order to encompass worse case conditions. During both loading conditions, determine which generators were active or interconnected when the historical load data was recorded. If generation is in the queue ahead of the interconnection being studied, take this into account for the impact study. If existing generation is not operational when the historical data was recorded, or if there is a significant amount of generation online that is behind the meter or has no telemetry, use best judgment based on historical average output for the generation source to take this into account for the study. Using existing conditions and queued generation, determine bus loading conditions to create the base case power factor.

2. Studying the New Interconnection

   Using the base case, determine the impact of the new interconnection by subtracting the output of the generator from the load at the system bus. If there is a need to operate the new interconnection at a reduced power factor to reduce the voltage impact to the system, add the new reactive load to the system bus.

   Note: If volt/VAR equipment reacts differently with generation conditions, use the aggregate feeder loading that was determined during the impact study.

   If the new interconnection negatively changes the aggregate power factor of the system bus the new interconnection may have to reduce the amount of reactive load to the system either by means of changing their output or paying for a solution to provide reactive load compensation.

Please see the **Eversource DER Briefing Sheet – Allowance for Static Off Unity Power Factor** for additional background information.

Volt – VAR Equipment Operation Frequency

GENERAL

Volt / VAR equipment on a distribution system refers to equipment that helps manage appropriate voltage levels and reactive power. This equipment includes substation transformer load tap changes (LTCs), voltage regulators, and capacitor banks. With the introduction of intermittent DG, this equipment can see increased operations throughout the day.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

In order to minimize the operations on the LTC, regulators, and capacitor banks, alternative settings may be applied which allow minor fluctuations in voltage. Any required alternative settings should be identified on a case by case basis as part of the impact study. If the impact on Volt / VAR equipment cannot be mitigated by alternative O&M costs, the Volt / VAR equipment may be required to be paid for by the generator.

Due to concern of decreased longevity of Volt / VAR equipment, it is recommended that voltage regulating equipment be limited to one operation due to DG ramping between five percent and 100 percent of nameplate power output.

MITIGATION STRATEGY

The strategy for reducing tap operations on LTCs and regulators is to reduce the set point, increase the bandwidth, and increase the time delay. Time delay settings shall also be adjusted to all regulating devices downstream, see **DSEM 13.49**. Regulator set point and bandwidth limitations are based on the voltage regulatory limitations within the state and the circuit topology. When changing regulator settings, the circuit shall be modeled to ensure low or high voltage does not occur. If a regulator is caused to operate due to DG output cycling after relaxed settings are applied, it is likely that the generator is violating the flicker policy, **DSEM 19.01**, and further upgrades or modifications to the DG are required to meet the flicker policy.

The strategy for preventing excessive operations to switched capacitor banks is to widen the window of settings for voltage and VAR controlled operations, and increase the time delay. When increasing the time delay for a capacitor bank, ensure all capacitor time delays coordinate appropriately, see **DSEM 12.102**.

A two percent change in voltage shall be allowed to occur before a tap change occurs, or capacitor bank operation.

Please see the **Eversource DER Briefing Sheet – Volt – VAR Equipment Operation Frequency** for additional background information.

Transient Overvoltage

GENERAL

Recent studies have shown that large–scale inverter–based distributed energy resources (DER) have shown that transient overvoltage is of concern due to load rejection overvoltage (LROV) by the inverters. This standard spells out the interim practice that Eversource distribution engineering will undergo while testing standards are updated to meet compliance with *IEEE 1547–2018*.

> *Note*: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

NEW DER FACILITLIES

The following practices must be adhered to for future DER impact studies. The following language shall be included in future distribution system impact studies:

> *Based on recent DER studies performed by Eversource, it has been determined that transient overvoltage is of concern due to potential load rejection overvoltage (LROV) by the inverters. There is concern that during step changes in load (such as tripping of an upstream device), the proposed inverters may cause transient over voltages in excess of 1.2pu, which can potentially cause damage to the customer's equipment, utility equipment, and/or nearby customer equipment. Due to this concern, Eversource requires that the customer demonstrate that the inverters limit their cumulative overvoltage according to the transient overvoltage curve in IEEE Std. 1547–2018 clause 7.4.2. If the inverters do not demonstrate compliance to the curve given in the standard, additional utility upgrades may be required to mitigate the overvoltage. All documentation shall include the applicable firmware version(s). The correct firmware version shall be demonstrated by the customer during witness testing/final review.*

Additionally, the DER developer may demonstrate compliance in one of the following ways:

1. Providing a copy of the most recent HECO qualified equipment list highlighting the inverter make/model and firmware that meets the above requirements. https://www.hawaiianelectric.com/documents/clean_energy_hawaii/qualified_equipment_list.pdf

2. Providing documentation that the inverter(s) have passed the Hawaiian Electric Companies (HECO) test procedure for transient overvoltage qualifications, as evaluated by a Nationally Recognized Testing Laboratory (NRTL). https://www.hawaiianelectric.com/documents/products_and_services/customer_renewable_programs/appendix_I_trov2_qualify_instructions.pdf

3. Providing a letter from the inverter manufacturer indicating that the proposed inverter is capable of and set to trip for no higher than 1.4pu voltage in 1ms or less clearing time.

4. Other means proposed by the customer/inverter manufacturer may be acceptable on a case–by–case basis.

EXISTING DER FACILITLIES

Some existing DER facilities have been shown in dynamic risk of islanding studies to potentially cause transient overvoltage concerns. Where possible, the demonstration of compliance above.

Please see the **Eversource DER Briefing Sheet – Transient Overvoltage** for additional background information.

Utility Accessible Disconnect Switch

GENERAL – The Eversource requirements and specifications for a Utility Accessible Disconnect Switch (UADS) for distributed generators are as follows.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

An externally accessible UADS is required for all generators unless waived due to state requirements or extenuating circumstances.

A UADS shall:

1. Be gang operated
2. Have a visible break when open
3. Be rated to interrupt the maximum generator facility output
4. Be capable of being locked open
5. Be easily accessible to Company personnel at all times

NH In NH, the state requirement is set by PUC 905.01, which does not allow the utility to require a UADS for generators less than 10 kW, unless specific conditions are not met by the interconnecting customer.

CT In CT, certified inverter generators less than or equal to 1 kW are exempt from the UADS requirement.

Please see the **Eversource DER Briefing Sheet – Requirements for a Utility Accessible Disconnect Switch** for additional background information.

General Standards − Large−Scale DER

GENERAL

The following set of general policy statements have been developed to guide users when considering evaluation on the feasibility of integrating large−scale DER with the Eversource distribution system. For this purpose, "large−scale DER" is defined as those resources with a primary mission to participate in the ISO−NE markets, rather than to serve the on−site usage of an Eversource retail customer. To the extent any of these policies are inconsistent with the tariff, state statutes, or state regulations, those other documents will be controlling.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

Deviation from the following general policies should be on a case−by−case basis and require approval of senior management:

1. It is the policy of Eversource to facilitate and expedite the interconnection of electric generation onto the Company's electric system consistent with applicable municipal, state, and federal rules and regulations.
2. Interconnections should adhere to standard construction and operating practices supported by industry, material and equipment manufacturers, and readily available, proven technology.
3. Unless superseded by state of federal statutes and/or regulations, Eversource should use the "But For" standard to determine the system upgrade costs that will typically be funded by the DER developer. Any design element of the upgrade project that would be rendered unnecessary if the DER project were to be withdrawn should be funded by the developer. The developer will typically not be charged for design elements that are not required to support interconnection or integration of the DER project. If an upgrade project includes surplus capacity or redundancy, over and above what is needed to integrate the DER or to eliminate a violation caused by the DER, only the portion required by the DER should be charged to the developer. This does not apply when surplus capacity is inherent in the Eversource standard equipment package.
4. Eversource will not deviate from normal design, operating, and Construction Standards to accommodate large−scale DER (including pole height, conductor size, etc.). Eversource Standard Construction and planning practices should apply, including those in the DSEM, Eastern Mass Optimal Design Guideline, and the Technical Standards for Distributed Generation Applications. This also applies to express feeders.
5. Regarding facility ownership, Eversource will consider all relevant state−specific statutes when designing interconnections and/or express feeders, to the extent it is consistent with state law, regulation, etc.
   a. Eversource will own and operate any interconnection equipment that is not within the property boundary of the DER site.
   b. Eversource will own and operate all distribution equipment on a ROW and on a public way.
6. When designing DER interconnections, Eversource will attempt to locate the POI/POCO as close as possible to the mainline feeder. Eversource will limit its ownership of equipment on the DER site.

Please see the **Eversource DER Briefing Sheet – Standards to Accommodate DER** for additional background information.

Substation Modifications

GENERAL

The following set of substation modifications policy statements have been developed to guide users when considering evaluation on the feasibility of integrating large−scale DER with the Eversource distribution system. For this purpose, "large−scale DER" is defined as those resources with a primary mission to participate in the ISO−NE markets, rather than to serve the on−site usage of an Eversource retail customer. To the extent any of these policies are inconsistent with the tariff, state statutes, or state regulations, those other documents will be controlling.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

Deviation from the following general policies should be on a case−by−case basis and require approval of senior management:

1. All appropriate Standards should apply and senior management should be consulted regarding the offering of substation real estate and/or spare breaker capacity for purposes of DER interconnection. The decision to offer a SS breaker position to a new DER will consider future expansion plans, space limitations, etc. Substation Engineering and System Planning must approve any conceptual interconnection designs that may limit future system expansion and/or reconfigurations. The Technical Review Committee (TRC) is one possible venue for this review. The DER developer should not be given a preliminary indication that a SS breaker position will be available until approval has been obtained.
2. If the closest substation cannot be modified to accommodate the DER express circuit, the next closest substation, or a new substation, may be considered.
3. **DSEM 19.012 – Transformer Reverse Power Capability**, may result in the need to upgrade the SS transformer to accommodate a DER project. In those cases, prudent system planning practices should be used to determine the appropriate transformer size.

Please see the **Eversource DER Briefing Sheet – Standards to Accommodate DER** for additional background information.

Express Feeders

GENERAL

The following set of express feeder policy statements have been developed to guide users when considering evaluation on the feasibility of integrating large−scale DER with the Eversource distribution system. For this purpose, "large−scale DER" is defined as those resources with a primary mission to participate in the ISO−NE markets, rather than to serve the on−site usage of an Eversource retail customer. To the extent any of these policies are inconsistent with the tariff, state statutes, or state regulations, those other documents will be controlling.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

Deviation from the following general policies should be on a case−by−case basis and require approval of senior management:

1. Eversource feeders will typically be built to all normal construction and power quality Standards for customer feeders, including voltage at POI. Operation of the DER on the express feeder should not limit the Company's ability to serve future customers from that feeder.
2. Future use of Express feeders to serve Eversource customers will be specifically addressed in each Interconnection Agreement.
3. Eversource should only use customary practices to acquire the permits and easements that may be necessary to site an express feeder.

Please see the **Eversource DER Briefing Sheet – Standards to Accommodate DER** for additional background information.

GENERAL

The following set of right−of−way policy statements have been developed to guide users when considering evaluation on the feasibility of integrating large−scale DER with the Eversource distribution system. For this purpose, "large−scale DER" is defined as those resources with a primary mission to participate in the ISO−NE markets, rather than to serve the on−site usage of an Eversource retail customer. To the extent any of these policies are inconsistent with the tariff, state statutes, or state regulations, those other documents will be controlling.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

Deviation from the following general policies should be on a case−by−case basis and require approval of senior management:

1. System upgrades to accommodate DER, including express feeders, should not limit or hinder the future use of Eversource ROW.
2. ROW should not be used for private distribution infrastructure owned by 3rd parties.
3. Any lateral crossings of a ROW should be designed in accordance with Eversource Standards. Ownership, maintenance, and any legal issues associated with the crossing will be included in the Interconnection Agreement or a separate agreement.
4. All requests to co−locate facilities parallel to, within, or adjacent to Eversource transmission line corridors should follow Eversource Administrative Procedure M2−SI−2008 (Co−Location Requests with Transmission).

Please see the **Eversource DER Briefing Sheet – Standards to Accommodate DER** for additional background information.

Power Factor Correction

GENERAL

The ROI Screening Process (below) has been developed to guide the evaluation and determine when mitigation is required. This process will be revisited following the anticipated revision to both the Sandia Islanding Report and IEEE–1547.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

Deviation from the following general policies should be on a case–by–case basis and require approval of senior management:

1. **DSEM 19.013** allows for off–unity power factor operation as a method from DER to mitigate steady–state voltage and flicker violations identified in the System Impact Study. Eversource is required to adhere to ISO–NE Operating Procedure OP–17 – Load Power Factor Correction. Any DER that is expected to cause a significant deviation from unity PF, as measured at the transmission interface, will be required to provide appropriate VAR support to enable compliance with OP–17.
2. Eversource shall not deviate from Substation Design Standards in order to accommodate power factor correction equipment that is only required due to the impact of a proposed DER project. For example, if standard substation design involves a single 5.4 MVAR switched capacitor bank, Eversource typically does not install a second capacitor bank to mitigate the DER.
3. Eversource usually does not own and operate dynamic VAR compensation equipment (e.g. DVAR, STATCOM) needed solely to address the impact DER.

Please see the **Eversource DER Briefing Sheet – Standards to Accommodate DER** for additional background information.

Compliance with ISO−NE Operating Procedures 14 & 18

GENERAL

ISO−New England requires that DER interconnections that aggregate 5.0 MW or greater of AC nameplate capacity at a common point of coupling comply with ISO−NE Operating Procedures 14 and 18.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

Operating Procedure 14 (OP 14) requires generator interconnections of 5 MW or greater at a Point of Common Coupling (PCC), including those on the distribution system, be defined and modeled as generators in the ISO−NE Energy Management System (EMS) system. As such, the DER must have a Designated Entity through which it communicates with ISO−NE, and must have or select a Lead Market Participant (LMP) to be responsible for the DER for compliance with all obligations under Northeast Power Coordinating Council (NPCC) and the North American Electric Reliability Corporation (NERC) operating criteria. Steps for compliance with OP 14 may take up to a year of preparation.

Operating Procedure 18 (OP 18) requires generator interconnections of 5 MW or greater, including those on the distribution system, have direct telemetry of metered generation values, including MW, MVAR, breaker status, and other telemetry to the ISO−NE. This requires installation of a local Remote Terminal Unit (RTU), including the need for backup telemetry from a nearby Eversource substation to protect for local RTU failure via a fiber optic link.

Eversource staff involved in the review of interconnection applications, and that provide customer service to applicants shall be familiar with OP 14 and OP 18, provide copies or links to customers, and will monitor compliance during the interconnection process. Eversource will communicate with ISO−NE, as needed, to coordinate compliance and to assist in the resolution of any issues of procedure interpretation. The following section provides additional details relative to the important determination of whether a “facility” triggers the 5 MW threshold for compliance.

Legacy projects installed before the new revision of OP 14 & 18 are grandfathered in and do not have to abide by the rules of these procedures. Although not required, telemetry for grandfathered projects is still provided to ISO−NE and the Company.

OP 14 GUIDELINES

The following language is derived from OP 14 and is relative to defining the 5 MW threshold.

For dispersed power generating facilities or distributed energy resources (excluding load reducers) that are interconnecting to the existing system through a common point of connection (e.g., a **common collector or an express feeder**), the following applies:

1. For the purposes of this Operating Procedure, **a common collector** is a system, usually operating at distribution or sub−transmission voltage levels, designed primarily for interconnecting capacity to a common point of connection on an existing transmission or distribution element. Where the existing point of connection is a substation, the interconnection facilities are commonly referred to as an **express feeder**. An **express feeder** serves no load other than that associated with the interconnected dispersed power generating facilities or distributed energy resource.

2. Where multiple dispersed power generating facilities or distributed energy resources are connecting to the existing system through a common point of connect at the same time, all generating facilities/resources (excluding load reducers) interconnected at the **common collector or express feeder** system will be aggregated for the determination of the less than five (5) MW eligibility threshold. However, a new dispersed power generating facility or distributed energy resource seeking to interconnect at the same common collector or express feeder system as other dispersed power

generating facilities or distributed energy resources will not be aggregated for the purposes of determining the less than five (5) MW eligibility threshold **if both following conditions are met:**

a. The other generating facilities or distributed energy resources on the common collector or express feeder system are **existing**, which, for purposes of this Operating Procedure means with executed interconnection agreements in place; **and**

b. The new dispersed power generating facility or distributed energy resource is **not an Affiliate** of the existing generating facilities or distributed energy resources on the common collector or express feeder system at the time of the interconnection request submittal.

3. The ISO may waive aggregation of an unaffiliated generating facility/resource that would otherwise be aggregated pursuant to Section II.A.2.f, if the ISO determines that not aggregating the unaffiliated generating facility/resource is acceptable from a reliability perspective.

4. ISO will consider project information included in the Generation Notification Form or Proposed Plan Application submitted pursuant to Section I.3.9 of the Tariff to determine if multiple points of connection are present.

Please see the **Eversource DER Briefing Sheet – Compliance with ISO–NE Operating Procedures 14 and 18** for additional background information.

OP−17 Compliance Survey

GENERAL

ISO−NE OP−17 establishes ranges of acceptable load power factors for various areas within the New England Control Area. Transmission operators have the responsibility to monitor the load power factor of all connected distribution loads and to maintain reactive balances defined by the ISO to maintain area voltage requirements.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

METHODOLOGY

The OP−17 compliance survey looks at regional PF requirements. Six specific load points are reviewed:

- Summer peak and intermediate
- Winter peak and intermediate
- Spring and fall light load

The substation metered megawatts and megavar quantities are then adjusted given known distributed energy resources values. Distribution, or low side, capacitor banks are not included in the survey. Distribution generation values are derived from metered quantities or estimated quantities. Current practice and preference are to utilize metered distributed generation contributions.

DETERMINATION

Distributed generation is not causing non−compliance. A separate briefing sheet is under creation to determine mitigating designs for var swings caused by distributed generation on distribution feeders.

Please see the **Eversource DER Briefing Sheet – OP−17 Compliance Survey** for additional background information.

Analyzing Non-Export Batteries, CHPs, and Base Loading Generation

GENERAL

Non-exporting, load reducing generators should be 'fast tracked' in a similar manner to current rooftop residential photovoltaics (PV).

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise

METHODOLOGY

Upon receiving a distributed generator (DG) greater than 20 kilowatts a distribution engineer should analyze and review the following screens whose failure shall result in supplemental screening:

1. Aggregate line section distributed energy resources (DER) do not exceed fifteen percent of the line section peak load
2. Aggregate DERs on a secondary does not exceed twenty kilowatts
3. Aggregate DERs on a substation transformer does not exceed 10 megawatts

The following sections highlight next steps when any of the above screens fail.

<u>1. Fifteen percent or greater distributed energy resources on line section</u>

Perform a stiffness factor calculation, risk of islanding analysis, and/or preliminary Synergi load flow analysis. Refer to DSEM 19.028 for a risk of islanding flowchart. A Synergi load flow is only necessary should the stiffness factor fall below 100.

<u>2.Twenty kilowatts or greater distributed energy resources on a secondary</u>

Develop a secondary model and run a Synergi load flow at light load to determine voltage rise and voltage flicker.

<u>3.Ten megawatts or greater distributed energy resources on a substation transformer</u>

Run a Synergi analysis of the substation and include the transmission sources. Verify that ninety-five percent of the substation transformer nameplate capacity is not exceeded with installed and queued generation.

GUIDELINES

☒

Determine whether the project is on a shared secondary. If the project is on a shared secondary, only a secondary load flow model is necessary. If the project is not on a shared secondary, all other required screens are required.

<u>Gathering Initial Data and Modeling</u>

Shared Secondary and/or Less than 100 kW

If the proposed DER is less than 100 kW and on a shared secondary, model the secondary per GIS. Include all customers that are fed from the same distribution transformer. Additionally, utilize customer usage information in the Spring or Fall to determine an accurate load to use in the Synergi model. If only a peak value is available, scale the value to 33%. Other minimum loading scaling factors may be used at the discretion of the local engineer per local engineering practices.

Standalone Generator or Greater than 100 kW

If the project is not on a shared secondary, or is larger than 100 kW, a stiffness factor and risk of islanding analysis shall be performed. Additionally, if the DER produces a stiffness factor result less than 100 kW, a Synergi load flow analysis shall be performed.

For circuits where DER penetration is less than thirty percent, include all distributed energy resources that are greater than or equal to 100 kW. Rooftop solar PVs may be omitted from this supplemental analysis. The DERs nameplate value and location may be found in the local DER tracking sheet. A Synergi analysis should be performed at light and peak load, for both cases where generation is on and off. If the proposed project is a base loader, combined head and power (CHP), or battery energy storage (BESS) and is anticipated to operate twenty-four seven, the night time minimum load with generation on and off cases should be studied. When performing the first four daytime analyses, ensure that the generation contribution from PVs is accounted for. For the instances of load flow during the night, photovoltaic generation will need to be turned off. Any batteries, fuel cells, etc that are anticipated to operate twenty-four seven; however, should be included in the night modeling.

For circuits that have DER penetrations more than thirty percent, all DERs shall be accounted for in a lumped manner. When lumping rooftop DERs downstream of side taps, ensure that they are allocated to the correct phase. All other assumptions stated above in the lower penetrated circuits should be considered when analyzing higher penetrated circuits.

FORMAL SCREENS

Please see the **Eversource DER Briefing Sheet – Analyzing Non-Export Batteries, CHPs, and Base Loading Generation** for additional background information.

DER Ride Through Settings

GENERAL

New England's Independent Systems Operator (ISO–NE) requires ride through settings for DER in the state of Massachusetts to support bulk reliability in the New England region. This policy is effective for all operating companies as of June 1, 2018.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

INVERTER RIDE THROUGH SETTINGS

All projects shall be certified per the requirements of UL1741–SA, as a grid support utility interactive inverter, and have the voltage and frequency trip points specified in Tables 1 and 2. The inverters shall ride through per requirements of UL1741–SA and shall follow the ride through capabilities specified in Table 3 and 4. Other functions required by UL1741–SA shall comply with the requirements specified in Table 5.

Table 1 – Inverter's Voltage Trip Settings

Tripping Voltage (%)	Clearing Time (Seconds)
120	0.16
110	2.10
88	2.00
50	1.10

Table 2 – Inverter's Frequency Trip Settings

Frequency (Hz)	Clearing Time (Seconds)
62.0	0.16
60.6	300
58.5	300
56.5	0.16

Table 3 – Inverter's Voltage Ride Through Settings

Ride Through Voltage (%)	Operating Mode	Ride Through Time (Seconds)
120 ≤ V	N/A	No ride through
110 ≤ V < 120	Momentary Cessation	2
88 < V < 110	Continuous Operation	Infinite
50 ≤ V ≤ 88	Mandatory Operation	1.9
V < 50	Momentary Cessation	1.0

Table 4 – Inverter's Frequency Ride Through Capability

Frequency Rance (Hz)	Operating Mode	Ride Through Time (Seconds)
f > 62.0	N/A	N/A
60.6 ≤ f < 62.0	Mandatory Operation a	299
58.5 < f < 60.6	Continuous Operation	Infinite
56.5 < f ≤ 58.5	Mandatory Operation b	299
f ≤ 56.5	N/A	N/A

Table 5 – Inverter's

Function	Status	Default Settings[1]
Anti–Islanding	ON	ON
Low / High Voltage Ride Through	ON	Per Table 3 above
Low / High Frequency Ride Through	ON	Per Table 4 above
SPF, Specified Power Factor (fixed power factor)	ON	Unity p.f[2]
Q (V), Volt–Var Function w/ Watt or Var Priority*	OFF	OFF
RR, Normal Ramp Rate	ON	100% of maximum current output per second[3]
Soft Start	ON	Minimum soft start ramp rate
FW, Freq–Watt Function OFF	OFF	OFF
* Also known as Dynamic Volt/VAR Operations		
1 Unless otherwise required by the utility		
2 Per existing utility interconnection requirements		
3 With a range of adjustments between 1% – 100%. Specific settings by mutual agreement with utility		

Please see the **Eversource DER Briefing Sheet – MA TSRG DER Ride Through Settings** for additional background information.

General Considerations

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

GENERAL

A study of either spot or area secondary network interconnection shall ensure that the presence and operation of DG meets the following criteria before allowing interconnection.

1. Network protectors (NP) shall not be used to connect, separate, switch, serve as breaker failure backup, or in any manner isolate a network or network primary feeder, to which DG is connected from the remainder of the network, unless the protectors are rated and tested per applicable Standards for such an application.
   a. IEEE C37.108TM−2002 [B8] and IEEE C57.12.44TM−2000 [B9] provide guidance on the capabilities of network systems to accept distributed resources.
2. DG installations on a network, using an automatic transfer scheme, in which load is transferred between the DG and the distribution system in a momentary make−before−break operation, shall meet all the requirements of this section regardless of the duration of paralleling, except by consent of Eversource. Power flow during this transition shall always be positive from the distribution system to the load and the DG, unless approved by and coordinated with Eversource.
3. The DG shall have provisions to monitor instantaneous power flow at the point of common coupling (PCC) for reverse power relaying, minimum import relaying, dynamically controlled inverter functions, and similar applications to prevent reverse power flow through network protectors.
4. The DG has provisions to maintain a minimum import level at the PCC as determined by Eversource.
5. The DG has provisions to control DG operation or disconnect the DG from the distribution system base on an autonomous setting at the PCC and/or a signal sent by Eversource.
6. The DG shall not cause any network protector (NP) to exceed its loading or fault−interrupting capability.
7. The DG shall not cause any NP to separate dynamic source.
   a. See C37.108 for discussion and definition of “dynamic sources/systems”
8. The DG shall not cause any NP to connect two dynamic systems together.
9. The DG shall not cause any NP to operate more frequency than prior to DG operation.
10. The DG shall not prevent or delay the NP from opening for faults on the distribution system.
11. The DG shall not delay or prevent NP closure.
12. The DG shall not energize any portion of the distribution system when the distribution system is de−energized.
13. The DG shall not require the NP settings to be adjusted, except by consent of Eversource.
14. The DG shall not prevent reclosing of any network protectors installed on the network. This coordination shall be accomplished without requiring any changes to prevailing network protector clearing time practices of the distribution system.

Spot Networks

GENERAL

The proposed generating facility to be interconnected to the load side of spot network protectors must utilize an inverter–based equipment package, and when aggregated with other inverter–based generation, shall not exceed the lesser of five percent of a spot network's maximum load or 50 kW. Under no condition shall the interconnection of a generating facility result in a backfeed of, or cause unnecessary operation of any spot network protectors. All inverters must be IEEE 1547 and UL 1741 compliant and certified to stop conducting prior to the three cycle response of the network protector relays.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

In addition to the requirements under Category 4 in Section 19 of the DSEM, all network interconnections shall also align with all sections of IEEE 1547 and IEEE 1547.6. Below are additional requirements with regard to IEEE 1547 compliance on Eversource networks.

1. Connection of the generating facility to the distribution system shall be permitted only if the network bus is already energized by more than 50 percent of the installed network protectors. The customer shall also install a utility grade control scheme capable of monitoring the status of all network protectors and will trip a dedicated generator breaker instantaneously any time the number of closed network protectors falls to 50 percent or less.
2. The generating facility shall comply with all Eversource anti–islanding requirements.
3. The customer shall install minimum import protection (32 relay functionality) that is set to trip a dedicated generator breaker(s) and isolate all generation from the distribution system any time power import at the metering location drops below five percent of the generator facility's total gross nameplate rating.

Please see the **Eversource DER Briefing Sheet – Spot Networks** for additional background information.

Area Networks

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

GENERAL

A generating facility proposed to be interconnected to the load side of an area network protector must utilize an inverter–based equipment package and meet all of the following requirements in addition to the requirements under Category 4 in Section 19 of the DSEM.

1. When aggregated with other inverter–based generation, the DG shall not exceed 50 kW at any location. A location is defined as any manhole, secondary network vault, or service box. This criteria is designed to ensure that no more than 50 kW of DG is located on the same secondary network node.
2. In addition, the aggregate DG interconnected to an area network grid shall be limited to three percent of the maximum network transformer connected kVA with the feeder supplying the largest number of network units out of service, or a maximum of 500 kW, whichever is less.
3. The DG shall comply with all applicable Standards (e.g. IEEE 1547, IEEE 1547.6, UL 1741, etc.)
4. The DG shall comply with all Eversource interconnection requirements.
5. The generation facility shall comply with all Eversource anti–islanding requirements.
6. The customer shall ensure that the DG cannot export power to the area network at any time under any contingency. Load history, dynamic network studies, engineering design drawings or additional equipment may be required by Eversource Engineering in order to allow for interconnection.

Please see the **Eversource DER Briefing Sheet – Area Networks** for additional background information.

Impact of DERs on Substation High Speed Bus Transfer Schemes

GENERAL

A high−speed bus transfer scheme is a standard feature in distribution bus design in Connecticut and Western Massachusetts. The intent of the transfer scheme is to immediately resupply the load served by a distribution bus which has been de−energized due to loss of its normal supply. This is accomplished by rapidly closing a tie breaker, connecting the bus to an adjacent source. This issue impacts most two and three transformer bulk supply substations where non−inverter DER applications are seeking to interconnect to one of the station's feeders.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

The loss of the normal source can be due to a failure of the supplying substation transformer, or more commonly, the portion of the transmission system (usually a transmission line) which feeds that transformer. Since the bus transfer is nearly instantaneous, load supplied by the distribution bus only experiences a momentary interruption that is less than 100 milliseconds. However, certain DERs supplied by the bus can be quite sensitive to this momentary interruption, and have been damaged when the bus transfer connects to the alternate supply due to loss of synchronization.

MITIGATION STRATEGY

The high−speed bus transfer scheme of five seconds provides any interconnected DERs adequate time to trip offline prior to the transfer taking place.

The DER customer also has the option to willingly accept liability for any damage sustained by their generator during a bus transfer operation.

If the installation of a non−inverter based DER requires interconnection to a feeder supplied by a bus section which serves a sensitive customer, consideration should be given to the impact the DER may have on the high−speed bus transfer scheme design, and the potential impact it may have on the sensitive customer. This may influence the changes and require a high−speed bus transfer scheme, or even the interconnection location or arrangement of the feeders within the station.

If unforeseen circumstances exist, such as the presence of sensitive customers elsewhere on the same bus section, which may favor implementation of other options (such as force tripping the feeder breaker supplying the DER), then it is recommended that these situations be dealt with on a case−by−case basis.

Please see the **Eversource DER Briefing Sheet – Impact of DERs on Substation High Speed Bus Transfer Schemes** for additional background information.

Compliance with ISO−NE Operating Procedures 14 & 18

GENERAL

ISO−New England requires that DER interconnections that aggregate 5.0 MW or greater of AC nameplate capacity at a common point of coupling comply with ISO−NE Operating Procedures 14 and 18.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

Operating Procedure 14 (OP 14) requires generator interconnections of 5 MW or greater at a Point of Common Coupling (PCC), including those on the distribution system, be defined and modeled as generators in the ISO−NE Energy Management System (EMS) system. As such, the DER must have a Designated Entity through which it communicates with ISO−NE, and must have or select a Lead Market Participant (LMP) to be responsible for the DER for compliance with all obligations under Northeast Power Coordinating Council (NPCC) and the North American Electric Reliability Corporation (NERC) operating criteria. Steps for compliance with OP 14 may take up to a year of preparation.

Operating Procedure 18 (OP 18) requires generator interconnections of 5 MW or greater, including those on the distribution system, have direct telemetry of metered generation values, including MW, MVAR, breaker status, and other telemetry to the ISO−NE. This requires installation of a local Remote Terminal Unit (RTU), including the need for backup telemetry from a nearby Eversource substation to protect for local RTU failure via a fiber optic link.

Eversource staff involved in the review of interconnection applications, and that provide customer service to applicants shall be familiar with OP 14 and OP 18, provide copies or links to customers, and will monitor compliance during the interconnection process. Eversource will communicate with ISO−NE, as needed, to coordinate compliance and to assist in the resolution of any issues of procedure interpretation. The following section provides additional details relative to the important determination of whether a “facility” triggers the 5 MW threshold for compliance.

Legacy projects installed before the new revision of OP 14 & 18 are grandfathered in and do not have to abide by the rules of these procedures. Although not required, telemetry for grandfathered projects is still provided to ISO−NE and the Company.

OP 14 GUIDELINES

The following language is derived from OP 14 and is relative to defining the 5 MW threshold.

For dispersed power generating facilities or distributed energy resources (excluding load reducers) that are interconnecting to the existing system through a common point of connection (e.g., a **common collector or an express feeder**), the following applies:

1. For the purposes of this Operating Procedure, **a common collector** is a system, usually operating at distribution or sub−transmission voltage levels, designed primarily for interconnecting capacity to a common point of connection on an existing transmission or distribution element. Where the existing point of connection is a substation, the interconnection facilities are commonly referred to as an **express feeder**. An **express feeder** serves no load other than that associated with the interconnected dispersed power generating facilities or distributed energy resource.
2. Where multiple dispersed power generating facilities or distributed energy resources are connecting to the existing system through a common point of connect at the same time, all generating facilities/resources (excluding load reducers) interconnected at the **common collector or express feeder** system will be aggregated for the determination of the less than five (5) MW eligibility threshold. However, a new dispersed power generating facility or distributed energy resource seeking to interconnect at the same common collector or express feeder system as other dispersed power

generating facilities or distributed energy resources will not be aggregated for the purposes of determining the less than five (5) MW eligibility threshold **if both following conditions are met:**

a. The other generating facilities or distributed energy resources on the common collector or express feeder system are **existing**, which, for purposes of this Operating Procedure means with executed interconnection agreements in place; **and**

b. The new dispersed power generating facility or distributed energy resource is **not an Affiliate** of the existing generating facilities or distributed energy resources on the common collector or express feeder system at the time of the interconnection request submittal.

3. The ISO may waive aggregation of an unaffiliated generating facility/resource that would otherwise be aggregated pursuant to Section II.A.2.f, if the ISO determines that not aggregating the unaffiliated generating facility/resource is acceptable from a reliability perspective.
4. ISO will consider project information included in the Generation Notification Form or Proposed Plan Application submitted pursuant to Section I.3.9 of the Tariff to determine if multiple points of connection are present.

Please see the **Eversource DER Briefing Sheet – Compliance with ISO–NE Operating Procedures 14 and 18** for additional background information.

OP−17 Compliance Survey

GENERAL

ISO−NE OP−17 establishes ranges of acceptable load power factors for various areas within the New England Control Area. Transmission operators have the responsibility to monitor the load power factor of all connected distribution loads and to maintain reactive balances defined by the ISO to maintain area voltage requirements.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

METHODOLOGY

The OP−17 compliance survey looks at regional PF requirements. Six specific load points are reviewed:

- Summer peak and intermediate
- Winter peak and intermediate
- Spring and fall light load

The substation metered megawatts and megavar quantities are then adjusted given known distributed energy resources values. Distribution, or low side, capacitor banks are not included in the survey. Distribution generation values are derived from metered quantities or estimated quantities. Current practice and preference are to utilize metered distributed generation contributions.

DETERMINATION

Distributed generation is not causing non−compliance. A separate briefing sheet is under creation to determine mitigating designs for var swings caused by distributed generation on distribution feeders.

Please see the **Eversource DER Briefing Sheet – OP−17 Compliance Survey** for additional background information.

GENERAL

The automatic under−frequency load shedding (UFLS) program preserves the security and integrity of the bulk power system during declining system frequency events in accordance with the NERC UFLS reliability standard characteristics. This program is designed to arrest declining frequency, and assist recovery of frequency following under−frequency events. Independent Source Operator – New England (ISO−NE) is currently in the process to define which generators must be compliant to the following standards:

- PRC−006−NPCC−1
- NPCC Directory 12
- ISO−NE OP−134
- ISO−NE Compliance Bulletin for PRC−006−1 and PRC−006−NPCC−01

Presently, ISO−NE's statement illustrates that their concern for such projects are NERC registered generators above 20 MVA and directly tied to transmission voltages 100 kV and greater, as well as a list of non−registered NERC generators that are defined below in Table 2.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

Each generator owner shall set each under−frequency trip relay, if so equipped, below the appropriate generator under−frequency trip protection settings threshold curve in Figure 1 of PRC−006−NPCC−1. In cases where a generator owner has a generator that cannot physically meet the set points defined by the curve in Figure 1, the generator owner shall arrange for a distribution provider or transmission owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator.

In−service generators not compliant and currently accounted for by compensatory load shedding in the Eversource UFLS program will be maintained until ISO−NE makes a final determination as to which generators must meet requirements of PRC−006−NPCC−01. New generators that cannot set under−frequency relays to be compliant with PRC−006−NPCC−01 may be responsible for costs associated with adding compensatory load shedding to the Eversource UFLS program.

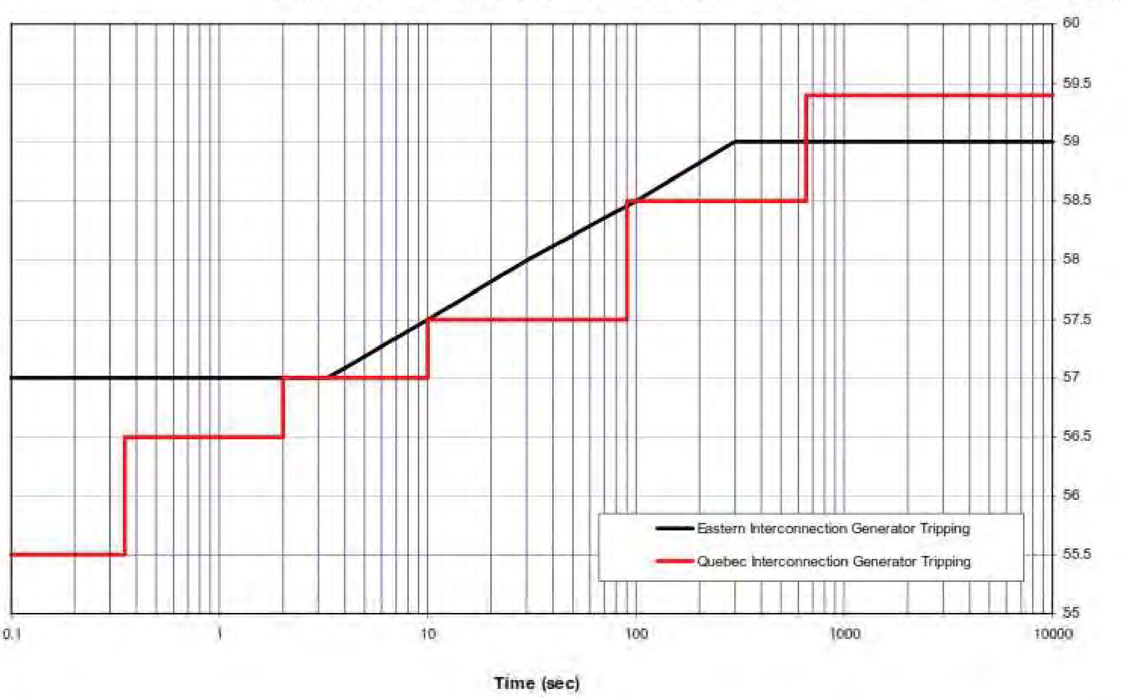
Table 1 below provides five distinct under−frequency relay trip settings that are applied to trip load at five distinct frequency thresholds.

Table 1 – Under−Frequency Trip Settings

Frequency Threshold (Hz)	Total Operating Time (sec)	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
59.5	0.3	6.5 – 7.5	6.5 – 7.5
59.3	0.3	6.5 – 7.5	13.5 – 14.5
59.1	0.3	6.5 – 7.5	20.5 – 21.5
58.9	0.3	6.5 – 7.5	27.5 – 28.5
59.5	10.0	2 – 3	29.5 – 31.5

The UFLS program also requires generators to remain connected to the electric system during declining frequencies and have under–frequency trip settings, if equipped, to not trip above the threshold curve provided in PRC–006–NPCC–1 Figure 1. Figure 1 is provided below:

Figure 1
Thresholds for Setting Underfrequency Trip Protection for Generators



The Company also complies with ISO–NE's mandate that all new generator applications be equipped with frequency ride through settings, as defined in DSEM 19–1.5. The frequency ride through settings comply with NPCC settings for new generator applications.

Table 2 – Additional Generators Needed to Support the New England UFLS Program

Generator Name	ISO Lead Market Participant	Summer Seasonal Capability	Presently NERC Registered
Kibby Wind Power	TransCanada Power Marketing, Ltd	18.275	
Amoskeag	Public Service Company of New Hampshire	16.781	
Bethlehem	GDF Suez Energy Marketing NA, Inc	15.303	
Bonny Eagle/W. Buxton	Brookfield White Pine Hydro LLC	16.151	
Branford 10	NRG Power Marketing LLC	15.840	
Bucksport G3	Tenaska Power Services Co	15.941	
Burlington GT	Burlington Electric Department	19.104	
Cape GT 4	NextEra Energy Power Marketing	15.487	
Cape GT 5	NextEra Energy Power Marketing	15.822	
Dartmouth CT Generator 3	Consolidated Edison Energy, Inc	18.812	
Deerfield 2/LWR Drfield	TransCanada Power Marketing, Ltd	19.275	
DG Whitefield, LLC	Exelon Generation Company, LLC	15.603	
Doreen	Essential Power Massachusetts	15.820	
Franklin Drive 10	NRG Power Marketing LLC	15.417	
Harris 1	Brookfield White Pine Hydro LLC	16.790	
Hemphill 1	Springfield Power, LLC	16.968	
Indeck Alexandria	Indeck Energy–Alexandria, LLC	15.031	
Kendall Jet 1	Kendall Green Energy, LLC	18.000	
Kendall Steam 2	Kendall Green Energy, LLC	19.669	
Kibby Wind Power	TransCanada Power Marketing, Ltd	18.275	
L Street Jet	Exelon Generation Company, LLC	16.030	
Lower Lamoille Composite	Green Mountain Power Corporation	15.800	
MAT3	MATEP, LLC	17.970	
Matep (Diesel)	MATEP, LLC	17.120	
Norwich Jet	Connecticut Municipal Electric Energy Cooperative	15.255	
Pinetree Power	GDF Suez Energy Marketing NA, Inc	16.465	
Ryegate 1–New	Vermont Electric Power Company	19.560	
Schiller CT 1	Public Service Company of New Hampshire	17.621	
Secrec–Preston	Connecticut Light and Power Co	15.857	
So. Meadow 6	NextEra Energy Power Marketing	16.623	
Swanton GT–1	Vermont Public Power Supply Authority	19.304	
Swanton GT–2	Vermont Public Power Supply Authority	19.349	
Tamworth	GDF Suez Energy Marketing NA, Inc	20.074	
Torrington Terminal 10	NRG Power Marketing LLC	15.638	

Please see the **Eversource DER Briefing Sheet – Automatic Under–Frequency Load Shedding** for additional background information.

FERC vs State Jurisdiction 19.039

Section

SCOPE – Requests to interconnect DER to the Eversource distribution system must be processed in accordance with either the applicable state interconnection tariff or the ISO–NE tariff (Schedule 23: Standardized Small Generator Interconnection Procedures of Section II of the ISO–NE Open Access Transmission Tariff). Both processes involve similar (or identical) technical screens and system impact study requirements. However, the administration of many key aspects of the process are significantly different. In addition, for FERC jurisdictional projects (i.e. those that follow the ISO–NE procedures) the resulting Interconnection Agreement must be filed with FERC. In the past, FERC has enforced economic penalties on transmission owners for failure to file agreements in a timely manner. For these reasons, it is critical that Eversource assign each new interconnection request to the appropriate jurisdiction. This briefing sheet documents the process that will be used to determine the proper jurisdiction.

GENERAL – The jurisdictional determination shall follow the “Decision Tree” found on the final page of this document. The discussion below provides details on the various factors used in the decision process.

In addition, the team concluded that a review be performed of all existing Interconnection Agreements to determine if FERC filing is warranted.

Definitions

Definition of a “Distribution Facility”

For the purposes of evaluating the applicability of ISO–NE Schedule 22 and/or 23, the Distribution Facility (“DF”) to which a generator interconnects shall be determined as noted below. This convention will be used both for the generator requesting a new or revised interconnection and for any existing generators (or other wholesale transactions) that may influence the jurisdictional determination.

The DF is the collection of Eversource–owned equipment that creates the electrical path by which the generator accesses the ISO–NE wholesale market. This path may involve multiple circuits segments at different voltages and with different circuit identifiers. The DF will generally start with the Point–of–Ownership–Change (i.e. the specific point at which customer–owned equipment interconnects to Eversource–owned equipment) and will proceed to the ISO–NE administered transmission system along an identifiable electrical path. The path will terminate at the bus position on the low–voltage side of the transmission substation transformer. For non–radial configurations, it may not be possible to determine the unique path by which the generator will access the transmission system. In such cases, the DF will involve multiple paths to multiple terminations. For portions of the system subject to source switching, the normal system configuration should be considered when making this determination.

Special considerations when defining the DF

1. Uncertainty in the exact DF
For larger Distributed Generation (“DG”) projects, the nearest Eversource facility may not ultimately be the DF to which the project interconnects. For example, the nearest facility may have low–voltage, single phase, small wire, etc. A more distant circuit, or even a new circuit, may be the actual DF when and if the project moves into the impact study and construction phases. In these cases, caution should be used in defining the DF that is used to determine jurisdiction. If there is the possibility that the ultimate Point of Interconnection (“POI”) is to a DF that is subject to the ISO–NE open access transmission tariff (“OATT”), the project may need to go through the ISO–NE interconnection process.

2. Express Feeders
Projects that are expected to require the construction of an express feeder must also be given special attention. The exact route and termination of the new feeder may be unknown at the time of application. Ultimately, it may be a tap (and recloser) into an existing circuit, or it may be a new circuit breaker. Also, the exact location of the POI may be uncertain. If no dual–use facilities are involved (i.e. those hosting

customers, now or in the future), then it may be appropriate for the entire substation transformer to be considered as the DF to which the DG is interconnecting. In general, distribution facilities that are constructed for the sole purposes of making sales for resale in interstate commerce (such as participation in the ISO−NE markets) are not "dual use" facilities.[1] If any ambiguity exists, transferring the project into the ISO−NE interconnection process should be considered.

What Types of Transactions result in a "Jurisdictional" Distribution Facility?

- Eversource wholesale delivery service to the Co−ops, Municipals, etc. for resale to end−use retail customers
- DG that are registered as assets and participate in the ISO−NE markets (including energy, capacity or ancillary services). This applies even for assets for which Eversource is the Lead Market Participant.

Note: only commercially operating DG will be considered, i.e. DG projects "in the queue" or under development will not trigger jurisdiction of a Distribution Facility. However, if a DF previously hosted a commercial DG making wholesale sales, and the DG has since been shut−down, the jurisdiction trigger still exists.

A retail customer interconnecting a new Generating Facility that will produce electric energy to be consumed only on the retail customer's site;

Exemption to ISO−NE Schedule 22/23

An interconnection request to a "FERC Jurisdictional Distribution Facility" must follow the ISO−NE Schedule 22/23 process unless it meets one of the following exemptions:

1. **A retail customer interconnecting a new Generating Facility that will produce electric energy to be consumed only on the retail customer's site;**

This exemption is for on−site "behind the meter" DG, including net metering, that does not export power to the grid.

2. **A request to interconnect a new Generating Facility to a distribution facility that is subject to the Tariff if the Generating Facility will not be used to make wholesale sales of electricity in interstate commerce;**

Any project that will be registered and participating in the ISO−NE Markets (i.e. any SOG or FCM resource) would represent a "wholesale sale" and fail this exemption, but may qualify for exemption #3.

3. **A request to interconnect a Qualifying Facility (as defined by the Public Utility Regulatory Policies Act, as amended by the Energy Policy Act of 2005 and the regulations thereto), where the Qualifying Facility's owner intent is to sell 100% of the Qualifying Facility's output to its interconnected electric utility.**

[1] "Dual Use" facilities are distribution facilities used both for retail and wholesale purposes. The first wholesale use of a distribution facility for interconnection purposes does not trigger FERC jurisdiction over the distribution facility and the need to file the interconnection agreement. The second wholesale use of a dual use or wholesale distribution facility is FERC jurisdictional. *See Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003*,* FERC Stats. And Regs. 31,146 at P 804 (the Commission may assert jurisdiction over interconnections to local distribution facilities where two requirements are met: (1) there is a preexisting interconnection and (2) there is a wholesale transaction over these local distribution facilities prior to the new interconnection request being made.)

Most net metered projects will be able to meet the definition of a “Qualifying Facility.” Most also have the intent to sell 100% to the utility (e.g. under a net metering tariff). However, if the project intends to sell energy to Eversource and capacity to another party, it would not satisfy this exemption. Note: if Eversource registers the output of a QF in the ISO−NE markets, that registration does not nullify this exemption. However, if the project developer or third party attempts to register the QF in the capacity or ancillary services market while the project is still in the interconnection process, ISO−NE may require the project to resubmit the interconnection request under Schedule 22/23.

What Defines a Qualifying Facility (QF)?

When reviewing a new interconnection request, QF status will apply if the facility 1) submits evidence of a valid FERC QF certification or self−certification, 2) is less than 1 MW and applicant attests that it satisfies all relevant criteria, or 3) applicant is ≥ 1 MW and attests that it intends to file for FERC QF certification and that it satisfies all relevant criteria.

Note: when option #3 (above) is used, Eversource will require proof of QF certification prior to the effective date of the interconnection agreement.

The above is based on 161 FERC 61,091 in Docket QF17−852−000.

Three Types of Interconnection Requests (see Decision Tree on next page)

1. FERC Jurisdictional – Order 2003/2006 and ISO−NE Schedule 22/23 Apply

[path 2, 3, and 4 on the Decision Tree]

QF or Non−QF Project requesting to interconnect to a jurisdictional DF, except for QFs intending to sell 100% of the output to Eversource (i.e. by participating in net metering or other state program). Three−party pro forma IA.

2. FERC Jurisdictional – Order 2003/2006 and ISO−NE Schedule 22/23 do not Apply

[path 6 on the Decision Tree]

QF or Non−QF Project requesting to interconnect to a jurisdictional DF, except for QFs intending to sell 100% of the output to Eversource (i.e. by participating in net metering or other state program). Three−party pro forma IA.

3. State Jurisdictional

[path 1, 5, 7 and 8 on the Decision Tree]

QF Project requesting to interconnect to either jurisdictional DF or non−jurisdictional DF that intends to sell 100% of the output to Eversource (including capacity and ancillary service products), i.e. by participating in net metering or other state programs.

Non−QF Project requesting to interconnect to a non−jurisdictional DF.

Treatment of Existing Interconnection Agreements

Eversource is party to existing interconnection agreements that have never been filed with FERC (i.e. they were initially deemed to be State jurisdictional and, thus, filed only with the state regulator).

There are two categories of primary concern: 1) DG that no longer sells energy to Eversource, and 2) DG that sells energy to Eversource but sells other products to a third party or in the wholesale market.

It is recommended that a review be performed of all existing Interconnection Agreements to determine if FERC filing is warranted.

Table 1: Interconnection Request Jurisdictional Decision Tree

FERC Jurisdictional Facility (Note 1)	Qualifying Facility (Note 2)	Selling 100% to Host Utility (Note 3)	Interconnection Procedure	Interconnection Agreement (Note 4)
Yes	Yes	Yes	State	State
		No	ISO Schedule 22 or 23	LGIA or SGIA − 3 Party
	No	Yes	ISO Schedule 22 or 23	LGIA or SGIA − 3 Party
		No	ISO Schedule 22 or 23	LGIA or SGIA − 3 Party
No	Yes	Yes	State	State
		No	State	LGIA or SGIA − 2 Party
	No	Yes	State	State
		No	State	State

Notes

1. FERC Jurisdictional Facilities means all Transmission Facilities plus Distribution Facilities that are used to "transmit electric energy in interstate commerce on behalf of a wholesale purchaser pursuant to a Commission−filed OATT." See guideline sections *"Definition of a Distribution Facility"* and "*What Types of Transactions result in a Jurisdictional Distribution Facility"* and list below.
2. QF status will apply if the facility 1) provides evidence of a valid FERC QF certification, 2) is less than 1 MW and owner attests that it satisfies the relevant criteria, 3) project >=1MW, owner intends to file for QF status and attests that it satisfies the relevant criteria. Note: when option #3 (above) is used, Eversource will require proof of QF certification prior to the effective date of the interconnection agreement.
3. At the time of application, DG group should request applicant to describe their intentions relative to power sales. Applicant may not be certain of future third party sale opportunities at time of initial application. If projects do not qualify for net metering and are unlikely to have a long−term PPA with Eversource, may be best to assume project will NOT sell 100% to Host Utility. Regardless of SOG status, QF and Net Metered facilities are considered as retail transactions selling 100% to Host Utility. However, future sales of Capacity or Ancillary Services to self or third party may trigger need to file IA at FERC. See list below.
4. Agreements originally executed under State jurisdiction must be periodically reviewed for possible FERC filing. See PSNH filings in 2012 and 2014 and FPL.

Wholesale Transactions (for purposes of Decision #3)
Wholesale Delivery (Muni, Coop, etc.)
DG registered at ISO−NE to sell Energy, Capacity or Ancillary Service

Sales to the Host Utility (for purposes of Decisions #3)
DG Net Metered (all products sold to Eversource)
DG QF sales to Eversource (all products sold to Eversource)

Maximum Allowable DG Fault Current Contribution

GENERAL

The following set of maximum allowable fault current contribution policy statements have been developed to guide users when considering evaluation on the feasibility of integrating DER. To the extent any of these policies are inconsistent with the tariff, state statutes, or state regulations, those other documents will be controlling.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

Deviation from the following general policies should be on a case–by–case basis and require approval of senior management:

1. The maximum allowable fault duty on the station bus is 10 kA without the use of reactors. The DER interconnection can not cause the substation bus fault duty to exceed 10 kA, or result in exceeding the interrupting rating of distribution line equipment.
2. DER interconnections, in aggregate with other generation on the distribution circuit, should not contribute more than 10 percent to the maximum fault current of the distribution circuit at the point on the high voltage (primary) level nearest the proposed Point of Common Coupling (PCC).
3. If either of the above requirements are violated, a System Impact Study (including a Protection Review*) will be required. As part of the System Impact Study, remediating actions and costs will be provided to the customer for consideration as to whether or not to proceed with the installation.

Note: *The Protection Review performed within the System Impact Study should not only verify proper protection and coordination of protective systems, but should also ensure that the pickup threshold settings of existing protective devices (especially for ground faults) have not be desensitized as a result of the infeed from the proposed DER installation.

Please see the **Eversource DER Briefing Sheet – Standards to Accommodate DER** for additional background information.

Impact of DERs on Substation High Speed Bus Transfer Schemes

GENERAL

A high–speed bus transfer scheme is a standard feature in distribution bus design in Connecticut and Western Massachusetts. The intent of the transfer scheme is to immediately resupply the load served by a distribution bus which has been de–energized due to loss of its normal supply. This is accomplished by rapidly closing a tie breaker, connecting the bus to an adjacent source. This issue impacts most two and three transformer bulk supply substations where non–inverter DER applications are seeking to interconnect to one of the station's feeders.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

The loss of the normal source can be due to a failure of the supplying substation transformer, or more commonly, the portion of the transmission system (usually a transmission line) which feeds that transformer. Since the bus transfer is nearly instantaneous, load supplied by the distribution bus only experiences a momentary interruption that is less than 100 milliseconds. However, certain DERs supplied by the bus can be quite sensitive to this momentary interruption, and have been damaged when the bus transfer connects to the alternate supply due to loss of synchronization.

MITIGATION STRATEGY

The high–speed bus transfer scheme of five seconds provides any interconnected DERs adequate time to trip offline prior to the transfer taking place.

The DER customer also has the option to willingly accept liability for any damage sustained by their generator during a bus transfer operation.

If the installation of a non–inverter based DER requires interconnection to a feeder supplied by a bus section which serves a sensitive customer, consideration should be given to the impact the DER may have on the high–speed bus transfer scheme design, and the potential impact it may have on the sensitive customer. This may influence the changes and require a high–speed bus transfer scheme, or even the interconnection location or arrangement of the feeders within the station.

If unforeseen circumstances exist, such as the presence of sensitive customers elsewhere on the same bus section, which may favor implementation of other options (such as force tripping the feeder breaker supplying the DER), then it is recommended that these situations be dealt with on a case–by–case basis.

Please see the **Eversource DER Briefing Sheet – Impact of DERs on Substation High Speed Bus Transfer Schemes** for additional background information.

Under–Frequency Load Shedding

GENERAL

The automatic under–frequency load shedding (UFLS) program preserves the security and integrity of the bulk power system during declining system frequency events in accordance with the NERC UFLS reliability standard characteristics. This program is designed to arrest declining frequency, and assist recovery of frequency following under–frequency events. Independent Source Operator – New England (ISO–NE) is currently in the process to define which generators must be compliant to the following standards:

- PRC–006–NPCC–1
- NPCC Directory 12
- ISO–NE OP–134
- ISO–NE Compliance Bulletin for PRC–006–1 and PRC–006–NPCC–01

Presently, ISO–NE's statement illustrates that their concern for such projects are NERC registered generators above 20 MVA and directly tied to transmission voltages 100 kV and greater, as well as a list of non–registered NERC generators that are defined below in Table 2.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

Each generator owner shall set each under–frequency trip relay, if so equipped, below the appropriate generator under–frequency trip protection settings threshold curve in Figure 1 of PRC–006–NPCC–1. In cases where a generator owner has a generator that cannot physically meet the set points defined by the curve in Figure 1, the generator owner shall arrange for a distribution provider or transmission owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator.

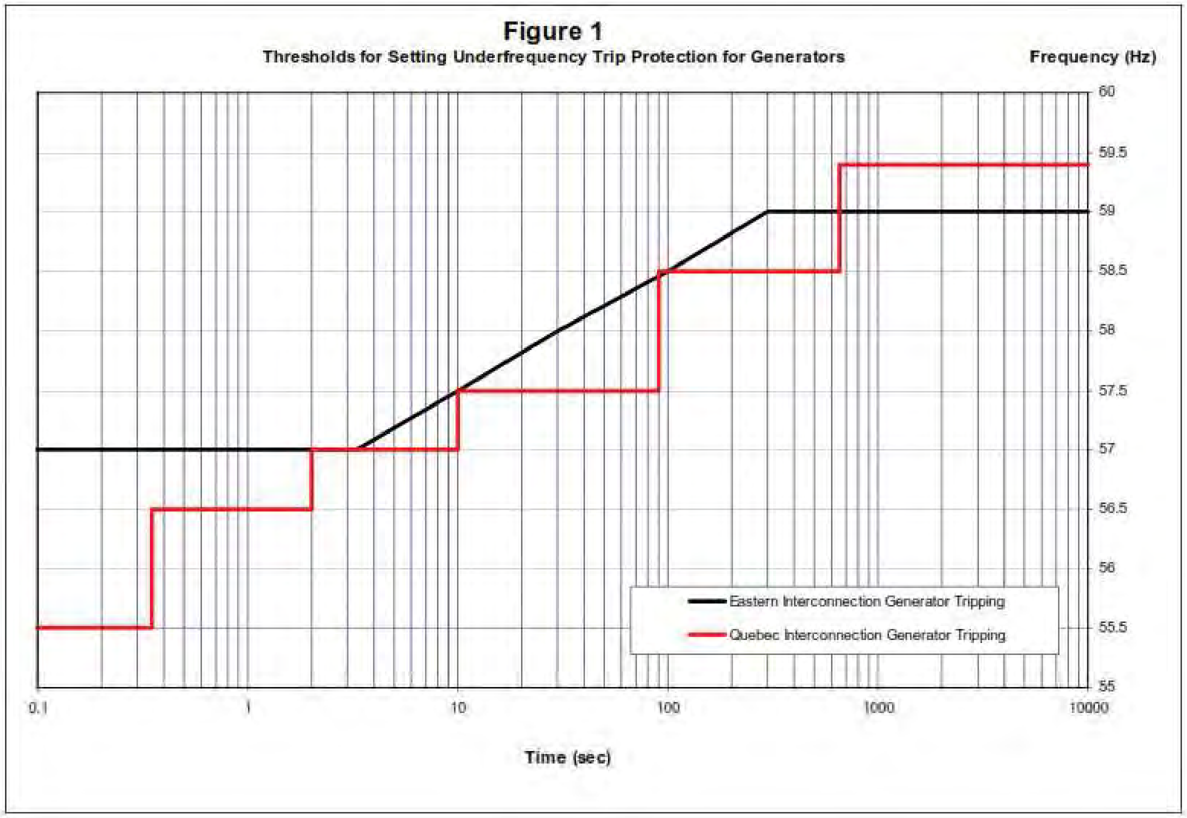
In–service generators not compliant and currently accounted for by compensatory load shedding in the Eversource UFLS program will be maintained until ISO–NE makes a final determination as to which generators must meet requirements of PRC–006–NPCC–01. New generators that cannot set under–frequency relays to be compliant with PRC–006–NPCC–01 may be responsible for costs associated with adding compensatory load shedding to the Eversource UFLS program.

Table 1 below provides five distinct under–frequency relay trip settings that are applied to trip load at five distinct frequency thresholds.

Table 1 – Under–Frequency Trip Settings

Frequency Threshold (Hz)	Total Operating Time (sec)	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
59.5	0.3	6.5 – 7.5	6.5 – 7.5
59.3	0.3	6.5 – 7.5	13.5 – 14.5
59.1	0.3	6.5 – 7.5	20.5 – 21.5
58.9	0.3	6.5 – 7.5	27.5 – 28.5
59.5	10.0	2 – 3	29.5 – 31.5

The UFLS program also requires generators to remain connected to the electric system during declining frequencies and have under–frequency trip settings, if equipped, to not trip above the threshold curve provided in PRC–006–NPCC–1 Figure 1. Figure 1 is provided below:



The Company also complies with ISO–NE's mandate that all new generator applications be equipped with frequency ride through settings, as defined in DSEM 19–1.5. The frequency ride through settings comply with NPCC settings for new generator applications.

Table 2 – Additional Generators Needed to Support the New England UFLS Program

Generator Name	ISO Lead Market Participant	Summer Seasonal Capability	Presently NERC Registered
Kibby Wind Power	TransCanada Power Marketing, Ltd	18.275	
Amoskeag	Public Service Company of New Hampshire	16.781	
Bethlehem	GDF Suez Energy Marketing NA, Inc	15.303	
Bonny Eagle/W. Buxton	Brookfield White Pine Hydro LLC	16.151	
Branford 10	NRG Power Marketing LLC	15.840	
Bucksport G3	Tenaska Power Services Co	15.941	
Burlington GT	Burlington Electric Department	19.104	
Cape GT 4	NextEra Energy Power Marketing	15.487	
Cape GT 5	NextEra Energy Power Marketing	15.822	
Dartmouth CT Generator 3	Consolidated Edison Energy, Inc	18.812	
Deerfield 2/LWR Drfield	TransCanada Power Marketing, Ltd	19.275	
DG Whitefield, LLC	Exelon Generation Company, LLC	15.603	
Doreen	Essential Power Massachusetts	15.820	
Franklin Drive 10	NRG Power Marketing LLC	15.417	
Harris 1	Brookfield White Pine Hydro LLC	16.790	
Hemphill 1	Springfield Power, LLC	16.968	
Indeck Alexandria	Indeck Energy–Alexandria, LLC	15.031	
Kendall Jet 1	Kendall Green Energy, LLC	18.000	
Kendall Steam 2	Kendall Green Energy, LLC	19.669	
Kibby Wind Power	TransCanada Power Marketing, Ltd	18.275	
L Street Jet	Exelon Generation Company, LLC	16.030	
Lower Lamoille Composite	Green Mountain Power Corporation	15.800	
MAT3	MATEP, LLC	17.970	
Matep (Diesel)	MATEP, LLC	17.120	
Norwich Jet	Connecticut Municipal Electric Energy Cooperative	15.255	
Pinetree Power	GDF Suez Energy Marketing NA, Inc	16.465	
Ryegate 1–New	Vermont Electric Power Company	19.560	
Schiller CT 1	Public Service Company of New Hampshire	17.621	
Secrec–Preston	Connecticut Light and Power Co	15.857	
So. Meadow 6	NextEra Energy Power Marketing	16.623	
Swanton GT–1	Vermont Public Power Supply Authority	19.304	
Swanton GT–2	Vermont Public Power Supply Authority	19.349	
Tamworth	GDF Suez Energy Marketing NA, Inc	20.074	
Torrington Terminal 10	NRG Power Marketing LLC	15.638	

Please see the **Eversource DER Briefing Sheet – Automatic Under–Frequency Load Shedding** for additional background information.

Closed Transition Generators

GENERAL

A DER may momentarily be paralleled with the Company EPS to provide disturbance free transfer of load to and from the EPS for testing, peak shaving, load curtailment, or returning load to Company supplied service. Interconnection requirements will be determined by the length of time the generation is paralleled with the EPS.

1) Instantaneous Parallel [Less than 10 cycles (0.167 seconds)].

Additional generator relaying in this section are generally not required, but may be specified, installed, and maintained at the discretion of the EG owner. If installed, the following conditions apply:

a) The EG does not have to present a grounded−wye source to the EPS.

b) The parallel and disconnecting operation must be automatic, instantaneous (switching time only) and less than 10 cycles (0.167 seconds) duration.

c) A paralleled transfer must be blocked if the normal source to the load is not within +/– 10% of nominal voltage.

d) The transfer scheme must be acceptable to the Utility.

e) The parallel operation must be monitored by a timing relay, which will trip the generators main breaker or contactor if the parallel operation lasts longer than 0.5 seconds. The tripping voltage must be from a battery. Capacitor trip devices are not acceptable.

2) Transitional Parallel

a) The EG does not have to present a grounded−wye source to the EPS. If the EG does not present a grounded−wye source, Zero Sequence Over voltage Relays (59G) must be installed and wired to trip the generator(s).

b) The parallel, EG loading and disconnecting operations must be automatic. Parallel time must be kept to a minimum and must never exceed five (5) seconds.

c) A paralleled transfer must be blocked if the normal source to the load is not within +/– 10% of nominal voltage.

d) The transfer scheme must be acceptable to the Utility.

e) The parallel operation must be monitored by a timing relay, which will trip the EG main breaker(s) if the parallel lasts longer than 5 seconds. The tripping voltage source must be from a battery. Capacitor trip devices are not acceptable

f) Over/under voltage and over/under frequency relays must be installed based on the size and type of generation being installed. Additional EG relaying is not required but may be specified, installed, and maintained at the discretion of the EG owner.

g) The EG owner must receive permission from the Company prior to making the parallel with the generator.

Open Transition Generating Facilities

GENERAL

Connection of an EG does not require an Interconnection Application when the EG facility's manual or automatic transfer switch will not allow any parallel operation of the EG Facility with the EPS. This electrical state (i.e., open transition transfer) is typically referred to as "break−before−make," which means that the EG Facility¿s transfer switch must be designed and operated to prevent the EPS−provided power and the EG Facility−provided power from powering the Facility circuits (i.e., load) at the same time. Consequently, this mode of operation will also prevent the generating Facility from potentially energizing the EPS.

Generator Step−Up Transformer Configurations

GENERAL

The Company may not specify Generator Step−Up (GSU) transformer configuration type. However, the transformer high side must be compatible with the EPS. The DER owner's engineer shall design a protection scheme that is able to sense and isolate the DER facility for all instances of Over/Under Voltage (27, 59), Over/Under Frequency (80/81) and Over Current (50/51) for BOTH sides of the GSU. Potential Transformers for relay application shall always be installed on the high voltage side of the GSU.

Risk of Islanding Screening Process

GENERAL

The Risk of Islanding (ROI) Screening Process (below) has been developed to guide the evaluation and determine when mitigation is required. This process will be revisited following the anticipated revision to the Sandia Islanding Report.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

ROI SCREENING PROCESS (see Figure 1)

1. All proposed Distributed Energy Resources (DER) projects greater than 200 kW will be reviewed.

   The line section minimum load to aggregate DER ration will be determined. This can be accomplished during a preliminary application review or as part of the system impact study. DER at customer sites equipped with reverse power or minimum import relays should also be evaluated to determine the appropriate contribution to aggregate capacity screens.

   Note: Pre−existing DER equipped with direct transfer trip (DTT), may not be factored into any aggregate DER screens identified within this document.

   a. For cases where the line section aggregated DER is less than or equal to 33 percent of minimum load, regardless of DER type mix, the risk of islanding shall be considered negligible, and no further screening is required.

   b. If any line section has an aggregate DER−to−minimum load ration greater than 33 percent, the following evaluation is performed in the project System Impact Study. Under this situation the applicant is required to submit supporting documentation regarding the project’s islanding detection methodology (see Appendix D of the DER Standards briefing sheet). Should the applicant fail to provide sufficient documentation, the project will be reviewed as a “non−certified” DER project.

2. Is the proposed DER project using certified inverters?

   a. Yes

   Note: Any inverter operating in frequency and/or in voltage regulating or in VAR support mode will be reviewed under the “non−certified” rules below. Furthermore, to be considered “certified” an inverter shall have an 88 percent voltage trip within two seconds.

   1) Line section aggregated non−certified DER is less than or equal to 10 percent of the mix **and** DER applications less than or equal to 2000 kW. No additional requirements related to ROI.

   2) Line section aggregated non−certified DER is greater than 10 percent of aggregate DER **or** DER is greater than 2000 kW. Sandia screening (see Appendix C of the DER briefing sheet) shall be performed.

   Note: When insufficient data exists to perform a complete VAR balance review, Sandia screen #2 shall be considered a failure.

If Sandia screens are passed, no additional requirements related to ROI are enforced.

If Sandia screen #1 and #2 fail, but there are no synchronous generators on the circuit segment, then as Eversource−owned, SCADA−enabled recloser, or other isolation device at the PCC is required. Reclose blocking of upstream devices will be evaluated (as described under “General Terms & Conditions”). DTT is not required. The customer may request a dynamic risk of islanding study (D−ROI). If the results are acceptable, the ROI mitigation above wil be waived. Note: the POI recloser may be waived for projects less than or equal to 500 kW.

If Sandia screen #1 is failed and there is synchronous generation on the circuit segment, a D−ROI may be offered. If the R−DOI study indicates negligible risk of islanding, no additional requirements related to ROI are enforced.

If the D−ROI study is either not offered, is declined by the applicant, or has unacceptable results, then an Eversource owned, SCADA−enabled recloser, or other isolation device at the PCC is required, reclose blocking of upstream devices will be evaluated. DTT may also be required (see Note 1).

b. No

1) Dynamic risk of islanding (D−ROI) study
A D−ROI may be offered. If the D−ROI study indicated negligible risk of islanding, no additional requirements related to ROI are enforced.

2) Other options
If the D−ROI study is either not offered, is declined by the applicant, or has unacceptable results, then an Eversource owned, SCADA−enabled recloser, or other isolation device at the PCC is required. Reclose blocking of upstream devises will be evaluated. DTT may also be required (see Note 1).

Notes

1. In addition to a site recloser and the implementation of reclose blocking, Eversource reserves the right to require direct transfer trip (DTT) for projects with unique characteristics that create a high risk of islanding, either under existing or future circuit conditions. In those cases, Eversource will determine whether a detailed risk of islanding (ROI) study is warranted. If sufficient data is available to conduct a robust ROI study, and the results are reasonably expected to create information that may alleviate the Company's concerns, the interconnection customer will be offered the opportunity to proceed with a detailed ROI study. If results of that study show no significant risk of islanding under all operating conditions for a period greater than two seconds, then Eversource will consider waiving the DTT requirement.

SPECIAL CONDITIONS

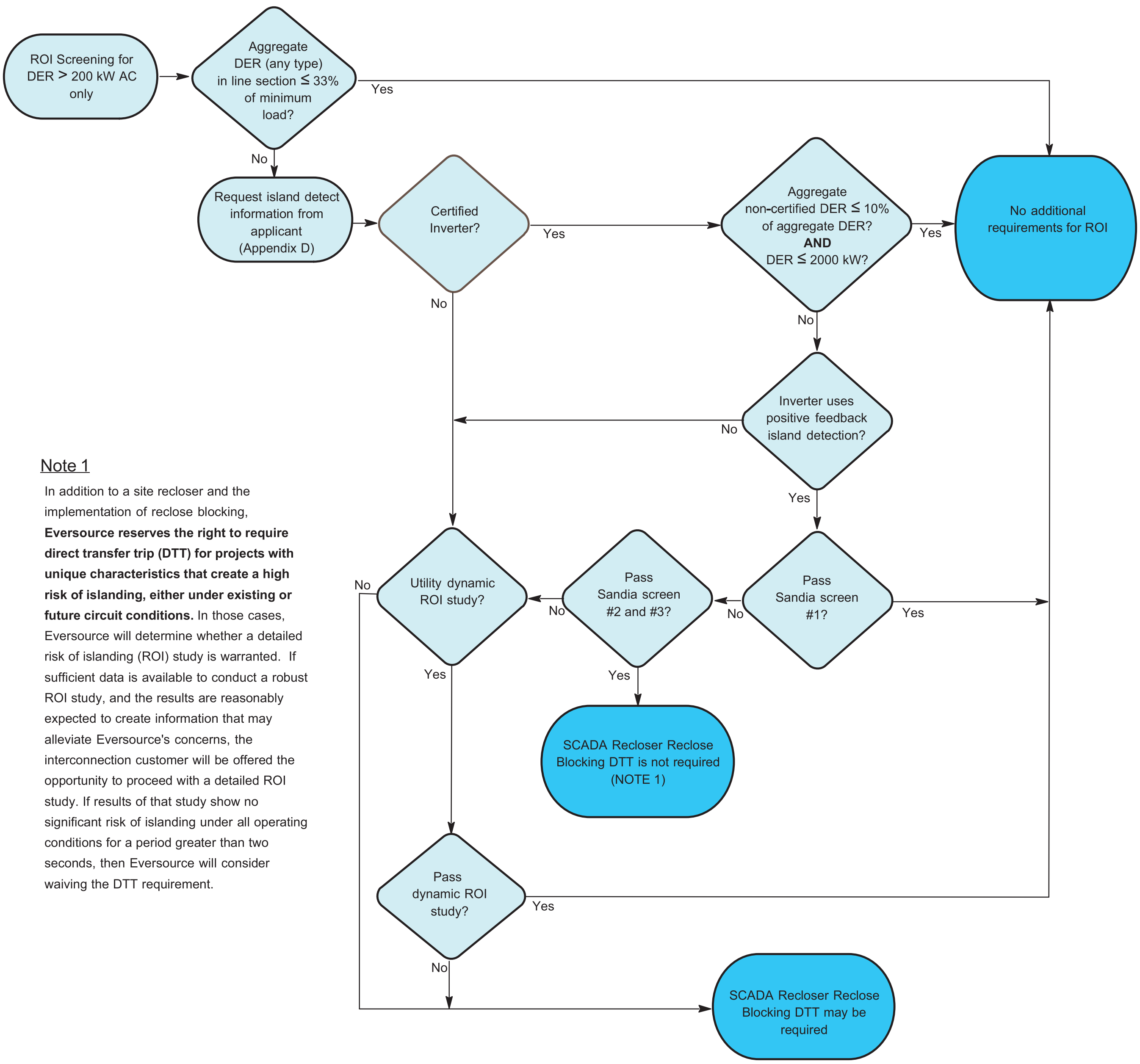
The following are conditions where additional EPS protection schemes, including but not limited to direct transfer tripping (DTT), may be required. These conditions may exist independent of the above ROI evaluation results.

1. If line faults (phase and ground where applicable) cannot be cleared by a DER protective device or Eversource owned PCC recloser.

2. Unique arrangements not explicitly defined within this document at Eversource's discretion. This includes a consideration of off−normal circuit configurations.

3. DER that cannot be tripped off with utility−owned devices when automated sectionalizing schemes operate.

Eversource DER Screening for Risk of Islanding



Note 1

In addition to a site recloser and the implementation of reclose blocking, **Eversource reserves the right to require direct transfer trip (DTT) for projects with unique characteristics that create a high risk of islanding, either under existing or future circuit conditions.** In those cases, Eversource will determine whether a detailed risk of islanding (ROI) study is warranted. If sufficient data is available to conduct a robust ROI study, and the results are reasonably expected to create information that may alleviate Eversource's concerns, the interconnection customer will be offered the opportunity to proceed with a detailed ROI study. If results of that study show no significant risk of islanding under all operating conditions for a period greater than two seconds, then Eversource will consider waiving the DTT requirement.

Please see the **Eversource DER Briefing Sheet – Risk of Islanding Evaluations** for additional background information.

General Considerations

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

GENERAL

A study of either spot or area secondary network interconnection shall ensure that the presence and operation of DG meets the following criteria before allowing interconnection.

1. Network protectors (NP) shall not be used to connect, separate, switch, serve as breaker failure backup, or in any manner isolate a network or network primary feeder, to which DG is connected from the remainder of the network, unless the protectors are rated and tested per applicable Standards for such an application.
   a. IEEE C37.108TM−2002 [B8] and IEEE C57.12.44TM−2000 [B9] provide guidance on the capabilities of network systems to accept distributed resources.
2. DG installations on a network, using an automatic transfer scheme, in which load is transferred between the DG and the distribution system in a momentary make−before−break operation, shall meet all the requirements of this section regardless of the duration of paralleling, except by consent of Eversource. Power flow during this transition shall always be positive from the distribution system to the load and the DG, unless approved by and coordinated with Eversource.
3. The DG shall have provisions to monitor instantaneous power flow at the point of common coupling (PCC) for reverse power relaying, minimum import relaying, dynamically controlled inverter functions, and similar applications to prevent reverse power flow through network protectors.
4. The DG has provisions to maintain a minimum import level at the PCC as determined by Eversource.
5. The DG has provisions to control DG operation or disconnect the DG from the distribution system base on an autonomous setting at the PCC and/or a signal sent by Eversource.
6. The DG shall not cause any network protector (NP) to exceed its loading or fault−interrupting capability.
7. The DG shall not cause any NP to separate dynamic source.
   a. See C37.108 for discussion and definition of “dynamic sources/systems”
8. The DG shall not cause any NP to connect two dynamic systems together.
9. The DG shall not cause any NP to operate more frequency than prior to DG operation.
10. The DG shall not prevent or delay the NP from opening for faults on the distribution system.
11. The DG shall not delay or prevent NP closure.
12. The DG shall not energize any portion of the distribution system when the distribution system is de−energized.
13. The DG shall not require the NP settings to be adjusted, except by consent of Eversource.
14. The DG shall not prevent reclosing of any network protectors installed on the network. This coordination shall be accomplished without requiring any changes to prevailing network protector clearing time practices of the distribution system.

Spot Networks

GENERAL

The proposed generating facility to be interconnected to the load side of spot network protectors must utilize an inverter–based equipment package, and when aggregated with other inverter–based generation, shall not exceed the lesser of five percent of a spot network's maximum load or 50 kW. Under no condition shall the interconnection of a generating facility result in a backfeed of, or cause unnecessary operation of any spot network protectors. All inverters must be IEEE 1547 and UL 1741 compliant and certified to stop conducting prior to the three cycle response of the network protector relays.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

In addition to the requirements under Category 4 in Section 19 of the DSEM, all network interconnections shall also align with all sections of IEEE 1547 and IEEE 1547.6. Below are additional requirements with regard to IEEE 1547 compliance on Eversource networks.

1. Connection of the generating facility to the distribution system shall be permitted only if the network bus is already energized by more than 50 percent of the installed network protectors. The customer shall also install a utility grade control scheme capable of monitoring the status of all network protectors and will trip a dedicated generator breaker instantaneously any time the number of closed network protectors falls to 50 percent or less.
2. The generating facility shall comply with all Eversource anti–islanding requirements.
3. The customer shall install minimum import protection (32 relay functionality) that is set to trip a dedicated generator breaker(s) and isolate all generation from the distribution system any time power import at the metering location drops below five percent of the generator facility's total gross nameplate rating.

Please see the **Eversource DER Briefing Sheet – Spot Networks** for additional background information.

Area Networks

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

GENERAL

A generating facility proposed to be interconnected to the load side of an area network protector must utilize an inverter–based equipment package and meet all of the following requirements in addition to the requirements under Category 4 in Section 19 of the DSEM.

1. When aggregated with other inverter–based generation, the DG shall not exceed 50 kW at any location. A location is defined as any manhole, secondary network vault, or service box. This criteria is designed to ensure that no more than 50 kW of DG is located on the same secondary network node.
2. In addition, the aggregate DG interconnected to an area network grid shall be limited to three percent of the maximum network transformer connected kVA with the feeder supplying the largest number of network units out of service, or a maximum of 500 kW, whichever is less.
3. The DG shall comply with all applicable Standards (e.g. IEEE 1547, IEEE 1547.6, UL 1741, etc.)
4. The DG shall comply with all Eversource interconnection requirements.
5. The generation facility shall comply with all Eversource anti–islanding requirements.
6. The customer shall ensure that the DG cannot export power to the area network at any time under any contingency. Load history, dynamic network studies, engineering design drawings or additional equipment may be required by Eversource Engineering in order to allow for interconnection.

Please see the **Eversource DER Briefing Sheet – Area Networks** for additional background information.

Analyzing Non−Export Batteries CHPs, and Base Loading Generation

GENERAL

Non−exporting, load reducing generators should be 'fast tracked' in a similar manner to current rooftop residential photovoltaics (PV).

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

METHODOLOGY

Upon receiving a distributed generator (DG) greater than 20 kilowatts a distribution engineer should analyze and review the following screens whose failure shall result in supplemental screening:

1. Aggregate line section distributed energy resources (DER) do not exceed fifteen percent of the line section peak load
2. Aggregate DERs on a secondary does not exceed twenty kilowatts
3. Aggregate DERs on a substation transformer does not exceed 10 megawatts

The following sections highlight next steps when any of the above screens fail.

1. Fifteen percent or greater distributed energy resources on line section

Perform a stiffness factor calculation, risk of islanding analysis, and/or preliminary Synergi load flow analysis. Refer to DSEM 19.028 for a risk of islanding flowchart. A Synergi load flow is only necessary should the stiffness factor fall below 100.

2. Twenty kilowatts or greater distributed energy resources on a secondary

Develop a secondary model and run a Synergi load flow at light load to determine voltage rise and voltage flicker.

3. Ten megawatts or greater distributed energy resources on a substation transformer

Run a Synergi analysis of the substation and include the transmission sources. Verify that ninety−five percent of the substation transformer nameplate capacity is not exceeded with installed and queued generation.

GUIDELINES

Determine whether the project is on a shared secondary. If the project is on a shared secondary, only a secondary load flow model is necessary. If the project is not on a shared secondary, all other required screens are required.

Gathering Initial Data and Modeling

Shared Secondary and/or Less than 100 kW

If the proposed DER is less than 100 kW and on a shared secondary, model the secondary per GIS. Include all customers that are fed from the same distribution transformer. Additionally, utilize customer usage information in the Spring or Fall to determine an accurate load to use in the Synergi model. If only a peak value is available, scale the value to 33 percent. Other minimum loading scaling factors may be used at the discretion of the local engineer per local engineering practices.

Standalone Generator or Greater than 100 kW

If the project is not on a shared secondary, or is larger than 100 kW, a stiffness factor and risk of islanding analysis shall be performed. Additionally, if the DER produces a stiffness factor result less than 100 kW, a Synergi load flow analysis shall be performed.

For circuits where DER penetration is less than thirty percent, include all distributed energy resources that are greater than or equal to 100 kW. Rooftop solar PVs may be omitted from this supplemental analysis. The DERs nameplate value and location may be found in the local DER tracking sheet. A Synergi analysis should be performed at light and peak load, for both cases where generation is on and off. If the proposed project is a base loader, combined head and power (CHP), or battery energy storage (BESS) and is anticipated to operate twenty−four seven, the night time minimum load with generation on and off cases should be studied. When performing the first four daytime analyses, ensure that the generation contribution from PVs is accounted for. For the instances of load flow during the night, photovoltaic generation will need to be turned off. Any batteries, fuel cells, etc that are anticipated to operate twenty−four seven; however, should be included in the night modeling.

FFor circuits that have DER penetrations more than thirty percent, all DERs shall be accounted for in a lumped manner. When lumping rooftop DERs downstream of side taps, ensure that they are allocated to the correct phase. All other assumptions stated above in the lower penetrated circuits should be considered when analyzing higher penetrated circuits.

FORMAL SCREENS

Please refer to the Eversource DER Briefing Sheet for a detailed step−by−step guidance on how to go through the Asset Management Review and/or Protection and Controls screening templates. The screening templates may be found at XXX

Please see the **Eversource DER Briefing Sheet – Analyzing Non−Export Batteries, CHPs, and Base Loading Generation** for additional background information.

GENERAL

Each state currently requires different kilowatt (kW) thresholds for self−certification on commissioning test requirements. This policy clarifies the requirements that should be considered when a developer wishes to self−certify their system during a commissioning test

> *Note*: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

CERTIFIED DISTRIBUTED ENERGY RESOURCES LESS THAN 500 KW

Qualified installers will be allowed to self−certify the latest UL 1741 certified inverter−based DERs less than 500 kW in value. Self−certification must be performed by qualified vendors or installers with at least three successful installations in the Eversource electric power system. Eversource reserves the right to allow installers to conduct the commissioning test and submit results to Eversource for approval and issue the authorization to connect. Eversource also reserves the right to witness the commissioning test of *any* DER installation on the reason for complex interconnections or for a new installer.

QUALIFIED INSTALLERS SELF−CERTIFICATION REQUIREMENTS

All self−certifications will be performed by a qualified installer. One of the following conditions must be met to become a qualified installer in accordance with individual state procedures:

1. Three successful interconnections completed and witnessed tested by Eversource personnel.
2. Licensed electrical contractor
3. Factory representative.
4. Third Party Eversource approved test contractor.
5. Develop procedure to allow installers to conduct the commissioning test and submit result to Eversource for approval and issue authorization to connect.

NON−CERTIFIED DERS GREATER THAN OR EQUAL TO 500 KW

Any non−certified DERs or certified DERs greater than or equal to 500 kW shall require a commissioning test to be witnessed by an Eversource approved personnel.

SELF−CERTIFICATION FORM: CT, MA, NH

The next page has the proposed self−certification form for UL 1741 SA inverters less than 500 kW. The self−certification form should be used for commissioning test requirements of DERs less than 500 kW.

Please see the **Eversource DER Briefing Sheet – Commissioning Test Requirements** for additional background information..

EVERSOURCE ENERGY

Self-Certification Form: CT, MA, NH

For UL 1741 SA Certified Inverters < 500 kW

CERTIFICATE OF COMPLIANCE

Date of Test ______________________
Project ID: ______________________
Customer Name: ______________________
Generator Address: ______________________
kW -AC ______________________
Inverter Voltage ______________________
Inverter Serial Number ______________________
Inverter Firmware Version ______________________

<***Electrical Contractor Name***>, hereby certify that, the facility stated above was installed commissioned and tested successfully as required by the Eversource interconnection requirements and applicable codes and standards, and the following was performed:

- ☐ The photovoltaic system has been inspected and approved by the local wiring inspector with jurisdiction and is safe to operate.
- ☐ All required documents have been submitted and approved by Eversource.
- ☐ Verification of proper AC voltage and phasing at inverters.
- ☐ Verification of proper DC voltage(s) from strings and combiners at inverters.
- ☐ Inverter manufacturer's start up procedures have been followed.
- ☐ System has been installed as approved by Eversource in the Approval to Install agreement and as shown on attached "As-Built" or final drawing.
- ☐ System meets IEEE 1547 two (2) second shut down upon opening of utility disconnect switch.
- ☐ System meets IEEE 1547 five (5) minute re-start upon closing of utility PV system disconnect switch.
- ☐ Inverter settings are programmed to the Inverter Source Requirement Document as published by ISO-New England (ISO-NE) in February 2018 (Refer to Appendix G)

Contractor ______________________ **Date** ____________
Signature ______________________

If electrical contractor
Electrical Contractor Name ______________________

License number ______________________

DER DSCADA Visibility and Control Requirements

GENERAL

Higher penetration of distributed energy resources (DERs) has created issues with operators who have concerns that large−scale DERs coupled with aggregate residential DERs can island a circuit or line section. The concern is the distribution system operators do not have visibility to the output of most DER facilities and cannot make the determination of islanding concerns. The purpose of this DSEM is to provide a standard requirement for implementing DSCADA visibility and control at larger DER facilities.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

DER LESS THAN 500 KW

Certified and non−certified DER less than 500 kW *generally* do not require DSCADA visibility for standalone facilities and behind−the−meter facilities. However, on a case−by−case basis, Eversource reserves the right to require DSCADA visibility when the risk of islanding exists for said facility or if direct transfer trip is required

DER GREATER THAN OR EQUAL TO 500KW AND LESS THAN 1 MW

DER facilities between 500 kW and 1 MW require that DSCADA visibility and control is implemented in the design of interconnection. It will be at the discretion of Eversource engineering to determine the means of DSCADA visibility. Eversource may require either a recloser, RTAC, or other form of DSCADA control device.

DER GREATER THAN OR EQUAL TO 1 MW

DER facilities greater than or equal to 1 MW require that DSCADA visibility and control is implemented in the design of interconnection. It will be at the discretion of Eversource engineering to determine the means of DSCADA visibility. Eversource may require either a recloser, RTAC, or other form of DSCADA control device.

STANDALONE FACILITIES

Common practice for standalone facilities is to require a DSCADA recloser. RTAC or other DSCADA capable devices may be warranted at the discretion of Eversource engineering.

BEHIND−THE−METER FACILITIES

Special consideration should be given to large load customers who have DER facilities equal to or greater than 1 MW. For these applications, a DSCADA RTAC would be more appropriate to only disconnect the connected DER facility. This option should be considered when it is not advantageous to trip off the load customer.

Please see the **Eversource DER Briefing Sheet – DER DSCADA Visibility & Control Requirements** for additional background information.

Battery Storage Equipment

GENERAL

Battery storage allows customers to store energy during operating periods and release stored energy at their own discretion for backup power, peak load shaving, load shifting, and/or providing ISO−NE market services. DER storage systems have the ability to be configured to export onto the distribution system.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

Customers who submit applications that include the installation of battery storage equipment in conjunction with a DER generating facility, or as a standalone storage facility, are required to complete the initial application process that is implemented throughout Eversource regarding the DER interconnection. The existing standard practice to determine system size uses the nameplate rating of the battery storage equipment, or inverter size, when determining application values and fees associated with the review. If the customer chooses to restrict or limit battery storage export with the installation of proper equipment, then the limited capacity value of the battery storage export would be used for designing system planning and modifications for the non−simplified applications. If the customer chooses to increase storage export levels in the future, then the customer would be required to submit a new application for interconnection as additional system modifications maybe required. Any required system modifications will be controlled and maintained by Eversource, but paid for by the customer.

Please see the **Eversource DER Briefing Sheet – Standards to Accommodate DER** for additional background information.

FERC vs State Jurisdiction

SCOPE – Requests to interconnect DER to the Eversource distribution system must be processed in accordance with either the applicable state interconnection tariff or the ISO−NE tariff (Schedule 23: Standardized Small Generator Interconnection Procedures of Section II of the ISO−NE Open Access Transmission Tariff). Both processes involve similar (or identical) technical screens and system impact study requirements. However, the administration of many key aspects of the process are significantly different. In addition, for FERC jurisdictional projects (i.e. those that follow the ISO−NE procedures) the resulting Interconnection Agreement must be filed with FERC. In the past, FERC has enforced economic penalties on transmission owners for failure to file agreements in a timely manner. For these reasons, it is critical that Eversource assign each new interconnection request to the appropriate jurisdiction. This briefing sheet documents the process that will be used to determine the proper jurisdiction.

GENERAL – The jurisdictional determination shall follow the “Decision Tree” found on the final page of this document. The discussion below provides details on the various factors used in the decision process.

In addition, the team concluded that a review be performed of all existing Interconnection Agreements to determine if FERC filing is warranted.

Definitions

Definition of a “Distribution Facility”

For the purposes of evaluating the applicability of ISO−NE Schedule 22 and/or 23, the Distribution Facility (“DF”) to which a generator interconnects shall be determined as noted below. This convention will be used both for the generator requesting a new or revised interconnection and for any existing generators (or other wholesale transactions) that may influence the jurisdictional determination.

The DF is the collection of Eversource−owned equipment that creates the electrical path by which the generator accesses the ISO−NE wholesale market. This path may involve multiple circuits segments at different voltages and with different circuit identifiers. The DF will generally start with the Point−of−Ownership−Change (i.e. the specific point at which customer−owned equipment interconnects to Eversource−owned equipment) and will proceed to the ISO−NE administered transmission system along an identifiable electrical path. The path will terminate at the bus position on the low−voltage side of the transmission substation transformer. For non−radial configurations, it may not be possible to determine the unique path by which the generator will access the transmission system. In such cases, the DF will involve multiple paths to multiple terminations. For portions of the system subject to source switching, the normal system configuration should be considered when making this determination.

Special considerations when defining the DF

1. Uncertainty in the exact DF
For larger Distributed Generation (“DG”) projects, the nearest Eversource facility may not ultimately be the DF to which the project interconnects. For example, the nearest facility may have low−voltage, single phase, small wire, etc. A more distant circuit, or even a new circuit, may be the actual DF when and if the project moves into the impact study and construction phases. In these cases, caution should be used in defining the DF that is used to determine jurisdiction. If there is the possibility that the ultimate Point of Interconnection (“POI”) is to a DF that is subject to the ISO−NE open access transmission tariff (“OATT”), the project may need to go through the ISO−NE interconnection process.

2. Express Feeders
Projects that are expected to require the construction of an express feeder must also be given special attention. The exact route and termination of the new feeder may be unknown at the time of application. Ultimately, it may be a tap (and recloser) into an existing circuit, or it may be a new circuit breaker. Also, the exact location of the POI may be uncertain. If no dual−use facilities are involved (i.e. those hosting

customers, now or in the future), then it may be appropriate for the entire substation transformer to be considered as the DF to which the DG is interconnecting. In general, distribution facilities that are constructed for the sole purposes of making sales for resale in interstate commerce (such as participation in the ISO−NE markets) are not “dual use” facilities.[1] If any ambiguity exists, transferring the project into the ISO−NE interconnection process should be considered.

What Types of Transactions result in a “Jurisdictional” Distribution Facility?

- Eversource wholesale delivery service to the Co−ops, Municipals, etc. for resale to end−use retail customers
- DG that are registered as assets and participate in the ISO−NE markets (including energy, capacity or ancillary services). This applies even for assets for which Eversource is the Lead Market Participant.

Note: only commercially operating DG will be considered, i.e. DG projects “in the queue” or under development will not trigger jurisdiction of a Distribution Facility. However, if a DF previously hosted a commercial DG making wholesale sales, and the DG has since been shut−down, the jurisdiction trigger still exists.

A retail customer interconnecting a new Generating Facility that will produce electric energy to be consumed only on the retail customer’s site;

Exemption to ISO−NE Schedule 22/23

An interconnection request to a “FERC Jurisdictional Distribution Facility” must follow the ISO−NE Schedule 22/23 process unless it meets one of the following exemptions:

1. **A retail customer interconnecting a new Generating Facility that will produce electric energy to be consumed only on the retail customer’s site;**

This exemption is for on−site “behind the meter” DG, including net metering, that does not export power to the grid.

2. **A request to interconnect a new Generating Facility to a distribution facility that is subject to the Tariff if the Generating Facility will not be used to make wholesale sales of electricity in interstate commerce;**

Any project that will be registered and participating in the ISO−NE Markets (i.e. any SOG or FCM resource) would represent a “wholesale sale” and fail this exemption, but may qualify for exemption #3.

3. **A request to interconnect a Qualifying Facility (as defined by the Public Utility Regulatory Policies Act, as amended by the Energy Policy Act of 2005 and the regulations thereto), where the Qualifying Facility’s owner intent is to sell 100% of the Qualifying Facility’s output to its interconnected electric utility.**

[1] “Dual Use” facilities are distribution facilities used both for retail and wholesale purposes. The first wholesale use of a distribution facility for interconnection purposes does not trigger FERC jurisdiction over the distribution facility and the need to file the interconnection agreement. The second wholesale use of a dual use or wholesale distribution facility is FERC jurisdictional. *See Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003*,* FERC Stats. And Regs. 31,146 at P 804 (the Commission may assert jurisdiction over interconnections to local distribution facilities where two requirements are met: (1) there is a preexisting interconnection and (2) there is a wholesale transaction over these local distribution facilities prior to the new interconnection request being made.)

Most net metered projects will be able to meet the definition of a “Qualifying Facility.” Most also have the intent to sell 100% to the utility (e.g. under a net metering tariff). However, if the project intends to sell energy to Eversource and capacity to another party, it would not satisfy this exemption. Note: if Eversource registers the output of a QF in the ISO−NE markets, that registration does not nullify this exemption. However, if the project developer or third party attempts to register the QF in the capacity or ancillary services market while the project is still in the interconnection process, ISO−NE may require the project to resubmit the interconnection request under Schedule 22/23.

What Defines a Qualifying Facility (QF)?

When reviewing a new interconnection request, QF status will apply if the facility 1) submits evidence of a valid FERC QF certification or self−certification, 2) is less than 1 MW and applicant attests that it satisfies all relevant criteria, or 3) applicant is ≥ 1 MW and attests that it intends to file for FERC QF certification and that it satisfies all relevant criteria.

Note: when option #3 (above) is used, Eversource will require proof of QF certification prior to the effective date of the interconnection agreement.

The above is based on 161 FERC 61,091 in Docket QF17−852−000.

Three Types of Interconnection Requests (see Decision Tree on next page)

1. FERC Jurisdictional – Order 2003/2006 and ISO−NE Schedule 22/23 Apply

[path 2, 3, and 4 on the Decision Tree]

QF or Non−QF Project requesting to interconnect to a jurisdictional DF, except for QFs intending to sell 100% of the output to Eversource (i.e. by participating in net metering or other state program). Three−party pro forma IA.

2. FERC Jurisdictional – Order 2003/2006 and ISO−NE Schedule 22/23 do not Apply

[path 6 on the Decision Tree]

QF or Non−QF Project requesting to interconnect to a jurisdictional DF, except for QFs intending to sell 100% of the output to Eversource (i.e. by participating in net metering or other state program). Three−party pro forma IA.

3. State Jurisdictional

[path 1, 5, 7 and 8 on the Decision Tree]

QF Project requesting to interconnect to either jurisdictional DF or non−jurisdictional DF that intends to sell 100% of the output to Eversource (including capacity and ancillary service products), i.e. by participating in net metering or other state programs.

Non−QF Project requesting to interconnect to a non−jurisdictional DF.

Treatment of Existing Interconnection Agreements

Eversource is party to existing interconnection agreements that have never been filed with FERC (i.e. they were initially deemed to be State jurisdictional and, thus, filed only with the state regulator).

There are two categories of primary concern: 1) DG that no longer sells energy to Eversource, and 2) DG that sells energy to Eversource but sells other products to a third party or in the wholesale market.

It is recommended that a review be performed of all existing Interconnection Agreements to determine if FERC filing is warranted.

Table 1: Interconnection Request Jurisdictional Decision Tree

FERC Jurisdictional Facility (Note 1)	Qualifying Facility (Note 2)	Selling 100% to Host Utility (Note 3)	Interconnection Procedure	Interconnection Agreement (Note 4)
Yes	Yes	Yes	State	State
		No	ISO Schedule 22 or 23	LGIA or SGIA – 3 Party
	No	Yes	ISO Schedule 22 or 23	LGIA or SGIA – 3 Party
		No	ISO Schedule 22 or 23	LGIA or SGIA – 3 Party
No	Yes	Yes	State	State
		No	State	LGIA or SGIA – 2 Party
	No	Yes	State	State
		No	State	State

Notes

1. FERC Jurisdictional Facilities means all Transmission Facilities plus Distribution Facilities that are used to ”transmit electric energy in interstate commerce on behalf of a wholesale purchaser pursuant to a Commission−filed OATT.” See guideline sections *”Definition of a Distribution Facility”* and ”*What Types of Transactions result in a Jurisdictional Distribution Facility”* and list below.
2. QF status will apply if the facility 1) provides evidence of a valid FERC QF certification, 2) is less than 1 MW and owner attests that it satisfies the relevant criteria, 3) project >=1MW, owner intends to file for QF status and attests that it satisfies the relevant criteria. Note: when option #3 (above) is used, Eversource will require proof of QF certification prior to the effective date of the interconnection agreement.
3. At the time of application, DG group should request applicant to describe their intentions relative to power sales. Applicant may not be certain of future third party sale opportunities at time of initial application. If projects do not qualify for net metering and are unlikely to have a long−term PPA with Eversource, may be best to assume project will NOT sell 100% to Host Utility. Regardless of SOG status, QF and Net Metered facilities are considered as retail transactions selling 100% to Host Utility. However, future sales of Capacity or Ancillary Services to self or third party may trigger need to file IA at FERC. See list below.
4. Agreements originally executed under State jurisdiction must be periodically reviewed for possible FERC filing. See PSNH filings in 2012 and 2014 and FPL.

Wholesale Transactions (for purposes of Decision #3)
Wholesale Delivery (Muni, Coop, etc.)
DG registered at ISO−NE to sell Energy, Capacity or Ancillary Service

Sales to the Host Utility (for purposes of Decisions #3)
DG Net Metered (all products sold to Eversource)
DG QF sales to Eversource (all products sold to Eversource)

Battery Storage Equipment

GENERAL

Battery storage allows customers to store energy during operating periods and release stored energy at their own discretion for backup power, peak load shaving, load shifting, and/or providing ISO−NE market services. DER storage systems have the ability to be configured to export onto the distribution system.

Note: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

Customers who submit applications that include the installation of battery storage equipment in conjunction with a DER generating facility, or as a standalone storage facility, are required to complete the initial application process that is implemented throughout Eversource regarding the DER interconnection. The existing standard practice to determine system size uses the nameplate rating of the battery storage equipment, or inverter size, when determining application values and fees associated with the review. If the customer chooses to restrict or limit battery storage export with the installation of proper equipment, then the limited capacity value of the battery storage export would be used for designing system planning and modifications for the non−simplified applications. If the customer chooses to increase storage export levels in the future, then the customer would be required to submit a new application for interconnection as additional system modifications maybe required. Any required system modifications will be controlled and maintained by Eversource, but paid for by the customer.

Please see the **Eversource DER Briefing Sheet – Standards to Accommodate DER** for additional background information.

Maximum Allowable DG Fault Current Contribution

GENERAL

The following set of maximum allowable fault current contribution policy statements have been developed to guide users when considering evaluation on the feasibility of integrating DER. To the extent any of these policies are inconsistent with the tariff, state statutes, or state regulations, those other documents will be controlling.

> *Note*: This policy is applicable to all four operating companies: CT, WMA, EMA, and NH; unless noted otherwise.

Deviation from the following general policies should be on a case−by−case basis and require approval of senior management:

1. The maximum allowable fault duty on the station bus is 10 kA without the use of reactors. The DER interconnection can not cause the substation bus fault duty to exceed 10 kA, or result in exceeding the interrupting rating of distribution line equipment.
2. DER interconnections, in aggregate with other generation on the distribution circuit, should not contribute more than 10 percent to the maximum fault current of the distribution circuit at the point on the high voltage (primary) level nearest the proposed Point of Common Coupling (PCC).
3. If either of the above requirements are violated, a System Impact Study (including a Protection Review*) will be required. As part of the System Impact Study, remediating actions and costs will be provided to the customer for consideration as to whether or not to proceed with the installation.

> *Note*: *The Protection Review performed within the System Impact Study should not only verify proper protection and coordination of protective systems, but should also ensure that the pickup threshold settings of existing protective devices (especially for ground faults) have not be desensitized as a result of the infeed from the proposed DER installation.

Please see the **Eversource DER Briefing Sheet – Standards to Accommodate DER** for additional background information.

Distribution System Planning and Capital Approval Process Flow Narrative

The development of Eversource's capital investment plan uses the input of various departments including Distribution System Planning, Distribution Engineering, Substation Technical, Substation Engineering, Protection and Controls Engineering, Line Engineering, System Resiliency, System Operations, Substation Operations, Grid Modernization, Distribution Energy Resources, and Energy Efficiency. These departments work together to develop a capital plan which balances the capacity, reliability, resiliency, and operability needs of the system. Each year, the Company identifies the distribution system needs through planning studies, reviews of equipment loading, the identification of asset condition and equipment obsolescence, reliability and resiliency improvement recommendations, system maintenance and operations improvements among others.

Load Forecast

Many of the larger and longer-term project recommendations are initiated by the Distribution System Planning department. This process begins with the development of a 10-year peak load (90/10) forecast. The forecast uses weather normalized historical peak loads combined with Moody's econometric data, spot load data (large additions or subtractions of MW at the substation level) and other inputs to create a bulk substation level load forecast. This process is defined further in the body of the report and in the Distribution System Planning Guide which is provided as an attachment. Eversource is in the process of developing probabilistic forecasting methodologies to better address various penetration levels of such technologies as DER including PV and battery storage as well as electric vehicle charging and electrification of other fossil fuel technologies. These methodologies, once developed, will not change the overall processes used by Eversource, but they will help to establish more granular forecast data to inform system planning.

Annual Distribution Planning Studies

Once the peak load forecast is developed as described above, it is incorporated into the distribution system model which is then used to identify planning criteria violations over a ten-year period. The planning criteria violations include basecase equipment overloads and contingency violations. The Annual Distribution Planning Study assesses bulk substations, the interconnected portions of the 34.5 kV system as well as interconnected portions of the 12.47 kV system which are served from bulk substations. Non-bulk transformer criteria violations are identified by using the peak load forecast for the associated bulk substation combined with anticipated spot loads beyond the non-bulk transformer.

Distribution Planning Solution Studies

Once the planning criteria violations are identified, solutions studies are performed to incorporate additional information such as reliability, asset condition or obsolescence, and maintenance and operating concerns. This information is used to assess whether an NWS is a potential solution or part of a solution to defer the capital investment. The non-wires solution process is defined further in the body of the report and in the Distribution System Planning Guide which is provided as an attachment.

Annual Circuit Loading and Reliability Review

The Distribution Engineering department is responsible for developing the distribution line needs for the 4.16 kV, 12.47 kV, radial 34.5 kV, and Manchester network. These needs include capacity and reliability driven projects and are typically near-term projects that can be engineered and constructed within one year. Due to the volatility of peak load at this level of the distribution system, capacity-driven projects are typically proposed to be constructed with limited lead time. Reliability projects are proposed and prioritized with a calculated cost per saved customer minute.

Other Sources of Projects

Other departments such as Substation Technical, Substation Engineering, and Protection and Control determine system needs based on asset condition or obsolescence.

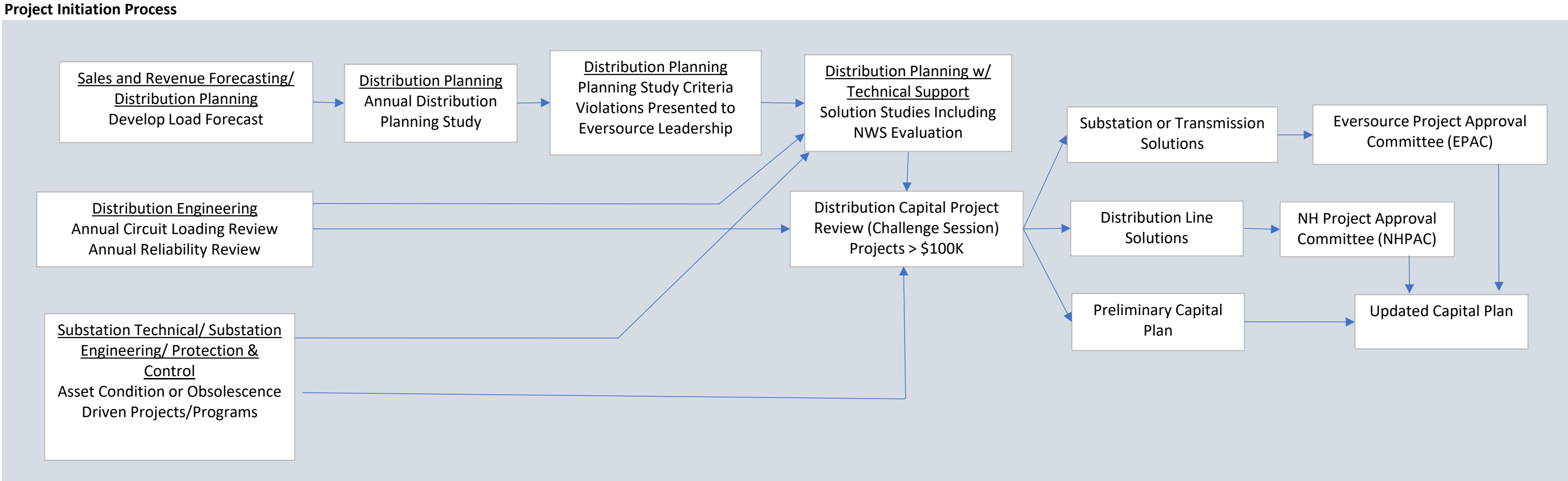
Distribution Capital Project Review (Challenge Session)

Each department presents their proposed projects with a cost estimate to a group of Engineering and Operations directors and managers at a Distribution Capital Project Review meeting. The resulting project list is reviewed, and a proposed capital plan is developed which best balances the competing needs of the system. The plan consists of nondiscretionary annuals (e.g. system repair, line relocations for NHDOT, new service, etc.), multi-year substation or line projects already underway, and new projects proposed. The annual proposed budget is presented to Eversource leadership and once approved is presented to the Board of Trustees.

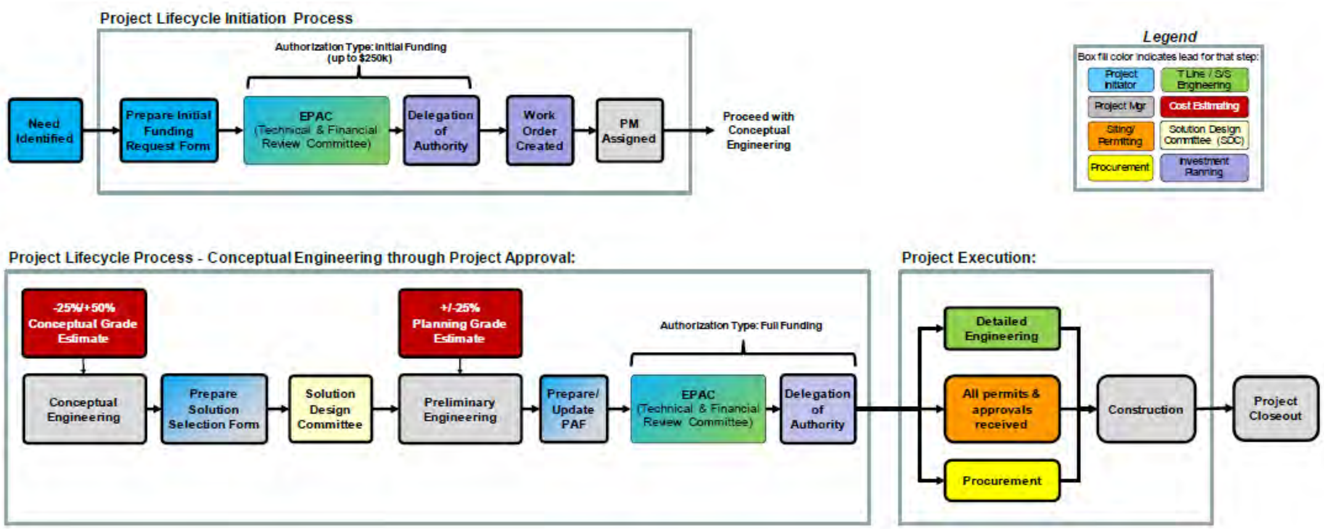
Each new project or program is required to go through additional technical review and project approval. Substation and Transmission Line projects must receive technical review approval from an Eversource level Solution Design Committee and overall project review approval from the Eversource Project Approval Committee. Each committee consists of Eversource Leadership representing various areas of expertise. Distribution Line projects must receive technical and overall project approval from the New Hampshire Project Approval Committee which consists of New Hampshire Leadership personnel.

Process flow diagrams for project initiation, state project approval and Eversource project approval are included in Appendix F-2. A job aid which outlines the Eversource technical and project approval process is included as Appendix F-3 - Capital Project Approval Process JA-AM-2001-A, Rev. 5.

Project Initiation Process



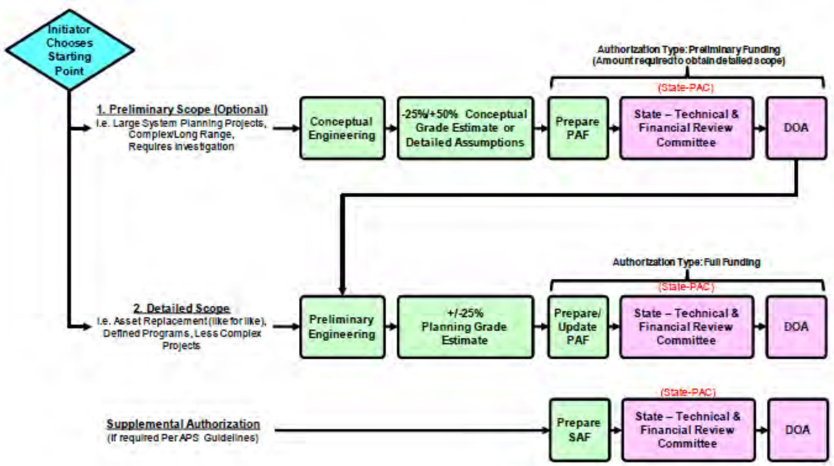
Eversource Project Approval Committee Process



Supplemental Authorization Process

(if required per APS guidelines)

New Hampshire Project Approval Committee Process



Eversource

Job

Aid

Capital Project Approval Process

JA-AM-2001-A, Rev. 5

Process Owner:

Effective Date: 6/1/2020

John Dipadla-Tromba

Director, Business and Quality Assurance, Transmission

Eversource

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Table of Contents

1 Purpose

This job aid provides instructions and guidance on the process for initiating and then obtaining technical and financial approval for capital projects within all three states. This job aid will focus on project initiation, solution vetting by the Solution Design Committee (SDC), and approval of the Project Authorization Form (PAF) by the Eversource Project Approval Committee (EPAC) for transmission and substation projects and by each of the state Project Approval Committees (state PACs) for distribution projects. The authorization forms used by each committee can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms. Completed samples of each form can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms\Sample Forms\. This job aid supports the guidance contained in Accounting Policy Statement 1 (APS01), Operations Project Authorization, which can be found on the Eversource intranet at https://eversourceenergy.sharepoint.com/sites/Accounting/SitePages/Accounting-Policies-%26-Procedures.aspx.

2 Affected Groups

As described in Responsibilities and General Instructions, the System Planning, Asset Management, Transmission Interconnections, and Project Management groups, along with the SDC, EPAC, and state PAC committees will have primary responsibility for the project review and approval process. The following general groups will also be affected by this job aid as their participation is critical to the successful initiation, development, review, and approval of capital projects.

- Transmission Line, Substation Design, Substation Technical, Transmission Protection and Control, and Distribution Engineering
- Construction
- Scheduling
- Siting/Permitting
- Environmental
- Siting and Construction Services
- Procurement
- Investment Planning
- Operations
- Engineering Project Controls
- Transmission Project Controls

3 Responsibilities

3.1 Project Initiator

In general, Transmission and Substation Projects will be initiated by either the System Planning (Reliability and Capacity Projects), Asset Management (Asset Condition Projects), or Transmission

Interconnections Department (Interconnection Projects). Distribution street and line projects with no substation scope will be initiated by the Distribution Engineering group. Telecom projects (aside from OPGW projects which will be initiated by the Asset Management group) will be initiated by the Communications Engineering Group. Distributed generation interconnection projects will be initiated by the Distributed Energy Resources Technology Group.

The project initiator will be responsible for securing initial funding from the EPAC for Transmission and Substation projects or from a state PAC for Distribution projects, coordinating conceptual engineering activities, and coordinating the development of conceptual grade cost estimates for alternatives (-25%/+50%). For applicable projects (See Section 3.4.1 below for details), the project initiator will be responsible for presenting the choice of a preferred solution to the SDC. The project initiator will own the PAF, including Program Level PAFs and Program Release Forms, that will be required documentation at the project approval committee meetings. The project initiator shall submit a PAF that includes the financial and technical details, a detailed backup cost estimate, a project checklist, and a Constructability Review Form at least seven working days prior to the next scheduled EPAC meeting for Transmission and Substation projects or three working days prior to the next scheduled state PAC meeting for Distribution projects. For transmission projects, the detailed cost estimate must be in accordance with Attachment D to PP4 (ISO-New England Planning Procedure 4). If a project manager is assigned, the project initiator will support the engineering phase and be responsible for updating the PAF to secure full funding.

For projects that do not have a project manager assigned, the project initiator will be responsible for leading preliminary engineering activities and developing an updated +/-25% planning grade cost estimate. The project initiator will then be responsible for updating the PAF and securing full funding from the EPAC or a state PAC. Once a project is fully approved and funded, project ownership transfers to the project manager for the project execution and closeout phases.

3.2 Project Manager (PM)

Once assigned, the PM will manage the project's schedule and budget and support the conceptual engineering phase by driving collaboration with the various engineering disciplines and affected departments. With support from the project initiator, the PM will be responsible for facilitating preliminary engineering activities and coordinating with the Cost Estimating team to develop cost estimates. Ultimate ownership of the project transfers from the project initiator to the PM once the project is fully approved and funded. The PM will also be responsible for any required supplemental approval with support from the project initiator, if necessary.

3.3 Project Sponsor

Typically, the Project Sponsor will be the director of the project initiator. The Project Sponsor will be responsible for review and approval of project documents before they are submitted to the committees for approval.

3.4 Solution Design Committee (SDC)

The SDC will serve as solution development gate keepers to ensure the best solution is selected, ensure guiding principles are followed, and drive standardization. SDC will review project alternatives, scope, and conceptual grade cost estimates during the solution vetting process. The SDC administrators will use the email address SolutionDesignCommittee@eversource.com to communicate with project initiators and for all committee communications. More information on solution vetting can be found in Section 4.3 and the full responsibilities of the SDC are contained in Attachment A, Solution Design Committee Charter.

3.4.1 Project Types

The SDC will review and approve solutions for the following Transmission and Substation project types:

- System Planning – Reliability and Capacity Projects
- Asset Management – Programs (OPGW Programs, Breaker Programs, etc.), Rebuilds, Conductor/Cable Replacements, Program releases with significant scope in addition to the program.
- Transmission Interconnection Projects – Projects on track to sign Interconnection Agreements may be reviewed by the SDC at the request of the sponsoring engineering director.
- Other Telecom projects and programs

Like-for-like asset replacement projects and individual releases within defined programs with minimal scope variations will not need to be reviewed or approved by the SDC. EPAC member directors will also have discretion to determine whether a specific project or program will require review and approval by the SDC.

3.5 Eversource Project Approval Committee (EPAC)

The EPAC will be responsible for the review and approval of the technical and financial merits of transmission and substation projects. For project and program initiations, the EPAC will review and authorize Initial Funding Request Forms (IFRs) typically up to $250,000, including Program Level PAFs with initial funding. The EPAC may also review requests for initial funding beyond $250,000 if a larger funding amount is required to complete preliminary engineering activities. For previously initiated projects and programs, the EPAC will review partial and full funding PAFs, Program Level PAFs, and Program Release Forms. The EPAC will review conceptual grade cost estimates (-25%/+50%) for projects looking to secure partial funding and will review planning grade cost estimates (+/-25%) for projects looking to secure full funding authorization. The EPAC administrators will use the email address TranEPAC@eversource.com to communicate with project teams and for all committee communications The full responsibilities of the EPAC are contained in Attachment B, Eversource Project Authorization Committee Charter.

3.5.1 Project Types

The EPAC will review and approve the following project types:

- Transmission line and/or substation projects (Transmission projects over $300,000 total cost and distribution substation projects over $100,00 direct costs)
- Transmission line and/or substation programs (OPGW Programs, Breaker Programs, etc.)
- Telecom projects that impact transmission lines and/or substations
- New or reconfiguration of a distribution substation (regardless of voltage level)
- Substation projects with transmission and distribution components will be reviewed as a package, only by the EPAC
- Customer interconnection requests that require transmission or substation work
- Any other project per the discretion of the EPAC chairperson(s)

All other distribution projects will be reviewed and approved by the state PAC (see section 3.6.1). See Section 5 for review process for transmission projects less than $300,000 total cost.

3.6 State Project Approval Committees (CT PAC, MPAC, and NH PAC)

The state PACs will be responsible for the review and approval of the technical and financial merits of Distribution projects. There will be three different project approval committees to review and approve the projects; one from each state (CT PAC, MPAC, and NH PAC). The state PACs will review PAFs with conceptual grade (-25%/+50%) estimates for distribution projects looking to secure initial funding and will review PAFs with planning grade (+/-25%) estimates for distribution projects looking to secure full funding authorization. The full responsibilities of the state PACs are contained in Attachment C, State Project Approval Committee (State PAC) Charter.

3.6.1 Project Types

The state PACs will review and approve the following project types:

- Underground distribution project greater than $250,000
- Overhead and underground-overhead mixed distribution projects over $1 million
- Customer interconnection requests with total cost estimates (including indirect costs) greater than $1 million. Customer interconnection projects less than $1 million are reviewed and approved in PowerPlan and typically will not require review and approval by the state PAC.
- DG interconnection request without substation scope that require a new feeder (regardless of cost) or with total cost estimate greater than $500,000. Note that DG interconnection projects with substation scope will be reviewed by EPAC as described in Section 3.5.1.)

Note that per APS01, all other underground, overhead, and underground-overhead mixed distribution projects under the dollar thresholds listed above but over $100,000 direct costs still require PAF documentation. These PAFs will be reviewed and approved directly in PowerPlan. The approving director can use his/her discretion to require any of these projects to be reviewed at the state PAC. See Section 5 for review process information for distribution projects under $100,000 direct costs. All other transmission and substation projects will be reviewed and approved by the EPAC (see section 3.5.1).

3.7 Cost Estimating

The Transmission Cost Estimating team will support development of project cost estimates for Transmission and Substation projects. Depending on the complexity of the project, the approximate cost, and other factors the level of support provided by the Cost Estimating team may range from taking the lead in developing the estimate to reviewing an estimate prepared by the project team. To request support from the Cost Estimating team, project teams should complete the Estimate Request Form which can be found at \\nu.com\data\SharedData\Estimating-Shared\2) Estimate Templates\1) Est Request form\ and submit it to the Manager of Transmission Cost Estimating.

4 General Instructions

The process to proceed with each successive phase of a capital project is designed to ensure that there is a valid need, the right solution alternatives are evaluated, the technical approach is sound, and resources are budgeted and prudently spent. The overall process flow for Transmission and Substation projects is depicted in Attachment D, Transmission and Substation Project Approval Process Flow Charts. Attachment E, Transmission and Substation Project Approval Process Detailed Flow Chart is a 17”x11” flowchart with more detailed descriptions. The overall process flow for Distribution projects is depicted in Attachment F, Distribution Project Approval Process Flow Chart. The initiation and major engineering and approval phases of the process flow charts correspond to the sections below.

These general instructions are for the project types listed in Sections 3.5.1 and 3.6.1. Refer to Section 5 for instructions for planned transmission projects less than $300,000 or planned distribution projects less than $100,000. Refer to Section 6 for instructions for securing approval of emergent work.

4.1 Project Initiation

Following the identification of a project need the initiator will secure a project number. Project initiators can email TranEPAC@eversource.com for assistance securing a project number. Project initiators will then complete an IFR and submit it to EPAC via TranEPAC@eversouce.com. The IFR may be used to request funding per Section 3.5. The form can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms\. The initiator will be required to state the project need and objectives and include an explanation of the funding request amount, including a budget for conceptual and preliminary engineering activities and a schedule for returning to EPAC with a full funding request. The IFR may include a budget for initial internal siting and permitting preparation activities. The IFR should not include funding for detailed engineering or procurement of any material. The EPAC chairman may decide to approve the request directly or may request that the initiator present the request for input and feedback to the EPAC.

Once an IFR is approved, the EPAC administrator will send the approved form to Investment Planning to create a project and submit it for Delegation of Authority approvals in PowerPlan, the Eversource software tool for financial approval. The initial funding is obtained once delegation of authority has been performed through PowerPlan in accordance with APS01 (See Section 4.5.3 for more information on Delegation of Authority Policy). Once fully approved in PowerPlan a Work Order (WO) will be assigned. The EPAC administer will copy the Directors of Project Management on the submittal to Investment Planning so that a Project Manager can be assigned as appropriate. For some projects the Project Manager role may remain with the Project Initiator, be assigned to a lead engineer, or be assigned to a Transmission Line Construction Manager.

4.2 Project Initiation for Programs

Initial funding can also be requested at the program level using the Program Level Project Authorization Form. The form can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms. The funding can be used to advance specific project scope under an approved program. Sections 4.5.1 and 4.5.2 contains more information on full approval of programs and program level releases.

4.3 Conceptual Engineering

The project initiator should follow the Project Alternative Process in procedure M2-TP-2018 for the identification, development and selection of project alternatives. As described in detail in M2-TP-2018, the project initiator will lead and coordinate the following activities with support from the PM and input from affected departments:

- Incorporate designs from standards library and develop scope and major equipment lists for all alternatives under consideration.
- Conceptual engineering of all appropriate alternatives including early field review and desktop analysis.
- Identification of key project risks with the appropriate level of detail with respect to constructability, routing, outage planning, possible Single Contingency Loss of Load (SCLL) conditions and applicable mitigation actions, siting and permitting, environmental impacts, community and external stakeholder impacts, site control, procurement, etc.
- Identification of any land rights needs.
- High level routing determinations (for linear projects).
- Develop project strategies to mitigate identified risks.
- Conceptual grade cost estimates (-25%/+50%) for all appropriate alternatives (at least the preferred solution and leading alternative). The project team should request support from the Cost Estimating team for all estimates.

The project team will then recommend a preferred solution and document the rationale for the choice of preferred solution. The Engineering Deliverables document which details activities required for estimating purposes can be found at N:\Estimating-Shared\2) Estimate Templates\4) Estimate Categories & Scope Deliverables\.

4.4 Solution Vetting

Prior to proceeding with Preliminary Engineering of the preferred solution, more comprehensive projects and asset condition projects at the program level will need to be reviewed and approved by the SDC (See Section 3.4.1 for list of project types the SDC will review). Project initiators will submit a Solution Selection Forms (SSF) to the SDC via SolutionDesignCommittee@eversource.com at least five business days prior to the next scheduled SDC meeting. The SDC will review the SSF and confirm that the project team has selected the best solution. The SSF will require a statement of project need and objectives, documentation of the alternatives analysis, scope and major equipment list for the preferred solution, and a conceptual grade cost estimates for the preferred solution and a leading alternative. The form can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms. The full responsibilities of the SDC are contained in Attachment A, Solution Design Committee Charter. Once reviewed and approved by the Solution Design Committee, projects will proceed with Preliminary Engineering.

Transmission and substation projects that do not require review and approval by the SDC such as like-for-like asset replacement projects and individual releases within defined programs with minimal scope variations will proceed directly with preliminary engineering activities and development of a full funding request to present to EPAC.

Distribution street and line projects without substation components may also require a solution vetting process. The state PAC chairperson may require more complex distribution street and line projects to complete a distribution design review prior to state PAC approval.

4.5 Preliminary Engineering

Once the project team has chosen a preferred solution with scope definition, it can proceed with preliminary engineering and development of an updated cost estimate of the preferred solution. In order to receive full funding approval, projects will require planning grade (+/-25%) cost estimates. The project team should request support from the Cost Estimating team to develop the planning grade cost estimate. The preliminary engineering phase will typically include:

- General requirements/specifications
- Preliminary design for civil, electrical, T-Line, and P&C
- Nomenclature, relay, metering, and equipment rating one-line diagram and preliminary three-line diagram
- More in-depth constructability review
- Below grade investigation
- Preliminary outage plan and Operations review
- Preferred route selection
- Equipment specifications and Bill of Materials
- Critical Path Schedule
- The project team will work with the affected groups listed in Section 2 to complete more in-depth investigations, develop a mitigation plan for project risks, and refine project strategies

The Engineering Deliverables document which details activities required for estimating purposes can be found at N:\Estimating-Shared\2) Estimate Templates\4) Estimate Categories & Scope Deliverables\.

If the initial funding is not sufficient to complete preliminary engineering and develop a planning grade cost estimate, then the project team can prepare a PAF and make a request for partial funding at EPAC per Section 3.5. The partial funding request should be for the budget amount that will be required to complete the detailed scope definition of the project and prepare a full funding request. As with IFRs, partial funding requests may include a budget for internal siting and permitting preparation activities but should not include funding for procurement of any material. The request should also include a proposed schedule to complete these activities and return to EPAC with a full funding request.

4.6 Full Project Authorization

After preliminary engineering is complete, the PAF will be completed and the project will be presented to either the EPAC or the state PAC for full approval and funding authorization. PAFs that will be reviewed at EPAC should be submitted to TranEPAC@eversource.com at least seven business days prior to the next scheduled EPAC meeting. For the project types listed in Section 3.4.1, the EPAC will not review full funding requests unless the project has already been approved by the Solution Design Committee. The project checklist, a Constructability Review Form, and a detailed backup cost estimate as described in Section 4.4 in accordance with Attachment D to ISO-NE Planning Procedure 4 (PP4) must accompany the PAF.

4.6.1 Program Approval

EPAC will review and approve Asset Management programs using the Operations Program Level Project Authorization Form. The form can be found at\\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms. In addition to the information required on the PAF for a regular project (need, objectives, scope, background/justification, etc.) the Program Level PAF will also require:

- A financial evaluation completed on a unit cost basis so that the capital cost of each application of the program can be fully understood. The unit cost is often based on a similar project that has been completed.
- A listing of proposed circuits or substations by state that will be included in the scope of the program.
- An estimate of the program capital investment value by state.
- A proposed schedule for bringing forward and executing the program level releases.
- A description of the investigations that will be needed at each location to develop the scope and cost estimate at a specific site.

As described in Section 4.1.1 Program Level PAFs may also be combined with an initial funding request at the program level so that the initiator will have funds to develop the scope of the program at specific sites and bring forward full funding program release requests.

4.6.2 Program Release Authorization

Once the scope, site-specific cost estimate, and constructability reviews are completed for a particular location or circuit, a Program Release Form will be submitted for full funding. The Program Release Form can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms\. Each Release will summarize the scope and cost estimate at a specific location and discuss any variances between the scope or cost estimates from the expected unit costs and scope approved in the Program Level PAF. Once an individual program release is approved at EPAC, any initial funding costs that were originally charged at the program level will be journaled to the specific project, which will allow those costs to be capitalized along with the specific project and also make more budget available at the program level to develop additional Program Release Forms. Once approved, the approval process for a Program Release Form will be the same as stated above for the full funding PAF.

4.6.3 Delegation of Authority

Once approved, the EPAC or state PAC administrator will submit the EPAC-approved PAF to Investment Planning for approvals in PowerPlan in accordance with the company Delegation of Authority Policy (DOA). The DOA specifies the capital authorization level of various company positions (manager, director, vice president, senior vice president / subsidiary president, Executive vice president, etc.). The MS Excel file "Power Plan Project Approval Trees" found at N:\EPAC\Administrative\ lists which specific individuals at each authorization level that will be required to approve projects authorized by EPAC. There are separate approval trees listed for transmission line and substation major projects, transmission line maintenance projects, and distribution substation projects. The full project funding is attained once delegation of authority has been performed through PowerPlan in accordance with APS01. PMs should include up to thirty days in project schedules to complete approvals in PowerPlan and sixty days for projects that will require Delegation of Authority approval by the Eversource Subsidiary Board.

Projects must be fully approved in PowerPlan before their scope or cost estimates can be shared publicly. This includes but is not limited to sharing cost estimates with ISO-NE, sharing cost estimates with customers for customer or interconnection projects, filing a siting or permitting application that includes a cost estimate, and conducting project outreach. If a project schedule requires the release of project information prior to full project approval in PowerPlan is possible, then a project team can request approval from EPAC to release the information. If EPAC approval is also not possible, then the project team can seek the SDC's approval to release the information.

4.7 Detailed Engineering, Siting, and Permitting

Once the project is fully authorized in PowerPlan, the project team can proceed with detailed engineering, siting and permitting application filings, project outreach, ordering major material, and other development activities.

4.8 Construction and Construction Variance Monitoring

The project manager or lead will manage the project's execution and construction. The project manager or lead will monitor spend vs. authorized costs and submit a revised PAF or Supplemental Request Form (SRF) to the EPAC or state PAC if any of the following occur:

- The project cost will exceed APS01 tolerances.
- Significant Scope change (even if cost alone does not trigger a supplement) such as an added unit of property (i.e. switches, relays, CCVTs, etc.) or a change in technology

- Technical Design Change (i.e. OH vs UG, air vs. GIS, etc.)

A revised PAF can be used for scope changes without significant cost changes and the SRF should be submitted for all other instances of project cost being expected to exceed APS01 tolerances. Supplemental authorization requests should be prepared as soon as it is likely that the project cost is expected to increase and the updated project estimate exceeds the APS01 tolerance for the current authorization. Supplement requests should also be submitted once a scope change is identified. The SRF can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms.

If a supplement is approved by the EPAC or state PAC, the committee administrator will send the approved SRF to Investment Planning for submittal for Delegation of Authority approvals in PowerPlan. When determining when to submit a supplement, PMs should note that attaining full approval in PowerPlan may take up to thirty days and sixty days for projects that will require Delegation of Authority approval by the Eversource Subsidiary Board.

4.9 Project Closeout

All project documents will be closed and affected databases updated upon project closeout in accordance with M6-PM-2001, Project Management Process, or applicable local project closeout process.

5 Instructions for Small Planned Projects

Each year annual distribution substation budgets are approved and funded to support the many small planned projects that will be completed that year. Per APS01, transmission projects less than or equal to $300,000 in total cost and distribution substation projects less than or equal to $100,000 in direct costs do not require their own PAFs.

5.1 Distribution Substation Projects Less Than or Equal to $50,000 in Direct Cost

To be issued a work order that will charge against one of these annual budgets for a small planned distribution substation project, the project lead must complete a Planned Annual Request Form which can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms. The completed Planned Annual Request Form is then attached in PowerPlan when a new work order is created with an EPAC Administrator included as a required approver.

5.2 Transmission Projects Less Than or Equal to $300,000 in Total Cost & Distribution Substation Projects with Direct Cost Over $50,000 and up to $100,000

To request project approval the project lead must complete a Planned Annual Request Form which can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms. The completed Planned Annual Request Form is then submitted to TranEPAC@eversource.com. The completed Planned Annual Request Form will be reviewed and approved directly in PowerPlan.

6 Instructions for Emergent Work

Each year annual transmission and distribution substation budgets are approved in each region and funded to support the many small projects that classify as emergent work within that year. Per APS01, transmission projects less than or equal to $300,000 in total cost and distribution substation projects less than or equal to $100,000 in direct costs do not require their own PAFs. Emergent work refers to work that could not be planned that is completed to repair or replace capital equipment that broke or failed.

To be issued a work order that will charge against one of these annual budgets for small transmission or distribution substation emergent work, the project lead must complete an Emergent Work Order Request Form which can be found at \\nu.com\data\SharedData\EPAC\Administrative\EPAC Forms. The completed Emergent Work Order Request Form is then attached in PowerPlan when a new work order is created with an EPAC Administrator included as a required approver.

7 Definitions & Acronyms

Annuals	Annuals refers to the annual project budgets that are approved to support small projects and small emergent work projects.
APS	Eversource Accounting Policy Statement
Conceptual Engineering	An optional project phase, for the engineering needed to obtain a project cost estimate accurate to -25%/+50% and to generate a PAF
Conceptual Estimate	A cost estimate with target accuracy of -25% to +50%
Construction	The project phase for the implementation of an engineered project
DOA	Delegation of Authority
Detailed Engineering	The project phase for the engineering needed for construction to begin, to obtain a project cost estimate accurate to ± 10%.
Emergent Work	Refers to work that could not be planned that is completed to repair or replace capital equipment that broke or failed
Engineering Estimate	A cost estimate with target accuracy of +/-10%
EPAC	Eversource Project Approval Committee
IFR	Initial Funding Request Form required to initiate a project with funding and setup a Work Order, the initiator will complete an IFR and submit it to the EPAC.
ISO-NE	The independent operator of New England's bulk electric power system and transmission lines. ISO-NE manages a comprehensive regional planning process.
M2-TP-2018	The Project Alternative Strategy procedure document published by the System Planning organization.
M6-PM-2001	The Project Management Process procedure document

PAF	Project Authorization Form required by Accounting Policy Statement 2 for the purpose of requesting authorization of capital funds for a particular project
Planning Estimate	A cost estimate with target accuracy of +/-25%
PM	Project Manager
PowerPlan	Eversource financial approval tool
PP4	ISO-NE Planning Procedure 4
Preliminary Engineering	The project phase for the engineering needed to obtain a project cost estimate accurate to ± 25% and to generate a PAF
Program Level PAF	Authorization document for programs. A program is a substation need that will be addressed at numerous sites (i.e. Oil Circuit Breaker Replacements, Relay Replacements, etc.) or a line need that will be addressed on numerous circuits (i.e. Structure Replacements, Fiber Optic Expansion, etc.)
Program Release Form	Authorization form for a specific site or circuit of an approved program.
SCLL	Single Contingency Loss of Load
SDC	Solution Design Committee is a three-state committee that reviews substation and transmission projects and programs to ensure that the best solution is selected and standardization is implemented across the company
SSF	Solution Selection Form – Document that the SDC will review and approve
SRF	Supplement Request Form
State PAC	State Project Approval Committee. There will be three state project approval committees for distribution projects: MPAC, CT PAC, and NH PAC
WO	Work Order

8 Revision History

Revision 5 – June 1, 2020

- Added Sections 4.1.1, 4.5.1, and 4.5.2 containing description and instructions for initiating programs, Program Level PAFs, and Program Release Forms
- Added Sections 4.5.3 to add additional description of Delegation of Authority Policy
- Added Sections 5 and 6 to include instructions for securing authorization for emergent work and annual projects
- All Sections: Added detail and instructions for distribution line projects, distributed generation interconnection projects, and communications engineering projects.
- Other minor updates

Revision 4 – November 2, 2018

- Updated all sections to align with updated project lifecycle including new Project Initiation Process and Solution Design Committee Process

Revision 3

- Minor updates

Revision 2 – October 27, 2017

- All Sections: Changed from TRC and CPAC to EPAC and state PACs

Revision 1 – December 7, 2016

- 4 General Instructions – Added location of forms
- 4.2 Detailed Engineering Approval – Added requirement to complete TAF Transmission Checklist
- 5 Definitions and Acronyms – Added acronyms used in Attachment F
- 6 Summary of Changes – Added section
- Added Attachment F, TAF Transmission Checklist and Instructions

Revision 0 – August 28, 2016

- Original issue

Attachment A, Solution Design Committee Charter

Purpose

The Solution Design Committee (SDC) will serve as solution development approval committee to ensure the best solution is selected, ensure guiding principles are followed, and drive standardization. SDC will review project alternatives, scope, and conceptual grade cost estimates during the solution vetting process.

Applicability

The SDC is responsible for solution selection review of electrical Transmission and Substation projects in all three states of the following types:

- System Planning – Reliability & Capacity Projects
- Asset Management – Programs (OPGW Programs, Breaker Programs, etc.), Rebuilds, Conductor/Cable Replacements, Program releases with significant scope in addition to the program.
- Transmission Interconnection Projects – Projects on track to sign Interconnection Agreements may be reviewed by the SDC at the request of the sponsoring engineering director.

Like-for-like asset replacement projects and individual releases within defined programs with minimal scope variations will not need to be reviewed or approved by the SDC. EPAC member directors will also have discretion to determine whether a specific project will require review and approval by the SDC.

Objectives

The objectives of the SDC are as follows:

1. Confirm that the right subject matter experts from affected departments were appropriately involved in the conceptual engineering, alternatives analysis, and solution selection.
2. Confirm project teams identified and considered a robust set of alternatives when selecting the best solution in accordance with M2-TP-2018 Project Alternative Process.
3. Ensure the development of project solutions and alternatives incorporate standardized design and equipment, where practical/possible.
4. Review initial conceptual engineering, scope, and cost estimates for all potential project alternatives. Cost estimates should be of conceptual grade (-25%/+50%) for the preferred solution and the leading alternative.
5. Review and confirm that project teams identify project risks for the preferred solution and its alternatives with the appropriate level of detail with respect to constructability, routing, outage planning, possible SCLLs, siting and permitting, environmental impacts, community and external stakeholder impacts, land rights needs and site control, procurement, etc.

6. Review and confirm project team's alternatives analyses and choice for preferred solutions and ensure the rationale is appropriately documented.
7. Coordinate with EPAC to initiate any needed process changes on at least a biennial basis.

Membership

SDC shall consist of an executive sponsor, a chairperson, voting members, an administrator, and non-voting attendees as shown on the below table. The chairperson may designate additional voting members, if required.

SDC Membership List

SDC Role	Company Position
Executive Sponsor	VP, Substation and Transmission Engineering
Co-Chairperson	Director, Substation Design Engineering
Co-Chairperson	Director, Substation Protection and Controls
Administrator(s)	As appointed by the Chairperson
Voting Member	Director, Transmission Business and Quality Assurance
Voting Member	Director, System Planning
Voting Member	Director, Transmission Line Engineering
Voting Member	Director, Substation Technical Engineering
Voting Member	Director, System Solutions
Voting Member	Director, Engineering Capital Projects
Voting Member	Manager(s), Transmission Projects
Voting Member	Manager of Standards
Voting Member	Manager of Transmission Siting
Voting Member	Manager of Siting and Construction Services
Attendee	Director, Transmission Project Controls
Attendee	Director, Engineering Project Controls
Attendee	Manager of Project Solutions
Attendee	Manager of Estimating
Attendee	Manager of Asset Management
Attendee	Manager(s) of Substation Engineering
Attendee	Manager(s) of Protection and Controls
Attendee	Manager(s)/Lead(s) of Transmission Line and Civil Eng.
Attendee	Manager(s) of Substation Technical Engineering
Attendee	Manager(s) of System Planning
Attendee	Manager of Licensing and Permitting
Attendee	Manager(s) of Environmental Affairs
Attendee	Manager(s) of Procurement
Attendee	Supervisor(s)/Manager(s) of Outage and Ops Planning
Attendee	Manager of Generation Interconnections
Attendee	Manager of Operational Compliance
Attendee	Manager(s) of Transmission Line Operations
Attendee	Manager(s) of Station Operations/ Field Engineering/ System Dispatch
Attendee	Manager(s) of Systems Engineering
Attendee	Manager of ISO Policy and Economic Analysis

Roles and Responsibilities

Executive Sponsor

- Provide senior management vision, direction and feedback to the SDC
- Appoint the Chairperson(s)

Chairperson(s)

- Preside at SDC meetings
- Designate a Voting Member as an alternate to preside at meetings in his/her absence
- Solicit Voting Member appointments
- Appoint a SDC administrator
- Determine the meeting schedule and location(s)
- Approve meeting agendas
- Review meeting materials on the agenda prior to the SDC meeting
- Hold votes as required
- Participate in discussions and votes to meet the SDC objectives
- Initiate the biennial review of the SDC process in coordination with EPAC
- Create subcommittees as required

Voting Member

- If required, designate a manager in the same organization as a voting alternate to participate in the SDC
- Review meeting materials on the agenda prior to the SDC meeting
- Participate in discussions and votes to meet the SDC objectives
- Participate in the biennial review of the SDC process as required

Administrator

- Schedule meetings
- Prepare draft meeting agendas
- Quality Screening of Project Documentation
- Distribute meeting materials to attendees five working days prior to a scheduled SDC meeting
- Record the result of any votes
- Prepare and distribute meeting notes
- Record Solution Select Forms presented and their attachments and meeting results
- Attend to and manage the SolutionDesignCommittee@eversource.com email inbox

Project Lead/Initiator

- Complete a Solution Selection Form (including statement of need, project objectives, alternatives analysis, and scope for preferred solution) for any proposed capital project that meets the applicability criteria described above

- Ensure that SDC objectives listed above are fully met, and that subject matter experts from affected departments were included in the alternatives analysis.
- Submit the Solution Selection Form to the SDC administrator via SolutionDesignCommitee@eversource.com at least five working days prior to the next scheduled SDC meeting (ensures document screening and review by committee members)
- Attend the SDC meeting and present the Solution Selection Form to SDC members
- Revise the Solution Selection Form and/or respond to comments from the SDC as required

Quorum

The Chairperson(s) (or alternate) plus a minimum of four Voting Members (or alternates) shall constitute a quorum for voting purposes if all appropriate disciplines are present to challenge the merits of the project(s).

Meeting Schedule and Location

The SDC shall schedule meetings twice monthly. The Chairperson(s) may cancel a meeting or require more frequent meetings from time to time as required. The location of the SDC meeting will rotate between MA, CT, and NH.

Voting

The Voting Members and the Chairpersons, or their designated alternates, are eligible to vote. A vote is carried by a simple majority. Each person has one vote.

Subcommittees

The Chairperson may establish standing or ad hoc subcommittees as required to meet the objectives of the SDC. Subcommittees shall be chaired by a voting member of the SDC or their designated alternate.

Attachment B, Eversource Project Authorization Committee Charter

Purpose

The Eversource Project Authorization Committee (EPAC) reviews and approves the technical and financial merits of Transmission and Substation projects, including the selection of preferred solutions that are consistent with Eversource priorities (e.g. safety, reliability, cost efficiency). The EPAC authorizes, monitors and adjusts capital expenditure and resources for projects; prioritizes projects for the capital program and defers projects based on budget and resource availability.

Applicability

The EPAC is responsible for the technical review and financial approval of electrical Transmission and Substation projects in all three states.

Objectives

The objectives of the EPAC are as follows:

1. Receive, review, and approve Initial Funding Request Forms
    a. Review the need and confirm that a capital project is needed to address the need.
    b. Review and approve the project's objectives.
    c. Ensure the funding request amount, planned development activities, and schedule are appropriate.
2. Receive, review, and approve PAFs for all projects that meet the Accounting Policy Statement No. 1 threshold. A lower threshold may be imposed by the EPAC, if desired.
    a. Ensure that the PAF justification is valid.
    b. Review and approve the project's technical merits.
    c. Ensure that all reasonable alternatives were evaluated and appropriately rejected.
    d. Ensure the scope and cost estimates are reasonable to ± 25% for projects seeking full authorization.
    e. The committee has the ability to review detailed engineering designs, ensuring the proposed work is in accordance with Eversource Standards, evaluate load implications, assess root cause / reliability and vet out all possible alternatives.
    f. Not all projects presented are requesting funding and require a vote – these projects will be noted "FOR DISCUSSION ONLY".
    g. Ensure the PAF project checklist is complete.
    h. Ensure the Constructability Review Form is complete
    i. Ensure the financial analysis is reasonable to the accuracy appropriate to the project phase.
    j. Ensure the project schedule is achievable and reasonable to the accuracy appropriate to the project phase
    k. Ensure risks and mitigation plans are identified.
3. Evaluate project funding and priorities relative to the five-year capital plan.

4. Ensure project approval statuses and DOA progress are reviewed at least monthly.
5. Prioritize projects for deferment or cancellation.
6. Review EPAC process performance and lessons learned and coordinate with the state PACs to initiate any needed changes on at least a biennial basis.

Membership

EPAC shall consist of an executive sponsor, a chairperson, voting member directors, an administrator, and non-voting attendees as shown on the below table. The chairperson may designate additional voting member directors, if required.

EPAC Membership List

EPAC Role	Company Position
Executive Sponsor	VP, Transmission Projects
Co-Chairperson	Director, Transmission Project Controls
Co-Chairperson	Director, Transmission Business and Quality Assurance
Administrator	EPAC Program Manager
Member Director	Director(s), Transmission Projects
Member Director	Director, Transmission Line Engineering
Member Director	Director, Substation Design Engineering
Member Director	Director, Substation Technical Engineering
Member Director	Director, Substation Protection and Controls
Member Director	Director, Transmission System Planning
Member Director	Director, Siting and Compliance
Member Director	Director, Investment Planning
Member Director	Director(s), Engineering
Member Director	Director, Reliability, Compliance and Implementation
Member Director	Director(s), Transmission/System Ops
Member Director	Director, System Operations
Member Director	Director(s), Field Operations Lines
Member Director	Director(s), Field Operations Substations
Member Director	Director(s), Field Engineering
Member Director	Director, Engineering Project Controls
Member Director	Director, Engineering Capital Projects
Attendee	Manager of Project Solutions
Attendee	Manager of Transmission Siting
Attendee	Manager of Siting and Construction Services
Attendee	Manager of Capital Program & Estimating
Attendee	Manager of Licensing and Permitting
Attendee	Manager(s) of Procurement
Attendee	Manager(s) of Substation Engineering
Attendee	Manager(s) of Protection and Controls
Attendee	Manager(s)/Lead(s) of Transmission Line and Civil Eng.
Attendee	Program Manager- Transmission Capital Program
Attendee	Supervisor(s)/Manager(s) of Outage and Ops Planning
Attendee	Manager of Standards

Attendee	Manager of Budget and Investment
Attendee	Manager of Generation Interconnections
Attendee	Manager of Asset Management
Attendee	Manager of Operational Compliance
Attendee	Manager(s) of Line Operations
Attendee	Manager(s) of Substation Technical Engineering
Attendee	Manager(s) of System Planning

Roles and Responsibilities

Executive Sponsor

- Provide senior management vision, direction and feedback to the EPAC
- Appoint the Chairperson(s)

Chairperson(s)

- Preside at EPAC meetings
- Designate a Member Director as an alternate to preside at meetings in his/her absence
- Solicit Member Director appointments from the leadership team
- Appoint a EPAC administrator
- Determine the meeting schedule and location(s)
- Approve meeting agendas
- Review meeting materials on the agenda prior to the EPAC meeting
- Hold votes as required
- Participate in discussions and votes to meet the EPAC objectives
- Initiate the biennial review of the EPAC process in coordination with the other EPACs
- Create subcommittees as required

Member Director

- If required, designate a manager in the same organization as a voting alternate to participate in the EPAC
- Review meeting materials on the agenda prior to the EPAC meeting
- Participate in discussions and votes to meet the EPAC objectives
- Participate in the biennial review of the EPAC process as required

Administrator

- Schedule meetings
- Prepare draft meeting agendas
- Quality Screening and Quality Measurement of Project Documentation.
- Distribute meeting materials to attendees three working days prior to a scheduled EPAC meeting
- Record the result of any votes
- Prepare and distribute meeting notes

- Record PAFs and SRFs presented and meeting results
- Submit PAFs and SRFs approved to Investment Planning for Delegation of Authority approvals in PowerPlan
- Attend to and manage the TranEPAC@eversource.com email inbox

Project Lead/Initiator

- Complete a PAF (including financial and technical details, cost estimate, project checklist, and Constructability Review Form) for any proposed capital project or change, ensuring that EPAC objective one items are fully met, and obtain any necessary reviews and approvals prior to submittal to the EPAC
- Submit the PAF to the EPAC administrator via TranEPAC@eversource.com at least seven working days prior to the next scheduled EPAC meeting for engineering approval (ensures document screening and review by committee members)
- Attend the EPAC meeting and present the PAF to EPAC members
- Revise the PAF and/or respond to comments from the EPAC as required
- Once fully authorized, if costs exceed the approved PAF levels by more than the amounts shown in Accounting Policy Statement No. 1, create a SRF, attach to the previously approved PAF, and resubmit to EPAC for review and approval.

Quorum

The Chairperson(s) (or alternate) plus a minimum of four Member Directors (or alternates) shall constitute a quorum for voting purposes if all appropriate disciplines are present to challenge the merits of the project(s).

Meeting Schedule and Location

The EPAC shall schedule meetings twice monthly. The Chairperson(s) may cancel a meeting or require more frequent meetings from time to time as required.

Voting

The Member Directors and the Chairpersons, or their designated alternates, are eligible to vote. A vote is carried by a simple majority. Each person has one vote.

Subcommittees

The Chairperson may establish standing or ad hoc subcommittees as required to meet the objectives of the EPAC. Subcommittees shall be chaired by a voting member of the EPAC or their designated alternate.

Attachment C, State Project Approval Committee (State PAC) Charter

Purpose

The State Project Approval Committees (State PACs) review and challenge the technical merit of proposed distribution projects, and approve them as consistent with Eversource priorities (e.g. safety, reliability, cost efficiency).

Applicability

This charter applies to the three state PACs in Connecticut, Massachusetts and New Hampshire that are responsible for all Eversource electrical distribution projects originating in their respective states.

Objectives

The objectives of a state PAC are as follows:

1. Receive, review and approve Project Authorization Forms (PAFs) for all projects that meet the Accounting Policy Statement No. 1 threshold. A lower threshold may be imposed by the state PAC, if desired.
    a. Ensure that the PAF justification is valid.
    b. Review and approve the project's technical merits.
    c. Ensure the scope and cost estimates are reasonable to ± 25% for projects seeking full authorization and to -25%/+50% for projects seeking initial funding.
    d. Ensure that all reasonable alternatives were evaluated and appropriately rejected.
    e. The committee has the ability to review detailed engineering designs, ensuring the proposed work is in accordance with our Standards, evaluate load implications, assess root cause / reliability and vet out all possible alternatives.
    f. Not all projects presented are requesting funding and require a vote – these projects will be noted "FOR DISCUSSION ONLY".
    g. Ensure risks and mitigation plans are identified.
    h. Ensure the PAF project checklist is complete.
    i. Ensure the Constructability Review Form is complete.
    j. Ensure the financial analysis is reasonable to the accuracy appropriate to the project phase.
    k. Ensure the project schedule is achievable and reasonable to the accuracy appropriate to the project phase.
    l. If CEO or subsidiary board approval is required, ensure project and cost analysis has been reviewed by the Enterprise Risk Management and Financial Planning & Analysis departments.
2. Release engineering labor and funds for detailed engineering on approved PAFs.
3. Review projects authorized for detailed engineering at least monthly to control engineering spend.

4. Review state PAC process performance and lessons learned and coordinate with the other state PACs and the EPAC to initiate any needed changes on at least a biennial basis.
5. Provide a forum for design review for more complex distribution street and line projects. The state PAC chairperson will use their judgement to determine which projects require distribution design review prior to state PAC approval.

Membership

Each state PAC shall consist of an executive sponsor, a chairperson, voting member directors, an administrator and non-voting attendees as shown in the below table. The chairperson may designate additional voting member directors, if required.

State PAC Membership List

State PAC Role	Company Position
Executive Sponsor	VP, Engineering
Chairperson	Director, Distribution Engineering
Administrator	Appointed by Chairperson
Voting Member	Manager, Distribution Engineering
Voting Member	Manager, Investment Planning
Voting Member	Manager, Distributed Generation
Voting Member	Manager/Supervisor, Field Engineering
Voting Member	Manager, Integrated Planning, Scheduling
Voting Member	Manager, System Operations
Voting Member	Manager, Field Operations
Voting Member	Manager, Substation Technical Engineering
Voting Member	Manager, Engineering Standards
Attendee	Project Manager(s)

Roles and Responsibilities

Executive Sponsor

- Provide senior management vision, direction and feedback to the state PAC
- Appoint the Chairperson

Chairperson

- Preside at state PAC meetings
- Designate a Member Director as an alternate to preside at meetings in his/her absence
- Solicit Member Director appointments from the leadership team
- Appoint a state PAC administrator
- Determine the meeting schedule and location(s)
- Approve meeting agendas
- Review meeting materials on the agenda prior to the state PAC meeting

- Hold votes as required
- Participate in discussions and votes to meet the state PAC objectives
- Release funds on approved PAFs for detailed engineering
- Initiate the biennial review of the state PAC process in coordination with the other state PACs
- Create subcommittees as required
- Determine which projects should complete a design review prior to state PAC approval

Voting Member

- If required, designate a voting alternate to participate in the state PAC
- Review meeting materials on the agenda prior to the state PAC meeting
- Participate in discussions and votes to meet the state PAC objectives
- Participate in the biennial review of the state PAC process as required

Administrator

- Schedule meetings
- Prepare draft meeting agendas
- Distribute meeting materials to attendees three days prior to a scheduled state PAC meeting
- Record the result of any votes
- Prepare and distribute meeting notes
- Record PAFs presented and meeting results in the capital project database

Project Initiator (typically engineer level)

- Complete a PAF for any proposed capital project, ensuring that state PAC objective 1 items are fully met, and obtain any necessary reviews and approvals prior to submittal to the state PAC
- Submit the PAF to the state PAC administrator at least three working days prior to the next scheduled state PAC meeting for engineering approval
- Attend the state PAC meeting and present the PAF to state PAC members
- Revise the PAF and/or respond to comments from the state PAC as required
- Once fully authorized, if costs exceed the approved PAF levels by more than the amounts shown in Accounting Policy Statement No. 1, create a SRF, attach to the previously approved PAF, and resubmit for review and approval.

Quorum

The Chairperson(s) (or alternate) plus a minimum of two Member Directors (or alternates) shall constitute a quorum for voting purposes if all appropriate disciplines are present to challenge the merits of the project(s).

Meeting Schedule

Each of the state PACs shall schedule meetings at least bimonthly. The Chairperson may cancel a meeting or require more frequent meetings from time to time as required.

Voting

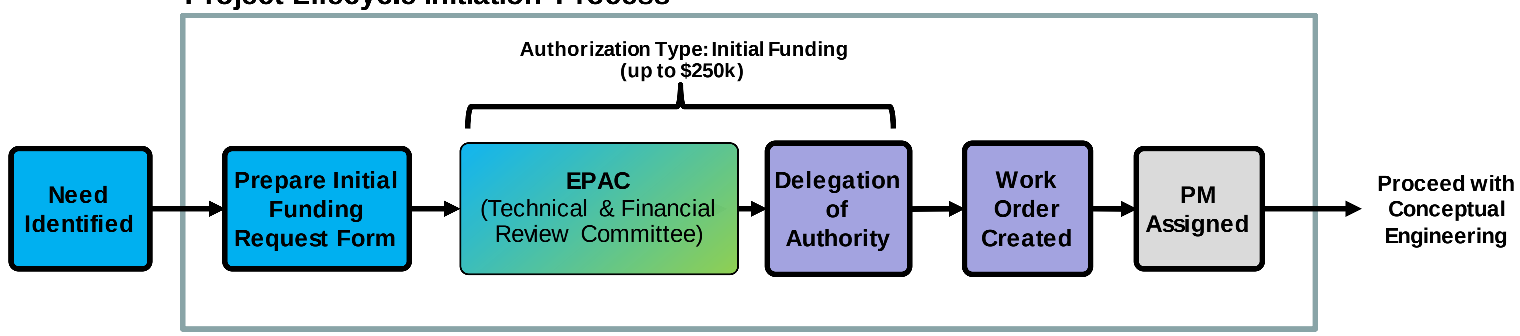
The Member Directors and the Chairperson, or their designated alternates, are eligible to vote. A vote is carried by a simple majority. Each person has one vote.

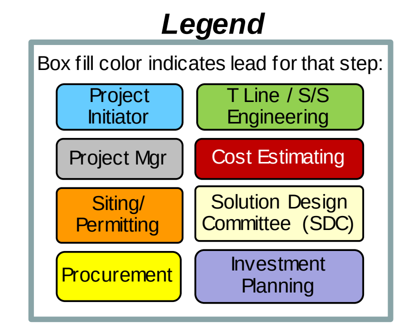
Subcommittees

The Chairperson may establish standing or ad hoc subcommittees as required to meet the objectives of the state PAC. Subcommittees shall be chaired by a voting member of the state PAC or their designated alternate.

Attachment D, Transmission and Substation Project Approval Process Flow Charts

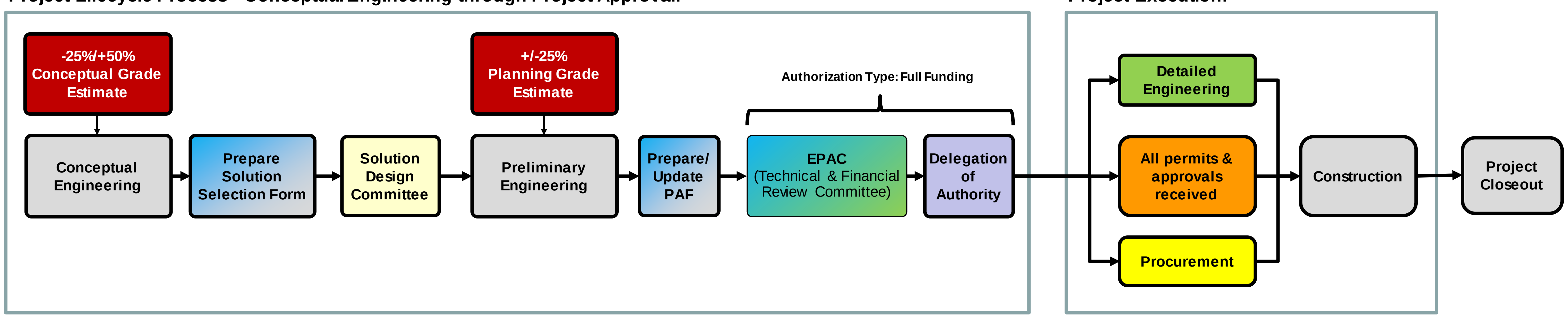
Project Lifecycle Initiation Process





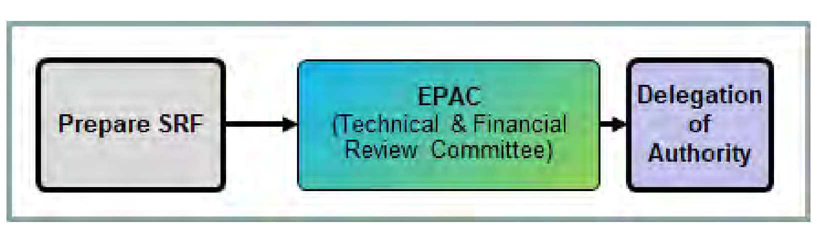
Project Lifecycle Process - Conceptual Engineering through Project Approval:

Project Execution:



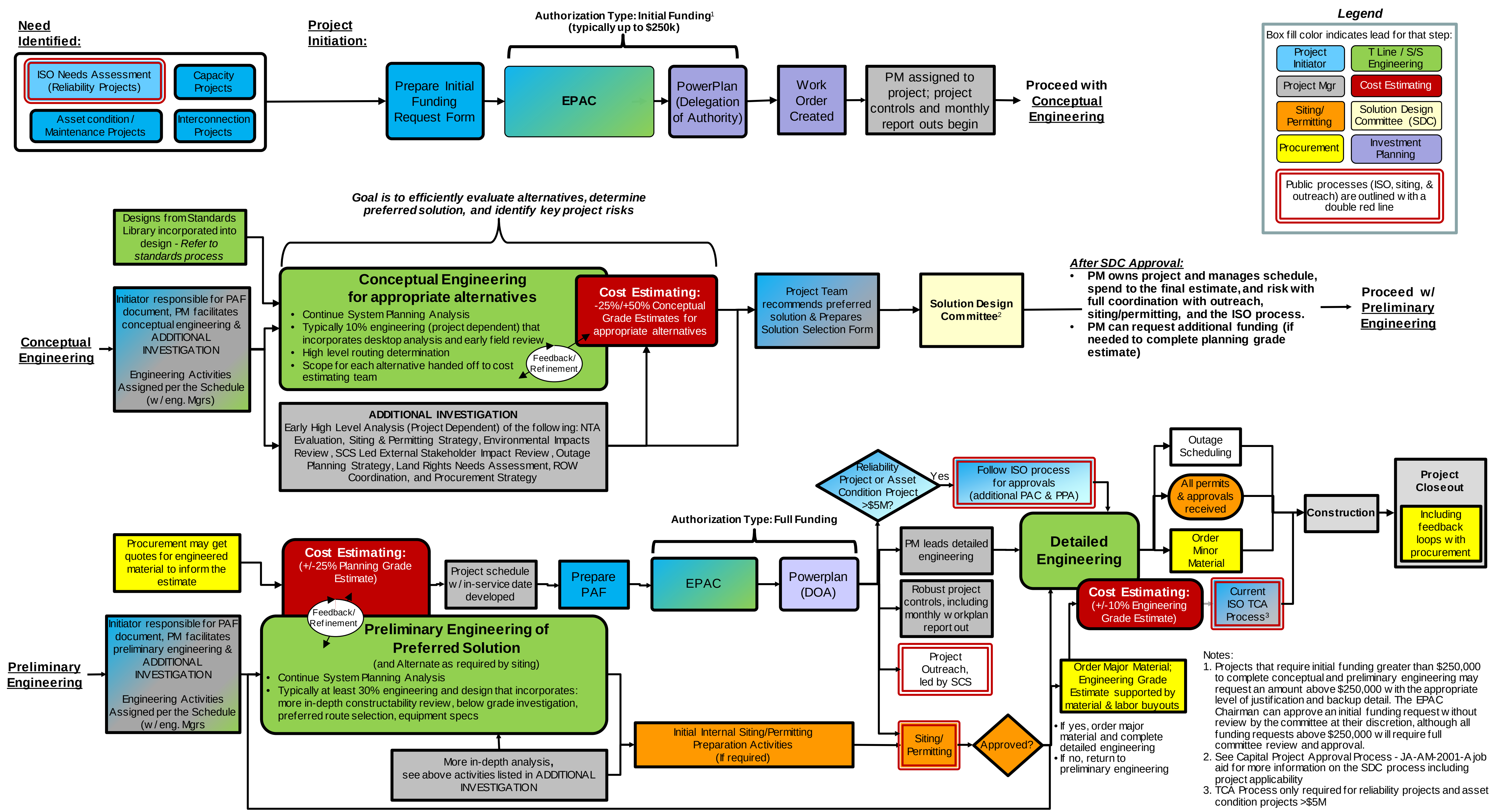
Supplemental Authorization Process

(if required per APS guidelines)



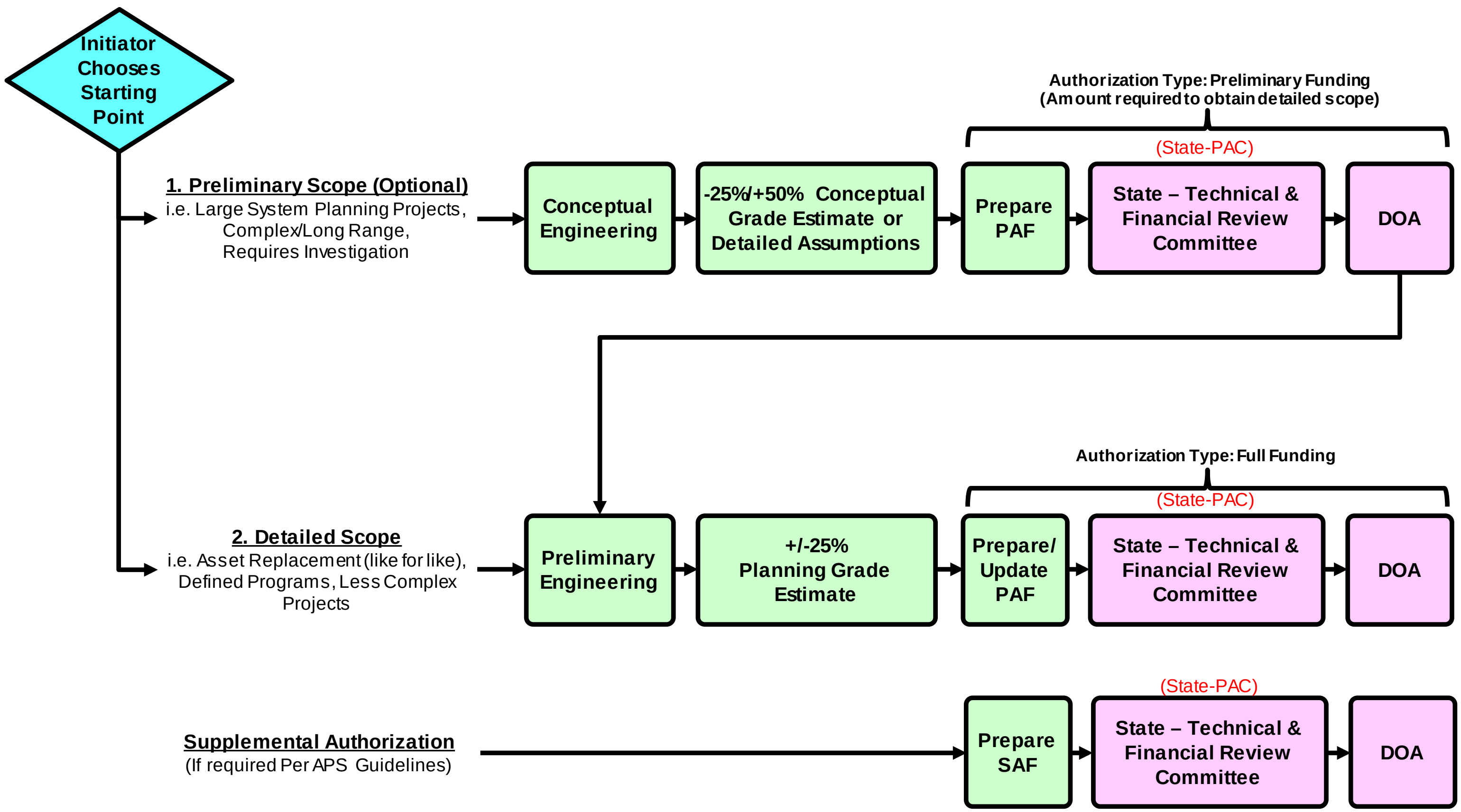
EVERSOURCE
Capital Project Approval Process

Attachment E, Transmission and Substation Project Approval Process Detailed Flow Chart



Notes:
1. Projects that require initial funding greater than $250,000 to complete conceptual and preliminary engineering may request an amount above $250,000 with the appropriate level of justification and backup detail. The EPAC Chairman can approve an initial funding request without review by the committee at their discretion, although all funding requests above $250,000 will require full committee review and approval.
2. See Capital Project Approval Process - JA-AM-2001-A job aid for more information on the SDC process including project applicability
3. TCA Process only required for reliability projects and asset condition projects >$5M

Attachment F, Distribution Project Approval Process Flow Chart



Reliability Report

Eversource Energy

New Hampshire

System Resiliency and Reliability

September 30, 2020

Table of Contents

I. Executive Summary

The purpose of this document is to report on the reliability performance of the Eversource distribution system in New Hampshire. It includes historical results back to 2005 but is focused on more recent activities in 2019 and 2020.

II. Reliability Performance

The Company evaluates reliability primarily based on generally accepted metrics of SAIDI, SAIFI, CAIDI, and CIII. See definitions for these terms in Appendix 1 of this document. Internally, the Company also evaluates performance using MBI, or Months Between Interruptions, which tracks the average number of months a customer goes between interruptions.

A. Goals

Reliability goals are established annually Corporate Performance Management, which is a group within the Financial Planning and Analysis Division that reports to the Chief Financial Officer of Eversource Energy. Corporate Performance Management works in conjunction with the business areas to develop corporate, organizational and department level performance goals, as appropriate, which are subsequently approved by Company management. This includes reliability goals for the Eversource operating company in New Hampshire.

Goals are set annually based on previous years' performance as defined in IEEE Reliability Performance Criteria (Standard 1366-2012) and also excludes "planned interruptions." Eversource's present goals are set out in the below table.

	SAIDI (mins)	CAIDI (mins)	MBI (months)
2020-YTD-thru-Q1	21.4	119.1	16.7
2020-YTD-thru-Q2	43.5	113.9	15.7
2020-YTD-thru-Q3	72.1	118.2	14.8
2020-YTD-thru-Q4	94.9	117.0	14.8

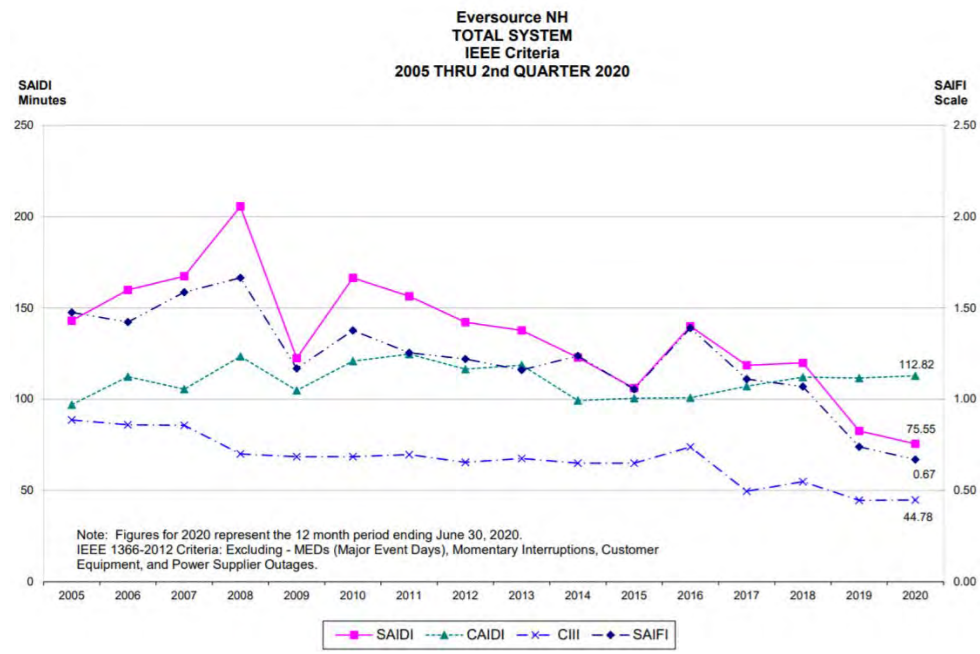
B. Actual Performance

1. IEEE Standard

Eversource reports its outage data based on IEEE Reliability Performance Criteria (Standard 1366-2012). All outages are included in these criteria except IEEE Major Event Days, momentary interruptions, customer equipment and power supplier outages.

The following chart shows the Total System reliability performance from 2005 to the present. The intention of the Reliability Enhancement Program (2007 – 2019) was to break the trend of an escalating SAIDI performance. As shown in the following Total System performance graph, SAIDI and SAIFI had roughly leveled off.

In the past five years, Eversource has made significant improvements in installing Distribution Automation and, as a result, the Company is not only showing continued improvement in SAIDI performance but also in reducing the number of customers affected by individual outages (SAIFI and CIII).



2. 2019 Performance Versus Goals

Eversource has measured its performance against its 2019 goals, shown in the table below. As indicated above, the goals are set based on IEEE Reliability Performance Criteria (Standard 1366-2012) and planned interruptions are then excluded.

	SAIDI (mins)		CAIDI (mins)		MBI (months)	
	Goal	Actual	Goal	Actual	Goal	Actual
2019-YTD-thru-Q1	21.6	18.7	117.9	119.8	16.3	19.2
2019-YTD-thru-Q2	47.8	34.8	113.9	122.6	14.3	21.1
2019-YTD-thru-Q3	78.7	53.1	116.9	124.1	13.4	21.0
2019-YTD-thru-Q4	102.2	68.9	115.0	123.3	13.5	21.5

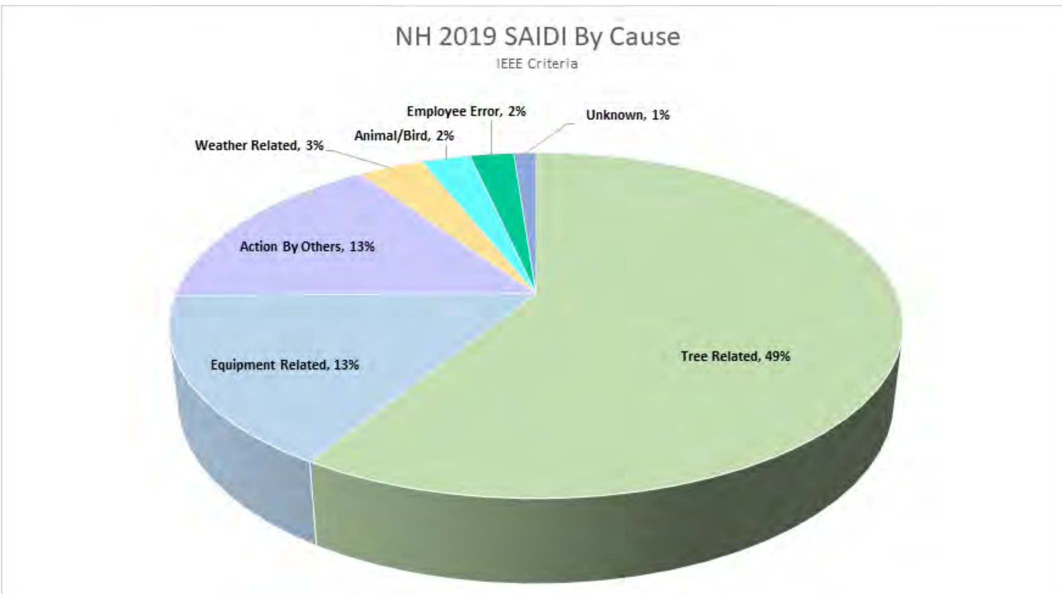
While some increases in reliability may be attributed to favorable weather and the stochastic nature of outages, even beyond these impacts, the trend in the chart above shows that Eversource's customers are experiencing fewer sustained interruptions and more reliable service over time. MBI has improved dramatically over recent years, resulting in customers experiencing interruptions, on average, every 21 months. The average duration of a customer interruption has been dramatically reduced as well with year-end SAIDI under 70 minutes, compared with Eversource's goal of 102. The CAIDI performance shows the effectiveness of system automation and supervisory control capability. With the ability to restore discrete blocks of customers in a very short amount of time, the average duration of an interruption event remains stable at approximately 2 hours.

III. Interruptions by Cause

A. Overview

Eversource regularly reviews the causes of interruptions and seeks patterns across the system. Corrective measures can, then, be put in place to address those vulnerable conditions before they impact customers.

Distribution Engineering has compiled data about recent interruptions and their contributions to SAIDI. Presented in the pie charts below, the most common cause of interruptions is trees/limbs, contributing approximately 50-60% of the company's annual SAIDI. Equipment failures and actions by others (that is, actions by non-Eversource employees, which may include vehicle accidents or individuals digging into underground cables, among other causes) are the next most common causes where, together, they make up about 30-35% of the total SAIDI impact.

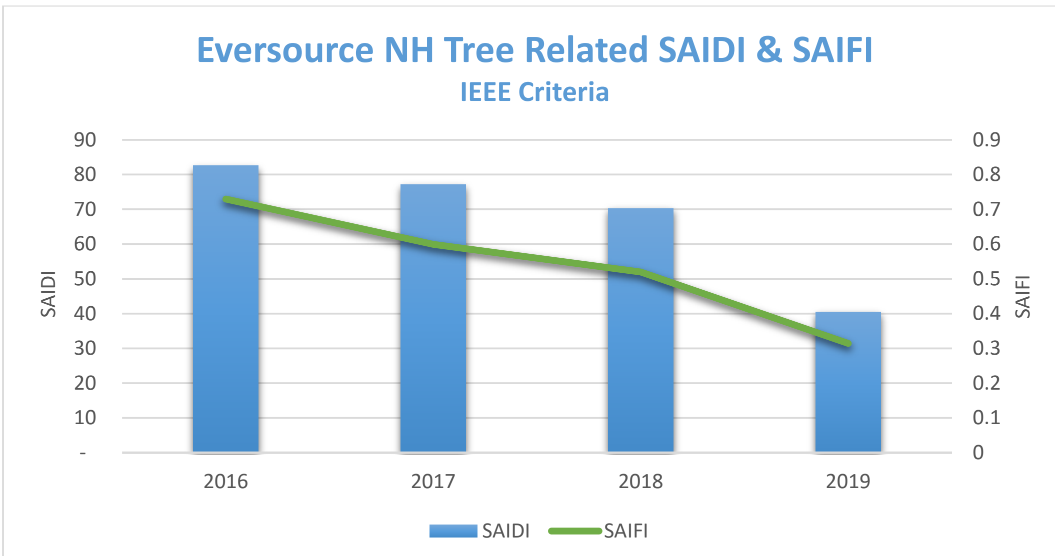


B. Tree Related Outages and Mitigation

New Hampshire is consistently ranked among the most forested States in the country. It's no surprise, then, that tree related outages dominate the reasons for power outages and customer interruptions.

To reduce the number of such events, Eversource's Vegetation Management team maintains proper clearance between trees and energized conductors along 12,500 miles of overhead distribution lines. On average, Eversource performs tree pruning on a four to five-year cycle. Tree species, growth conditions, and actual clearances achieved are reasons why trimming may need to be performed either more or less frequently. Trees which are likely to pose a risk to the electric infrastructure, but are located outside the normal trimming zone, may also be removed while Scheduled Maintenance Trimming (SMT) is being performed on roadside circuits or while right of way maintenance is being performed.

On an as-needed basis, localized areas may be trimmed or additional hazard trees may be removed. Trees which pose a reliability risk to the electric infrastructure are often reported by customers, tree wardens, Department of Transportation personnel as well as Eversource's engineering and operations staff. These are reviewed by Company Arborists and a determination made as to whether or not they should be addressed. As shown in the below graph, while tree related events remain the highest among events affecting the system, the overall customer impact from those events has been decreasing in recent years.



In addition to Eversource's SMT specification, the Company also maintains an Enhanced Tree Trimming (ETT) specification that is applied in certain areas, particularly those very prone to tree related outages and along certain circuit backbones. Eversource had previously performed a reliability assessment of circuits where ETT and, possibly, follow up maintenance of the ETT specification (METT) has been performed. The below table shows tree related reliability statistics using IEEE criteria for circuits where ETT was performed.

		Tree - Circuit SAIFI (Based on Circuit Customers Served)					
NH Circuit	ETT Year	**2015	2016	2017	2018	2019	YTD Feb 2020
17W1_43	2017	0.41	0.47	1.34	1.83	0.56	0.03
3102X2_63	2017	0.07	0.00	0.08	0.22	0.22	0.00
3102X5_63	2017	0.00	0.00	0.01	0.34	0.00	0.00
3103X1_65	2017	0.52	2.16	1.26	0.18	0.76	0.00
3108X1_12	2017	0.41	1.36	2.55	0.23	0.01	0.01
3164X8_12	2017	0.00	0.00	0.00	0.01	0.00	0.00
3175X_21	2017	0.00	0.49	0.01	0.06	0.07	0.00
328X1_12	2017	0.00	0.06	0.80	0.01	0.01	0.00
32X4_62	2017	0.00	0.55	0.39	0.51	0.00	0.08
33W1_36	2017	0.67	1.46	1.30	0.68	0.40	0.01
348X19_43	2017	0.00	0.28	0.00	0.00	1.13	0.00
348X20_43	2017	0.59	0.19	1.16	0.15	0.64	0.00
360X2_12	2017	0.01	0.31	0.30	0.43	0.00	0.01
367X2_63	2017	0.00	1.00	0.46	0.04	0.02	0.00
41W1_43	2017	0.74	0.17	0.24	0.48	0.24	0.07
51H1_61	2017	0.38	0.00	0.00	0.00	0.00	0.00
10W1_41	2018		0.01	0.03	0.00	0.00	0.00
3174X4_61	2018		0.34	0.45	1.03	1.16	0.02
32W3_23	2018		0.44	0.01	0.08	0.03	0.00
339X8_63	2018		0.39	0.00	0.00	0.04	0.00
346X1_45	2018		0.30	0.22	0.31	0.40	1.00
350X2_77	2018		1.77	0.49	2.14	1.95	0.00
362_61	2018		0.03	0.02	0.00	0.00	0.00
362X1_61	2018		0.39	1.03	0.01	1.06	0.00
362X2_61	2018		0.84	0.22	1.03	0.51	0.00
362X3_61	2018		0.00	0.18	0.02	0.00	0.00
362X4_61	2018		0.00	0.03	0.00	0.03	0.00
377X7_65	2018		5.69	1.14	0.68	0.17	0.00
44H1_32	2018		0.23	0.25	0.10	0.27	0.00
58W1_63	2018		0.01	0.01	0.00	0.00	0.00
75W2_32	2018		0.39	0.43	0.44	0.48	0.02
9W1_41	2018		0.01	0.19	0.02	0.00	0.00

Note: NH OMS went live as of 9/13/2015 - prior to that, NH reliability data will be less accurate because of missing/inaccurate isolating device information.

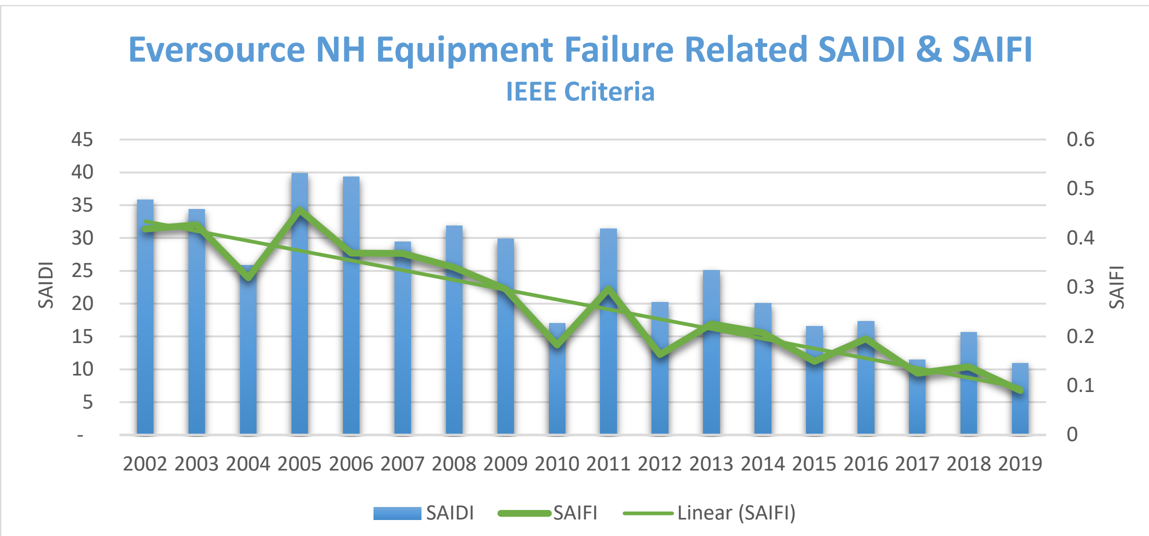
Eversource's Vegetation Management Program has successfully improved reliability. Tree related SAIDI and SAIFI have both improved over the past few years. With continued focus on trees and vines, Eversource expects reliability to be maintained or improved in the coming years.

In all cases, permission from the property owner, either expressed or implied, is required before trimming can be performed.

C. Equipment Failure Outages and Mitigation

The second largest cause group for SAIDI is equipment failures on distribution lines. Historically, efforts to reduce equipment failures have included testing and injection or replacement of underground cable, replacement of porcelain cutouts and insulators with polymer, utilization of vice-top insulators to eliminate the need for insulator ties, and increasing the use of wedge connectors instead of hot line clamps for many applications. As demonstrated in the below graph, results in this area showed a decrease in SAIDI in 2019, a continuation of a declining trend since the start of REP in 2007.

Eversource will continue to monitor equipment failure patterns and to share anomalies with equipment manufacturers. Adjustments to construction specifications, as well as equipment specifications, will be considered and implemented as appropriate.



D. Action by Others

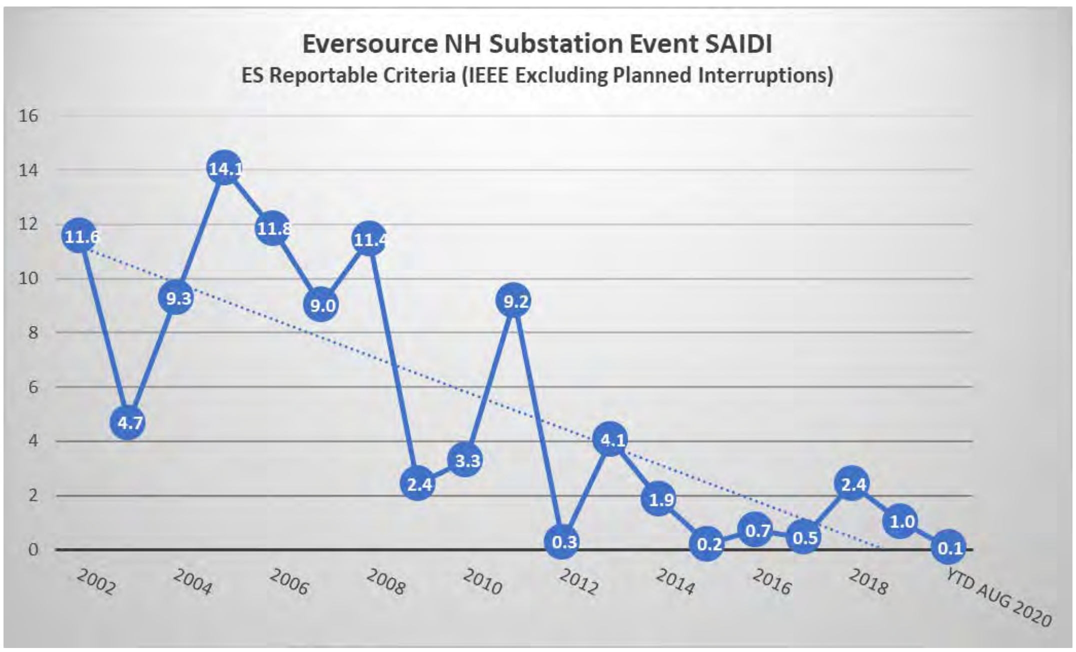
This category includes outages caused by people who are not Eversource employees. Examples include digging into underground cables and vehicle accidents.

Eversource is a member of Dig Safe/Call Before You Dig and is a sponsor of the Managing Underground Safety Training (M.U.S.T) program which presents training sessions annually. Eversource employees are presenters and support staff at the M.U.S.T. training sessions, working closely with the Commission's Safety Division, other electric and gas utilities, and others.

To help prevent outages due to motor vehicle accidents, Eversource has worked with the New Hampshire Department of Transportation to gain approval to place reflectors on any poles located within eight feet of edge of pavement in State rights-of-way. Reflector installation for poles meeting these criteria has been a standard practice since 2018.

E. Substation Outages and Mitigation

The Company's efforts to reduce Substation-related outages have resulted in dramatic improvement since 2005, as shown below. Projects include efforts to replace aged equipment, increase the installation of wildlife protectors, and the replacement of electromechanical relays with solid state relays. The installation of distribution automation has also aided in reducing substation SAIDI by allowing operators to rapidly transfer customers to adjacent circuits and substations in the event of an outage, if capacity on the neighboring circuitry exists.



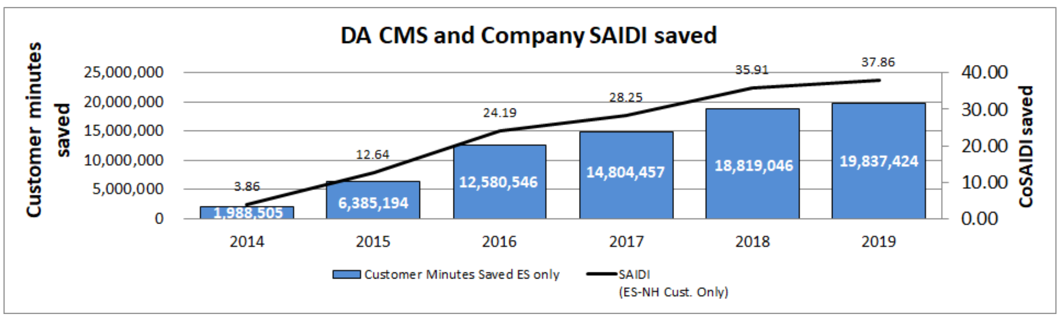
IV. Reliability Improvement Strategies

A. Customers Experiencing Multiple Interruptions

Internal reports are published on a monthly basis to highlight devices where multiple outages have occurred. Field Engineers review this report to determine if improvements could be made, either through equipment updates or additions, additional tree trimming, or other improvements which would result in better reliability performance for customers.

B. Distribution Automation

SCADA controlled switches and reclosers have been installed on the Company's distribution system for many years. In recent years this work has been significantly accelerated, with over 1,600 devices installed since 2014. These devices saved nearly 20,000,000 customer minutes in 2019 by allowing the Company's operators to remotely isolate fault locations down to smaller areas. This corresponds to almost 38 minutes of SAIDI. Additional devices are planned for deployment in future years, based on analysis performed by Field Engineers to determine optimum locations.



C. Circuit Ties

The Company has been constructing circuit ties to provide an alternate feed to many of its radial distribution circuits and incorporating Distribution Automation work into the projects. Since 2016, 21 circuit ties have been completed, providing an alternate source to 78,625 customers, with three more projects under construction in 2020 which will benefit 9,828 additional customers. Those three projects are described below:

AWC	Circuit	Project Description	Justification/Need statement	Cost Estimate	Cust. Served	$ / CMS
Newport	315 - 3410	Create circuit tie between 3410 and 315 lines	Construct 1.7 miles of three phase spacer cable along Route 103 to tie the 3410 to the 315 line	$1,800,000	4,235	$2.84
Keene	24X1 - 313X1	Create a circuit tie between the 24X1 and 313X1 along Hwy 136 and Hwy 31	Save over 965,000 minutes annually. The 313X1 and 24X1 are perennial poor performing radial circuits. Major customers to benefit from this upgrade would be Monadnock Hospital, Crotched Mtn Rehab Center, Conval Middle and High Schools, Crotched Mtn Ski Area, Monadnock Paper, and the communities of Greenfield and Francestown.	$2,800,000	4,326	$5.89
Lancaster	43W1 - 348X20	Construct circuit tie 43W1 to 348X20	GMP has had 5 outages in 2 years. Outages June 1 2018 and August 25 2020 on Eversource side each took 9+ hours to fix.	$2,200,000	1,267	$4.92

D. Worst Performing Circuit Analysis

Eversource annually produces a list ranking circuits by their contribution to the Company's SAIDI. This list, known internally as the Hit List, is reviewed by regional field engineering. Mitigation recommendations are produced to attempt to improve the circuits' reliability indices. Proposed solutions may include additional tree trimming, installation of additional protective or distribution automation devices, or other improvements. Large capital projects are given an engineering estimate and proposed as part of the Company's annual capital budget process. These projects are then ranked, typically by cost per saved customer minute and, depending on the availability of funding, are included in the following year's capital budget. The 2019 Hit List has been reproduced below with notes on causes as well as mitigating actions planned or intended at that time:

2019 Circuit Hit List - Ranked By COSAIDI - IEEE Criteria

Rank	Circuit	COSAIDI	CAIDI	Circuit MBI	CIII	# Outages	Customers Interrupted (CI)	Customer Minutes (CMI)	Customers Served By Circuit	Circuit Miles	Cust Inter Per Mile	Outages Per Mile	Circuit SAIDI	Circuit SAIFI	# Cust_3 Or Mores	#Cust >4Hr Outage	Customer Weighting	AWC	Region
1	3139X_31	2.13	109	3	41	254	10,416	1,133,650	2,636	150.88	69.03	1.68	430.01	3.95	74	670	265.8	KEENE	WESTERN
2	3525X5_77	1.78	204	2	141	33	4,645	946,788	845	60.01	77.41	0.55	1,120.68	5.50	1,050	2,284	944.8	BERLIN	NORTHER
3	316X1_32	1.70	130	6	77	91	6,983	904,695	3,444	157.77	44.26	0.58	262.68	2.03	415	582	262.2	NEWPORT	WESTERN
4	3525X2_77	1.64	161	1	449	12	5,385	869,631	403	21.12	255.00	0.57	2,157.45	13.36	-	1,582	992.4	BERLIN	NORTHER
5	355X10_76	1.28	104	4	72	91	6,554	678,397	2,320	122.21	53.63	0.74	292.47	2.83	60	299	159.2	LANCASTER	NORTHER
6	76W7_31	1.08	118	8	23	213	4,827	571,267	3,399	179.96	26.82	1.18	168.06	1.42	290	516	194.2	KEENE	WESTERN
7	348_76	1.02	86	0	6,319	1	6,319	543,434	12	16.07	393.10	0.06	45,286.17	526.58	-	-	15,850.2	LANCASTER	NORTHER
8	3128X_23	1.01	110	16	56	87	4,884	535,247	6,432	149.25	32.72	0.58	83.22	0.76	-	128	48.3	DERRY	SOUTHER
9	3133X_23	1.00	120	13	67	66	4,410	529,267	4,773	125.96	35.01	0.52	110.89	0.92	-	266	78.7	DERRY	SOUTHER
10	23X5_22	0.99	83	9	48	131	6,348	524,810	4,696	162.57	39.05	0.81	111.76	1.35	81	671	156.0	BEDFORD	CENTRAL
11	3217X_22	0.89	84	8	97	58	5,653	473,141	3,544	84.50	66.90	0.69	133.50	1.59	302	118	124.8	BEDFORD	CENTRAL
12	392X7_62	0.87	115	8	79	51	4,049	464,468	2,607	97.92	41.35	0.52	178.14	1.55	2,377	127	556.8	ROCHESTER	EASTERN
13	11W1_41	0.87	260	12	43	41	1,776	462,169	1,714	35.34	50.25	1.16	269.62	1.04	905	799	395.2	TILTON	NORTHER
14	3410_32	0.85	110	11	53	78	4,118	453,128	3,853	178.27	23.10	0.44	117.59	1.07	-	411	102.8	NEWPORT	WESTERN
15	63W1_65	0.82	101	6	90	48	4,320	436,203	2,273	85.94	50.27	0.56	191.94	1.90	597	54	194.7	EPPING	EASTERN
16	347_45	0.80	130	12	49	67	3,251	423,582	3,266	98.71	32.94	0.68	129.68	1.00	-	205	76.1	CHOCORUA	NORTHER
17	3818_23	0.78	128	17	55	59	3,251	415,678	4,511	90.44	35.95	0.65	92.16	0.72	-	613	124.2	DERRY	SOUTHER
18	3141X_23	0.76	79	11	75	68	5,109	401,975	4,841	115.03	44.41	0.59	83.03	1.06	-	30	33.6	DERRY	SOUTHER
19	3148X2_62	0.74	96	8	295	14	4,123	395,678	2,804	16.46	250.42	0.85	141.10	1.47	-	39	55.2	ROCHESTER	EASTERN
20	42X3_32	0.73	157	10	77	32	2,473	388,893	2,125	76.79	32.21	0.42	183.01	1.16	-	10	65.6	NEWPORT	WESTERN
21	3218_45	0.73	80	2	101	48	4,865	388,713	976	52.55	92.58	0.91	398.44	4.99	3,705	26	884.4	CHOCORUA	NORTHER
22	3191X1B_65	0.73	105	4	217	17	3,687	388,433	1,176	11.18	329.68	1.52	330.32	3.14	2,767	40	675.0	EPPING	EASTERN
23	3211X_21	0.73	310	25	42	30	1,252	387,742	2,628	51.19	24.46	0.59	147.57	0.48	-	568	136.8	NASHUA	SOUTHER
24	27X1_41	0.72	83	4	158	29	4,573	379,973	1,490	48.43	94.42	0.60	255.04	3.07	198	41	135.0	TILTON	NORTHER
25	19W2_45	0.70	107	9	52	66	3,457	370,488	2,543	101.72	33.98	0.65	145.67	1.36	9	115	70.0	CHOCORUA	NORTHER
26	348X3_76	0.67	133	8	61	44	2,689	357,206	1,892	107.95	24.91	0.41	188.81	1.42	-	20	69.1	LANCASTER	NORTHER
27	3154_21	0.65	122		2,842	1	2,842	346,724		9.32	304.85	0.11			-	-		NASHUA	SOUTHER
28	348X1_76	0.65	166	9	19	107	2,079	346,072	1,554	104.93	19.81	1.02	222.66	1.34	372	325	201.1	LANCASTER	NORTHER
29	14W7_11	0.64	211	6	147	11	1,619	341,960	750	26.35	61.45	0.42	456.25	2.16	-	763	274.1	HOOKSETT	CENTRAL
30	43W1_43	0.64	176	5	96	20	1,927	339,428	838	61.39	31.39	0.33	405.21	2.30	-	859	270.7	TILTON	NORTHER
31	3155X2_22	0.63	127	10	64	41	2,618	332,820	2,170	86.17	30.38	0.48	153.34	1.21	42	2	62.4	BEDFORD	CENTRAL
32	377X2_65	0.62	144	7	91	25	2,268	327,470	1,374	25.08	90.44	1.00	238.26	1.65	77	954	241.9	EPPING	EASTERN
33	3178_31	0.60	172	10	20	93	1,854	318,168	1,587	46.13	40.19	2.02	200.53	1.17	-	416	132.6	KEENE	WESTERN
34	4W2_31	0.59	132	9	66	36	2,376	313,301	1,830	55.54	42.78	0.65	171.18	1.30	-	340	110.9	KEENE	WESTERN
35	348X2_76	0.58	147	4	41	51	2,106	310,436	701	77.00	27.35	0.66	442.85	3.00	117	77	189.9	LANCASTER	NORTHER
36	3103X1_65	0.55	115	11	72	35	2,531	292,172	2,349	65.83	38.45	0.53	124.39	1.08	-	89	56.9	EPPING	EASTERN
37	3108_12	0.55	86	6	106	32	3,390	291,164	1,793	61.38	55.23	0.52	162.40	1.89	324	5	122.4	BEDFORD	CENTRAL
38	3615X1_11	0.54	125	13	43	53	2,270	284,844	2,456	95.73	23.71	0.55	115.97	0.92	-	402	100.9	HOOKSETT	CENTRAL
39	37W1_12	0.52	126	8	67	33	2,195	276,188	1,404	58.73	37.37	0.56	196.77	1.56	-	3	69.3	BEDFORD	CENTRAL
40	371X4_61	0.50	187	7	129	11	1,418	265,294	796	15.87	89.35	0.69	333.11	1.78	-	129	135.9	ROCHESTER	EASTERN
41	38W2_62	0.50	101	5	97	27	2,612	263,774	1,183	41.56	62.84	0.65	222.94	2.21	31	7	85.3	ROCHESTER	EASTERN
42	4W1_31	0.49	144	10	38	48	1,825	262,902	1,563	70.86	25.76	0.68	168.24	1.17	134	316	133.1	KEENE	WESTERN
43	4411_32	0.49	131		1,989	1	1,989	259,860		0.48	4,182.09	2.10			-	-		NEWPORT	WESTERN
44	3105_63	0.47	217	0	1,155	1	1,155	250,635	5	3.99	289.29	0.25	50,127.00	231.00	-	-	17,544.5	PORTSMOUTH	EASTERN
45	3115X_23	0.46	74	10	64	52	3,351	246,822	2,738	89.98	37.24	0.58	90.16	1.22	87	31	53.6	DERRY	SOUTHER
46	75W2_32	0.46	224	19	26	43	1,097	246,181	1,773	52.83	20.77	0.81	138.82	0.62	-	341	99.7	NEWPORT	WESTERN
47	32W5_23	0.46	110	15	63	35	2,208	243,395	2,739	45.38	48.65	0.77	88.87	0.81	-	3	31.6	DERRY	SOUTHER
48	19W1_45	0.46	116	7	116	18	2,094	241,973	1,261	47.77	43.84	0.38	191.93	1.66	-	6	68.1	CHOCORUA	NORTHER
49	3116X1_45	0.45	129	8	27	67	1,842	237,293	1,288	86.15	21.38	0.78	184.31	1.43	564	231	212.0	CHOCORUA	NORTHER
50	73W1_61	0.43	178	11	48	27	1,288	228,625	1,223	40.51	31.80	0.67	186.89	1.05	123	352	142.8	ROCHESTER	EASTERN

Rank	Circuit	Review Notes
1	3139X_31	Pursuit of Westmorland Battery Full circuit review of protection. Fuses moved to main line, Trip Savers added, and line removed from ROW. Full DA (7 Devices) 2019 Capital Project completed to upgrade open wire/heatherlite backbone to spacer cable ETT of entire backbone. Trip Savers/Spears added - 6
2	3525X5_77	Partial circuit review of protection. Fuses moved to main line, coordination down-line of OCR's checked. Full DA (2 Devices)
3	316X1_32	Full DA (6 Devices) ETT of all three phase including Eastman Development Circuit Loop within Eastman Trip Savers/Spears added - 4 2021 Capital project proposal for new feed to Grantham from Newport.
4	3525X2_77	Partial circuit review of protection. Fuses moved to main line, coordination down-line of OCR's checked. Full DA (2 Devices)
5	355X10_76	Partial circuit review of protection. Fuses moved to main line, Tripsavers added, and coordination down-line of OCR's checked. Full DA (2 Devices) Tripsavers added - 3.
6	76W7_31	Circuit Hardening - Route 9 in Roxbury Spacer cable upgrade - Route 10, Gilsum Trip Savers/Spears added - 13 Equipment upgrade and conversion - Surry Full DA (7 Devices)
7	348_76	Partial circuit review of protection. Fuses moved to main line, coordination down-line of OCR's checked. Full DA (6 Devices)
8	3128X_23	Currently the largest single circuit in NH system by customer count. Trees are the top category with 22 outages totalling 150,606 customer outage minutes. A single vehicle accident caused 181,631 customer outage minutes (multiple causes listed - VHCL, PLAN, OPER) DA - 15 devices and 5 ties to 3 other circuits. Capital Project to convert High Range Rd. and create self-tie between 3128X2 and 3128X3R1 completed in 2018. Recommend new circuit out of Lawrence Rd. to split up 3133X and 3128X customer count (will propose for 2022 budget funding). ETT - entire backbone. Maintenance trimmed in 2018. Tripsavers/Spears added - 10
9	3133X_23	Currently the third largest single circuit in NH system. Vehicle accidents are the top category with 3 events totalling 205,144 customer outage minutes. DA - 11 devices and 3 ties to 2 other circuits. Recommend new circuit out of Lawrence Rd. to split up 3133X and 3128X customer count (will propose for 2022 budget funding). ETT - entire backbone. Maintenance trimmed in 2018.

Rank	Circuit	Review Notes
10	23X5_22	DA - 11 devices and 2 ties to 2 other circuits. Capital project to extend three phase on Boston Post Rd completed in 2020. This transfers several hundred custmers from the end of the 23X5 to near the source of the 3159X which is a more reliable circuit. Capital project to convert Route 13 will be completed 8/20. This transfers customers to the more reliable 23X6. 2 Trip savers installed in 2019 ETT - 2020
11	3217X_22	Loop feed from South Milford to Broad St substation DA - 9 devices and 2 ties to 2 other circuit ETT - last trimmed in 2016, due in 2020. 3 DA installed in 2019 4 Tripsavers installed in 2019
12	392X7_62	69% CMI due to Trees. SMT scheduled to be completed in 2020 17% CMI due to 4 vehicle accidents 12% CMI due to single LA failure. We replaced fuses with TripSavers 2% Misc. Added 4 DA device to reduce customer blocks. Most of the customers are fed radially via 12kV S.D. Xfmr. Looking into long term study to extend 34kV along Rte 202 to offload radial steps fed from Rte 125
13	11W1_41	Planned outages for submarine cable installation to islands will not be a recurring event. Partial circuit review of protection. Fuses moved to main line, coordination down-line of OCR's checked. Full DA (2 Devices) Tripsavers added - 1.
14	3410_32	Full DA (10 Devices) Trip Savers/Spears added - 4 2020 Capital project under construction - Circuit Tie with the 315 circuit.
15	63W1_65	27% CMI due to Trees. SMT scheduled to be completed in 2022 40% CMI due to 4 vehicle accidents 19% CMI due to planned outages for system maintenance 14% Misc equipment failures. 63W1 is a radially fed circuit with numerouse large single phase sidetaps. Engineering will be submitting a 2020 budget challenge project to extend a 3rd phase towards Bow lake to better balance 63W1 and improve reliabiltiy. Engineering is also looking into long term study to create a circuit tie with 392X7.
16	347_45	Partial circuit review of protection. Fuses moved to main line, Trip Savers added. Coordination down-line of OCR's checked. Full DA (13 Devices) Tripsavers added - 8.
17	3818_23	Created in 2016 to split 3141X into two circuits. Top outage category is trees with 19 outages totalling 217,913 customer outage minutes. A single tree-related outage caused 123,145 customer outage minutes. DA - 10 devices and 2 ties to 3141X circuit. Sandown Rd. 1500 kVA step bank is overloaded and needs partial conversion to utilize tie to 3141X 12 kV step down and obtain the full reliability benefit of the tie.

Rank	Circuit	Review Notes
10	23X5_22	DA - 11 devices and 2 ties to 2 other circuits. Capital project to extend three phase on Boston Post Rd completed in 2020. This transfers several hundred custmers from the end of the 23X5 to near the source of the 3159X which is a more reliable circuit. Capital project to convert Route 13 will be completed 8/20. This transfers customers to the more reliable 23X6. 2 Trip savers installed in 2019 ETT - 2020
11	3217X_22	Loop feed from South Milford to Broad St substation DA - 9 devices and 2 ties to 2 other circuit ETT - last trimmed in 2016, due in 2020. 3 DA installed in 2019 4 Tripsavers installed in 2019
12	392X7_62	69% CMI due to Trees. SMT scheduled to be completed in 2020 17% CMI due to 4 vehicle accidents 12% CMI due to single LA failure. We replaced fuses with TripSavers 2% Misc. Added 4 DA device to reduce customer blocks. Most of the customers are fed radially via 12kV S.D. Xfmr. Looking into long term study to extend 34kV along Rte 202 to offload radial steps fed from Rte 125
13	11W1_41	Planned outages for submarine cable installation to islands will not be a recurring event. Partial circuit review of protection. Fuses moved to main line, coordination down-line of OCR's checked. Full DA (2 Devices) Tripsavers added - 1.
14	3410_32	Full DA (10 Devices) Trip Savers/Spears added - 4 2020 Capital project under construction - Circuit Tie with the 315 circuit.
15	63W1_65	27% CMI due to Trees. SMT scheduled to be completed in 2022 40% CMI due to 4 vehicle accidents 19% CMI due to planned outages for system maintenance 14% Misc equipment failures. 63W1 is a radially fed circuit with numerouse large single phase sidetaps. Engineering will be submitting a 2020 budget challenge project to extend a 3rd phase towards Bow lake to better balance 63W1 and improve reliabiltiy. Engineering is also looking into long term study to create a circuit tie with 392X7.
16	347_45	Partial circuit review of protection. Fuses moved to main line, Trip Savers added. Coordination down-line of OCR's checked. Full DA (13 Devices) Tripsavers added - 8.
17	3818_23	Created in 2016 to split 3141X into two circuits. Top outage category is trees with 19 outages totalling 217,913 customer outage minutes. A single tree-related outage caused 123,145 customer outage minutes. DA - 10 devices and 2 ties to 3141X circuit. Sandown Rd. 1500 kVA step bank is overloaded and needs partial conversion to utilize tie to 3141X 12 kV step down and obtain the full reliability benefit of the tie.

Rank	Circuit	Review Notes
18	3141X_23	Currently the second largest single circuit in NH system. Vehicle accidents are the top category with 3 events totalling 162,151 customer outage minutes. One single vehicle accident caused 161,963 outage minutes. DA - 18 devices and 3 ties to 2 other circuits. DA added to Little Mill Rd. to improve reliability to Sandown town center, needs conversion to be fully utilized (see 3818X). ETT - entire backbone. Maintenance trimmed in 2018. Tripsavers/Spears added - 9
19	3148X2_62	97% of outages caused by 2 vehicle accidents. We've since added 8 new DA devices and additional fusing. We do not expect this circuit to make the top 50 again.
20	42X3_32	Full DA (3 Devices) Trip Savers/Spears added - 4 Reviewing options to utilize 42X4 feed to off load or tie circuit.
21	3218_45	Partial circuit review of protection. Fuses moved to main line, Trip Savers added. Coordination down-line of OCR's checked. Full DA (7 Devices) Tripsavers added - 1.
22	3191X1B_65	94% CMI due to Trees. SMT trimming was completed in 2019 next SMT scheduled for 2023. 6% CMI due to misc outages (Equipment, Lightning, Planned)recommended. The 3191X1B is currently a radially fed circuit. Engineering will submit 2020 Budget Challenge to create new 34.5kV circuit tie with 377X2
23	3211X_21	Loop feed from Hudson to Lawrence Rd substation DA - 5 devices of which 4 of them installed in 2019 Tripsaver/Spear added - 2 Installed Spear to allow backfeed of 400 customers on Robinson Rd, a long single phase tap, for outages on the main line. Insulator failure just outside substation. At that time DA was installed but not commisioned.
24	27X1_41	Partial circuit review of protection. Fuses moved to main line, Tripsavers added. Coordination down-line of OCR's checked. Full DA (3 Devices) Tripsavers added - 3.
25	19W2_45	Partial circuit review of protection. Fuses moved to main line, Speers/Tripsavers added. Coordination down-line of OCR's checked. Full DA (2 Devices) Tripsavers added - 6. Spears added - 3.
26	348X3_76	Partial circuit review of protection. Fuses moved to main line, Tripsavers added. Coordination down-line of OCR's checked. Pending WR to install recloser at Bretton Woods Ski Area. Full DA (5 Devices).

Rank	Circuit	Review Notes
27	3154_21	Circuit is entirely ROW from Long Hill to Broad Street substation with two major taps that makes up almost all customers. Due to double vertical 115 kV construction, there are no inline DA devices for sectionalizing. Single tree outage caused it to rank it on Hitlist. Install N.O tie between 3177X and 3154X2 to sectionalize for restoration which is currently scheduled for 2021. ETT 2018. SMT scheduled for 2022.
28	348X1_76	Partial circuit review of protection. Fuses moved to main line, coordination down-line of OCR's checked. Full DA (4 Devices)
29	14W7_11	The bulk of the minutes (94%) are due to two pole hits on Manchester Rd, Auburn. Pole reflectors requested and installed on 11 poles along along Manchester Rd, Auburn (location of pole hits) Full ETT completed on Manchester Rd Trip Saver added - 1. DA 1 device.
30	43W1_43	Circuit tie to 348X20 Lisbon in progress. Full circuit review of protection. Fuses moved to main line, Tripsavers added. Full DA (3 Devices) Tripsavers added - 2.
31	3155X2_22	Radial distribution tap off ROW DA - 4 devices of which 2 were installed in 2020 Tripsaver/Spear added - 2 ETT due in 2020 Proposing 2021 budget item to offload Rte 13 steps to 3155X8, a more reliable circuit. Looking into replacing heavily loaded parallel Quimby Rd steps with pad mounted step for capacity and creating in-phase backfeed for 24W1 circuit.
32	377X2_65	91% CMI due to single tree related outage that destroyed 377X2J1 ScadaMate. SMT Trimming expected to be completed in 2020 Engineering will submit 2020 Budget Challenge to create new 34.5kV circuit tie between 377X2 and 3191X1B
33	3178_31	Circuit Tie with the 3178X3 Trip Savers/Spears added - 3 2019 project to replace lattice steel towers in ROW Removal of large ROW feed to Waste Water Treatment Plant. New feed along roadway. Full DA (6 Devices)
34	4W2_31	Full automation of the Circuit Tie to W2 circuit. Full DA (7 Devices) Trip Savers/Spears added - 2
35	348X2_76	Partial circuit review of protection. Fuses moved to main line, coordination down-line of OCR's checked. Full DA (3 Devices)
36	3103X1_65	67% CMI due to Trees. Next SMT/ETT is scheduled in 2022 16% CMI due to single insulator failure 14% CMI due to vehicle accident 3% Misc. The 3103X1 currently has 6 DA devices and circuit tie (complered Nov 2017) with 3115X. No Budget challenge project being submitted for 2020.

Rank	Circuit	Review Notes
37	3108_12	67% of minutes were tree related. SMT scheduled 2021. Trip Savers added - 4. DA (2 devices added & 1 requested for 2021). ETT - 2.3 miles (all 3 PH main line) in 2017.
38	3615X1_11	44% minutes due to vegetation, 40% of minutes planned. SMT just completed for 2019/2020. ETT done for the entire length of Rt 27 (approx. 11 miles) and Adams Rd (scenic road). Rt. 43 consists entirely of 477 spacer cable (5.3 miles). Circuit recently converted and reconductored creating circuit tie with Epping 3115X12 circuit. Full DA (6 devices).
39	37W1_12	94% of minutes were tree related. SMT being done this year. 1 outage (tree related) on main line responsible for 40% of customer minutes. Trip Saver/Spear added - 3. DA(1 device).
40	371X4_61	82% of outages were due to planned outages for system upgrades. The largest being 3 phase transfer to replace junction pole 13% was due a hotline clamp failure 2% tree 3% vehicle accident No Budget challenge project being submitted
41	38W2_62	86% CMI due to single ptp failure 9% CMI due to tree. SMT trimming scheduled for 2021. 5% CMI due to misc (equip, lightning, animal, Planned) Doing long term study to offload/eliminate 38W2 and create 34kV circuit ties.
42	4W1_31	Circuit Tie with the W185 Rebuild of ROW section at beginning of the circuit. Trip Savers/Spears added - 4 Full DA (3 Devices)
43	4411_32	Outage related to animal contact on line side Spring Street Substation. Animal guards installed. Capital Project - Spring Street Substation Rebuild and Automation
44	3105_63	Made hit list due to single outage. A phase broke in ROW during lightning storm. The 3105X2 radially feeds Rye SS. No Budget Challenge project being rcommended for 2020 session.
45	3115X_23	Circuit feeds into Epping AWC. Outages within Epping AWC affect ranking of the Derry AWC circuit. Subtracting Epping AWC outages (47,415 minutes) puts this at #62 in the hit list ranking. Vehicle accidents are the top category with 5 events totalling 107,953 customer outage minutes. One single vehicle accident caused 102,312 customer outage minutes. DA - 4 devices and 2 ties to 2 other circuits (within Derry AWC). ETT - entire backbone. Mantenance trimmed in 2019. Tripsavers/Spears added - 7 (within Derry AWC).

Rank	Circuit	Review Notes
46	75W2_32	Trip Savers/Spears added - 2 Full DA (6 Devices) Circuit loops with adjacent circuits. Capital Project - Spring Street Substation Rebuild and Automation
47	32W5_23	Trees are the top outage category, with 12 events totalling 149,148 customer outage minutes. One single tree-related outage caused 101,346 customer outage minutes. DA - 6 devices and 3 ties to 3 other circuits. ETT - entire backbone. Maintenance trimmed in 2018. Tripsavers/Spears added - 1
48	19W1_45	Full circuit review of protection. Fuses moved to main line, Speers/Tripsavers added. Coordination down-line of OCR's checked. Full DA (2 Devices) Trip Savers added - 5. Spears added - 2
49	3116X1_45	Partial circuit review of protection. Fuses moved to main line, Tripsavers added. Coordination down-line of OCR's checked. Full DA (1 Device) Trip Savers added - 2.
50	73W1_61	86% CMI due to Trees. SMT trimming scheduled to be completed in 2020. 10% CMI due to sigle insulator failure 4% CMI due to misc planned outages. Sandbornville has new backup up supply but 12kV circuits are radially fed. Most large taps have Hydraulic recloser and are being replaced with TripSavers as they come up for maintenance. No budget challenge project being recommended.

V. Conclusion

Customers depend on reliable electric service, particularly under the untraditional conditions caused by the pandemic. Even more people are working and learning at home and require reliable electric service to properly contribute their knowledge and skills.

Regular reliability reviews of individual events and overall system response are both important components of a proper reliability performance assessment. Mitigation and resolution techniques need to be both timely and effective. Installation of automated and other state-of-art equipment provides additional insight to the system operators and engineers, allowing them to make better decisions about how to operate and improve the distribution system. Improvements on a more local level can continue to be achieved with assessments of tree growth, equipment type, equipment condition, outage history and more.

As noted throughout this document, Eversource will continue to make reliability performance a primary focus of its operation.

VI. Appendix 1 – Definitions

CAIDI – Customer Average Interruption Duration Index
This index measures the average service restoration time or the average interruption duration for those customers interrupted during a year. It is determined by dividing the sum of all customer interruption durations by the total number of customers interrupted in a year.

Calculation: **CAIDI** = Customer Minutes Out / Customer Interruptions

CIIII – Customer Interruptions per Interruption Index
This index measures the average number of customers without power per interruption. It is determined by dividing the number of customer interruptions in a year by the total number of interruptions.

Calculation: CIII = Customer Interruptions / Interruptions

SAIDI – System Average Interruption Duration Index
This index measures the average interruption duration in minutes per customer served. It is determined by dividing the sum of all customer interruption durations during a year by the number of customers served.

Calculation: SAIDI = Customer Minutes Out / Customers Served

SAIFI – System Average Interruption Frequency Index
This index measures the average number of times that a system customer is interrupted during a year. It is computed by dividing the total number of customers interrupted in a year by the average number of customers served during the year. A customer interruption is considered to be one interruption to one customer.

Calculation: SAIFI = Customer Interruptions / Customers Served

MBI - Months Between Interruptions
This index measures the number months between interruptions the typical customer experiences.

*Calculation: MBI = Number of Months in SAIFI Data Set / SAIFI**

*Refer to SAIFI Calculation.

All the Distribution data in this report is calculated on information obtained from the trouble reporting database, based on IEEE criteria:

1. Excludes non-outages
2. Excludes momentary interruptions
3. Excludes Customer Equipment
4. Excludes outages caused by loss of power supply (non-Eversource)

CMI – Customers experiencing Multiple Interruptions

Customer Interruptions – The number of customers affected by an interruption

Customer Minutes (CM) – The number of customer interruptions multiplied by the number of minutes they were without power

CMS – Customer Minute Saved

DA – Distribution Automation

ETT – Enhanced Tree Trimming

GMP – Green Mountain Power

IEEE – Institute of Electrical and Electronics Engineers

Interruption – An event in which an outage to customers occurs

MBI – Months Between Interruptions

MUST – Managing Underground Safety Training program

NHPUC – State of NH's Public Utilities Commission

Power Supplier Outages – Those outages where the power source is not Eversource owned

REP – Reliability Enhancement Program

ROW – Right of Way

SCADA – Supervisory Control and Data Acquisition

SMT – Scheduled Maintenance Trimming

Eversource / Unitil Energy Systems

2020 Joint Planning Report

September 10, 2020

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1 EXECUTIVE SUMMARY

Eversource and Unitil have conducted the annual joint planning meeting(s) and completed the joint planning process for 2020. Planning departments from both companies were represented at the meeting(s) and loading of joint facilities under basecase and contingency configurations were reviewed.

This report summarizes the findings of the joint planning process. The Eversource 2020-2029 Loadflow Study and the Unitil 2021-2030 Electric System Planning Studies were used as the basis for identifying constraints for the years 2021-2030. Alternatives are developed and evaluated per each company's planning and design guidelines. Evaluation criteria include total cost in today's dollars, net present value, system benefit and technical preference.

The 2020 Eversource and UES joint planning process identified two non-capital modifications as a result of the joint planning effort:

- Due to loading constraints on the Great Bay transformer, starting in 2021 Unitil will switch an additional 7.5 MW from Great Bay to Timber Swamp during the summer load season.
- Unitil will continue to transfer its 34 line (approximately 10 MW of load) from Penacook to Bridge Street at the request of the ESCC for ISO-NE load levels above 22,100 MW, to alleviate loading constraints on the Oak Hill Transformers.

Additionally, Unitil and Eversource will continue to work to develop a long term solution to the identified Short Term Emergency (STE) loading concerns at Oak Hill for the loss of an Oak Hill transformer. The options currently being review to resolve this constraint are:

- Continuing the non-capital solution of transferring load from of Oak Hill.
- Replace the existing Oak Hill transformers with larger units.
- Make modification to the UES-Capital system to allow the Oak Hill and Penacook buses to be split and operated with bus ties normally open.
- Non-traditional alternatives, including but not limited to photovoltaic generation, energy storage, load curtailment and energy efficiency.
- Implement transformer protection scheme(s) that will automatically trip load off-line or development of procedures that would manually remote-trip load in the event total Oak Hill load is above the STE limit of one transformer and a transformer fault occurs.

2 INTRODUCTION

Unitil is a transmission customer of Eversource in New Hampshire. Unitil is provided 34.5 kV service at four Eversource distribution substations; Oak Hill and Garvins in Concord, Timber Swamp in Hampton, and Great Bay in Stratham. Additionally, Unitil is supplied 115 kV service at Unitil's Kingston substation in Kingston and Broken Ground substation in Concord. Three of the distribution substations supply both Unitil and Eversource distribution load. Due to the joint nature of the Eversource distribution and transmission facilities that supply Unitil, Eversource and Unitil participate in a joint planning process to develop short term and long term plans for these areas that represent the best interests of all customers as a whole.

Although transmission needs are discussed, the joint planning process is a distribution planning effort and any recommendations that have transmission implications need to be reviewed by Eversource Transmission Planning and ISO-NE.

The joint planning process is an annual process that typically consists of Unitil and Eversource developing independent system load projections and loadflow models. Unitil and Eversource exchange load projections and incorporate them into their loadflow models. As needed Eversource will provide Unitil with an updated transmission loadflow model that Unitil will incorporate the Unitil distribution model into and return to Eversource for use in their studies. Unitil and Eversource complete separate planning studies (Eversource Loadflow Study and Unitil Electric System Planning Studies). With the study work complete joint meetings are held to discuss the results and project scopes and estimates are developed for any identified constraints that affect joint facilities.

3 RELEVANT SYSTEM CHANGES

Relevant system changes since the release of the previous Joint Planning Report are described below:

3.1 Eversource Transformer Ratings

Eversource is in the process of updating their bulk transformer rating methodology. The proposed methodology assumes a preload of 95% of nameplate. Due to this methodology change Eversource is implementing a planning threshold of 95% of nameplate for all bulk transformers under basecase conditions. Based on this threshold and proposed changes to Eversource planning criteria, projects should be implemented prior to transformer loading exceeding this limit.

4 TRANSFORMER RATINGS

The following table lists the summer ratings of the Eversource transformers that supply UES based on the previous planning methodology of a preload of 75% on nameplate. Also included in the table is the planning load threshold under basecase conditions described in section 3.1 above.

Transformers	Nameplate Capacity (MVA)	Normal Planning Threshold (MVA)	Summer Ratings		
			Normal (MVA)	LTE (MVA)	STE/DAL (MVA)
Garvins TB39	67.2	63.8	67	79	100
Garvins TB51	67.2	63.8	67	79	100
Oak Hill TB15	44.8	42.6	44	53	67
Oak Hill TB84	45	42.8	45	49	61
Timber Swamp TB25	140	133	140	180	210
Timber Swamp TB69	140	133	140	163	200
Great Bay TB141	44.8	42.6	44	51	67

5 BASECASE REVIEW

The following table summarizes the percent loading of the jointly planned transformers.

Year	Location/Element	Percent Loading
2021	Great Bay TB141 Transformer	102% of Planning Threshold (43.4 MVA)
2030	Garvins TB39 Transformer[1]	72% of Planning Threshold (46.0 MVA)
	Garvins TB51 Transformer[1]	72% of Planning Threshold (45.7 MVA)
	Oak Hill TB15 Transformer[1]	71% of Planning Threshold (30.3 MVA)
	Oak Hill TB84 Transformer[1]	80% of Planning Threshold (29.9 MVA)
	Great Bay TB141 Transformer[2]	107% of Planning Threshold (45.6 MVA)
	Timber Swamp TB25	69% of Planning Threshold (92.3 MVA)
	Timber Swamp TB69	28% of Planning Threshold (37.3 MVA)

During summer conditions the following switching is currently performed to reduce the loading of the Great Bay transformer.

- [redacted]

In this configuration the Great Bay TB141 transformer is expected to exceed its planning threshold under basecase conditions in 2021. To reduce loading of the Great Bay TB141 transformer the following switching is proposed instead of the switching that is currently being performed during summer load conditions.

[1] Assumes SES Concord and all area hydroelectric generators are off-line. UES-Capital 34 line supplied via Bridge Street

[2] Loading based on 2020 Configuration

REDACTED

[redacted]

6 CONTINGENCY EVALUATION

The following section describes the power flow simulation results for contingent loss of jointly planned power transformers, any contingency that is expected to load jointly used infrastructure over its normal rating, and contingencies which identify deficiencies that have alternatives requiring modifications to jointly used facilities in the next ten years.

The following planning violations were identified:

- [redacted]

The switching described below is a guide and is not meant as step by step switching procedures to be implemented in the field. The switching described assumes the system is in its normal configuration for peak summer conditions prior to the contingency.

All scenarios below assume Unitil's 34 line is supplied via Bridge Street substation and SES Concord and all area hydroelectric generators are off-line.

6.1 Loss of Garvins TB51 Transformer

(Garvins TB51 transformer fault)

Initial Event:

[redacted]

Automatic Restoration:

[redacted]

System Concerns:

2021:

REDACTED

- Garvins TB39 transformer at 76 MVA (96% of LTE)

2030:
- Garvins TB39 transformer at 78 MVA (99% of LTE)

Unitil Switching Procedures to Reduce Garvins Loading:

[redacted]

Eversource perform switching to restore load:

[redacted]

System Concerns:

2021:
- Oak Hill TB15 transformer at 42.2 MVA (99% of Planning Threshold / 96% of Normal)
- Oak Hill TB84 transformer at 41.7 MVA (97% of Planning Threshold / 93% of Normal)
- Garvins TB39 transformer at 53.3 MVA (84% of Planning Threshold / 80% of Normal)

2030:
- Oak Hill TB15 transformer at 43.3 MVA (102% of Planning Threshold / 98% of Normal)
- Oak Hill TB84 transformer at 42.6 MVA (100% of Planning Threshold / 95% of Normal)
- Garvins TB39 transformer at 55.0 MVA (86% of Planning Threshold / 82% of Normal)

… install Eversource 35MVA mobile at Garvins S/S and reconfigure system to reduce loading at Oak Hill and Garvins...

6.2 Loss of Garvins TB39 Transformer
(Garvins TB39 transformer fault)

Reference section 6.1 above, Loss of Garvins TB51 transformer. The remaining Garvins TB51 transformer for this contingency has a slightly higher thermal limit. Otherwise, details on initial event, automatic restoration, follow-on switching procedures, and associated system concerns are effectively the same.

REDACTED

6.3 Loss of Oak Hill TB15 Transformer

(Oak Hill TB15 transformer fault or fault on B15 line between J315 switch at Farmwood and 15J1 circuit switcher at Oak Hill)

Initial Event:
[redacted]

System Concerns:
2021:
- Oak Hill TB84 transformer at 59.2 MVA (97% of STE)

2030:
- Oak Hill TB84 transformer at 60.0 MVA (98% of STE)

Unitil Switching Procedures:
[redacted]

Note: Additional switching required if J84 and TB84 lockout on overcurrent.

System Concerns:
2021:
- Oak Hill TB84 transformer at 45.2 MVA (106% of Planning Threshold / 100% of Normal)
- Garvins TB39 transformer at 51.9 MVA (81% of Planning Threshold / 77% of Normal)
- Garvins TB51 transformer at 51.6 MVA (81% of Planning Threshold / 77% of Normal)

2030:
- Oak Hill TB84 transformer at 45.9 MVA (107% of Planning Threshold / 102% of Normal)
- Garvins TB39 transformer at 53.2 MVA (83% of Planning Threshold / 79% of Normal)
- Garvins TB51 transformer at 52.9 MVA (83% of Planning Threshold / 79% of Normal)

Eversource Switching Procedures:
[redacted]

… install Eversource 35MVA mobile at Oak Hill S/S and reconfigure system to reduce loading at Oak Hill and Garvins…

REDACTED

6.4 Loss of Oak Hill TB84 Transformer
(Oak Hill TB84 transformer fault or fault on B84 line between J484 switch at Farmwood and J84 circuit switcher at Oak Hill)

Reference section 6.3 above, Loss of Oak Hill TB15 transformer. The remaining Oak Hill TB84 transformer for this contingency has a slightly higher thermal limit. Otherwise, details on initial event, automatic restoration, follow-on switching procedures, and associated system concerns are effectively the same.

6.5 Various UES-Capital Contingencies
The following contingencies require [redacted]

- [redacted]
- [redacted]

Additionally, the following contingencies [redacted]

- [redacted]
- [redacted]
- [redacted]

6.6 Loss of Timber Swamp TB25 Transformer
(Timber Swamp TB25 transformer fault)

Initial Event:
[redacted]

Automated Switching
[redacted]

No Manual Switching Required
- No load out of service

System Concerns:
2021:
- Timber Swamp TB69 Transformer at 123.0 MVA (92% of Planning Threshold / 88% of Normal)

REDACTED

2030:
- Timber Swamp TB69 Transformer at 130.7 MVA (98% of Planning Threshold / 93% of Normal)

6.7 Loss of Timber Swamp TB69 Transformer
(Timber Swamp TB69 transformer fault)

Reference section 6.6 above, Loss of Timber Swamp TB25 Transformer. Details on initial event, automatic restoration, follow-on switching procedures, and associated system concerns are effectively the same.

6.8 Loss of Great Bay TB141 Transformer
(Great Bay TB141 transformer fault)

Initial Event:
[redacted]

Unitil Switching Procedures:
[redacted]

System Concerns:
2021:
- Timber Swamp TB25 Transformer at 127.2 MVA (96% of Planning Threshold / 91% of Normal)

2030:
- Timber Swamp TB25 Transformer at 138.7 MVA (104% of Planning Threshold / 99% of Normal)

…Eversource to transfer load from Timber Swamp substation to Ocean Road substation as needed to alleviate loading concerns…

6.9 Line Contingencies
There are no line contingencies that cause elements to exceed their planning thresholds.

REDACTED

7 SYSTEM IMPROVEMENT OPTIONS

The following sections describe details of system improvement options examined to address the deficiencies identified earlier in this report.

7.1 Oak Hill Transformer STE Loading

The remaining Oak Hill transformer is expected to be loaded above its STE (Short Term Emergency) limit for loss of the other Oak Hill transformer during summer peak conditions. This requires remedial action to be implemented within five minutes following the failure.

Unitil and Eversource have determined that the following switching can be performed to alleviate the STE loading concern at Oak Hill.

- [redacted]
- [redacted]

It is expected that this switching solution will provide the necessary load reduction at Oak Hill for the foreseeable future. This will provide Unitil and Eversource time study and evaluation long term solutions.

At this time the following options are being considered as long term solutions to the Oak Hill STE loading concern.

- Continuation of the pre-contingent load transfer.
- Replace both the existing Oak Hill transformers with larger units.
- Make modification to the UES-Capital system to allow the Oak Hill and Penacook buses to be split and operated with the bus ties normally open. *(see note below)*
- Implement transformer protection scheme(s) or establish operating orders to trip load off line for Oak Hill loads above the STE of one transformer and loss of an Oak Hill transformer.
- Non-traditional alternatives, including but not limited to distributed generation, energy storage, load curtailment and energy efficiency.

Note about the UES-Capital system configuration:
Unitil is planning to perform a detailed system evaluation to determine the feasibility of operating the UES-Capital radially. In addition to other potential benefits operating the Capital system radially will allow the Penacook and Oak Hill 34.5 kV buses to be operated split with the bus ties open. This reconfiguration may resolve the Oak Hill STE violation, but would result in a short outage to all load supplied from the faulted Oak Hill transformer. This load will most likely have the ability to be restored relatively quickly via remote switching.

REDACTED

8 ADDITIONAL ITEMS DISCUSSED

In addition to the traditional basecase and N-1 contingencies the joint planning group also discussed the following items.

8.1 Voltage Reduction

Eversource will be participating in the less than 10 minute voltage reduction group this fall. In the event Eversource meets this requirement they plan to move from the greater than 10 minute voltage reduction group to the less than 10 minute group.

This change does not require Unitil to change from its current group of greater than 10 minutes. At this time Unitil intends to stay in the great than 10 minute voltage reduction group and not move to the less than 10 minute group as Unitil has to dispatch crews to many locations to manually implement voltage reduction.

8.2 Great Bay Loading

Unitil received a request from the ESCC to switch in capacitor banks in the Great Bay area during a peak day in 2020. The reason provided by the ESCC was to reduce heating of the Great Bay transformer. Unitil complied with this request and no other action was requested by the ESCC.

Eversource will be reviewing this scenario and will provide Unitil with additional information regarding the request and why it was needed.

8.3 34 Line Switching

Unitil received multiple requests from the ESCC this summer to reduce Oak Hill loading by transferring the 34 line from Penacook to Bridge Street. Eversource will review the correlation between ISO-NE load levels and Oak Hill load levels to confirm that 23,300 MW ISO-NE load level is the necessary switching threshold. Unitil will then use this information to determine if they will continue to switch the 34 line upon request or will leave the 34 line supplied from Bridge Street throughout the summer.

Preliminary review of summer 2020 loading data suggests that the correlation of an ISO-NE load level of 22,100 MW relates to approximately 61 MVA (the smaller STE rating) of load on Oak Hill Substation. During the summer months when Oak Hill experiences its peak, substation load remains between 0.27 to 0.28 percent of the total ISO-NE load.

8.4 Timber Swamp Substation – Loss of Both the TB25 and TB69 Transformers

With input from Unitil Eversource has completed their evaluation of the loss of multiple 345-34.5 kV transformers at the same substation. As a result of this evaluation it is proposed that a spare 345-34.5 kV transformer be purchased.

[redacted]

REDACTED

[redacted] A risk versus cost analysis will be performed to determine where the spare transformer will be located.

9 CONCLUSION

The 2020 joint planning process identified no required capital improvement projects and two non-capital modifications:

- Starting in 2021 Unitil will switch an additional 7.5 MW from Great Bay to Timber Swamp during the summer load season, to reduce load on the Great Bay transformer.
- Unitil will continue to transfer its 34 line (approximately 10 MW of load) from Penacook to Bridge Street at the request of the ESCC for ISO-NE load levels above 22,100 MW, to reduce load on the Oak Hill transformers.

Additionally, Eversource and Unitil will continue to explore and evaluate options that will provide a long term resolution to the Oak Hill STE loading constrain.

10 ACCEPTANCE

This joint planning report is accepted by both Eversource and Unitil as meeting the needs for the long term planning of jointly used distribution facilities.

Russel Johnson
Russel Johnson
Manager – System Planning, Eversource

9/15/2020
Date

Kevin Sprague
Vice President – Engineering, Unitil

9/17/2020
Date

2020

JOINT PLANNING REPORT

Eversource Energy &
New Hampshire Electric Cooperative

September 1, 2020

Contents

Executive Summary

Eversource Energy and New Hampshire Electric Cooperative (NHEC) have conducted the annual joint planning meeting(s) and completed the joint planning process for 2020. The planning department from Eversource met with the engineering department of NHEC and loading of joint facilities under base case and contingency configurations were reviewed.

This report summaries the findings of the joint planning process. The Eversource 2020-2029 Load Flow Study was used as the basis for identifying constraints for the years 2020-2029. The 2020 Eversource and New Hampshire Electric Cooperative joint planning process identified seven improvement projects.

Introduction

New Hampshire Electric Cooperative is a wholesale transmission customer of Eversource Energy and is provided service at 115 kV, 34.5 kV and 12.47 kV at 33 delivery points. Due to the joint nature of the Eversource distribution and transmission facilities that supply NHEC, Eversource and NHEC participate in a joint planning process to develop short-term and long-term plans for these areas that represent the best interests of all customers and members as a whole.

Eversource develops system load projections, loadflow models, and completing its planning study. Once the study work is complete, joint meetings are held to discuss the results and project scopes and estimates are developed for any identified constraints that affect joint facilities or supplies to NHEC substations and meter locations.

Although transmission may be discussed, the joint planning process is a distribution planning effort and any recommendations that have transmission implications need to be reviewed by Eversource Transmission Planning and ISO-New England.

System Supply Capacity

System capacity organized by system supply for Eversource equipment supplying NHEC delivery points.

Capacity noted is the Normal Rating of the transformer or line. Forecast Loading is the 90/10 forecasted Summer 2021 peak load.

Eversource Energy System Supply

Ashland Substation - Serving Bridgewater, Center Harbor, Green Street, Meredith, and Moultonborough Neck.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
TB5	Transformer 115-34.5 kV	44	39.9	Bridgewater Center Harbor Green Street Meredith Moultonborough Neck
338	Feeder 34.5 kV	40	29.6	Center Harbor Meredith Moultonborough Neck
3196	Feeder 34.5 kV	32.3	10.3	Bridgewater Green Street

Beebe River Substation – Serving Fairgrounds, Rumney, and Thornton.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
TB62	Transformer 115-34.5 kV	44	20.5	Fairgrounds Rumney Thornton
342A	Feeder 34.5 kV	32.3	12.4	Fairgrounds Rumney
342B	Feeder 34.5 kV	32.3	8.1	Thornton

Brentwood Substation – Serving Brentwood and Raymond.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
TB126	Transformer 115-34.5 kV	44	24.8	Brentwood Raymond
3103	Feeder 34.5 kV	40.0	24.8	Brentwood Raymond

Chester Substation – Serving Chester and Deerfield.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
TB71	Transformer 115-34.5 kV	44	29.0	Chester Deerfield
3115X	Feeder 34.5 kV	40.0	28.9	Chester Deerfield

Daniel & Webster Substations – Serving Northfield and Webster.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
TB43	Transformer 115-34.5 kV	44	17.9	Northfield Webster
3193	Feeder 34.5 kV	53.2	6.0	Webster
3216	Feeder 34.5 kV	40.9	11.9	Northfield

Laconia Substation – Serving Belmont.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
TB24	Transformer 115-34.5 kV	44	32.9	Belmont
TB125	Transformer 115-34.5 kV	44	32.2	Belmont
398	Feeder 34.5 kV	40.9	8.3	Belmont

Lost Nation Substation – Serving Colebrook.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
TB033	Transformer 115-34.5 kV	28	4	Colebrook
TX129	Transformer 115-34.5 kV	44	6.9	Colebrook
355X	Feeder 34.5 kV	23.6	9.6	Colebrook

Madbury Substation – Serving Lee.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
TB65	Transformer 115-34.5 kV	44	39.5	Lee
TB74	Transformer 115-34.5 kV	44	39.7	Lee
3137X	Feeder 34.5 kV	26.3	24.0	Lee

North Road Substation – Serving Sunapee.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
TB38	Transformer 115-34.5 kV	44	20.6	Sunapee
TB49	Transformer 115-34.5 kV	44	20.7	Sunapee
3180	Feeder 34.5 kV	9.0	3.9	Sunapee

North Woodstock Substation – Serving North Woodstock.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
TB67	Transformer 115-34.5 kV	44	10.9	North Woodstock
3126	Feeder 34.5 kV	40.9	2.4	North Woodstock
3822	Feeder 34.5 kV	40.9	8.5	North Woodstock

Oak Hill Substation – Serving Barnstead.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
TB15	Transformer 115-34.5 kV	44	31.2	Barnstead
TB84	Transformer 115-34.5 kV	45	33.2	Barnstead
319	Feeder 34.5 kV	40.0	19.6	Barnstead

Pemigewasset Substation – Serving Alexandria and Corliss Hill.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
TX88	Transformer 115-34.5 kV	44	24.5	Alexandria Corliss Hill
345	Feeder 34.5 kV	32.9	11.7	Corliss Hill
3114X	Feeder 34.5 kV	23.9	12.7	Alexandria

Saco Valley Substation – Serving Perkins Corner.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
TB60	Transformer 115-34.5 kV	44	22	Perkins Corner
395	Feeder 34.5 kV	40.0	9.3	Perkins Corner

Scobie Pond Substation – Serving Derry.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
TB132	Transformer 115-12.47 kV	30	21.5	Derry
32W5	Feeder 12.47 kV	14.5	10.3	Derry

Tasker Farm Substation – Serving New Durham/Alton.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
TB78	Transformer 115-34.5 kV	44	29.4	New Durham/Alton
3174	Feeder 34.5 kV	40.0	15.2	New Durham/Alton

White Lake Substation – Serving Melvin Village and West Ossipee/Tamworth.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
TB76	Transformer 115-34.5 kV	28	25	Melvin Village West Ossipee/Tamworth
TB82	Transformer 115-34.5 kV	28	26.7	Melvin Village West Ossipee/Tamworth
346	Feeder 34.5 kV	32.3	28.4	Melvin Village West Ossipee/Tamworth

Whitefield Substation – Serving Lisbon.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
TB89	Transformer 115-34.5 kV	43	23.8	Lisbon
348	Feeder 34.5 kV	32.3	15.3	Lisbon

Green Mountain Power System Supply

GMP 46 kV / Eversource River Road Substation – Serving North Charlestown.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
46W1	Transformer 46-12.47 kV	6.72	5.4	North Charlestown
46W1	Feeder 12.47 kV	8.5	5.4	North Charlestown

GMP Newbury / Eversource 12W1 – Serving North Haverhill.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
12W1	Circuit 12.47 kV	4.1	Forecast not Available	North Haverhill

GMP Thetford / Eversource 17W1 – Serving Lyme.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
17W1	Circuit 12.47 kV	4.1	Forecast not Available	Lyme

GMP Windsor / Eversource 47W1 – Serving Cornish.

Element	Type	Capacity (MVA)	Forecast Peak Load (MW)	NHEC Delivery Points
47W1	Circuit 12.47 kV	4.1	Forecast not Available	Cornish

System Analysis

The following analysis was based on Eversource's draft Distribution System Planning Guide which is expected to be approved within Eversource in the fall of 2020. These results are from the 2020-2029 Load Flow Study and are summarized here based on violation type. The violations noted here are for Eversource facilities serving NHEC delivery points.

Base Case Review (N-0)

Bulk Substations, Load > 95% Nameplate

- White Lake Substation (2021)

Non-Bulk Substations, Load > 100% Nameplate

- For the non-bulk distribution substations that supply NHEC, no violations were identified.

Contingency Evaluation (N-1)

Bulk Substations, Load > STE Rating

For the loss of a transformer within a two-transformer substation, station load shall not exceed the STE rating of the remaining transformer. STE is the 30-minute short-term emergency rating and is the highest overload emergency rating provided for bulk substation transformers.

- Laconia Substation (2024)
- Madbury Substation (2020)
- Oak Hill Substation (2020)
- White Lake Substation (2020)

Bulk Substations, Isolated Load > 0 MW after 3 load block transfers

Within the three load block transfers (approximately 6 switching steps), one of the blocks is allowed to offload a secondary supply to increase capacity with restoration (aka cascading load block transfer).

- Ashland Substation (2020)
- Beebe River Substation (2020)
- North Woodstock Substation (2020)
- Pemigewasset Substation (2020)
- Saco Valley Substation (2020)
- White Lake Substation (2020)

System Improvement Options

Eversource's current capital plan anticipates the following improvements to the above noted design violation. These are presented here in chronological order of in-service date.

REDACTED

Oak Hill Substation

Summer mitigation switching – ISD 2020

Summer system reconfiguration with Unitil's Capital Region reduces load levels on Oak Hill below the smallest STE rating. Eversource has the ability to perform additional switching within its distribution system to reduce load levels below LTE as necessary.

White Lake Substation

Replace two 28 MVA transformer with two 62.5 MVA transformers – ISD 2023

The increased capacity at White Lake addresses base case loading at White Lake and contingency violations at White Lake and Saco Valley Substations. In addition to the system design violations, this project addresses asset condition issues and physical access separation due to the divestiture of generation.

Ashland Substation

Addition of a second 44.8 MVA transformer – ISD 2024

The increased capacity at Ashland Substation addresses contingency violations at Ashland, Beebe River and Pemigewasset Substations.

Laconia Substation

Summer mitigation switching – ISD 2024

Summer or permanent system reconfigurations are being reviewed as a solution to reduce load levels on Laconia Substation to below the smallest STE rating. [redacted]

Madbury Substation

Addition of a bus tie breaker – ISD 2024

To address the STE violation at Madbury, a bus tie breaker would be added to the single straight bus. [redacted]

North Woodstock Substation

NHEC SCADA

New Hampshire Electric Cooperative has identified in the next few years it is adding SCADA control to its distribution system. Initially focusing on their 12.47 kV system, it will eventually be added to the 34.5 kV system. When NHEC adds SCADA control to its 34.5 kV system, this will be reflected in Eversource's load flow analysis [redacted]

Gore Regulator Station

NHEC Regulator replacement

New Hampshire Electric Cooperative has identified that its three-phase regulator at Gore Station is a single-direction unit. For supporting internal NHEC contingencies and an Eversource Beebe River 342B feeder contingency and Beebe River transformer contingency, the regulator control would need to be upgraded as well as adding SCADA control to the station. NHEC has identified that a full replacement with three new single-phase regulators is a cost-effective solution than retrofitting the older three-phase unit.

The historical peak at North Woodstock Substation for the winter of 2019-2020 was 22.5 MW and on Beebe River feeder 342B it was 19.1 MW for the same period. Based on Eversource's practice of rating and operating regulators, 335 amp single-phase regulators would be suited for this location. Eversource would rate these units with a 20 MVA normal rating and a 29.6 MVA 24-hour winter emergency rating, 23.5 MVA 24-hour summer emergency rating.

Additional Joint Planning Topics

In addition to the traditional base case and N-1 contingencies, the joint planning group also discussed the following topics.

Ashland 338 Line N-1 Contingency

NHEC has expressed concern over the N-1 capacity of the supply line to its Meredith District. Eversource's 34.5 kV 338 Line from Ashland Substation is a 22.5 mile line with three NHEC meter locations (Meredith, Center Harbor, and Moultonborough) serving a portion of NHEC's Meredith District 12.47 kV distribution system.

This discussion is primarily driven by a February 7, 2020 outage on the 338 line that caused NHEC's Meredith Substation to be isolated for the duration of the outage (6 hours, 41 minutes). Further research on the day's system events indicated stormy weather had passed through and both sources from Ashland and White Lake were interrupted.

Eversource, by the end of 2020, will have a larger transformer at its Pemigewasset Substation, which will have extra capacity to restore 338 Line load on N-1 contingencies. For faults between Ashland Substation and the Straits Road switching area, the 346 Line from Pemigewasset can restore NHEC load under most load conditions. During summer peak, it's recognized that NHEC's Moultonborough cannot be restored due to voltage limit violations.

A line regulator already exists at Meredith, but additional voltage support could be gained from line capacitors. Unfortunately, Eversource's line between Straits Road in New Hampton to Center Ossipee lacks a neutral (ungrounded-wye configuration). Eversource and NHEC will investigate any opportunities to install 34.5 kV line capacitor banks utilizing NHEC's distribution neutral to support system voltage on contingencies in order to improve reliability to NHEC members.

System Impedance at NHEC Delivery Points

New Hampshire Electric Cooperative has requested the system impedance at their delivery points for their own system analysis. The following table has the system impedance in per-unit on a 100 MVA base. This data is provided by Eversource's Protection & Controls department.

Location	Nominal kV	3LG (PU)	2LG	1LG	R1 (PU)	X1	R0	X0
Alexandria	34.5							
Barnstead	34.5							
Belmont	34.5							
Brentwood	34.5							
Bridgewater	34.5							
Center Harbor	34.5							
Chester	34.5							
Colebrook	34.5							
Corliss Hill	34.5							
Cornish	12.47							
Deerfield	34.5							
Derry	12.47							
Fairgrounds	34.5							
Green Street	34.5							
Intervale	115							
Lee	34.5							
Lisbon	34.5							
Lyme	12.47							
Melvin Village	34.5	*This data is unavailable at time of publication. Eversource will follow-up with an update once system impedance data is ready.*						
Meredith	34.5							
Moultonborough Neck	34.5							
New Durham/ Alton	34.5							
North Charlestown	12.47							
North Haverhill	12.47							
North Woodstock	34.5							
Northfield	34.5							
Perkins Corner	34.5							
Raymond	34.5							
Rumney	34.5							
Sunapee	34.5							
Thornton	34.5							
Tuftonboro	34.5							
Webster	34.5							
West Ossipee/ Tamworth	34.5							

Underfrequency Load Shed Program

Per ISO-New England OP-13:

"In accordance with the provisions of the NERC Reliability Standard PRC-006-NPCC – Automatic Underfrequency Load Shedding, each Distribution Provider/Transmission Owner with 100 MW or more of peak net Load shall implement an Underfrequency Load Shedding (UFLS) program..."

New Hampshire Electric Cooperative has requested a list of feeders that Eversource has identified as participating in the Underfrequency Load Shed program that would affect its members if initiated. The following Eversource feeders and the associated NHEC delivery points are included in the UFLS program:

This data is unavailable at time of publication.

Eversource will follow-up once a list associating UFLS feeders with NHEC delivery points is completed.

Conclusion

The 2020 Joint Planning process between Eversource and New Hampshire Electric Cooperative has not identified any capital system improvements. NHEC highlighted future improvements to their system that would improve reliability to the North Woodstock Substation and Eversource has indicated its plans to increase contingency capacity in many areas that supply NHEC members. Eversource and NHEC will investigate opportunities to improve reliability to the members at Moultonborough Neck.

Acceptance

This joint planning report is accepted by both Eversource Energy and New Hampshire Electric Cooperative as meeting the needs for the long-term planning of supply lines and jointly used distribution facilities.

Russel Johnson ____________________ 09/17/2020
Manager – System Planning, Eversource — Date

Michael Jennings ____________________ 09/17/2020
Engineering Manager, New Hampshire Electric Cooperative — Date

Smart Grid Technology Overview

I. Enhanced System Visibility

(i) Advanced Sensing Technologies

In many areas of the grid, system operators lack adequate visibility and control required to optimize the modern grid. In several substations, feeders still rely on older electromechanical relay technology that do not allow for remote operations, such as application of fast-trip and lock-out settings for worker safety or changes in protection settings. These older relays are not capable of remote interrogation for engineering analysis, requiring a crew to visit the substation to collect the necessary data to diagnose power quality events or basic loading information. Additional opportunities for monitoring exist in substations that serve industrial customers with equipment that is highly sensitive to power quality events. Without advanced meters that provide continuous, high fidelity data collection, the Company typically relies on customers to pinpoint times of disruption and has limited information to identify potential solutions.

Along distribution lines, operators have no visibility into load and voltage conditions at many high priority locations. These locations include step-down transformers and medium sized solar facilities that do not require recloser protection.

Plans to deploy a distribution management system (“DMS”) are amplifying the importance of real-time telemetry. A DMS provides operators with a system-wide load flow model updated multiple times every hour and provides insight into opportunities to optimize system conditions, including advanced automated feeder reconfiguration reflecting current loading conditions. Without enough strategically placed telemetry, DMS model accuracy will be insufficient to support calculations such as fault location.

Advanced sensing technology is a critical enabling investment supporting the transition to the modern grid. High penetrations of telemetry support an accurate DMS model that will improve operators’ ability to identify opportunities to optimize system conditions and improve reliability with sophisticated fault location, isolation and service restoration (“FLISR”) schemes. Microprocessor relays enable next generation analysis and control, including adaptive protection and predictive outage detection. Increased penetration of devices with remote monitoring capabilities will reduce inefficiency and delays associated with the need to travel to substations to collect system measurements. System operators will have the information needed to address emerging issues, such as high-heat driven loading concerns or reverse flow overload concerns in areas of high solar penetration. Industrial customers with sensitive loads will benefit from power quality metering that will support proactive identification and analysis of power quality events. This information will inform future system improvements to reduce these types of events without reducing overall system reliability.

(ii) Advanced Metering

Generally speaking, deployment of advanced metering technology (“AMI”) has the following categories of potential benefits:

> Customer Satisfaction – Several programs, tools and capabilities are geared towards increasing customer satisfaction. Customers can have access to detailed usage data and useful information and alerts via multiple communications channels. Improved outage communications enabled by AMI is another source of value for customers.
>
> Energy Efficiency and Demand Response Participation – Data available from AMI will enable more sophisticated targeting of customers likely to benefit from the Company's conservation and load management programs.
>
> Reliability and Resiliency – Without AMI, the Company is dependent on customer call patterns to support restoration activities. Two-way communications and "last gasp" technology enable system operators to confirm service at individual meters. This capability is particularly important in major events, where AMI can identify "nested" outages reducing the duration and complexity of events. Granular data will also support pro-active identification of equipment overload conditions.
>
> System Efficiency – Improved grid-edge visibility will enhance the effectiveness of Volt VAR optimization schemes, leveraging investments in distribution equipment and control systems to deliver increased energy and demand savings.
>
> Support for Grid Modernization – Data available from AMI will improve the ability of system planners to prioritize upgrades and forecast the impact of distributed energy resources. System operators will have access to improved load flows based on more detailed and accurate customer load data, increasing the functionality of distribution and distributed energy resource management systems.
>
> Lowering Shared Costs – AMI can help reduce costs currently passed on to all customers. Theft and non-technical line losses, for instance, can be effectively identified using AMI data analytics and remote turn-on and turn-off capabilities implemented. Improved efficiency in the credit and collection process has the potential to reduce bad debt expense shared by all customers.
>
> Indirect Customer Savings – The Company would improve operational efficiency in areas such as meter reading, turn-on and turn-off activities and bad debt expense. The communications network required to support AMI is also capable of transmitting data from non-mission critical data such as line sensors.

While Eversource acknowledges the potential benefits of AMI, at present, the costs of deploying such a system and the robust communications network to support it, are currently not justified for full implementation in New Hampshire. Eversource is continually monitoring both the benefits and the costs of AMI and will continue to do so as part of its overall mission to provide a safe and reliable system.

II. Automation Technologies

(i) Distribution Automation

As described in previous REP reports, Eversource has implemented an extensive distribution automation program across New Hampshire. The primary benefit of overhead automated feeder reconfiguration is reduction in the impact of outages. With advanced technology, Eversource will design its schemes to restore power to unaffected segments reducing the number of customers affected by an outage event.

Eversource is also committed to reducing the impact of outages during major events. These events are hugely impactful to customers, causing major disruptions and in some cases requiring at-risk customers to take extreme measures to avoid being subject to power outages. These events result in significant restoration costs. Even relatively small reductions in the duration and extent of these events can result in meaningful benefits to customers. Eversource expects its automated feeder reconfiguration program will have a reduction in the duration of major events. This benefit will be realized near the beginning through the middle of an event when repairs have been completed on the backbone and system operators can restore large numbers of customers immediately following the repair remotely from the dispatch center. The Company also estimates it will gain a reduction in the number of customers affected. This potential savings will vary significantly with the type of event. The greatest reduction will be in events where the damage is localized in certain areas such that adjacent alternate supplies are available and the Company can reconfigure the system to support customers from these alternate supplies.

Beyond the reliability benefits, the addition of automated devices in the field will reduce the amount of day-to-day manual switching operations which occur as a normal part of maintaining the electric system and adding new customers. In addition to saving time for planned and unplanned switching operations, automating switches reduces operations cost, environmental impact and safety exposure. From a system planning perspective, the enhanced flexibility to shift load based on prevailing conditions has the potential to defer capital upgrades as well.

(ii) Volt VAR Optimization (“VVO”)

Opportunities exist throughout the Eversource service territory in New Hampshire to improve system efficiency with advanced voltage control technology. Managing system voltage to reduce energy consumption and optimize demand will provide direct benefits to customers. Improving system efficiency and reducing line losses will also support reductions in greenhouse gas emissions. Advances in technology are both increasing the imperative for VVO and are providing more tools to increase the effectiveness of the programs. In addition to mitigating some of the high voltage concerns caused by distributed energy resource (“DER”) facilities, VVO can address low voltage concerns associated with automatically switching load from one feeder to another.

Deploying automated load tap changers, voltage regulators, capacitor banks and line sensors along with control software, it is possible to achieve approximately two percent reduction in end-use energy consumption for customers on affected circuits, as well as a small reduction in line losses on affected circuits. In addition, the program has the potential to result in approximately 0.6 percent reduction in peak load for every percent reduction in voltage for the feeders on which VVO is deployed. These savings have both economic and environmental benefit.

III. Optimization Technologies

(i) Distribution Management System

Historically, system operators have relied on traditional control room tools designed to maintain safe and reliable service of a system characterized by relatively predictable customer loads and one-way power flow. These tools are no longer sufficient for operators to manage the complexity associated with increasing penetration of distribution automation.

One of the primary challenges of the modern grid is the difficulty for operators to maintain situational awareness while processing massive amounts of data from a multitude of field devices. Managing data and alarms from thousands of points on the system requires more sophisticated analytics and visualization tools. Today's control rooms are often high-stress environments where operators are challenged to make rapid decisions processing data from multiple systems simultaneously. Difficulties managing high volumes of data in the moment often drive additional conservatism in decision-making, which has the potential to affect customers. For instance, during high-load conditions, to avoid potential overloads, operators limit the transfer of load when the system is in an abnormal condition, increasing the potential for an outage event to affect more customers.

Maintaining situational awareness amid the receipt of such a significant amount of data is even more challenging with increasing penetration of solar and other types of DER. At backbone and substation monitoring points, operators are limited to seeing net power flows with no ability to disaggregate load and generation. The risk that a sudden change in weather will diminish solar output and "un-mask" unknown levels of additional load requires operators to maintain conservative reserve margins in making operational decisions. Difficulty in managing voltage with limited visibility into the effect of intermittent solar generation is a growing concern. With no ability to disaggregate the impact of individual solar facilities on voltage conditions, operators must manage voltage at the transformer level, with no insight into the impact at the customer level. Today's operators must manage voltage reactively to avoid adverse conditions without tools of the modern grid to proactively optimize system efficiency.

The modern grid has the potential to be characterized by sophisticated "self-healing" logic designed to process large amounts of data and recommend the optimal configuration to maximize reliability benefit. Currently, the system is characterized by automation devices that require system operators to react dynamically to system conditions. With limited situational awareness, operators are unable to precisely direct field crews to the location of a fault, increasing the time to repair and restore.

Implementation of DMS technology in the control room will provide tools necessary to greatly improve situational awareness, leverage extensive monitoring and control capabilities to make gains in reliability performance, deliver a more effective training environment to build operator proficiency under multiple operating scenarios, and serve as a foundation for greater optimization of system conditions with wide-spread VVO capability and ultimately DER management system ("DERMS") capability to enable use of DER as grid assets.

A distribution load flow model providing real time visibility into current and voltage conditions relative to equipment ratings will provide system operators with tools to pro-actively configure the distribution system based on large volumes of data processed automatically to support effective and efficient decision- making. The DMS will provide a "study mode" functionality to evaluate the impact of a proposed switching action to identify potential adverse consequences on an hourly basis (e.g., voltage problems, equipment overload, protection system issues). Sophisticated data processing and analytics will allow for the identification of opportunities to pro-actively mitigate risks of operating in contingency conditions. Multiple actions such as load transfers and temporary back-up equipment can be considered quickly and accurately.

The DMS will provide an important next step in reliability benefit for customers. Improved fault location will shorten outage duration. Advanced analysis will use pre-fault loading conditions to calculate restoration steps ensuring protection schemes work as designed accounting for DER output and masked load. Modeling the system with real time load data will eliminate the need to disable auto restoration loop schemes based on conservative worst-case scenarios improving the utilization of switching devices to reduce the impact of outages. DMS intelligence will also prevent automatic switching into faulted circuit segments reducing a potential safety concern.

Achieving the promise of the modern grid will require system operators to process massive volumes of data, utilizing advanced analytics to support efficient, intelligent decision-making, optimizing system conditions for multiple variables. The DMS will serve as the platform for optimization. Without a real-time model of the system based on the power flow of load and generation on the as-operated model, options to use DER to capture meaningful locational value are limited. Utilizing DER to solve real-time problems on the grid requires a DERMS solution paired with the DMS load flow. In the future, the DMS will identify a fault condition and use FLISR to automatically sectionalize and re-supply unaffected sections. If closing a tie would cause an overload condition, a model-based DERMS solution would be able to dispatch energy storage to avoid the overload condition in the affected circuit segment, enabling the restoration scheme to proceed. If the revised circuit configuration caused a voltage concern, the model-based DERMS could change settings on advanced inverters to maintain system stability. Similarly, model-based DERMS solution integrated with the DMS will increase the ability of sophisticated VVO schemes to achieve energy and demand savings in the presence of high-penetration of DER, utilizing advanced inverters as another tool to support optimization.

(ii) Hosting Capacity and Data Analytics

Efforts to improve the efficiency and transparency of distribution system planning and engineering are often limited by lack of tools to process, analyze and share large volumes of data. Without load flow tools with full automation capabilities, engineers cannot perform batch process analysis required to produce output for all feeders at the circuit segment level at once. This type of batch process analysis is necessary to produce widespread hosting capacity analysis and publish results available in a regularly updated map format.

Currently, planning engineers use basic tools to forecast load and generation at the circuit level. This process involves a combination of “top down” allocation from regional forecasts and “bottoms up” understanding of expected step changes in load and generation. Using a traditional approach to forecasting, planners typically use assumptions including average load growth over wide areas, basic analysis of weather impacts, and have limited insight into changing economic, resource deployment, or network topology changes. A manual process is used to account for load masked by large generators, a process that is not feasible for smaller behind-the-meter solar facilities. Without accurate forecasts, planners must use conservative assumptions to ensure adequate system capacity. It is also difficult and time consuming to produce multiple scenarios of future load and generation penetration to enable probabilistic planning under a range of outcomes.

The Company presently has several databases which have evolved separately from legacy environments. Recent grid modernization efforts, along with a general trend to increase visibility and control of more distribution equipment, are rapidly increasing the availability and quantity of this valuable data. While this has significantly improved the ability of Company engineering and operations groups to monitor and examine individual points on the distribution system, the current state of these databases makes any comprehensive reporting or analytics extremely difficult and time consuming.

Full automation of the load flow tool will provide the capability required to support batch process analysis. Full automation will allow for engineers to perform studies based on adding solar generation to the system in small increments in all circuit segments until a voltage or thermal limit is reached. This analysis will support a more accurate circuit segment level hosting capacity value that also reflects the potential for up-stream electrical devices to serve as the limiting factor for additional solar generation. This type of automated analysis can be performed rapidly based on direct interfaces to the Company’s geographic information system, DER and other databases, improving transparency by making results available more frequently with a higher degree of accuracy. Other types of batch process analysis include arc flash analysis and rapid contingency analysis, both of which will increase the efficiency and effectiveness of planning studies. Integration with the Company's protection database and substation equipment maintenance database will further streamline the interconnection study process with improved contingency analysis and faster screening of expedited applications.

Improved forecasting capability using spatial analysis will enable planners to more accurately predict load and power changes, where on the grid the loads will occur, how DER changes the load shape, and when system upgrades are required. Increasing complexity of the distribution system characterized by high penetration of DER and uncertainty regarding penetration of EV and other beneficial electrification requires a more sophisticated approach to forecasting that is based on a statistical representation of the geographic, economic, distributed resources, and weather diversity across the Eversource service territory. This information and analysis will be used to forecast circuit and substation level peak loads, sub-sections of the circuit and impacts from various scenarios over the planning horizon. Planners will be able to decompose system impacts using map layers superimposed on the spatial representation of the distribution infrastructure. With access to this type of analytical tool, Eversource will be well-positioned to incorporate various EV and DER planning scenarios and share results with stakeholders.

Gaining actionable insights from large volumes of system data is a key outcome supporting the grid of the future. Improvements to the Company's data historian environment and implementation of an asset framework will give engineers a greater ability to utilize data in a variety of analytical tools, including more comprehensive assessment of the impact and opportunities associated with DER penetration. Asset management strategies will be enhanced by analysis of equipment performance over time. Transparency will be increased with a more automated process for reporting of system conditions and performance, including trends in power quality and line losses.

(iii) Energy Storage

Energy storage offers an opportunity to fundamentally change the existing just-in-time delivery model to a delivery model that is more flexible and responsive to momentary changes in distributed generation and customer load. Today, the grid is characterized by the need to balance load and generation every second, primarily by dispatching generation. Early applications of storage such as pumped hydro provide proven benefits, but are typically long distances from load, rely on transmission infrastructure, and are difficult to site in most areas of New England. Eversource is tracking and learning from other jurisdictions that have implemented local energy storage pilots and demonstrations. Energy storage systems have the potential to serve multiple applications simultaneously. The range of possible applications includes peak shaving, load shifting, system resilience, renewable intermittency mitigation and ancillary services. There are multiple applications at the transmission, distribution and end-user level that may ultimately prove to have net benefits for customers.

Grid Needs Assessment

In Liberty Utilities November 19, 2018 settlement on its proposal in Docket No. DE 17-189, Liberty agreed to provide a so-called "Grid Needs Assessment" as part of its next LCIRP filing. Specifically, that settlement stated that Liberty would provide:

> To that end, Liberty shall provide a detailed grid needs assessment within its next LCIRP. That grid needs assessment shall describe all forecasted grid needs related to distribution system capital investments of $250,000 or more over a five-year planning horizon at the circuit level. The grid needs assessment shall be available in spreadsheet format and shall include the following attribute-based columns and content: (1) Substation, Circuit, and/or Facility ID: identify the location and system granularity of grid need; (2) Distribution service required: capacity, reliability, and resiliency; (3) Anticipated season or date by which distribution upgrade must be installed; (4) Existing facility/equipment rating: MW, kVA, or other; and (5) Forecasted percentage deficiency above the existing facility/equipment rating over five years.

Through the settlement on the 2019 plan for the EERS in Docket No. DE 17-136, Eversource agreed to provide a similar assessment in its LCIRP. The following spreadsheets comprise that Grid Needs Assessment.

In the attached spreadsheet, Eversource has included information on the grid needs estimated at greater than $250,000 as identified for Bulk Substations, Non-bulk Substations, and distribution lines. Typically, distribution line related projects are specifically identified for the following year because they can be designed and constructed within one budget year. This allows the Company to address those facilities with the most pressing need and/or that provide the greatest reliability benefit. Asset condition projects are often due to emergent issues and therefore specific projects are prioritized from year to year and specifically identified in the next year's capital plan.

As noted above, the description of the Grid Needs Assessment calls for the "Equipment Rating" and the "Forecasted percentage deficiency above the existing facility/equipment rating over five years." Providing this analysis is straight forward for a basecase overload of a piece of equipment or conductor. When the criteria violation is an N-1 contingency, however, the equipment rating and percentage deficiency become ambiguous since the equipment is now out of service and the system is relying on a combination of circuits and transformers to restore the load. The limitations become a combination of voltage criteria, conductor ratings, transformer ratings, equipment ratings and protection settings. For this reason, the equipment ratings and percentage deficiencies in the attached document have been provided for basecase overloads but not for N-1 contingencies. This information is also not applicable for asset condition driven projects.

The "Anticipated season or date by which distribution upgrade must be installed" is shown as 2023 for all projects for which a criteria violation presently exists. The percent deficiency is assumed to increase by the forecasted annual growth rate of 0.38% per year.

“Annuals,” which are budget line items used to fund multiple work orders under $100,000 each, associated with connecting new customers, basic business (e.g., line relocations for NHDOT, emergent equipment failures, tools and equipment, etc.), maintain voltage, and reliability are not included in the spreadsheet. Multiyear projects that are under construction and will be completed in 2021 are not included since the grid need will have been addressed.

Circuit	Town	System Granularity of Grid Need	Capacity/ Reliability/ Resiliency	Anticipated season or date by which distribution upgrade must be installed	Equipment Rating	Forecasted percentage deficiency above the existing facility/equipment rating	Additional Information:
Various	Various	Replace degraded manholes	Reliability - Asset Condition	Ongoing	N/A	N/A	
13A,B,C,D	Manchester	Replace 1950's vintage PILC cables in Manchester Network	Reliability - Asset Condition	4 year program	N/A	N/A	Experiencing an increased number of cable failures.
Various	Rochester	Convert 4 kV as a result of Retiring 4kV substations	Reliability - Asset Condition	Summer 2021	N/A	N/A	
334X18	Pembroke	334X18 Reconductor bare conductor with 1/0 spacer cable.	Reliability/Resilency	12/31/2021	N/A	N/A	
3891	Nashua	Replace 40 year old 3891 Cable and address inaccessible riser structures	Reliability - Age, Access	12/31/2021	N/A	N/A	
3212	Hollis/Amherst	3212 Convert 2.4 kV line to 19.9 kV	Reliability	12/31/2021	N/A	N/A	Provides backup source to radial taps.
22W2, 23W2, 16W1	Manchester	Malvern-Valley-Hanover substations Construct Circuit Tie	Reliability	12/31/2021	N/A	N/A	
3191X3 to 3191X	Greenland	Construct Circuit Tie 3191X3 to 3191X	Reliability	12/31/2021	N/A	N/A	
3177X1 - 3177X3	Nashua	Construct Circuit Tie 3177X1 - 3177X3	Reliability	12/31/2021	N/A	N/A	
14X188-3248	Manchester	Construct Circuit Tie 14X188-3248	Reliability	12/31/2021	N/A	N/A	
365X	Londonderry	365X Rebuild Apple Tree Cinema URD	Reliability - Asset Condition	12/31/2021	N/A	N/A	
32W1	Derry	32W1 Replace Pine Isle Drive URD	Reliability - Asset Condition	12/31/2021	N/A	N/A	
313X1	Jaffrey	313X3 Replace Sherwood Lane URD	Reliability - Asset Condition	12/31/2021	N/A	N/A	
317/3410	Bradford/Warner	317/3410 Reconstruction, Bradford to Warner	Reliability - Asset Condition	Multi-year project	N/A	N/A	
Various	Various	Distribution Automation - Pole Top	Reliability	Program	N/A	N/A	
322X14	Manchester	322X14 Circuit Offload to address conductor overload	Capacity	06/01/2021	190 Amps	18%	
63W1	Strafford	63W1 Reconductor 1Ø 1/0 ACSR on Drake Hill Rd to 477 3Ø spacer cable to address conductor overload	Capacity	06/01/2021	250 Amps	11%	
3191XA	Newfield	3191X1A Piscassic Rd Conversion to address overloaded step transformers	Capacity	06/01/2021	999 kVA	43%	
377X3	Epping	377X3 Fogg Rd Conversion to address overloaded step transformers	Capacity	06/01/2021	500 kVA	34%	

Circuit	Town	System Granularity of Grid Need	Capacity/ Reliability/ Resiliency	Anticipated season or date by which distribution upgrade must be installed	Equipment Rating	Forecasted percentage deficiency above the existing facility/equipment rating	Additional Information:
392X7	Barrington	392X7 Beauty Hill Rd Conversion to address overloaded step transformers	Capacity	06/01/2021	1000 kVA	2%	
360X5	New Boston	360X5 Add phases on New Boston Rd	Phase Imbalance/Capacity/ Reliability	06/01/2021	N/A	N/A	Addresses severe phase imbalance, new URD development and prepares for future circuit tie.
3798X2	Northfield	3798X2 Convert Rte 132 in Northfield to address protection miscoordination	Capacity	06/01/2021	N/A	N/A	
3141X	Derry	3141X Damren Rd Conversion to address overloaded step transformers	Capacity	06/01/2021	500 kVA	55%	

Substation	Location	system granularity of grid need	Capacity/ Reliability/ Resiliency	Anticipated season or date by which distribution upgrade must be installed	Equipment Nameplate Rating (MVA)	Forecasted percentage deficiency above the existing facility/equipment rating	Additional Information:
345 - 34.5 kV Spare Transformer	N/A	Spare for five in-service 345 - 34.5kV transformers.	Reliability	N/A		N/A	No spare presently exists.
Ashland	Ashland	N-1 Transformer contingency - Loss of Load Need - 2nd transformer at Ashland	N-1 Capacity	Dec 2023	N/A	-	2nd Ashland transformer
Bedford	Bedford	N-1 Transformer contingency - Exceed transformer STE rating Need - Additional Transformer Capacity at Bedford S/S	N-1 Capacity	Dec 2023		-	Preliminary - Requires additional study.
Beebe River	Campton	N-1 Transformer contingency - Loss of Load Need: 2nd transformer at Ashland	N-1 Capacity	Dec 2023	N/A	-	Solved with 2nd Ashland transformer
Chestnut Hill	Hinsdale	N-1 Transformer contingency - Loss of Load Substandard design, no low side transformer breakers, no low side bus, no bus-tie breaker, 1946 Transformers Need: Rebuild with standard design and larger transformers	Asset Condition/Sub-standard design/ N-1 Capacity	Dec 2023	25	-	No low-side transformer breaker - prevents DSCADA control
Dover (Cocheco)	Dover	N-1 Transformer contingency - Exceed transformer STE rating Asset condition/substandard design, no low side bus-tie breaker Need: Additional Transformer Capacity at Cocheco	Reliability-Asset Condition/ N-1 Capacity	Dec 2023	N/A	-	S/S Upgrade
Eddy	Bedford	N-1 Transformer contingency - Exceed transformer STE rating Need: Additional Transformer Capacity at Eddy	N-1 Capacity	Dec 2023		-	
Huse Road	Manchester	N-1 Transformer contingency - Exceed transformer STE rating Need: Additional Transformer Capacity at Huse Road	N-1 Capacity	Dec 2023		-	
Lawrence Road	Hudson	N-1 Transformer contingency - Loss of load Substandard design Need: Addition of low side transformer breaker.	N-1 Capacity/Reliability	2022	N/A	-	No low-side transformer Breaker
Long Hill	Nashua	Need bus-tie breaker and additional transformer capacity.	N-1 Capacity	Dec 2023	N/A	-	Shift load to Hudson may solve contingency violation - Need to update model to capture recent DA devices and discrete load transfer capability.
Madbury	Madbury	Need bus-tie breaker and additional transformer capacity.	N-1 Capacity	Dec 2023	N/A	-	Shift load to Ocean Road and Brentwood may solve contingency violation. Need to further study reliabilty impacts of reconfiguration.
Mill Pond	Portsmouth	N-1 Transformer contingency - Permanent loss of load Need: Additional Transformer Capacity at Cutts St.	N-1 Capacity	Dec 2023	N/A	-	Single Transformer - limited ties
Monadnock	Troy	N-1 Transformer contingency - Permanent loss of load Asset condition/sub-standard design, poor transformer health, no low side transformer breakers, no ABR scheme Need: Substation rebuild with standard design and additional transformer capacity	Reliability-Asset Condition/ N-1 Capacity	Dec 2022	48	-	Asset Condition, no low-side transformer breakers

Substation	Location	system granularity of grid need	Capacity/ Reliability/ Resiliency	Anticipated season or date by which distribution upgrade must be installed	Equipment Nameplate Rating (MVA)	Forecasted percentage deficiency above the existing facility/equipment rating	Additional Information:
North Woodstock	North Woodstock	N-1 Transformer contingency - Permanent loss of load Need: Future NHEC Distribution Automation	N-1 Capacity	N/A	N/A	-	Supply into New Hampshire Electric Cooperative distribution system.
Pemigewasset	New Hampton	N-1 Transformer contingency - Permanent loss of load Need: 2nd Transformer at Ashland	N-1 Capacity	Dec 2023	62.5	-	
Rochester	Rochester	Rochester substation ABR scheme is obsolete Need: Replace S/S Bus-Tie Autoclose sysem	Reliability	Program	N/A	N/A	
Saco Valley	Conway	N-1 Transformer contingency - Permanent loss of load Need: Additional Transformer Capacity at White Lake	Reliability-Asset Condition/ N-1 Capacity	Dec 2023	44.8	-	Solved with White Lake Upgrade
South Milford	Milford	Basecase loading of S. Milford transformer exceeds 95% nameplate N-1 Transformer contingency - Permanent loss of load Substandard design - S/S bus fed by parallel lines from Amherst Need: 2nd transformer at S. Millford	Reliability/Capacity/ N-1 Capacity	Dec 2023	N/A	-	
White Lake	Tamworth	Basecase loading of White Lake transformers forecasted to exceed 95% N-1 Transformer contingency - Permanent loss of load N-1 Transformer contingency - Exceed transformer STE rating Asset Condition, substandard design Need: Substation rebuild with standard design and larger transformers.	Reliabillity - Asset Condition/N-1 Capacity/Other	Dec 2023	N/A	-	Asset Condition, S/S Upgrade
Varioius	Various	34.5 KV Substation OCB and Ancillary Equipment Replacement Program	Reliability - Asset Condition	Program	N/A	N/A	
Various	Various	PLC Automation Scheme Replacement	Reliability-Obsolescence	Program	N/A	N/A	
Various	Various	Electromechanical Relay Replacement Feeder electromechanical, Xfmr overcurrent, ABB Diff, GE BDD Diff	Reliability-Obsolescence	Program	N/A	N/A	
Various	Various	Capacitor Switch Replacements	Reliability - Asset Condition	Program	N/A	N/A	
Various	Various	Substation Animal Protection Equipment Program	Reliability	Program	N/A	N/A	

Substation	Location	system granularity of grid need	Capacity/ Reliability/ Resiliency	Anticipated season or date by which distribution upgrade must be installed	Equipment Nameplant Rating (MVA)	Forecasted percentage deficiency above the existing facility/equipment rating	Additional Info:
Brook St	Manchester	Replace 1950 vintage 13TR1 Switchgear	Reliability - Asset Condition	2022	N/A	N/A	
Goffstown 27W2	Goffstown	Asset Condition - Poor transformer health Basecase loading forecasted to exceed nameplate rating. Need: Retire substation	Reliability - Asset Condition/Capacity	Dec 2023	3	4.7%	Distribution Line conversion project will retire this transformer and provide 34.5 kV circuit tie between 3271 and 360X2.
Goffstown 45H1	Goffstown	Asset Condition - Poor transformer health Basecase loading forecasted to exceed nameplate rating. Need: Retire substation	Reliability - Asset Condition/Capacity	Dec 2023	1.8	5.6%	Distribution Line conversion project will retire this transformer and provide 34.5 kV circuit tie between 3271 and 360X2.
Loudon 31W1	Loudon	Basecase loading forecasted to exceed nameplate rating. Need: Reduce load or increase transformer size. NWS candidates recommended for evaluation	Capacity	Dec 2023	5.25	5.3%	
Loudon 31W2	Loudon	Basecase loading exceeded nameplate rating. Need: Reduce load or increase transformer size. NWS candidates recommended for evaluation	Capacity	Dec 2023	3.36	8.9%	
Meetinghouse Road 3W2	Bedford	Basecase loading exceeded nameplate rating. Need: Reduce load or Increase transformer size 2021 Line project will reduce load	Capacity	Jun 2021	5.04	12.5%	2021 distribution line project reduces loading on 3W2 transformer and 322X12 parallel 500 kVA steps. (>$200K)
Millyard	Nashua	Rebuild 1950's vintage Millyard 4kV S/S	Reliability - Asset Condition	Feb 2022	N/A	N/A	
Rye 48H1	Rye	Basecase loading forecasted to exceed nameplate rating. Need: Reduce load or increase transformer size.	Capacity	Dec 2023	3.75	5.6%	Load shift to neighboring 12.47 kV circuit may be an option. Additional study needed.
Salmon Falls 51H1	Rollinsford	Basecase loading forecasted to exceed nameplate rating. Need: Reduce load or increase transformer size. Extend 34.5kV, install standard 34.5 - 4.16 kV padmounted step	Capacity	Dec 2023	1.5	6.0%	
Suncook 44W2	Suncook	Basecase loading forecasted to exceed nameplate rating. Need: Reduce load or increase transformer size. Proposed load shift to neighboring 34.5kV circuit for new customer may resolve loading violation.	Capacity	2027	5.04	0.2%	Additional study needed.
Weirs	Laconia	Overload on parallel 500 KVA Steps Large customer impact for loss of heavily loaded Black Brook S/S Need: Rebuild Weirs S/S to support 12kV area.	Reliability/Capacity	Summer 2022	N/A	N/A	Weirs S/S consists of step transformers and regulators, station transformer was removed.
Various	Various	Distribution Automation - Non-bulk Substation	Reliability	Program	N/A	N/A	
Various	Various	CVEC Substation upgrades	Reliability - Asset Condition	Program	N/A	N/A	Includes items like fence and ground grid upgrades.

Project Authorization Forms

Pursuant to the Settlement Agreement in DE 19-139, this LCIRP submission was to contain numerous items, including:

> Consistent with RSA 378:38, III, an assessment of distribution system requirements, including a five-year forward-looking evaluation of planned system investments and alternatives that were considered. For purposes of this Agreement, the Settling Parties agree that any existing area planning studies and solution selection forms impacting investment during the five-year timeframe shall be included as appendices.

Project approval documentation for non-bulk substation and distribution line projects approved by the New Hampshire Project Approval Committee or the Solution Design Committee are provided. To the extent documentation is presently awaiting approval, it will be provided in one or more supplemental filings in this docket when complete.

The area planning studies and solution selection forms prepared for bulk substation projects included in the capital plan were based, in part, upon legacy planning criteria that has been superseded by the new Distribution System Planning Guide, and therefore are not included with this filing. Further, given the relatively recent vintage of the Distribution System Planning Guide, additional review and analysis is required for certain projects. Accordingly, the solution selection forms that document the need and project scope of each of these proposed projects will be reviewed and revised where appropriate based upon the new planning guide before work will commence. When the review and revision is complete, they will be provided as supplements to this submission.

Consistent with the requirement and based on the rationale above, Eversource includes the following documents as attachments to this filing:

- Appendix L-1 - A19S40 - T1407A -- Amherst SS - PLC Automation Upgrade and P&C Upgrades - SSF –
- Appendix L-2 - A19X22 - Substation Animal Protection - Program Level PAF
- Appendix L-3 - A19X35 - 34.5kV Capacitor Bank Switch Replacement Program Level – PAF
- Appendix L-4 - A19X36 - 34.5kV OCB Breaker and Ancillary Equipment Replacement Program Level - Initial Funding – PAF
- Appendix L-5 - A20X26 - Spare 345-34.5kV Transformer Initial Funding Request r3 – PAF
- Appendix L-6 - Initial Funding Request A20C40 Replace Manchester Network Cables

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Solution Selection Form

Approved at October 16, 2019 SDC

Link to Meeting Minutes

Date Prepared: September 25, 2019	**Project Title:** Amherst S/S – PLC Automation and Protection and Controls Upgrades
Company/ies: Eversource NH	**Project ID Number:** A19S40 (D SS), T1407A (T SS)
Organization: Protection and Controls Engineering	**Class(es) of Plant:** Transmission SS & Distribution SS
Project Initiator: Dennis Western	**Project Category:** Stations - Other
Project Manager: David Plante	**Project Type:** Specific
Project Sponsor: George Wegh	**Project Purpose:** Replace PLC Automation Scheme
Estimated in service date: 6/30/2022	**If Transmission Project: PTF?** Yes

Project Need Statement

The Programmable Logic Controller (PLC) designed automation scheme is outdated and has become a problem to update and maintain. There are three (3) substations remaining on the Eversource system that require replacement of the PLC designed automation scheme, including Amherst. The other two are Ashland and Great Bay substations, which will be addressed under separate future projects. The automation scheme replacements at Chester and Pine Hill substations were recently completed and Bedford substation is currently in design.

Issues with the existing system are:

1. The original data maps were developed using specific SEL relay firmware which is now classified as legacy. A failed relay must be sent back to the factory for repair because a new relay cannot be retrofit with the old firmware. The old firmware is not IEC 61850 compliant. A new design and materials will result in the ability to use up-to-date relays and firmware.
2. The Human Machine Interface (HMI) computer is using a Windows 95 operating system which is no longer supported by the supplier and presents a significant reliability risk to the system.
3. The PLC contacts are rated for 24 -110 VDC. The station battery is rated at 125 VDC. This has resulted in PLC contacts being welded together.
4. The existing feeder relays do not have DNP 3.0 protocol capability. Therefore, these relays are not capable of providing the distribution automation (DA) soft wired point list currently being requested for all 34.5 kV feeders to support the future Distribution Management System (DMS).

5. The data maps and parsing of data was developed by EPRO (now TRC). Eversource employees are not familiar with this programming and depend on one vendor (TRC) to make major modifications.

6. SCADA control of breakers is through relays and a relay failure will cause loss of supervisory control.

7. The existing 34.5kV line protection is provided by electromechanical KD-10, IAC, and CR-9 relays.

8. Reclose logic and timing for the 345kV breakers is currently provided by the PLC. The existing SEL-352 345kV breaker failure relays are not capable of performing reclosing functionality when the PLC is removed.

9. The existing primary protection for 345kV line 367 and secondary protection for 345kV line 3195 rely on powerline carrier channels in order to achieve high speed fault clearing. Eversource has taken the approach to move teleprotection systems off Powerline Carrier where possible. A significant number of misoperations in recent years have been due to problems with Powerline Carrier communications. Powerline Carrier Channel performance can be affected by transient voltages during faults, system loading, weather and aging of substation components outside the control house such as line traps, coaxial cable, line tuning units and spark gaps. Diagnostics are extremely limited. Unlike a fiber channel or leased line, the on/off Powerline Carrier channels on these two lines cannot be continuously monitored. Channel monitoring is limited to a checkback test performed once daily. Troubleshooting a mis-operation due to Powerline Carrier channel failures, or "holes" requires specialized and increasingly rare skills and is often inconclusive. Migrating protection channels to fiber would reduce the risk of misoperation by installing a more reliable continuously monitored path.

Project Objectives

The project objective is to replace the existing PLC based automated system design at Amherst substation with a design and materials that facilitate operation/maintenance flexibility and the ability to use up-to-date relays and firmware.

Associated with the automation upgrades are several distribution and transmission relay replacements that are necessary for continued functionality. There are also several optional scope items that are not necessary to achieve the objectives of the automation upgrade but would be cost effective to perform simultaneously.

There are several transmission relays at Amherst that are covered by relay replacement programs which would be executed concurrently with the automation project for efficiency.

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Alternatives Considered with Cost Estimates:

Alternative 1a: (This is the preferred solution)

The following items will be included in the scope of work and addressed by this project. This scope is supported by fully defined project scoping documents based upon field investigation of existing conditions:

1. Replace the GE-Fanuc PLC with SEL-2240 Axion substation I/O.
2. Replace GE-D20 RTU with SEL-3530 RTAC.
3. Remove the SEL-2030s and add an ethernet connection between the relays and RTAC, and serial connections to the Garrettcom 10XTS SCAD for engineering access to relays.
4. Replace the PLC based GUI system with a new touch screen HMI/annunciator.
5. Install SEL-Axion substation I/O in each control/relay cabinet to replace all ESCC metering, status and control functions now performed by protective relays.
6. Replace existing primary protection for five 34.5kV feeders with SEL-351-7 numerical relays in new cabinets. The new SEL-351-7 relays are capable of providing the distribution automation (DA) soft wired point list currently being requested for all 34.5 kV feeders to support the future Distribution Management System (DMS).
7. Remove breaker condition monitoring equipment from 34.5kV breakers TB68, TB85 and BT56.
8. The current design will be replaced with SEL numerical devices and I/O modules. SCADA control and alarms will not be integrated within feeder or bank protection relays.
9. New automation schemes will not rely on the protective relays for any ESCC metering data, digital data or control points.
10. Replace four existing SEL-352 relays with new SEL-351-7 to relocate 345kV breaker reclosing function from the PLC. (Transmission Scope).
11. Update I/O as necessary to replace reclosing functionality in 34.5kV feeder relaying.
12. Addition of a new SEL 2411 relay to perform bus tie auto close functionality for BT56.
13. Addition of hydrogen detection system.

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14. Addition of DC circuit monitoring relays as required to meet current Eversource standards.

15. Addition of P&C Cabinets as needed to support scope mentioned above.

16. Replacement of cable tray mounted heaters with new HVAC system (heating and cooling).

17. Replacement of one battery charger.

18. The existing station DC system will also be evaluated, and the station battery may be replaced to support the additional loads.

The cost of Alternative 1a is:

$4,020k +/- 25% Distribution (A19S40)
$767k +/-25% Transmission (T1407A)
$4,787k Total

Concurrent Transmission scopes:

1. T1390AM – Amherst 345kV Bus 2 Differential Primary Protection – Full funding approved
2. T1399AM – Amherst 3195 and 367 Line Secondary Protection – Replace GE D60 Relays – Initial funding approved
3. T1399E3 – Eagle 3195 Line Secondary Protection – Replace GE D60 Relay – Initial funding approved
4. T1399FT– Fitzwilliam 367 Line Secondary Protection – Replace GE D60 Relay – Initial funding approved

The estimated cost of these concurrent Transmission scopes is $1,184k +/- 25%.

The following Alternatives 1b through 1e are potential additions to the Alternative 1a scope and are recommended by P&C Engineering:

Alternative 1b: (This is a recommended addition to the Alternative 1a scope) Replace existing GE NGA breaker failure protection for five 34.5kV feeders with SEL-751 numerical relays (same cabinets as new primary protection). The new SEL-751 relays will also provide secondary feeder protection functions. This would support the overall Eversource P&CE initiative to replace electromechanical relays on the system and by removing this equipment from the existing switchboard panel it will simplify the future removal of that panel from the control house. Adding a 2nd line protection system will increase the operational flexibility of the 34.5kV system by allowing for the primary relay to be taken out of service for maintenance or replacement without taking a breaker outage. The additional cost of this alternative incremental to the Alternative 1a cost is $889k +/- 25% to the Distribution project cost.

Alternative 1c: (This is a recommended addition to the Alternative 1a scope) Replace existing GE STD differential relay with SEL-587 numerical relay in new cabinet for TB68 Primary protection. This would support the overall Eversource P&C initiative to replace electromechanical relays on the system. This relay and the Basler listed in Alternative 1d are the only electromechanical relays remaining on the Amherst 345-34.5kV transformers. The additional cost of this alternative incremental to the Alternative 1a cost is $200k +/- 25% to the Distribution project cost.

Alternative 1d: (This is a recommended addition to the Alternative 1a scope) Replace existing Basler BE1-51 overcurrent relay with SEL-351-7 numerical relay in existing cabinet for 34.5kV Bus #1 secondary protection. This would support the overall Eversource P&C initiative to replace electromechanical relays on the system and by removing this equipment from the existing switchboard panel it will simplify the future removal of that panel from the control house. This relay and the GE STD listed in Alternative 1c are the only electromechanical transformer relays remaining on the Amherst 345-34.5kV transformers. The additional cost of this alternative incremental to the Alternative 1a cost is $195k +/- 25% to the Distribution project cost.

Alternative 1e: (This is a recommended addition to the Alternative 1a scope) Replace existing SEL-421 and RFL 9785 Powerline Carrier equipment with SEL-411L at Amherst and Eagle for 345kV Line 3195 and at Amherst and Fitzwilliam for Line 367. Includes installation of new SEL ICON SONET multiplexers at Eagle, Amherst and Fitzwilliam and removal of JMUX at Amherst and Fitzwilliam as well as removal of wave traps/tuners at all three sites. Install 10 spans of OPGW on Line 3195 from Eagle s/s to Structure #103 needed for relay communication. (Transmission scope) Opting not to replace this system would continue to expose the system to mis-operations of the Powerline Carrier equipment whereas completing the replacement eliminates this risk. In favor of modern, more reliable technology. The additional cost of this alternative incremental to the Alternative 1a cost is $2,290k +/- 25% to the Transmission project.

The total cost of Alternatives 1a through 1e is:

$5,305k +/- 25% Distribution (A19S40)
<u>$3,257k +/-25% Transmission (T1407A)</u>
$8,562k Total

Alternative 2: (This is not the preferred alternative)
One alternative is to perform the recommended substation project scope noted minus the cabinet SEL-2240 Axion I/O devices and associated materials. This was not chosen because the metering and equipment alarm topology would not be changed and remain dependent on relays to pass the digitals to ESCC.

The estimated project cost per substation would be $800,000 +200%/-50%.

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Cost Estimate Backup Details

The following table summarizes the detailed +/-25% estimates that have been developed for the various scope items contemplated in this document by the Eversource estimating group.

Proposals for engineering, testing and commissioning have been solicited and are used as basis for those costs in the estimates.

A tentative construction/outage plan has been developed for the entire scope of work and spans approximately 88 weeks.

The basic distribution and transmission automation scopes are sub-totaled along with the optional or program related scopes. The optional or program related costs all assume concurrent execution without separate engineering deliverables or construction mobilizations.

Summary of Cost Estimates - Amherst Automation Upgrade and Transmission Relay Program Scope
Estimates dated August 29, 2019 - September 6, 2019, as revised

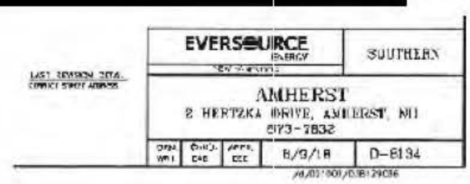
Project #	Description	Estimate #	Estimate, $k	Prior	2019	2020	2021
A19S40 Alt. 1a	Amherst Automation Upgrade (Distribution)	P-19-249Dist, rev2	4,020.80	28.60	105.00	2,233.50	1,653.70
T1407A Alt. 1a	Amherst 345kV Breaker Failure Protection	P-19-249c, rev2	767.00		5.30	166.70	595.00
A19S40 Alt. 1b	Replace 5 GE NGA Relays	P-19-249a, rev1	888.80		8.60	221.20	659.00
A19S40 Alt. 1c & 1d	Replace TB68 Primary and 34.5kV Bus #1 Secondary Prot.	P-19-249b, rev1	395.30		6.10	152.80	236.40
T1407A Alt. 1e	Amherst 3195 and 367 Powerline Carrier Repl.	P-19-249d, rev4	584.00		14.80	134.10	435.10
T1407A Alt. 1e	Fitz 367 Powerline Carrier Replacement	P-19-249g, rev4	564.80			165.30	399.50
T1407A Alt. 1e	Eagle 3195 Powerline Carrier Repl. and OPGW (Line)	P-19-249i Line, rev4	664.60			60.00	604.60
T1407A Alt. 1e	Eagle 3195 Powerline Carrier Repl. and OPGW (Station)	P-19-249i SS, rev4	676.90			199.30	477.60
	Total		8,562.20	28.60	139.80	3,332.90	5,060.90
	Sub-total Base Distribution Automation Scope		4,020.80	28.60	105.00	2,233.50	1,653.70
	Optional Distr. Scope - Replace GE NGA Relays		888.80	-	8.60	221.20	659.00
	Optional Distr. Scope - Replace TB68 Primary Protection		395.30	-	6.10	152.80	236.40
		Distribution Total	5,304.90	28.60	119.70	2,607.50	2,549.10
	Sub-total Breaker Failure Protection (Base T)		767.00	-	5.30	166.70	595.00
	Sub-total Powerline Carrier Replacement		2,490.30	-	14.80	558.70	1,916.80
		Transmission Total	3,257.30	-	20.10	725.40	2,511.80

REDACTED

<u>Attachments (maps, images, one-line diagrams, MS PowerPoint presentations, MS Excel cost estimate files, etc.)</u>

Amherst s/s One Line Diagram

[redacted]



Estimate Attachments:

Amherst s/s One Line Diagram

Summary of estimates including breakdown by cost category

Estimate cover page for each estimate

Project Scope Documents

- Amherst Automation Upgrade
- Appendix A – 34.5kV Feeder Breaker Failure Relay Replacements
- Appendix B – 345/34.5kV Transformer TB68 Primary Relay Replacements
- Appendix C – 345kV Powerline Carrier Equipment Replacements
- Control House Floorplan Layout
- Network Diagram

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[redacted]

LAST REVISION DETAIL
CORRECT STREET ADDRESS

EVERSOURCE ENERGY
NEW HAMPSHIRE

SOUTHERN

AMHERST
2 HERTZKA DRIVE, AMHERST, NH
673-7832

DRN. WHT	CHKD. CAB	APPR. CEC	8/9/18	D-8134

/e/021002/038129036

Summary of Cost Estimates - Amherst Automation Upgrade and Transmission Relay Program Scope
Estimates dated August 29, 2019 - September 6, 2019, as revised

								Estimate Components, $k											
Project #	**Description**	**Estimate #**	**Estimate, $k**	**Prior**	**2019**	**2020**	**2021**	**CST**	**ENG**	**MAT**	**PSM**	**REM**	**TST**	**Cont.**	**Esc.**	**LDR**	**AFUDC**		**TRC Eng.**
A19S40 Alt. 1b	Replace 5 GE NGA Relays	P-19-249a, rev1	888.80		8.60	221.20	659.00	218.10	125.80	39.00	17.60	5.90	76.70	65.00	39.30	275.50	25.90		86.928
A19S40 Alt. 1c & 1d	Replace TB68 Primary and 34.5kV Bus #1 Secondary Prot.	P-19-249b, rev1	395.30		6.10	152.80	236.40	73.60	62.60	34.00	10.00	9.00	44.10	29.00	15.00	105.10	12.90		incl.
T1407A Alt. 1a	Amherst 345kV Breaker Failure Protection	P-19-249c, rev2	767.00		5.30	166.70	595.00	102.10	116.20	18.00	12.00	5.90	216.70	77.00	32.90	162.80	23.40		85.509
T1407A Alt. 1e	Amherst 3195 and 367 Powerline Carrier Repl.	P-19-249d, rev4	584.00		14.80	134.10	435.10	77.80	74.50	41.90	5.40	36.40	139.00	41.50	25.60	123.30	18.60		56.778
A19S40 Alt. 1a	Amherst Automation Upgrade (Distribution)	P-19-249Dist, rev2	4,020.80	28.60	105.00	2,233.50	1,653.70	764.30	659.00	368.50	50.90	79.60	489.40	280.00	128.80	1,048.70	151.60		604.474
T1399AM	Amherst 345kV GE Relay Replacements	P-19-249e, rev3	385.80		6.50	95.90	283.40	71.40	47.90	12.50	11.40	2.20	82.40	29.00	16.80	99.90	12.30		33.651
T1399FT	Fitz 367 GE D60 Replacement	P-19-249f, rev4	289.00			55.30	233.70	49.10	37.30	19.40	8.70	1.00	75.20	22.50	13.20	54.10	8.50		30.719
T1407A Alt. 1e	Fitz 367 Powerline Carrier Replacement	P-19-249g, rev4	564.80			165.30	399.50	76.00	64.50	71.90	16.50	21.60	127.60	42.50	24.30	101.70	18.20		52.128
T1399E3	Eagle 3195 GE D60 Replacement	P-19-249h, rev4	304.90			62.80	242.10	49.10	40.40	19.40	8.70	1.20	83.00	22.50	13.90	57.60	9.10		33.893
T1407A Alt. 1e	Eagle 3195 Powerline Carrier Repl. and OPGW (Line)	P-19-249i Line, rev4	664.60			60.00	604.60	423.00	29.40	25.20	15.00	11.30	24.50	43.00	33.90	41.50	17.80		In house
T1407A Alt. 1e	Eagle 3195 Powerline Carrier Repl. and OPGW (Station)	P-19-249i SS, rev4	676.90			199.30	477.60	123.30	82.30	77.50	13.50	21.60	123.70	54.50	28.70	130.10	21.70		60.517
T1390AM	Amherst 345kV Bus 2 Diff Relay Replacement	P-19-249j, rev2	204.70	3.70	11.20	189.80	-	49.10	26.10	10.60	4.70	1.00	42.80	16.50	5.00	43.20	5.70	Full auth. for $157k	17.501
	Total		9,746.60	32.30	157.50	3,736.70	5,820.10	2,076.90	1,366.00	737.90	174.40	196.70	1,525.10	723.00	377.40	2,243.50	325.70		
	Sub-total Base Distribution Automation Scope		4,020.80	28.60	105.00	2,233.50	1,653.70	764.30	659.00	368.50	50.90	79.60	489.40	280.00	128.80	1,048.70	151.60		
	Optional Distr. Scope - Replace GE NGA Relays		888.80	-	8.60	221.20	659.00	218.10	125.80	39.00	17.60	5.90	76.70	65.00	39.30	275.50	25.90		
	Optional Distr. Scope - Replace TB68 Primary Protection		395.30	-	6.10	152.80	236.40	73.60	62.60	34.00	10.00	9.00	44.10	29.00	15.00	105.10	12.90		
	Distribution Total		5,304.90	28.60	119.70	2,607.50	2,549.10	1,056.00	847.40	441.50	78.50	94.50	610.20	374.00	183.10	1,429.30	190.40		
	Sub-total Breaker Failure Protection (Base T)		767.00	-	5.30	166.70	595.00	102.10	116.20	18.00	12.00	5.90	216.70	77.00	32.90	162.80	23.40		
	Sub-total Powerline Carrier Replacement		2,490.30	-	14.80	558.70	1,916.80	700.10	250.70	216.50	50.40	90.90	414.80	181.50	112.50	396.60	76.30		
	Sub-total Bus Diff Relay Replacement		204.70	3.70	11.20	189.80	-	49.10	26.10	10.60	4.70	1.00	42.80	16.50	5.00	43.20	5.70		
	Sub-total GE Relay Replacement		979.70	-	6.50	214.00	759.20	169.60	125.60	51.30	28.80	4.40	240.60	74.00	43.90	211.60	29.90		
	Transmission Total		4,441.70	3.70	37.80	1,129.20	3,271.00	1,020.90	518.60	296.40	95.90	102.20	914.90	349.00	194.30	814.20	135.30		

ESTIMATE SUMMARY

Project Title: Amherst Substation Automation Upgrade Distribution (Alternative 1a - Distribution)
Estimate By: MPD
Project Mgr/Lead: David L. Plante
Date of Estimate: 9/3/19
Project Number: A19S40
ISD: 12/31/21
Est. Revision # 02
Estimate # P-19-249Dist

Template Revision # 0s

ESTIMATE SUMMARY

Estimate Type Planning

WBS		TOTAL	% of Total	Prior	2019	2020	2021	2022	2023	2024
1	Construction	$764,300	19.0%			$481,900	$282,400			
2	Engineering / Design	$659,000	16.4%	$14,200	$58,900	$458,500	$127,400			
3	Land									
	Material	$368,500	9.2%			$330,800	$37,700			
5	Project Mgmt. & Sppt.	$50,900	1.3%	$3,600	$5,300	$21,000	$21,000			
6	Removal	$79,600	2.0%				$79,600			
7	Test	$489,400	12.2%			$205,200	$284,200			
8	Risk / Contingency	$280,000	7.0%			$95,000	$185,000			
9	Escalation	$128,800	3.2%			$44,500	$84,300			
10	Indirects	$1,048,700	26.1%	$10,700	$37,600	$541,200	$459,200			
11	AFUDC	$151,600	3.8%	$100	$3,200	$55,400	$92,900			
	Total Cost	**$4,020,800**	100.0%	**$28,600**	**$105,000**	**$2,233,500**	**$1,653,700**			

Estimate Range	**-25%**	**25%**
	$3,016,000	**$5,026,000**

COMMENTS:

Project Scope

Amherst Substation Automation Upgrade Distribution portion.

The Amherst Substation Automation project will involve the replacement of GE-Fanuc PLCs with SEL-2240 Axion I/O devices. The Axions will replace all Electric System Control Center (ESCC) metering, status and control functions currently performed by the protective relays and PLC System. The existing GE-D20 RTU will be replaced with a SEL-3530 real-time automation controller (RTAC), and the PLC based Graphical User Interface (GUI) will be replaced with a new touch screen HMI system (the same system used in recent Transmission Substations). The existing SEL-2030 communications processors will be removed, and remote interrogation of the relays will be accomplished via a RS-485 communication connection to a new GarrettCom 10XTS Substation Communication Access Device (SCAD). Time synchronization for all relays will be accomplished by connecting directly to a demodulated IRIG-B output of a new Arbiter 1094B GPS clock. A new SEL-2411 relay will be installed to perform the BT56 auto close functions currently performed by the PLC. Four new cabinets will be installed to support this design: three Axion RTU cabinets and one HMI/annunciator cabinet.

The existing protection for 34.5kV lines 3445X, 3159X, 3110X, 3143X, and 3212X as well as the control for 34 5kV breakers 3445, 3195, 3110, 3143, and 3212 will be replaced with modern protection and control schemes located in new cabinets.

The Scope includes the installation of 9 new cabinets 3 RTU Cabinets, 1 HMI Annunciator Cabinet, and 5 34.5kV Control and relaying cabinets.
Upgrading the Security Cabinet.
Two Hydrogen sensors.
New Battery Charger
Two new HVAC units
Exterior Amber Strobe light and signage.
Existing Panels # 9, 10, 11, 12,13, 14,15, 17,31 and 41 will have existing equipment removed and panels left in place. Station Personal Computer and UPS and remote PLC #2 racks will be

Assumptions/Clarifications

Indirect rates based on: 6D - NH , Station work
Engineering will be out-sourced based on TRC proposal dated 9/4/19, with internal review, relay settings will be completed in-house.
Equipment will be purchased and supplied by Eversource.
Construction and testing will be out-sourced with internal support based on portion of total proposal by TRC dated 9/4/19.
LCE will be shared resource as part of Amherst Automation Project this estimate is portion of TRC proposal for LCE for transmission.
This estimate is based on scope document dated 7/16/19.
Existing DC power circuits will be provide adequate DC power.
BPS separations of wiring will be as per SUB013.7.2, "Separate Systems Electrically Only." Alterations to existing raceway systems are not included in this scope of work.
A station walkdown was not made in preparation of this estimate.
Comprehensive scope document has been prepared and provided for use in developing estimate. A site walk down was performed to prepare the scope.
Engineering, Test Engineer and LCE will be a single source procurement to TRC.
This estimate is based on a TRC proposal dated 9/4/19, escalation on this proposal is included after 2020.
This project will have the new cabinets installed during 2020 with all required wiring and pre-transfer testing. The transfer of systems during outages to the new automatoion system will be done in 2021 on scheduled outages.

Risks

Design development/ Enginering deliverables do not ma	$ 100,000
Outage Delays and rescheduling	$ 120,000
Additional Communication signal troubleshooting	$ 60,000
Total	$ 280,000

E S T I M A T E   S U M M A R Y

Project Title: Amherst Substation Breaker Failure Protection (Alternative 1a - Transmission)
Project Mgr/Lead: David L. Plante
Project Number: T1407A
Est. Revision # 02

Estimate By: MPD
Date of Estimate: 9/3/19
ISD: 12/31/21
Estimate # P-19-249c Rev 2

Template Revision # 0s

ESTIMATE SUMMARY

Estimate Type Planning

WBS		TOTAL	% of Total	Prior	2019	2020	2021	2022	2023	2024
1	Construction	$102,100	13.3%				$102,100			
2	Engineering / Design	$116,200	15.1%			$83,900	$32,300			
3	Land									
	Material	$18,000	2.3%			$17,200	$800			
5	Project Mgmt. & Sppt.	$12,000	1.6%		$2,600	$5,200	$4,200			
6	Removal	$5,900	0.8%				$5,900			
7	Test	$216,700	28.3%				$216,700			
8	Risk / Contingency	$77,000	10.0%			$5,000	$72,000			
9	Escalation	$32,900	4.3%			$2,900	$30,000			
10	Indirects	$162,800	21.2%		$2,600	$48,100	$112,100			
11	AFUDC	$23,400	3.1%		$100	$4,400	$18,900			
	Total Cost	**$767,000**	100.0%		**$5,300**	**$166,700**	**$595,000**			

Estimate Range	**-25%**	**25%**
	$575,000	**$959,000**

COMMENTS:

Project Scope

Amherst Substation Automation Project

The Amherst Substation Automation project will involve the replacement of GE-Fanuc PLCs with SEL-2240 Axion I/O devices. The Axions will replace all Electric System Control Center (ESCC) metering, status and control functions currently performed by the protective relays and PLC System. The existing GE-D20 RTU will be replaced with a SEL-3530 real-time automation controller (RTAC), and the PLC based Graphical User Interface (GUI) will be replaced with a new touch screen HMI system (the same system used in recent Transmission Substations). The existing SEL-2030 communications processors will be removed, and remote interrogation of the relays will be accomplished via a RS-485 communication connection to a new GarrettCom 10XTS Substation Communication Access Device (SCAD). Time synchronization for all relays will be accomplished by connecting directly to a demodulated IRIG-B output of a new Arbiter 1094B GPS clock. A new SEL-2411 relay will be installed to perform the BT56 auto close functions currently performed by the PLC. Four new cabinets will be installed to support this design: three Axion RTU cabinets and one HMI/annunciator cabinet.

This portion of the project is for the replacement of the 345kV Breaker Failure Protection relays.
The existing Schweitzer SEL-352 breaker failure relays will be replaced with Sel-351-7 relays for GCB's 3885, 6768, 0951 and 0295. In Cabinets #33 & 34

This change is to facilitate the relocation of breaker reclosing functions from the PLC to the breaker failure relay. The SEL-352 relay does not have automatic reclosing capability.

The existing test switches will remain wired as they were before, with the exception that any I/O not required for protection and control will be removed.

Assumptions/Clarifications
Indirect rates based on: 6T - NH , Station work
Engineering will be out-sourced based on TRC proposal dated 9/4/19, with internal review, relay settings will be completed in-house.
Equipment will be purchased and supplied by Eversource.
Construction and testing will be out-sourced with internal support based on portion of total proposal by TRC dated 9/4/19.
LCE will be shared resource as part of Amherst Automation Project this estimate is portion of TRC proposal for LCE for transmission.
This estimate is based on scope document dated 7/16/19.
Existing DC power circuits will be provide adequate DC power.
BPS separations of wiring will be as per SUB013.7.2, "Separate Systems Electrically Only." Alterations to existing raceway systems are not included in this scope of work.
A station walkdown was not made in preparation of this estimate.
Comprehensive scope document has been prepared and provided for use in developing estimate. A site walk down was performed to prepare the scope.
Engineering, Test Engineer and LCE will be a single source procurement to TRC.
This estimate is based on a TRC proposal dated 9/4/19, escalation on this proposal is included after 2020.

Risks

Design development/ Enginering deliverables do not match field conditions	$	10,000
Outage Delays and rescheduling	$	8,000
Additional Communication signal troubleshooting	$	8,000
Relay settings and Testing	$	51,000
Totals	$	77 000

ESTIMATE SUMMARY

Project Title: Amherst - Replace five (5) GE NGA relays with SEL-751 (Alternative 1b)
Project Mgr/Lead: David L. Plante
Project Number: A19S40
Est. Revision # 01

Estimate By: MPD
Date of Estimate: 9/19/19
ISD: 12/31/21
Estimate # P-19-249a Rev 1

Template Revision # 0s

ESTIMATE SUMMARY

Estimate Type Planning

WBS		TOTAL	% of Total	Prior	2019	2020	2021	2022	2023	2024
1	Construction	$218,100	24.5%				$218,100			
2	Engineering / Design	$125,800	14.2%			$84,300	$41,500			
3	Land									
	Material	$39,000	4.4%			$37,500	$1,500			
5	Project Mgmt. & Sppt.	$17,600	2.0%		$3,700	$4,200	$9,700			
6	Removal	$5,900	0.7%				$5,900			
7	Test	$76,700	8.6%				$76,700			
8	Risk / Contingency	$65,000	7.3%			$15,000	$50,000			
9	Escalation	$39,300	4.4%			$4,300	$35,000			
10	Indirects	$275,500	31.0%		$4,700	$70,500	$200,300			
11	AFUDC	$25,900	2.9%		$200	$5,400	$20,300			
	Total Cost	**$888,800**	100.0%		**$8,600**	**$221,200**	**$659,000**			

Estimate Range	**-25%**	**25%**
	$667,000	**$1,111,000**

COMMENTS:

Project Scope

Amherst Substation Automation Project

The Amherst Substation Automation project will involve the replacement of GE-Fanuc PLCs with SEL-2240 Axion I/O devices. The Axions will replace all Electric System Control Center (ESCC) metering, status and control functions currently performed by the protective relays and PLC System. The existing GE-D20 RTU will be replaced with a SEL-3530 real-time automation controller (RTAC), and the PLC based Graphical User Interface (GUI) will be replaced with a new touch screen HMI system (the same system used in recent Transmission Substations). The existing SEL-2030 communications processors will be removed, and remote interrogation of the relays will be accomplished via a RS-485 communication connection to a new GarrettCom 10XTS Substation Communication Access Device (SCAD). Time synchronization for all relays will be accomplished by connecting directly to a demodulated IRIG-B output of a new Arbiter 1094B GPS clock. A new SEL-2411 relay will be installed to perform the BT56 auto close functions currently performed by the PLC. Four new cabinets will be installed to support this design: three Axion RTU cabinets and one HMI/annunciator cabinet.

Appendix A: 34.5kV Feeder Secondary Line and Breaker Failure Relay Replacements.
This portion of the project is for the replacement of the 34.5kV Secondary Line and Breaker Failure Protection relays.
The existing GE NGA Auxiliary relays will be replaced with Sel-751 relays for OCB's 3445, 3110, 3159, 3143 and 3212.
Additionally each cabinet will have installed the following equipment:
One (1) Electroswitch Permissive switch.
One (1) Electroswitch Breaker Fail Permissive Switch.
Two (2) ABB Test Swithches Type FT-19R
During the site walkdown, several equipment upgrades unrelated to the automation project were identified. This appendix addresses the replacement of the existing 34.5kV feeder breaker failure protection with modern numerical relays.

Assumptions/Clarifications

Indirect rates based on: 6D - NH , Station work
Engineering will be out-sourced based on TRC proposal dated 9/4/19, with internal review, relay settings will be completed in-house.
Equipment will be purchased and supplied by Eversource.
Construction and testing will be out-sourced with internal support based on portion of total proposal by TRC dated 9/4/19.
LCE will be shared resource as part of Amherst Automation Project this estimate is portion of TRC proposal for LCE for transmission.
This estimate is based on scope document dated 7/16/19.
Existing DC power circuits will be provide adequate DC power.
BPS separations of wiring will be as per SUB013.7.2, "Separate Systems Electrically Only." Alterations to existing raceway systems are not included in this scope of work.
A station walkdown was not made in preparation of this estimate.
Comprehensive scope document has been prepared and provided for use in developing estimate. A site walk down was performed to prepare the scope.
Each relay to be replaced during scheduled 5 week outages for each line.
Engineering, Test Engineer and LCE will be a single source procurement to TRC.
This estimate is based on a TRC proposal dated 9/4/19, escalation on this proposal is included after 2020.

Risks

Design development/ Enginering deliverables do not	$	35,000
Outage Delays and rescheduling	$	15,000
Additional Communication signal troubleshooting	$	15,000
Total	$	65,000

ESTIMATE SUMMARY

Project Title: Replace TB68 Primary Protection with Sel-587 (Alternative 1c and 1d)
Project Mgr/Lead: David L. Plante
Project Number: A19S40
Est. Revision # 01

Estimate By: MPD
Date of Estimate: 09/01/19
ISD: 12/31/21
Estimate # P-19-249b Rev 1

Template Revision # 0s

ESTIMATE SUMMARY

Estimate Type Planning

WBS		TOTAL	% of Total	Prior	2019	2020	2021	2022	2023	2024
1	Construction	$73,600	18.6%				$73,600			
2	Engineering / Design	$62,600	15.8%			$51,400	$11,200			
3	Land									
	Material	$34,000	8.6%			$30,100	$3,900			
5	Project Mgmt. & Sppt.	$10,000	2.5%		$2,600	$3,200	$4,200			
6	Removal	$9,000	2.3%				$9,000			
7	Test	$44,100	11.2%			$14,400	$29,700			
8	Risk / Contingency	$29,000	7.3%			$8,000	$21,000			
9	Escalation	$15,000	3.8%			$2,600	$12,400			
10	Indirects	$105,100	26.6%		$3,400	$39,400	$62,300			
11	AFUDC	$12,900	3.3%		$100	$3,700	$9,100			
	Total Cost	**$395,300**	100.0%		**$6,100**	**$152,800**	**$236,400**			

Estimate Range	**-25%**	**25%**
	$296,000	**$494,000**

COMMENTS:

Project Scope

Amherst Substation Automation Project

The Amherst Substation Automation project will involve the replacement of GE-Fanuc PLCs with SEL-2240 Axion I/O devices. The Axions will replace all Electric System Control Center (ESCC) metering, status and control functions currently performed by the protective relays and PLC System. The existing GE-D20 RTU will be replaced with a SEL-3530 real-time automation controller (RTAC), and the PLC based Graphical User Interface (GUI) will be replaced with a new touch screen HMI system (the same system used in recent Transmission Substations). The existing SEL-2030 communications processors will be removed, and remote interrogation of the relays will be accomplished via a RS-485 communication connection to a new GarrettCom 10XTS Substation Communication Access Device (SCAD). Time synchronization for all relays will be accomplished by connecting directly to a demodulated IRIG-B output of a new Arbiter 1094B GPS clock. A new SEL-2411 relay will be installed to perform the BT56 auto close functions currently performed by the PLC. Four new cabinets will be installed to support this design: three Axion RTU cabinets and one HMI/annunciator cabinet.

Appendix B: 115/34 5kV Transformer TB68 Primary Relay Replacements

New primary transformer current differential protection for the existing 115-34.5 kV Transformer TB68 will be installed in a new cabinet #27 located in the Distribution side of the control house. The existing GE STD Differential Relays and associated equipment will be replaced with Schweitzer SEL-587 Differential relay, an Electroswitch Lockout Relay, Electroswitch Control Switch and 2 ABB Test Switches Type FT-19R

Assumptions/Clarifications

Indirect rates based on: 6D - NH , Station work

Engineering will be out-sourced based on TRC proposal dated 9/4/19, with internal review, relay settings will be completed in-house.

Equipment will be purchased and supplied by Eversource.

Construction and testing will be out-sourced with internal support based on portion of total proposal by TRC dated 9/4/19.

LCE will be shared resource as part of Amherst Automation Project this estimate is portion of TRC proposal for LCE for transmission.

This estimate is based on scope document dated 7/16/19.

Existing DC power circuits will be provide adequate DC power.

BPS separations of wiring will be as per SUB013.7.2, "Separate Systems Electrically Only." Alterations to existing raceway systems are not included in this scope of work.

A station walkdown was not made in preparation of this estimate.

Comprehensive scope document has been prepared and provided for use in developing estimate. A site walk down was performed to prepare the scope.

Engineering, Test Engineer and LCE will be a single source procurement to TRC.

This estimate is based on a TRC proposal dated 9/4/19, escalation on this proposal is included after 2020.

Risks

Design development/ Enginering deliverables do not match field conditions	$ 15,000
Outage Delays and rescheduling	$ 6,000
Additional Communication signal troubleshooting	$ 8,000
Total	$ 29,000

ESTIMATE SUMMARY

Project Title: Amherst 367 and 3195 Powerline Carrier Replacement (Alternative 1e) — **Estimate By: MPD**

Project Mgr/Lead: David L. Plante — **Date of Estimate: 9/24/19**

Project Number: T1407A — **ISD: 12/31/21**

Est. Revision # 04 — **Estimate # P-19-249d Rev 4**

Template Revision # 0s

ESTIMATE SUMMARY

Estimate Type Planning

WBS		TOTAL	% of Total	Prior	2019	2020	2021	2022	2023	2024
1	Construction	$77,800	13.3%				$77,800			
2	Engineering / Design	$74,500	12.8%		$8,600	$48,500	$17,400			
3	Land									
	Material	$41,900	7.2%			$41,400	$500			
5	Project Mgmt. & Sppt.	$5,400	0.9%		$1,300	$1,300	$2,800			
6	Removal	$36,400	6.2%				$36,400			
7	Test	$139,000	23.8%				$139,000			
8	Risk / Contingency	$41,500	7.1%			$9,500	$32,000			
9	Escalation	$25,600	4.4%			$2,500	$23,100			
10	Indirects	$123,300	21.1%		$4,500	$27,100	$91,700			
11	AFUDC	$18,600	3.2%		$400	$3,800	$14,400			
	Total Cost	**$584,000**	100.0%		**$14,800**	**$134,100**	**$435,100**			

Estimate Range	-25%	25%
	$438,000	**$730,000**

COMMENTS:

Project Scope

Amherst Substation Automation Project
The Amherst Substation Automation project will involve the replacement of GE-Fanuc PLCs with SEL-2240 Axion I/O devices. The Axions will replace all Electric System Control Center (ESCC) metering, status and control functions currently performed by the protective relays and PLC System. The existing GE-D20 RTU will be replaced with a SEL-3530 real-time automation controller (RTAC), and the PLC based Graphical User Interface (GUI) will be replaced with a new touch screen HMI system (the same system used in recent Transmission Substations). The existing SEL-2030 communications processors will be removed, and remote interrogation of the relays will be accomplished via a RS-485 communication connection to a new GarrettCom 10XTS Substation Communication Access Device (SCAD). Time synchronization for all relays will be accomplished by connecting directly to a demodulated IRIG-B output of a new Arbiter 1094B GPS clock. A new SEL-2411 relay will be installed to perform the BT56 auto close functions currently performed by the PLC. Four new cabinets will be installed to support this design: three Axion RTU cabinets and one HMI/annunciator cabinet.

This estimate is for Appendix C the Amherst SS portion of the 345kV Lines 367 and 3195 Powerline Carrier Replacement.

Cabinets #32 and #42 Will have the existing GE D60 Line Relays, the RFL 9785 Carrier Set and the Electroswitch Series 24 Permissive Switchs removed and replaced with SEL-411L Line Relays.

Amherst SS will also be equipped with a SEL ICON SONET Multiplexer.

Assumptions/Clarifications
Indirect rates based on: 6T - NH , Station work
Engineering will be out-sourced based on TRC proposal dated 9/4/19, with internal review, relay settings will be completed in-house.
Equipment will be purchased and supplied by Eversource.
Construction and testing will be out-sourced with internal support based on portion of total proposal by TRC dated 9/4/19.
LCE will be shared resource as part of Amherst Automation Project this estimate is portion of TRC proposal for LCE for transmission.
This estimate is based on scope document dated 7/16/19.
Existing DC power circuits will be provide adequate DC power.
BPS separations of wiring will be as per SUB013.7.2, “Separate Systems Electrically Only.” Alterations to existing raceway systems are not included in this scope of work.
A station walkdown was not made in preparation of this estimate.
Comprehensive scope document has been prepared and provided for use in developing estimate. A site walk down was performed to prepare the scope.
Engineering, Test Engineer and LCE will be a single source procurement to TRC.
This estimate is based on a TRC proposal dated 9/4/19, escalation on this proposal is included after 2020.
Work to be performed during 6 week outages on lines 3195 and 367.

Risks

Design development/ Enginering deliverables do not match field conditions	$ 19,000
Outage Delays and rescheduling	$ 13,500
Additional Communication signal troubleshooting	$ 9,000
Totals	$ 41,500

ESTIMATE SUMMARY

Project Title: Fitzwilliam 367 Powerline Carrier Replacement (Alternative 1e) | **Estimate By: JPM**

Project Mgr/Lead: David L. Plante | **Date of Estimate: 08-29-19**

Project Number: T1407FT | **ISD: 12-31-21**

Est. Revision # 04 | **Estimate # P-19-249q**

Template Revision # 0s

ESTIMATE SUMMARY

Estimate Type Conceptual

WBS		TOTAL	% of Total	Prior	2019	2020	2021	2022	2023	2024
1	Construction	$76,000	13.5%				$76,000			
2	Engineering / Design	$64,500	11.4%			$44,500	$20,000			
3	Land									
	Material	$71,900	12.7%			$71,200	$700			
5	Project Mgmt. & Sppt.	$16,500	2.9%			$11,500	$5,000			
6	Removal	$21,600	3.8%				$21,600			
7	Test	$127,600	22.6%				$127,600			
8	Risk / Contingency	$42,500	7.5%				$42,500			
9	Escalation	$24,300	4.3%			$3,800	$20,500			
10	Indirects	$101,700	18.0%			$30,100	$71,600			
11	AFUDC	$18,200	3.2%			$4,200	$14,000			
	Total Cost	**$564,800**	100.0%			**$165,300**	**$399,500**			

Estimate Range	-25%	50%
	$424,000	$847,000

COMMENTS:

Project Scope

The **Amherst Substation Automation Project** will involve the replacement of GE-Fanuc PLCs with SEL-2240 Axion I/O devices.
The Axions will replace all Electric System Control Center (ESCC) metering, status and control functions currently performed by the protective relays and PLC System.

During the site walkdown, several equipment upgrades unrelated to the automation project were identified.
Execution of these upgrades in a coordinated fashion with the Amherst Automation Project will improve cost and outage efficiency.
This estimate for the replacement of the Fitzwilliam LP-367 Powerline Carrier System is for work being performed in conjunction with the Amherst Automation Project and not as a stand-alone project.

Fitzwilliam LP-367 Powerline Carrier Replacement:

The remote Schweitzer SEL-421 relay, device 21Z/LP-367, and associated RFL-9785 carrier set, device 85DCB/LP-367, located at Fitzwilliam Substation will be removed and replaced with a new Schweitzer SEL-411L.
Remove wave traps and tuners and install a new Phase B strain bus in place of traps

A new SEL ICON SONET multiplexer will be installed to replace the existing Lucent DMXtend with dual ring connections. The ICON will join the existing Lucent/ICON SONET ring which provides true ring redundancy.
Existing protection, utilizing JMUX, will be removed and all secondary relay schemes on both lines will connect to the new SEL ICON nodes.
Remove JMUX equipment

Assumptions/Clarifications

Indirect rates based on 6T - NH , Station work
Equipment will be purchased and supplied by Eversource.
Outsourced construction, testing and engineering with in-house review. relay settings completed in-house
Engineering, Test Engineer and LCE will be a single source procurement to TRC.
This estimate is based on a TRC proposal dated 9/4/19, escalation on this proposal is included after 2020.
This estimate is based on a one for one replacement of existing relaying.
Panel space of existing relay will be reused with only minor panel modifications required.
The existing Satellite Clock is adequate to avoid signal degradation.
Existing DC power circuits will be provide adequate DC power.
BPS separations of wiring will be as per SUB013.7.2, "Separate Systems Electrically Only." Alterations to existing raceway systems are not included in this scope of work.
A station walkdown was not made in preparation of this estimate.

Risks

Outage Delays and Rescheduling	$	15,000
Additional Communication signal troubleshooting	$	3,500
Engineering deliverables do not match field conditions	$	4,000
Severe Weather, Delays	$	15,000
Additional manlift and crew required for wavetrap removal	$	5,000

E S T I M A T E   S U M M A R Y

Project Title: Eagle Powerline Carrier Replacement and Line 3195 OPGW (Alternative 1e) — **Estimate By: JPM**

Project Mgr/Lead: David L. Plante — **Date of Estimate: 08-29-19**

Project Number: T1407E3 — **ISD: 12-31-21**

Est. Revision # 04 — **Estimate # P-19-249i Line**

Template Revision # 0s

ESTIMATE SUMMARY

Estimate Type Conceptual

WBS		TOTAL	% of Total	Prior	2019	2020	2021	2022	2023	2024
1	Construction	$423,000	63.6%				$423,000			
2	Engineering / Design	$29,400	4.4%			$20,500	$8,900			
3	Land									
	Material	$25,200	3.8%			$21,100	$4,100			
5	Project Mgmt. & Sppt.	$15,000	2.3%			$8,000	$7,000			
6	Removal	$11,300	1.7%				$11,300			
7	Test	$24,500	3.7%				$24,500			
8	Risk / Contingency	$43,000	6.5%				$43,000			
9	Escalation	$33,900	5.1%			$1,700	$32,200			
10	Indirects	$41,500	6.2%			$7,200	$34,300			
11	AFUDC	$17,800	2.7%			$1,500	$16,300			
	Total Cost	**$664,600**	100.0%			**$60,000**	**$604,600**			

Estimate Range	-25%	50%
	$498,000	**$997,000**

COMMENTS:

Project Scope

The **Amherst Substation Automation Project** will involve the replacement of GE-Fanuc PLCs with SEL-2240 Axion I/O devices.
The Axions will replace all Electric System Control Center (ESCC) metering, status and control functions currently performed by the protective relays and PLC System.

During the site walkdown, several equipment upgrades unrelated to the automation project were identified.
Execution of these upgrades in a coordinated fashion with the Amherst Automation Project will improve cost and outage efficiency.
This work order is for the replacement of the Eagle Powerline Carrier System and Line 3195 OPGW is for work being performed in conjunction with the Amherst Automation Project and not as a stand-alone project.

This estimate Estimate (P-19-249i Line) is for the OPGW line work in the right-of-way beyond the substation. Estimate (P-19-249i SS) is for the work within the substation.

Eagle Line 3195 OPGW:
Install 1.35 miles OPGW on 3195 from Str. 103 to Eagle Terminal Structure on existing structures.

Assumptions/Clarifications

Indirect rates based on 6T - NH , Lines work
Equipment will be purchased and supplied by Eversource.
Outsourced construction, testing and engineering with in-house review.
LCE will be shared resource as part of Amherst Automation Project.
No allotment has been made for extended outages.
Structures with OPGW replacing shield wire are suitable for a new OPGW installation.
All work is within the existing Eversource right-of-way.
Environmental mapping information was not available.
OPGW spliced in existing splice cans on 3195/103 and 3195/93. Additional splicing will be in a new splice can on the Eagle terminal structure included in another work order.
Additional OPGW splicing will be in a new splice can included in estimate P-19-249h installed on the existing Eagle terminal structure.
Constructability review with operations was not conducted.

Risks

Outage Delays and Rescheduling	10000
Snow Plowing	4000
Engineering deliverables do not match field conditions	4000
Severe Weather, Delays	25000

ESTIMATE SUMMARY

Project Title: Eagle Powerline Carrier Replacement and Line 3195 OPGW (Alternative 1e)	Estimate By: JPM
Project Mgr/Lead: David L. Plante	Date of Estimate: 08-29-19
Project Number: T1407E3	ISD: 12-31-21
Est. Revision # 04	Estimate # P-19-249i SS

Template Revision # 0s

ESTIMATE SUMMARY

Estimate Type Conceptual

WBS		TOTAL	% of Total	Prior	2019	2020	2021	2022	2023	2024
1	Construction	$123,300	18.2%				$123,300			
2	Engineering / Design	$82,300	12.2%			$63,500	$18,800			
3	Land									
	Material	$77,500	11.4%			$76,400	$1,100			
5	Project Mgmt. & Sppt.	$13,500	2.0%			$8,300	$5,200			
6	Removal	$21,600	3.2%				$21,600			
7	Test	$123,700	18.3%				$123,700			
8	Risk / Contingency	$54,500	8.1%				$54,500			
9	Escalation	$28,700	4.2%			$4,400	$24,300			
10	Indirects	$130,100	19.2%			$41,700	$88,400			
11	AFUDC	$21,700	3.2%			$5,000	$16,700			
	Total Cost	**$676,900**	100.0%			**$199,300**	**$477,600**			

Estimate Range	-25%	50%
	$508,000	$1,015,000

COMMENTS:

Project Scope

The **Amherst Substation Automation Project** will involve the replacement of GE-Fanuc PLCs with SEL-2240 Axion I/O devices.
The Axions will replace all Electric System Control Center (ESCC) metering, status and control functions currently performed by the protective relays and PLC System.

During the site walkdown, several equipment upgrades unrelated to the automation project were identified.
Execution of these upgrades in a coordinated fashion with the Amherst Automation Project will improve cost and outage efficiency.
This work order is for the replacement of the Eagle Powerline Carrier System and Line 3195 OPGW is for work being performed in conjunction with the Amherst Automation Project and not as a stand-alone project.

This estimate (P-19-249i SS) is for the work within the substation. Estimate (P-19-249i Line) is for the OPGW line work in the right-of-way beyond the substation.

Eagle Powerline Carrier Replacement and Line 3195 OPGW:

The remote Schweitzer SEL-421 relay, device 21Z/LS-3195, and associated RFL-9785 carrier set, device 85DCB/LS-3195, located at Eagle Substation will be removed and replaced with a new Schweitzer SEL-411L.
Remove wave traps and tuners and install a new Phase B strain bus in place of traps
A new SEL ICON SONET multiplexer will be installed to replace the existing Lucent DMXtend with dual ring connections. The ICON will join the existing Lucent/ICON SONET ring which provides true ring redundancy.
Existing protection, utilizing JMUX, will be removed and all secondary relay schemes on both lines will connect to the new SEL ICON nodes.
Remove JMUX equipment
Install ADSS through new duct and cable trench from Substation Term structure to Control House

Assumptions/Clarifications

Indirect rates based on 6T - NH , Station work
Equipment will be purchased and supplied by Eversource.
Outsourced construction, testing and engineering with in-house review. relay settings completed in-house
Engineering, Test Engineer and LCE will be a single source procurement to TRC.
This estimate is based on a TRC proposal dated 9/4/19, escalation on this proposal is included after 2020.
This estimate is based on a one for one replacement of existing relaying.
Panel space of existing relay will be reused with only minor panel modifications required.
The existing Satellite Clock is adequate to avoid signal degradation.
Existing DC power circuits will be provide adequate DC power.
BPS separations of wiring will be as per SUB013.7.2, "Separate Systems Electrically Only." Alterations to existing raceway systems are not included in this scope of work.
A station walkdown was not made in preparation of this estimate.
No allotment has been made for extended outages.
Area wide settings changes not required as a result of OPGW installation.
Fiber optic cable will tie into existing communication equipment or new communication equipment in a separate project.
All new equipment will be installed within the confines of the existing fenced yard or ROW

Risks

Outage Delays and Rescheduling	$	11,500
Additional Communication signal troubleshooting	$	1,600
Engineering deliverables do not match field conditions	$	2,000
Severe Weather, Delays	$	24,400
Additional manlift and crew required for wavetrap removal	$	5,000
Potential UG Obstructions	$	5,000
Additional outreach and environmental funding	$	5,000

Project Scope Document

Rev. B-Final – October 1, 2019

Amherst Automation Scoping Project

Prepared by: TRC Engineers	**Date: July 16, 2019**
Reviewed By: Chris O'Brien	**Date: July 26, 2019**
Reviewed By: Cory Wess, Telecom Eng.	**Date: July 26, 2019**
Reviewed By: Patrick Bradshaw	**Date: Aug. 1, 2019**
Reviewed By: Lucas Croteau	**Date: July 26, 2019**
Reviewed By: Joseph Sperry, P.E.	**Date: July 30, 2019**
Approved/Issued By:	**Date:**

Eversource WO # A19S4001

Revision History:

Rev. A - Issued by TRC for Eversource Review – 6/21/2019
Rev. B – Issued by TRC for Eversource Review – 8/13/2019
Rev. B-Final - Issued by TRC for Eversource Use – 10/1/2019

I. GENERAL DESCRIPTION

The Amherst Substation Automation project will involve the replacement of GE-Fanuc PLCs with SEL-2240 Axion I/O devices. The Axions will replace all Electric System Control Center (ESCC) metering, status and control functions currently performed by the protective relays and PLC System. The existing GE-D20 RTU will be replaced with a SEL-3530 real-time automation controller (RTAC), and the PLC based Graphical User Interface (GUI) will be replaced with a new touch screen HMI system (the same system used in recent Transmission Substations). The existing SEL-2030 communications processors will be removed, and remote interrogation of the relays will be accomplished via a RS-485 communication connection to a new GarrettCom 10XTS Substation Communication Access Device (SCAD). Time synchronization for all relays will be accomplished by connecting directly to a demodulated IRIG-B output of a new Arbiter 1094B GPS clock. A new SEL-2411 relay will be installed to perform the BT56 auto close functions currently performed by the PLC. Four new cabinets will be installed to support the automation changes: three Axion RTU cabinets and one HMI/annunciator cabinet.

The existing electromechanical relay protection for 34.5kV lines 3445X, 3159X, 3110X, 3143X, and 3212X as well as the control for 34.5kV breakers 3445, 3195, 3110, 3143, and 3212 will be replaced with numerical relaying and new controls located in new cabinets. 5 new cabinet will be installed to support the relay changeouts.

The existing SEL-352 relays used for 345kV breaker failure will be replaced with new SEL-351-7 relays to provide reclosing functionality for the 345kV breakers. The existing 345kV line secondary relays (GE D60) will be replaced as part of an overall effort to replace GE relays with SEL relays on the Eversource system.

The existing electromechanical 345kV primary bus #2 differential relay system (GE PVDs) will be replaced with a numerical relay (SEL-587Z). Since this portion of the scope involves replacing an electromechanical relay with a numerical relay, a Directory 4 submittal to the NPCC Task Force for System Protection will be required. The 345kV bus differential relay replacement is covered under a separate scope document.

There are several optional scope items addressed in Appendices A through C.

II. DETAILED DESCRIPTION OF WORK

A. Substation Electrical Design

The Control House Equipment Layout drawing will be updated to show the four (4) new P&C cabinets, and additional equipment additions and removals described below. A full DC analysis will be conducted to verify that the size of the existing batteries and battery chargers are sufficient for the modifications in the sections below. Mobile battery connections are to be installed on the exterior of the control house. The 48V ALCAD battery charger is to be replaced. Two new hydrogen sensors, including remote accessories, and junction box will be added above each of the batteries. The existing cable tray mounted heaters will be removed and replaced by a new HVAC system that will provide both heating and cooling. A full AC analysis will be conducted to verify that the existing station service can accommodate the HVAC addition. If it is found that the AC station service needs to be replaced, the new calculations will need to include the load from the battery trailer if it was utilized. Additionally, a new exterior mounted amber strobe light and signage will be installed as indication for high levels of hydrogen within the control house. In order to accommodate the latest standards, the HVAC circuits will be rewired to utilize the new equipment mentioned above.

B. Civil Design:

1. No activity anticipated for this scope of work.

C. Line Design:

1. No activity anticipated for this scope of work. See Appendix C for scope of work.

D. General P&C Design

The existing PLC system interfaces with protective relays to collect digital and analog data and to control the substation equipment. This project will remove this functionality from all the protective relays and move it to new SEL-2240 Axion I/O devices. Typical changes to the protective relays include the following:

- Alarm points will be removed from the protective relays and added to the new SEL-2240 Axion Digital Input Modules (e.g. Breaker Low SF6 Alarm, Transformer Low Oil Level Alarm).
- Status points will be removed from the protective relays and added to the new SEL-2240 Axion Digital Input Modules (e.g. SUPV-LOCAL Switch Status).
- Alarms that are developed by the protective relays will require additional outputs to be added to the relays and provided as inputs to the new SEL-2240 Axion Digital Input Modules (e.g. LOP Alarms, Trip Coil Monitor Alarms).
- SCADA control points will be removed from the protective relays and added to the new SEL-2240 Axion Digital Output Modules (e.g. Breaker Trip and Close Contacts).

E. 345kV Line Protection

REDACTED

1. Primary Line 367 Protection (21Z/LP-367)

   The existing primary line 367 relay will be modified to remove any I/O and settings not required for protection and control functions.

   New outputs performing reclose initiate will be added and wired to the appropriate reclosing relays.

   Note: An option to replace the Line 367 power line carrier scheme is addressed in Appendix C.

2. Secondary Line 367 Protection (21Z/LS-367)

   The funding for this section is already covered by Project # T1399AM

   The existing secondary GE D60 relay, device 21Z/LS-367, will be removed and replaced.

   The new secondary protection for line 367 will be a Permissive Overreaching Transfer Trip (POTT) scheme in addition to a new step distance scheme. [redacted]

3. Primary Line 3195 Protection (21Z/LP-3195)

   The existing primary line 367 relay will be modified to remove any I/O and settings not required for protection and control functions.

   New outputs performing reclose initiate will be added and wired to the appropriate reclosing relays.

4. Secondary Line 3195 Protection (21Z/LS-3195)

The funding for this section is already covered by Project # T1399AM

The existing secondary GE D60 relay, device 21Z/LS-3195, will be removed and replaced.

[redacted]

Note: An option to replace the Line 3195 power line carrier scheme is addressed in Appendix C.

F. <u>345kV Breaker Failure Protection</u>

1. <u>345KV GCB 3885 Breaker Failure Protection (50/62/BF-3885)</u>

The existing GCB 3885 breaker failure relay will be renamed from 50/62/BF-3885 to 50/79/BF-3885 to incorporate new reclosing functionality.

The existing Schweitzer SEL-352 breaker failure relay, will be removed and replaced with a new SEL-351-7 relay. This change is to facilitate the relocation of breaker reclosing functions from the PLC to the breaker failure relay. The SEL-352 relay does not have automatic reclosing capability.

The existing test switches will remain wired as they were before, with the exception that any I/O not required for protection and control will be removed.

2. 345KV GCB 6768 Breaker Failure Protection (50/62/BF-6768)

   The existing GCB 6768 breaker failure relay will be renamed from 50/62/BF-6768 to 50/79/BF-6768 to incorporate new reclosing functionality.

   The existing Schweitzer SEL-352 breaker failure relay, will be removed and replaced with a new SEL-351-7 relay. This change is to facilitate the relocation of breaker reclosing functions from the PLC to the breaker failure relay. The SEL-352 relay does not have automatic reclosing capability.

   The existing test switches will remain wired as they were before, with the exception that any I/O not required for protection and control will be removed.

3. 345KV GCB 0951 Breaker Failure Protection (50/62/BF-0951)

   The existing GCB 0951 breaker failure relay will be renamed from 50/62/BF-0951 to 50/79/BF-0951 to incorporate new reclosing functionality.

   The existing Schweitzer SEL-352 breaker failure relay, will be removed and replaced with a new SEL-351-7 relay. This change is to facilitate the relocation of breaker reclosing functions from the PLC to the breaker failure relay. The SEL-352 relay does not have automatic reclosing capability.

   The existing test switches will remain wired as they were before, with the exception that any I/O not required for protection and control will be removed.

4. 345KV GCB 3885 Breaker Failure Protection (50/62/BF-0295)

   The existing GCB 0295 breaker failure relay will be renamed from 50/62/BF-0295 to 50/79/BF-0295 to incorporate new reclosing functionality.

   The existing Schweitzer SEL-352 breaker failure relay, will be removed and replaced with a new SEL-351-7 relay. This change is to facilitate the relocation of breaker reclosing functions from the PLC to the breaker failure relay. The SEL-352 relay does not have automatic reclosing capability.

The existing test switches will remain wired as they were before, with the exception that any I/O not required for protection and control will be removed.

G. 345kV Bus Protection

1. 345kV Primary Bus #1 Differential (87/B1P-345)

   The existing SEL-487B 345kV bus differential relay, device 87/B1P-345, will be modified to remove any I/O and settings not required for protection and control functions.

2. 345kV Primary Bus #2 Differential (87/B2P-345)

   The funding for this section is already covered by Project # T1390AM

   The existing GE PVD single phase relay devices, 87-1,2,3/B2P-345, are obsolete and will be removed and replaced with a single SEL-587Z relay. This work is being performed under Work Order #T1390AM. The new relay will provide the necessary alarms to the new Axion system as required.

H. 345/34.5kV Transformer Protection

1. Primary Transformer TB68 Differential (87/TP-TB68)

   The existing 345/34.5kV TB68 STD transformer differential relays will remain in place. All available switch statuses and alarms will be provided to the new Axion system.

   Note: An option to replace this protection system is addressed in Appendix B.

2. Secondary Transformer TB68 Differential (87/TS-TB68)

   The existing secondary transformer TB68 relay will be modified to remove any I/O and settings not required for protection and control functions.

3. Transformer TB68 Voltage Protection (21/RADIAL/TB68)

   The existing transformer TB68 voltage protection relay will be modified to remove any I/O and settings not required for protection and control functions.

4. Primary Transformer TB85 Differential (87/TP-TB85)

The existing primary transformer TB85 relay will be modified to remove any I/O and settings not required for protection and control functions.

5. Secondary Transformer TB85 Differential (87/TS-TB85)

   The existing secondary transformer TB85 relay will be modified to remove any I/O and settings not required for protection and control functions.

6. Transformer TB85 Voltage Protection (21/RADIAL/TB85)

   The existing transformer TB85 voltage protection relay will be modified to remove any I/O and settings not required for protection and control functions.

I. 34.5kV Transformer Circuit Breaker Failure Protection

1. Circuit Breaker Failure Protection (50/62/BF-TB68)

   The existing TB68 breaker failure relay will be modified to remove any I/O and settings not required for protection and control functions.

   The automatic reclosing logic will be moved from the PLC to the 50/62/BF-TB68 relay. The reclosing parameters will remain the same.

2. Circuit Breaker Failure Protection (50/62/BF-TB85)

   The existing TB85 breaker failure relay will be modified to remove any I/O and settings not required for protection and control functions.

   The automatic reclosing logic will be moved from the PLC to the 50/62/BF-TB85 relay. The reclosing parameters will remain the same.

J. 34.5kV Bus Protection

1. 34.5kV Bus 1 Primary Differential Protection (87/B1P-34)

   The existing 34.5kV bus #1 PVD bus differential relays will remain in place. All available switch statuses and alarms will be provided to the new Axion system.

2. 34.5kV Bus 1 Secondary Overcurrent Protection (50/51/B1S-34)

   The existing secondary Bus 1 protective relay will be modified to remove any I/O and settings not required for protection and control functions.

3. 34.5kV Bus 2 Primary Differential Protection (87/B2P-34)

The existing 34.5kV bus #2 PVD bus differential relays will remain in place. All available switch statuses and alarms will be provided to the new Axion system.

4. 34.5kV Bus 2 Secondary Overcurrent Protection (50/51/B2S-34)

   The existing secondary Bus 2 protective relay will be modified to remove any I/O and settings not required for protection and control functions.

K. <u>34.5kV Bus Tie Circuit Breaker Failure Protection</u>

1. Circuit Breaker Failure Protection (50/62/BF-BT56)

   The existing bus tie GCB BT56 auto close scheme will be modified to move all of the logic from the PLC to the new SEL-2411 relay (3-1/BT56AC). The existing 50/62/BF-BT56 relay will continue to supervise the volt/sync check and perform the actual BT56 close function when an auto close signal is received from the 3-1/BT56AC relay.

   The following Device Designations will change for this project:

   - Permissive Switch 69/BT56AC
   - Permissive Aux Relay 69X/BT56AC
   - Summer/Winter MVA Switch 43SW/BT56AC
   - Summer/Winter MVA Aux Relay 43SWX/BT56AC

2. Circuit Breaker Auto Close (3-1/BT56AC)

   The existing bus tie GCB BT56 auto close scheme will be modified to move all of the logic from the PLC to the new SEL-2411 (3-1/BT56AC). The existing 50/62/BF-BT56 relay will continue to supervise the volt/sync check and perform the actual BT56 close function.

[redacted]

[redacted]

REDACTED

[redacted]

The following functions will be moved from the PLC to the new Axion system:

- SCADA Enable Auto Close GCB BT56
- SCADA Disable Auto Close GCB BT56
- SCADA 43SW/BT56AC Summer Selection
- SCADA 43SW/BT56AC Winter Selection

A description of the operation of the auto close scheme is as follows:

[redacted]

[redacted]

[redacted]

[redacted]

The auto close guidelines are:

- [redacted]

- [redacted]
- [redacted].
- The summer/winter MVA settings for each transformer are as follows:
  TB85-Summer: 206 MVA, Winter: 210MVA
  TB68-Summer: 202 MVA, Winter: 210 MVA

L. 34.5kV Feeder Protection

1. 34.5kV Line 3445X Protection

   Primary line protection for 34.5kV Line 3445X will be installed in a new cabinet located in the Distribution side of the control house. [redacted]

2. 34.5kV Line 3110X Protection

   Primary line protection for 34.5kV Line 3110X will be installed in a new cabinet located in the Distribution side of the control house. [redacted]

[redacted]

3. 34.5kV Line 3159X Protection

   Primary line protection for 34.5kV Line 3159X will be installed in a new cabinet located in the Distribution side of the control house. [redacted]

4. 34.5kV Line 3143X Protection

   Primary line protection for 34.5kV Line 3143X will be installed in a new cabinet located in the Distribution side of the control house. [redacted]

5. 34.5kV Line 3212X Protection

   Primary line protection for 34.5kV Line 3212X will be installed in a new cabinet located in the Distribution side of the control house. [redacted]

[redacted]

M. <u>34.5kV Breaker Failure Protection</u>

1. 34.5kV Bus #1 Breaker Failure Protection (/BFB1-34)

   The existing bus #1 breaker failure protection consists of electro-mechanical timing and lockout relays. The available switch statuses and alarms will be provided to the new Axion system.

   Note: An option to replace this protection system is addressed in Appendix A.

2. 34.5kV Bus #2 Breaker Failure Protection (/BFB2-34)

   The existing bus #2 breaker failure protection consists of electro-mechanical timing and lockout relays. The available switch statuses and alarms will be provided to the new Axion system.

   Note: An option to replace this protection system is addressed in Appendix A.

N. <u>Control Systems</u>

Controls for the following breakers will be relocated from the existing distribution switchboard to new cabinets:

- 34.5kV OCB 3445
- 34.5kV OCB 3110
- 34.5kV OCB 3159
- 34.5kV OCB 3143
- 34.5kV OCB 3212

O. <u>Digital Fault Recorder:</u>

New analog and digital points will be added to the existing DFR per Eversource requirements, as necessary.

P. Metering Functions

Metering quantities for the Line 3195, Line 367, 345kV Bus 1, 345kV Bus 2, 34.5kV Bus 1, 34.5kV Bus 2, Transformer TB85, Transformer TB68, distribution Lines 3445X, 3110X, 3159X, 3143X and 3212X will be obtained from their respective Axion meters. Metering information will be displayed on the Station HMI One-Line Screens and be provided to ESCC via the SCADA system. Specific metering quantities provided to ESCC and scaling factors for each meter will be provided in the RTU Points List.

Additional analog input points are also obtained from an Axion analog input module. These points will also be displayed on the Station HMI and provided to ESCC via the SCADA system. The following is a general list of the analog points to be installed at Amherst Substation as part of this upgrade:

- Transformer Gas PPM
- Transformer LTC Position
- Outside Ambient Air Temperature
- Inside Control House Air Temperature
- Transformer Main Tank Temperature
- Transformer LTC Tank Temperature

The existing revenue meters for transformer TB68 and transformer TB85 currently provide KYZ pulse accumulator points to the D20 RTU. These KYZ points will be relocated to the new Axion System. The revenue meters can currently be accessed remotely via the Line Sharing Switch and JMUX, this connection will be maintained.

Q. Smart Grid Data

A communication path between the RTAC and all new 67/LP relays will be created to allow the RTAC to poll the relays for detailed metering and fault data. This connection will use DNP3 protocol over a new RS485 network that will connect into optically isolated port 17 of the RTAC.

R. Battery Monitoring

The Arga battery monitor alarms will be moved from inputs on the SEL-2030 to the new Axion system.

S. Annunciation

Annunciation for all alarm points at Amherst Substation will be provided by the new station Human Machine Interface (HMI) annunciator. Active alarms are time stamped and displayed in the Alarms section of the HMI. All alarms are provided as individual alarms, but will also display group alarms if part of a group. A speaker located in the HMI cabinet will alert to active alarms in the station. A selector switch at the cabinet can mute/unmute the alarm tone. The HMI will not be programmed to perform any control functions.

T. SCADA/RTU

The existing GE D20 RTU, GE Fanuc PLCs, and the PC (GUI) will be removed. The new SCADA system will consist of a Schweitzer SEL-3530 RTAC and a system of SEL Axion Nodes. The RTAC will collect status, alarms, analog, and metering values, via multiple SEL-2240 Axion nodes, and will provide them to the ESCC. The RTAC will also perform SCADA control functions via Axion digital output modules. Axion Nodes will communicate to the RTAC over EtherCAT fieldbus connections using EtherCAT protocol. The RTAC (1U tall) will be housed in Cabinet #30. Twelve (12) Axion nodes make up the distributed I/O network and are housed in Cabinets 30, 40, and 21.

All terminations to Axion cards will be done on specifically keyed SEL Phoenix terminal blocks. All cards will be mounted in slots at the Axion node and communicate through the Axion using an EtherCAT connected backplane. Slot labels will be visible through holes at the top right of each card and range from A-J. Slot A will always be occupied by a SEL-2243 power coupler. If redundant power supplies exist, Slot B will be occupied by an SEL-2243.

Status and alarms (not including Loss of DC Alarms) will be wired directly to the Axion digital input card. Loss of DC Alarms will utilize auxiliary relays (Releco MR-C C2-A20FX/125VDC). Each input card will include 24 125VDC inputs with LED indicators.

Controls will be terminated to the digital output card. Each output will be independently controlled from the RTAC. Each output will be rated to make at 30A and have a continuous carry of 6A. All control outputs will be wired to test switches at the RTU Cabinets for circuit isolation.

Analog connections will be terminated to the DC analog input card. Each analog input will be individually configured to accept 0-1mA or 4-20mA DC analog inputs. Analog inputs will be current sensing and will not need external resistors. All RTD signals will be wired to a signal conditioner and wire to the analog input cards as a 4-20ma signal.

Metering values will be derived from the AC metering card which contains 4 current transformer inputs and 4 potential transformer inputs. Derived metering values will be sent to the station HMI, via a DNP link on Comm 2 of the RTAC, and made available on the Station One-Line Screens as well as remote ESCC analog data.

The RTU Points List will outline all of the control, status and analog points utilized by the ESCC system. Scaling information for analog data will be included on these sheets.

U. Communications

1. IED Communications

The existing distribution communications scheme allows remote interrogation of all numerical relays through SEL-2030s which are connected to a Frame Relay Access Device (FRAD). The FRAD will be removed and replaced with a Garrettcom 10XTS Substation Communication Access Device (SCAD). The SEL-2030s will be removed and a new RS-485 daisy-chain link will connect the relays directly to the SCAD. IRIG-B signals, formerly propagated to the relays via SEL-2030s, will be replaced with a wired coaxial connection to the station GPS clock. Engineering access for transmission relays will also be removed from the FRAD and reconnected to the SCAD.

The SCAD will also provide remote access, via a serial connection, to the local HMI annunciator computer.

The new Axion nodes will communicate over an EtherCAT network which will connect to ETH1 on the RTAC. All Axion configurations are programmed in the RTAC and do not require local configuration.

The GPS clock will be connected to the RTAC, which will supply time stamping for SCADA communications as well as time sync for all Axion nodes.

The station Power Quality node (Dranetz-BMI 5590T Dualnode) will be removed from the Substation Line Sharing Switch (SLSS) and a new connection will be established from the 10BaseT Ethernet port of the Dranetz to an Ethernet port on the existing Cisco connected grid switch.

2. SCADA/RTU Communications

Communication port 1 (COM1) of the RTAC will connect to the existing master port on the non-port powered switch (NPPS) which will split the communications path to a low speed data card on the JMUX as well as two serial ports on the existing Cisco connected grid switch.

ESCC communications will use DNP 3.0 protocol.

V. Primary Equipment Modifications

1. Breaker Condition Monitoring (BCM) devices will be removed from the following 34.5kV Circuit Breakers:

    - GCB TB68
    - GCB TB85
    - GCB BT56

W. AC/DC Power

1. AC Power:
    - It is assumed the existing AC station service will not require upgrades. All new AC circuits will be added to the existing AC panels.

2. DC Power:
    - A full DC analysis will be conducted to verify the existing station batteries and battery chargers are sized appropriately for the above-mentioned modifications. All new DC circuits will be added to the existing DC panels.

X. Hydrogen

1. Two new hydrogen sensors will be installed including the remote accessories. A new amber strobe light and signage will be mounted to the exterior of the building for indication of high levels of hydrogen within the control house. Hydrogen 1% and 2% alarms will be brought to the new Axion and sent to SCADA.

III. SUMMARY OF MAJOR EQUIPMENT TO BE REMOVED

A. Substation Equipment

1. Four (4) Cable tray mounted heater units

B. Civil Equipment

1. No major equipment to be removed.

C. Line Equipment

1. No major equipment to be removed. See Appendix C for Line removals.

D. P&C Equipment

1. Switchboard Panel #9, Line 3445X Metering & Control
    - Analogic AN25 Meter – Volts (DPM-V-3445X)

- Analogic AN25 Meter – Amps (DPM-A-3445X)
- Analogic AN25 Meter – MW (DPM-MW-3445X)
- Analogic AN25 Meter – MVAR (DPM-MX-3445X)
- Sangamo ADF-7 Thermal Demand Meter (TA-1-3445X)
- Sangamo ADF-7 Thermal Demand Meter (TA-2-3445X)
- Sangamo ADF-7 Thermal Demand Meter (TA-3-3445X)
- S-C XLWV Watt/Var Transducer (MW/MX-XDCR-3445X)
- S-C Current Transducer (A-XDCR-3445X)
- S-C Voltage Transducer (V-XDCR-3445X)
- GE SLJ Sync Check Relay (25-3445)
- GE SB1 Amp Switch (A-3445X)
- GE SB1 Sync Switch (SYN-3445)
- GE SB1 Control Switch (1-3445)
- GE SB1 Reclose Permissive Switch (69-79-3445)
- GE SB1 Supv/Local Switch (43SL-3445)
- Various Auxiliary Relays, Indicating Lights, PK Blocks

2. Switchboard Panel #10, Line 3445X Relaying
    - ABB KD-10 Distance Relay (21Z2/L-3445X)
    - GE IAC-80 Overcurrent Relay (51Z2/L-3445X)
    - ABB CR-9 Directional Overcurrent Relay (67N/L-3445X)
    - GE HGA Auxiliary Relay (94/L-3445X)
    - GE HGA Auxiliary Relay (79RI-3445)
    - Various Auxiliary Relays, Terminal Blocks

3. Switchboard Panel #11, Line 3159X & 3110X Metering & Control
    - Analogic AN25 Meter – Volts (DPM-V-3159X)
    - Analogic AN25 Meter – Amps (DPM-A-3159X)
    - Analogic AN25 Meter – MW (DPM-MW-3159X)
    - Analogic AN25 Meter – MVAR (DPM-MX-3159X)
    - Sangamo ADF-7 Thermal Demand Meter (TA-1-3159X)
    - Sangamo ADF-7 Thermal Demand Meter (TA-2-3159X)
    - Sangamo ADF-7 Thermal Demand Meter (TA-3-3159X)
    - S-C XLWV Watt/Var Transducer (MW/MX-XDCR-3159X)
    - S-C Current Transducer (A-XDCR-3159X)
    - S-C Voltage Transducer (V-XDCR-3159X)
    - GE SLJ Sync Check Relay (25-3159)
    - GE SB1 Amp Switch (A-3159X)
    - GE SB1 Sync Switch (SYN-3159)
    - GE SB1 Control Switch (1-3159)
    - GE SB1 Reclose Permissive Switch (69-79-3159)
    - GE SB1 Supv/Local Switch (43SL-3159)
    - Analogic AN25 Meter – Volts (DPM-V-3110X)

- Analogic AN25 Meter – Amps (DPM-A-3110X)
- Analogic AN25 Meter – MW (DPM-MW-3110X)
- Analogic AN25 Meter – MVAR (DPM-MX-3110X)
- Sangamo ADF-7 Thermal Demand Meter (TA-1-3110X)
- Sangamo ADF-7 Thermal Demand Meter (TA-2-3110X)
- Sangamo ADF-7 Thermal Demand Meter (TA-3-3110X)
- S-C XLWV Watt/Var Transducer (MW/MX-XDCR-3110X)
- S-C Current Transducer (A-XDCR-3110X)
- S-C Voltage Transducer (V-XDCR-3110X)
- GE SLJ Sync Check Relay (25-3110)
- GE SB1 Amp Switch (A-3110X)
- GE SB1 Sync Switch (SYN-3110)
- GE SB1 Control Switch (1-3110)
- GE SB1 Reclose Permissive Switch (69-79-3110)
- GE SB1 Supv/Local Switch (43SL-3110)
- Various Auxiliary Relays, Indicating Lights, PK Blocks

4. Switchboard Panel #12, Line 3159X & 3110X Relaying
    - ABB KD-10 Distance Relay (21Z2/L-3159X)
    - GE IAC-80 Overcurrent Relay (51Z2/L-3159X)
    - ABB CR-9 Directional Overcurrent Relay (67N/L-3159X)
    - GE HGA Auxiliary Relay (94/L-3159X)
    - GE HGA Auxiliary Relay (79RI-3159)
    - ABB KD-10 Distance Relay (21Z2/L-3110X)
    - GE IAC-80 Overcurrent Relay (51Z2/L-3110X)
    - ABB CR-9 Directional Overcurrent Relay (67N/L-3110X)
    - GE HGA Auxiliary Relay (94/L-3110X)
    - GE HGA Auxiliary Relay (79RI-3110)
    - Various Auxiliary Relays, Terminal Blocks

5. Switchboard Panel #13, Line 3143X & 3212X Metering & Control
    - Analogic AN25 Meter – Volts (DPM-V-3143X)
    - Analogic AN25 Meter – Amps (DPM-A-3143X)
    - Analogic AN25 Meter – MW (DPM-MW-3143X)
    - Analogic AN25 Meter – MVAR (DPM-MX-3143X)
    - Sangamo ADF-7 Thermal Demand Meter (TA-1-3143X)
    - Sangamo ADF-7 Thermal Demand Meter (TA-2-3143X)
    - Sangamo ADF-7 Thermal Demand Meter (TA-3-3143X)
    - S-C XLWV Watt/Var Transducer (MW/MX-XDCR-3143X)
    - S-C Current Transducer (A-XDCR-3143X)
    - S-C Voltage Transducer (V-XDCR-3143X)
    - GE SLJ Sync Check Relay (25-3143)
    - GE SB1 Amp Switch (A-3143X)

- GE SB1 Sync Switch (SYN-3143)
- GE SB1 Control Switch (1-3143)
- GE SB1 Reclose Permissive Switch (69-79-3143)
- GE SB1 Supv/Local Switch (43SL-3143)
- Analogic AN25 Meter – Volts (DPM-V-3212X)
- Analogic AN25 Meter – Amps (DPM-A-3212X)
- Analogic AN25 Meter – MW (DPM-MW-3212X)
- Analogic AN25 Meter – MVAR (DPM-MX-3212X)
- Sangamo ADF-7 Thermal Demand Meter (TA-1-3212X)
- Sangamo ADF-7 Thermal Demand Meter (TA-2-3212X)
- Sangamo ADF-7 Thermal Demand Meter (TA-3-3212X)
- S-C XLWV Watt/Var Transducer (MW/MX-XDCR-3212X)
- S-C Current Transducer (A-XDCR-3212X)
- S-C Voltage Transducer (V-XDCR-3212X)
- GE SLJ Sync Check Relay (25-3212)
- GE SB1 Amp Switch (A-3212X)
- GE SB1 Sync Switch (SYN-3212)
- GE SB1 Control Switch (1-3212)
- GE SB1 Reclose Permissive Switch (69-79-3212)
- GE SB1 Supv/Local Switch (43SL-3212)
- Various Auxiliary Relays, Indicating Lights, PK Blocks

6. Switchboard Panel #14, Line 3143X & 3212X Relaying
   - ABB KD-10 Distance Relay (21Z2/L-3143X)
   - GE IAC-80 Overcurrent Relay (51Z2/L-3143X)
   - ABB CR-9 Directional Overcurrent Relay (67N/L-3143X)
   - GE HGA Auxiliary Relay (94/L-3143X)
   - GE HGA Auxiliary Relay (79RI-3143)
   - ABB KD-10 Distance Relay (21Z2/L-3212X)
   - GE IAC-80 Overcurrent Relay (51Z2/L-3212X)
   - ABB CR-9 Directional Overcurrent Relay (67N/L-3212X)
   - GE HGA Auxiliary Relay (94/L-3212X)
   - GE HGA Auxiliary Relay (79RI-3212)
   - Various Auxiliary Relays, Terminal Blocks

7. Switchboard Panel #15, 34.5kV Bus #1 & 2 Metering & Control
   - Analogic AN25 Meter – Volts (BUS-V-34)
   - S-C Voltage Transducer (V-XDCR-B1-34)
   - S-C Voltage Transducer (V-XDCR-B1-34)
   - S-C Voltage Transducer (V-XDCR-M-34)
   - GE SB1 Volt Switch (VS-34)

8. Switchboard Panel #17, CS J68 Control

- Analogic AN25 Meter – Volts (DPM-V-TB68)
- Analogic AN25 Meter – Amps (DPM-A-TB68)
- Analogic AN25 Meter – MW (DPM-MW-TB68)
- Analogic AN25 Meter – MVAR (DPM-MX-TB68)
- S-C XLWV Watt/Var Transducer (MW/MX-XDCR-TB68)
- S-C Voltage Transducer (V-XDCR-TB68)
- GE SB1 Amp Switch (A-TB68)

9. Cabinet #31, PLC #1 & Data Acquisition
    - GE Series 90-30 PLC (PLC #1 Rack #0)
    - SEL-2030 Communications Processor (SEL-2032 Unit #1)
    - ABB FT-19R Test Switches (TD1,2,3-SEL-2030)
    - GE D20ME Module (D20ME)
    - GE D20 SI I/O Module (D20 SI Module)
    - Wilmore 1653 Inverter (DC/AC INVERTER)

10. Cabinet #32, 345kV Secondary Line Relaying
    - GE D60 Line Relay (21Z/LS-367)
    - GE D60 Line Relay (21Z/LS-3195)

11. Cabinet #33, 345kV Breaker and Line Switch Control/Relaying
    - SEL-352 Breaker Failure Relay (50/62/BF-6768)
    - SEL-352 Breaker Failure Relay (50/62/BF-3885)

12. Cabinet #34, 345kV Breaker and Line Switch Control/Relaying
    - SEL-352 Breaker Failure Relay (50/62/BF-0295)
    - SEL-352 Breaker Failure Relay (50/62/BF-0951)

13. Cabinet #41, PLC #2 & Data Acquisition
    - GE Series 90-30 PLC (PLC #2 Rack #0)
    - SEL-2030 Communications Processor (SEL-2032 #2)
    - ABB FT-19R Test Switches (TD1,2,3-SEL-2030)
    - Arbiter 1094B GPS Clock (GPS-CLOCK)
    - ABB FT-19R Test Switch (PLC I/O)

14. Remote PLC Cabinet, PLC#2, Rack#1 & Rack#2
    - GE Series 90-30 PLC (PLC #2 Rack #1)
    - GE Series 90-30 PLC (PLC #2 Rack #2)

15. Cabinet #48, Security Cabinet
    - Dynastar 2000 (FRAD)

16. Control House Desk
    - Station Personal Computer (PC)

- Uninterruptible Power Supply (UPS)

IV. SUMMARY OF MAJOR EQUIPMENT TO BE INSTALLED

A. Substation Equipment

1. Two (2) Hydrogen Sensors
2. Exterior Amber Strobe Light and signage
3. HVAC

B. Civil Equipment

1. No major equipment to be installed.

C. Line Equipment

1. No major equipment to be installed. See Appendix C for Line additions.

D. P&C Equipment

1. Cabinet #21, RTU 3 Cabinet (New)
    - Westell Fuse Panel (RTU Fuse Panel #5)
    - Westell Fuse Panel (RTU Fuse Panel #6)
    - SEL-2240 Axion (Node #7)
    - ABB FT-19R Test Switch (TD1,2,3-AXION NODE #7)
    - ABB FT-19R Test Switch (TD4,5,6-AXION NODE #7)
    - ABB FT-19R Test Switch (TD7,8,9-AXION NODE #7)
    - SEL-2240 Axion (Node #8)
    - ABB FT-19R Test Switch (TD1,2,3-AXION NODE #8)
    - ABB FT-19R Test Switch (TD4,5,6-AXION NODE #8)
    - ABB FT-19R Test Switch (TD7,8,9-AXION NODE #8)
    - SEL-2240 Axion (Node #9)
    - SEL-2240 Axion (Node #10)

2. Cabinet #22, 34.5kV Breaker & Line 3445X Control/Relaying (New)
    - Schweitzer SEL-351-7 Directional Overcurrent Relay (67/LP-3445X)
    - ABB Test Switch Type FT-19R (TD1, 2, 3-67/LP-3445X)
    - ABB Test Switch Type FT-19R (TD4, 5, 6-67/LP-3445X)
    - Electroswitch Supervisory/Local Switch (43SL-3445)
    - Electroswitch Control Switch (1-3445)

- Electroswitch Permissive Reclosing Control Switch (69/79-3445)
- Electroswitch Synchronizing Switch (SYN-3445)
- Electroswitch Setting Group Selector Switch, (43GRP-67/L-3445X)
- Various Indicating Lamps and Auxiliary Relays

3. Cabinet #23, 34.5kV Breaker & Line 3159X Control/Relaying (New)
    - Schweitzer SEL-351-7 Directional Overcurrent Relay (67/LP-3159X)
    - ABB Test Switch Type FT-19R (TD1, 2, 3-67/LP-3159X)
    - ABB Test Switch Type FT-19R (TD4, 5, 6-67/LP-3159X)
    - Electroswitch Supervisory/Local Switch (43SL-3159)
    - Electroswitch Control Switch (1-3159)
    - Electroswitch Permissive Reclosing Control Switch (69/79-3159)
    - Electroswitch Synchronizing Switch (SYN-3159)
    - Electroswitch Setting Group Selector Switch, (43GRP-67/L-3159X)
    - Various Indicating Lamps and Auxiliary Relays

4. Cabinet #24, 34.5kV Breaker & Line 3110X Control/Relaying (New)
    - Schweitzer SEL-351-7 Directional Overcurrent Relay (67/LP-3110X)
    - ABB Test Switch Type FT-19R (TD1, 2, 3-67/LP-3110X)
    - ABB Test Switch Type FT-19R (TD4, 5, 6-67/LP-3110X)
    - Electroswitch Supervisory/Local Switch (43SL-3110)
    - Electroswitch Control Switch (1-3110)
    - Electroswitch Permissive Reclosing Control Switch (69/79-3110)
    - Electroswitch Synchronizing Switch (SYN-3110)
    - Electroswitch Setting Group Selector Switch, (43GRP-67/L-3110X)
    - Various Indicating Lamps and Auxiliary Relays

5. Cabinet #25, 34.5kV Breaker & Line 3143X Control/Relaying (New)
    - Schweitzer SEL-351-7 Directional Overcurrent Relay (67/LP-3143X)
    - ABB Test Switch Type FT-19R (TD1, 2, 3-67/LP-3143X)
    - ABB Test Switch Type FT-19R (TD4, 5, 6-67/LP-3143X)
    - Electroswitch Supervisory/Local Switch (43SL-3143)
    - Electroswitch Control Switch (1-3143)
    - Electroswitch Permissive Reclosing Control Switch (69/79-3143)
    - Electroswitch Synchronizing Switch (SYN-3143)
    - Electroswitch Setting Group Selector Switch, (43GRP-67/L-3143X)

- Various Indicating Lamps and Auxiliary Relays

6. Cabinet #26, 34.5kV Breaker & Line 3212X Control/Relaying (New)
   - Schweitzer SEL-351-7 Directional Overcurrent Relay (67/LP-3212X)
   - ABB Test Switch Type FT-19R (TD1, 2, 3-67/LP-3212X)
   - ABB Test Switch Type FT-19R (TD4, 5, 6-67/LP-3212X)
   - Electroswitch Supervisory/Local Switch (43SL-3212)
   - Electroswitch Control Switch (1-3212)
   - Electroswitch Permissive Reclosing Control Switch (69/79-3212)
   - Electroswitch Synchronizing Switch (SYN-3212)
   - Electroswitch Setting Group Selector Switch, (43GRP-67/L-3212X)
   - Various Indicating Lamps and Auxiliary Relays

7. Cabinet #30, RTU 1 Cabinet (New)
   - Westell Fuse Panel (RTU Fuse Panel #1)
   - Westell Fuse Panel (RTU Fuse Panel #2)
   - Arbiter 1094B GPS Clock (GPS CLOCK)
   - SEL-3530 Controller (RTAC)
   - SEL-2240 Axion (Node #1)
   - ABB FT-19R Test Switch (TD1,2,3-AXION NODE #1)
   - ABB FT-19R Test Switch (TD4,5,6-AXION NODE #1)
   - SEL-2240 Axion (Node #2)
   - ABB FT-19R Test Switch (TD1,2,3-AXION NODE #2)
   - ABB FT-19R Test Switch (TD4,5,6-AXION NODE #2)
   - ABB FT-19R Test Switch (TD7,8,9-AXION NODE #2)
   - SEL-2240 Axion (Node #3)
   - SEL-2240 Axion (Node #4)
   -

8. Cabinet #32, 345kV Secondary Line Relaying (Existing)
   - SEL-311C Line Relay (21Z/LS-367)
   - SEL-311C Line Relay (21Z/LS-3195)

9. Cabinet #33, 345kV Breaker and Line Switch Control/Relaying (Existing)
   - SEL-351-6 Breaker Failure Relay (50/79/BF-6768)
   - SEL-351-6 Breaker Failure Relay (50/79/BF-3885)

10. Cabinet #34, 345kV Breaker and Line Switch Control/Relaying (Existing)
    - SEL-351-6 Breaker Failure Relay (50/79/BF-0295)
    - SEL-351-6 Breaker Failure Relay (50/79/BF-0951)

11. Cabinet #40, RTU 2 Cabinet (New)

    - Westell Fuse Panel (RTU Fuse Panel #3)
    - Westell Fuse Panel (RTU Fuse Panel #4)
    - SEL-2240 Axion (Node #5)
    - SEL-2240 Axion (Node #6)

12. Cabinet #48, Security Cabinet (Existing)

    - Garrettcom 10XTS (SCAD)

13. Cabinet #49, HMI/Annunciator Cabinet (New)

    - Speco Speaker (HMI Speaker)
    - AB Switch 800T-H2A (HMI Speaker Switch)
    - Wilmore DC-DC converter (HMI DC-DC Converter)
    - Dynics 19 in. Touch Screen (HMI Monitor)
    - Uno 2473G Computer (HMI Computer)

V. <u>ROLES AND RESPONSIBILITIES</u>

A. <u>Eversource S/S Engineering Group Responsibilities:</u>

1. Review, comment on, and approve Scope of Work (this document).
2. Work with engineering contractor to establish and maintain project schedule.
3. Review, comment on, and approve electrical drawings and documentation.
4. Respond to engineering contractor RFI’s in a timely fashion.
5. Provide procurement of hydrogen gas detectors, remote displays, junction box, and associated cables.
6. Approve and issue the Substation Electrical construction package.
7. Field engineering support during construction.

B. <u>Eversource P&C Engineering Group Responsibilities:</u>

1. Review, comment on, and approve Scope of Work (this document).
2. Provide input on conceptual issues as necessary.
3. Review and comment on all P&C drawings and documents submitted by the engineering contractor.
4. Provide support at the “Master Station” to establish remote communications with substation numerical relays.

5. Work with Eversource Electrical System Control Center (ESCC), Construction Representative (CR) and contractors to schedule field efforts.
6. Develop and issue the new relay basis documents and setting files.
7. Provide/update secondary thermal ratings.
8. Update Crossbow programming for relay engineering access.

C. Eversource Transmission Civil Engineering Group Responsibilities:

1. No activity anticipated for this scope of work.

D. Eversource Transmission Line Engineering Group Responsibilities:

1. No activity anticipated for this scope of work. See Appendix C for Transmission Line Engineering Group responsibilities.

E. Engineering Contractor Responsibilities –TRC:

1. General Engineering Support.
2. Construction Support
3. Develop and finalize Scope of Work (this document).
4. S/S Electrical Design related deliverables as listed below:
   - Control House Equipment Layout
   - Control House General Arrangements
   - Elementary and Wiring Diagrams of ventilation system
   - Cable Schedules
   - Bill of Materials
   - DC Station Service Calculations and Report
   - AC Station Service Calculations and Report
   - General Engineering Support
   - Cascade sheets
5. P&C Design related deliverables as listed below:
   - Application Diagrams
   - Front Views
   - Elementary Diagrams
   - Logic Diagrams
   - Interconnection Diagrams
   - Wiring Diagrams
   - Material Lists
   - Cable Schedules
   - Communications Block Diagram
   - RTU Points List

- RTU Tab Sheets
- P&C Cabinet Specifications
- P&C Description Document
- Cascade sheets
- NPCC Directory 4 submittal to address the PVD replacement

6. Automation and Controls
   - HMI Data Map
   - RTAC/Axion Programming
   - On-Site Work
     a. Software Installations
     b. Initial Equipment Startup
     c. Automation System Commissioning
7. Technical Specifications for Construction.
8. Perform site visits as required.
9. Use of AutoCAD "Tab Method" for drawing management.
10. Incorporate the As-Built mark-ups.

F. Eversource Construction Test and Maintenance Group Responsibilities:

1. Review, comment on, and approve Scope of Work (this document).
2. Review and comment on drawings and documents submitted by the engineering contractor.
3. Additional responsibilities TBD by Eversource when the project construction and contracting plan is established.

G. Eversource Automation Group Responsibilities:

1. Review, comment on, and approve Scope of Work (this document).
2. Review and comment on drawings and documents submitted by the engineering contractor.
3. Program HMI based on the point-by-point data map developed by engineering contractor.
4. Additional responsibilities TBD by Eversource when the project construction and contracting plan is established.

H. Eversource Telecommunication Engineering Group Responsibilities:

1. Review, comment on, and approve Scope of Work (this document).
2. Review and comment on drawings and documents submitted by the engineering contractor.
3. Provide input on conceptual issues as necessary.

4. Coordination with Communications and Control to implement transport network communications equipment and circuits.
5. Additional responsibilities TBD by Eversource when the project construction and contracting plan is established.

I. Eversource System Operations Group (ESCC) Responsibilities:

1. Prepare Station Orders.
2. Program Energy Management System (EMS) for new SCADA system points.
3. Check out RTU functionality with field personnel.

J. Eversource Purchasing Group Responsibilities:

1. Assist with purchasing all materials.

K. Eversource Revenue Metering Group Responsibilities:

1. No activity anticipated for this scope of work.

VI. CLARIFYING COMMENTS & ASSUMPTIONS

A. Substation:

1. No clarifications necessary at this time.

B. Civil:

1. No clarifications necessary at this time.

C. Line:

1. No clarifications necessary at this time. See Appendix C for Transmission Line clarifications.

D. P&C:

1. No clarifications necessary at this time.

VII. CRITICAL DATES:

A. Scope of Work (This Document) – 8/13/19

B. Issue for Construction – TBD

C. Construction start – TBD

D. In-Service Date – TBD

E. Outages:

1. TBD

VIII. WORK ORDERS

Eversource WO# A19S4001 –Amherst Automation Scope

IX. PROJECT TEAM

A. Project Management Contact Details
1. Primary Contact: David Plante – Eversource
   - Tel: (603) 634-3078
   - Email: David.L.Plante@eversource.com
2. Secondary Contact: Jarett Contino – TRC
   - Tel: (207) 274-2647
   - Email: JContino@trccompanies.com
3. Any questions, comments or concerns related to Project Management should be addressed to the above named individuals.

B. S/S Engineering Contact Details
1. Primary Contact: Christopher O'Brien – Eversource
   - Tel: (603) 634-2702
   - Email: christopher.obrien@eversource.com
2. Secondary Contact: Robert Croce - TRC
   - Tel: (603) 263-9396
   - Email: rcroce@trccompanies.com
3. Any questions, comments or concerns related to S/S should be addressed to the above named individuals.

C. S/S Drafting Contact Details:
1. Primary Contact: Lisa Maille – Eversource
   - Tel: (603) 634-3295
   - Email: lisa.maille@eversource.com
2. Secondary Contact: Robert Croce - TRC
   - Tel: (603) 263-9396
   - Email: rcroce@trccompanies.com

3. Any questions, comments or concerns related to S/S drawings should be addressed to the above named individuals.

D. Telecom Engineering Contact Details:
1. Primary Contact: Nate Grant (Eversource Staff Aug)
    - Tel: (603) 634-3711
    - Email: Nathan.grant@eversource.com
2. Secondary Contact: William Perkins – TRC
    - Tel: (603) 263-9391
    - Email: wperkins@trccompanies.com
3. Any questions, comments or concerns related to Automation engineering should be addressed to the above named individuals.

E. Automation Engineering Contact Details:
1. Primary Contact: TBD by Eversource
2. Secondary Contact: William Perkins - TRC
    - Tel: (603) 263-9391
    - Email: wperkins@trccompanies.com
3. Any questions, comments or concerns related to Automation engineering should be addressed to the above named individuals.

F. P&C Engineering Contact Details:
1. Primary Contact - Distribution: Lucas Croteau – Eversource
    - Tel: (603) 634-2904
    - Email: lucas.croteau@eversource.com
2. Primary Contact - Transmission: Patrick Bradshaw – Eversource
    - Tel: (603) 634-2263
    - Email: patrick.bradshaw@eversource.com
3. Secondary Contact: Alex Norton - TRC
    - Tel: (603) 263-9398
    - Email: anorton@trccompanies.com
4. Any questions, comments or concerns related to P&C engineering should be addressed to the above named individuals.

G. P&C Drafting Contact Details:
1. Primary Contact: Lisa Maille – Eversource
    - Tel: (603) 634-3295
    - Email: lisa.maille@eversource.com
2. Secondary Contact: Jaimee Kruger - TRC

- Tel: (603) 263-9394
- Email: jkruger@trccompanies.com

3. Any questions, comments, or concerns related to drawings should be addressed to the above named individuals.

H. Transmission Line Engineering Contact Details
1. Primary Contact: Joseph Sperry, P.E. – Eversource
   - Tel: (603) 634-2562
   - Email: joseph.sperry@eversource.com
2. Secondary Contact: Not Applicable
   - Tel: NA
   - Email: NA
3. Any questions, comments or concerns related to Transmission Line Engineering should be addressed to the above named individuals.

I. Transmission Line Drafting Contact Details:
1. Primary Contact: Brent Sullivan – Eversource
   - Tel: (603) 634-3048
   - Email: geraldbrent.sullivan@eversource.com
2. Secondary Contact: Not Applicable
   - Tel: NA
   - Email: NA
3. Any questions, comments or concerns related to Transmission Line drawings should be addressed to the above named individuals.

X. EVERSOURCE STANDARDS

TRC will continue to execute the work described above using all applicable standards in the most recent Eversource Bookshelf as of the date on which the Purchase Order was received.

REDACTED

EVERSOURCE
ENERGY

APPENDIX A
34.5kV Feeder Breaker Failure Relay Replacements

I. GENERAL DESCRIPTION

The Amherst Substation Automation project will involve the replacement of GE-Fanuc PLCs with SEL-2240 Axion I/O devices. The Axions will replace all Electric System Control Center (ESCC) metering, status and control functions currently performed by the protective relays and PLC System. During the site walkdown, several equipment upgrades unrelated to the automation project were identified. This appendix addresses the replacement of the existing 34.5kV feeder breaker failure protection with modern numerical relays. The new relays would also provide a 34.5kV secondary line protection system which does not exist at the station today. The additional relaying and controls detailed by the appendix would be located in the new cabinets allocated for the primary relaying as described in the main scoping document (no additional cabinets required).

II. DETAILED DESCRIPTION OF WORK

A. Substation Electrical Design

1. No activity anticipated for this scope of work.

B. Civil Design:

1. No activity anticipated for this scope of work.

C. Line Design:

1. No activity anticipated for this scope of work.

D. 34.5kV Line and Breaker Failure Protection

1. 34.5kV Line 3445X and OCB 3445 Secondary Line and Breaker Failure Protection

Secondary line and breaker failure protection for 34.5kV line 3445X and breaker 3445 will be installed in a new cabinet located in the Distribution side of the control house. [redacted]

[redacted]

2. 34.5kV Line 3110X and OCB 3110 Secondary Line and Breaker Failure Protection

   Secondary line and breaker failure protection for 34.5kV line 3110X and breaker 3110 will be installed in a new cabinet located in the Distribution side of the control house. [redacted]

[redacted]

3. 34.5kV Line 3159X and OCB 3159 Secondary Line and Breaker Failure Protection

   Secondary line and breaker failure protection for 34.5kV line 3159X and breaker 3159 will be installed in a new cabinet located in the Distribution side of the control house. [redacted]

4. 34.5kV Line 3143X and OCB 3143 Secondary Line and Breaker Failure Protection

   Secondary line and breaker failure protection for 34.5kV line 3143X and breaker 3143 will be installed in a new cabinet located in the Distribution side of the control house. [redacted]

5. 34.5kV Line 3212X and OCB 3212 Secondary Line and Breaker Failure Protection

Secondary line and breaker failure protection for 34.5kV line 3212X and breaker 3212 will be installed in a new cabinet located in the Distribution side of the control house. [redacted],

[redacted]

III. SUMMARY OF MAJOR EQUIPMENT TO BE REMOVED

A. Substation Equipment

1. No major equipment to be removed.

B. Civil Equipment

1. No major equipment to be removed.

C. Line Equipment

1. No major equipment to be removed.

D. P&C Equipment

1. Switchboard Panel #10, Line 3445X Relaying
   - GE NGA Auxiliary Relay (62X-3445X)
2. Switchboard Panel #12, Line 3159X & 3110X Relaying
   - GE NGA Auxiliary Relay (62X-3159X)
   - GE NGA Auxiliary Relay (62X-3110X)
3. Switchboard Panel #14, Line 3143X & 3212X Relaying
   - GE NGA Auxiliary Relay (62X-3159X)
   - GE NGA Auxiliary Relay (62X-3110X)
4. Switchboard Panel #16, 34.5kV Bus 1 and Bus 2 Relaying
   - GE SB1 Permissive Switch (69-BFB1-34)

IV. SUMMARY OF MAJOR EQUIPMENT TO BE INSTALLED

A. Substation Equipment

1. No major equipment to be installed.

B. Civil Equipment

1. No major equipment to be installed.

C. Line Equipment

1. No major equipment to be installed.

D. P&C Equipment

1. Cabinet #22, 34.5kV Breaker & Line 3445X Control/Relaying (New)
   - Electroswitch Permissive Switch (69/67/LS-3445X)
   - Electroswitch Breaker Failure Permissive Switch (69/BF-3445X)
   - SEL-751 Feeder Protection Relay (67/50BF/LS-3445X)
   - ABB Test Switch Type FT-19R (TD1, 2, 3-67/50BF/LS-3445X)
   - ABB Test Switch Type FT-19R (TD4, 5, 6-67/50BF/LS-3445X)

2. Cabinet #23, 34.5kV Breaker & Line 3159X Control/Relaying (New)
   - Electroswitch Permissive Switch (69/67/LS-3159X)
   - Electroswitch Breaker Failure Permissive Switch (69/BF-3159X)
   - SEL-751 Feeder Protection Relay (67/50BF/LS-3159X)
   - ABB Test Switch Type FT-19R (TD1, 2, 3-67/50BF/LS-3159X)
   - ABB Test Switch Type FT-19R (TD4, 5, 6-67/50BF/LS-3159X)

3. Cabinet #24, 34.5kV Breaker & Line 3110X Control/Relaying (New)
   - Electroswitch Permissive Switch (69/67/LS-3110X)
   - Electroswitch Breaker Failure Permissive Switch (69/BF-3110X)
   - SEL-751 Feeder Protection Relay (67/50BF/LS-3110X)
   - ABB Test Switch Type FT-19R (TD1, 2, 3-67/50BF/LS-3110X)
   - ABB Test Switch Type FT-19R (TD4, 5, 6-67/50BF/LS-3110X)

4. Cabinet #25, 34.5kV Breaker & Line 3143X Control/Relaying (New)
   - Electroswitch Permissive Switch (69/67/LS-3143X)
   - Electroswitch Breaker Failure Permissive Switch (69/BF-3143X)
   - SEL-751 Feeder Protection Relay (67/50BF/LS-3143X)
   - ABB Test Switch Type FT-19R (TD1, 2, 3-67/50BF/LS-3143X)
   - ABB Test Switch Type FT-19R (TD4, 5, 6-67/50BF/LS-3143X)

5. Cabinet #26, 34.5kV Breaker & Line 3212X Control/Relaying (New)
   - Electroswitch Permissive Switch (69/67/LS-3212X)
   - Electroswitch Breaker Failure Permissive Switch (69/BF-3212X)
   - SEL-751 Feeder Protection Relay (67/50BF/LS-3212X)

- ABB Test Switch Type FT-19R (TD1, 2, 3-67/50BF/LS-3212X)
- ABB Test Switch Type FT-19R (TD4, 5, 6-67/50BF/LS-3212X)

REDACTED

APPENDIX B
345/34.5kV Transformer TB68 Primary Relay Replacements

I. GENERAL DESCRIPTION

The Amherst Substation Automation project will involve the replacement of GE-Fanuc PLCs with SEL-2240 Axion I/O devices. The Axions will replace all Electric System Control Center (ESCC) metering, status and control functions currently performed by the protective relays and PLC System. During the site walkdown, several equipment upgrades unrelated to the automation project were identified. This appendix addresses the replacement of the existing 345/34.5kV transformer TB68 primary protection and 34.5kV Bus#1 secondary protection with modern numerical relays. The new relaying would be located in a new cabinet that would be in addition to the cabinets described in the main scoping document.

An NPCC Directory 4 presentation will be required since the relay replacement will involve converting from numerical to non-numerical.

II. DETAILED DESCRIPTION OF WORK

A. Substation Electrical Design

1. No activity anticipated for this scope of work.

B. Civil Design:

1. No activity anticipated for this scope of work.

C. Line Design:

1. No activity anticipated for this scope of work.

D. 345-34.5kV Transformer Protection

1. 345-34.5kV Transformer TB68 Primary Protection

New primary transformer current differential protection for the existing 345-34.5 kV Transformer TB68 will be installed in a new cabinet located in the Distribution side of the control house. [redacted]

[redacted]

E. 34.5kV Bus #1 Secondary Protection

The existing Basler BE1-51 bus overcurrent protection for 34.5kV Bus #1 will be removed and replaced with a new numerical relay system.

[redacted]

III. SUMMARY OF MAJOR EQUIPMENT TO BE REMOVED

A. Substation Equipment

1. No major equipment to be removed.

B. Civil Equipment

1. No major equipment to be removed.

C. Line Equipment

1. No major equipment to be removed.

D. P&C Equipment

1. Switchboard Panel "TP TB68", Transformer TB68 Primary Relaying
   - GE STD Differential Relay (87-A/TP-TB68)
   - GE STD Differential Relay (87-B/TP-TB68)
   - GE STD Differential Relay (87-B/TP-TB68)
   - ABB AR Tripping Relay (94/TP-TB68)

- GE SB1 Permissive Switch (69-87/TP-TB68)
- GE HEA Lockout Relay (86-1/TP-TB68)
- GE HEA Lockout Relay (86-2/TP-TB68)
- Various Auxiliary Relays, Indicating Lights, and Terminal Blocks

2. Switchboard Panel #16, 34.5kV Bus #1 Secondary Relaying
   - Basler BE1-51 Phase Overcurrent Relay (50-51/B1S-34)
   - Basler BE1-51 Neutral Overcurrent Relay (51NL/B1S-34)
   - GE SB1 Permissive Switch (69-51NL-B1S-34)
   - GE HEA Lockout Relay (86-1/B1S-34)
   - GE HEA Lockout Relay (86-2/B1S-34)
   - Various Auxiliary Relays, Indicating Lights, and Terminal Blocks

IV. SUMMARY OF MAJOR EQUIPMENT TO BE INSTALLED

A. Substation Equipment

1. No major equipment to be installed.

B. Civil Equipment

1. No major equipment to be installed.

C. Line Equipment

1. No major equipment to be installed.

D. P&C Equipment

1. Cabinet #27, 345-34.5kV Transformer TB68 Primary Relaying (New)
   - Schweitzer SEL-587 Differential Relay (87/TP-TB68)
   - ABB Test Switch Type FT-19R (TD1, 2, 3-87/TP-TB68)
   - Electroswitch Lockout Relay (86/TP-TB68)
   - Electroswitch Control Switch (69/87/TP-TB68)
   - ABB Test Switch Type FT-19R (TD1-86/TP-TB68)

2. Cabinet #36, 345/34.5kV Transformer TB68 and 34.5kV Bus #1 Control/Relay (Existing)
   - Schweitzer SEL-351-7 Overcurrent Relay (50/51/B1S-34)
   - ABB Test Switch Type FT-19R (TD1, 2, 3-50/51/B1S-34)
   - ABB Test Switch Type FT-19R (TD4, 5, 6-50/51/B1S-34)
   - Electroswitch Control Switch (69/51NL/B1S-34)
   - Electroswitch Lockout Relay (86/B1S-34)
   - ABB Test Switch Type FT-19R (TD1, 2, 3-86/B1S-34)

APPENDIX C
345kV Power-Line Carrier Equipment Replacements

I. GENERAL DESCRIPTION

The Amherst Substation Automation project will involve the replacement of GE-Fanuc PLCs with SEL-2240 Axion I/O devices. The Axions will replace all Electric System Control Center (ESCC) metering, status and control functions currently performed by the protective relays and PLC System. During the site walkdown, several equipment upgrades unrelated to the automation project were identified. This appendix addresses the replacement of the existing 345kV Power-Line Carrier systems associated with 345kV Line 367 and 345kV Line 3195.

II. DETAILED DESCRIPTION OF WORK

A. Substation Electrical Design

1. The existing wave traps and line tuners associated with 345kV line 367 and 345kV line 3195 will be removed. New strain bus will be installed on phase B from the high bus to low bus for both line 367 and 3195.

2. One new splice can will be installed on the line 3195 terminal structure at Eagle to transition to ADSS fiber optic cable for control house entry. Conduit will be installed from the Eagle 345kV line 3195 terminal structure to the cable trench. The 4" conduit will rise 6 feet above grade, contain three 1.25" I.D., orange, corrugated innerducts, and will be sealed with triplex, simplex, and blank duct plugs. The two unused innerducts will terminate 3 feet inside the trench fastened to the wall. The innerduct occupied by the new ADSS fiber optic cable will be continuous from the terminal structure, through the trench, into the control house and will be fastened in an elevated position on the wall of the trench to minimize water exposure.

B. Civil Design:

1. The two (2) existing 1 phase 345kV wave trap stands will be removed. The two (2) foundations along with one (1) previously abandoned wave trap foundation will be chipped below grade.

C. Line Design:

REDACTED

1. The existing shield wire (north static position) will be replaced with 48 fiber OPGW between 345kV Line 3195 structures 103 and 93 (1.14 miles), 93 and the Eagle 345kV (.34 miles) terminal structure. The OPGW will be spliced to existing splice cans on 3195/103 and 3195/93.

D. 345kV Line Protection

1. Primary Line 367 Protection (21Z/LP-367)

   The existing primary SEL-421 relay, device 21Z/LP-367, and primary RFL 9785 carrier set, device 85DCB/LP-367 will be removed.

   New primary protection for line 367 will be installed in existing cabinet #42. [redacted]

   The remote Schweitzer SEL-421 relay, device 21Z/LP-367, and associated RFL-9785 carrier set, device 85DCB/LP-367, located at Fitzwilliam Substation will be removed and replaced with a new Schweitzer SEL-411L. This work is covered under a separate work order.

2. Secondary Line 367 Protection (21Z/LS-367, 85POTT/LS-367)

   Existing relay communication connections will be removed from the existing JMUX T1MUX (not ring protected) to the new SEL-ICON SONET multiplexer (ring protected).

3. Primary Line 3195 Protection (21Z/LP-3195)

   The existing primary SEL-421 relay, device 21Z/LP-3195, and its associated JMUX cards will be removed.

   New primary protection for line 3195 will be installed in existing cabinet #42. [redacted]

REDACTED

[redacted]

The remote Schweitzer SEL-421 relay, device 21Z/LP-3195, and its associated JMUX cards, located at Eagle 345kV Substation will be removed and replaced with a new Schweitzer SEL-411L. This work is covered under a separate work order.

4. Secondary Line 3195 Protection (21Z/LS-3195)

Note this section supersedes the changes described in the base scope section II.E.4

The existing secondary GE-D60 relay, device 21Z/LS-3195, and secondary RFL 9785 carrier set, device 85DCB/LS-3195 will be removed.

The new secondary protection for line 3195 will be a Permissive Overreaching Transfer Trip (POTT) scheme in addition to a new step distance scheme. [redacted]

The remote GE D60 relay, device 21Z/LS-3195, and associated RFL-9785 carrier set, device 85DCB/LS-3195, located at Eagle 345kV Substation will be removed and replaced with a new Schweitzer SEL-311C. This work is covered under a separate work order.

E. Telecommunications

1. Fiber Optic Cable

Install wall mounted fiber demark and fiber patch panel for new 48 fiber cable entry at Eagle 345kV.

Install one fiber patch cable in fiber patch panel "FPP" in Eagle 115kV to connect redundant SEL ICON SONET link.

Remove WDM module from Amherst fiber patch panel then install in Busch fiber patch panel to preserve ring redundancy of ICON/Lucent SONET fiber.

Fiber optic splice can engineering of line 3195 and fiber splicing will be handled by Eversource.

2. Multiplexers

Three new SEL ICON SONET multiplexers will be installed at Fitzwilliam, Amherst, and Eagle 345kV. The Fitzwilliam SEL ICON will replace the existing Lucent DMXtend with dual ring connections. The ICONs will join the existing Lucent/ICON SONET ring which provides true ring redundancy.

Existing line 367 and line 3195 protection, utilizing JMUX, will be removed and all secondary relay schemes on both lines will connect to the new SEL ICON nodes.

JMUX equipment associated with line 367 will be removed at Fitzwilliam and Amherst.

III. SUMMARY OF MAJOR EQUIPMENT TO BE REMOVED

A. Substation Equipment

1. Two (2) Wave Traps and associated line tuners.

B. Civil Equipment

1. Two (2) Wave Trap Stands

C. Line Equipment

1. Northern shield wire between 3195/103 and Eagle 345kV terminal structure.

D. P&C Equipment

1. Cabinet #32, 345kV Secondary Line Relaying
   - GE D60 Line Relay (21Z/LS-3195)
   - RFL 9785 Carrier Set (85DCB/LS-3195)
   - Electroswitch Series 24 Permissive Switch (69/LS-3195)

2. Cabinet #42, 345kV Primary Line Relaying
   - SEL-421 Line Relay (21Z/LP-367)
   - RFL 9785 Carrier Set (85DCB/LP-367)
   - Electroswitch Series 24 Permissive Switch (69/LS-3195)

E. Telecommunications Equipment

1. Fitzwilliam Comm Rack
   - Lucent DMXtend
   - JMUX Equipment (associated with Amherst circuits)

2. Amherst Comm Rack
   - JMUX Equipment (associated with Fitzwilliam circuits)
   - WDM Module

IV. SUMMARY OF MAJOR EQUIPMENT TO BE INSTALLED

A. Substation Equipment

1. Fiber optic splice can on Eagle 345kV line 3195 terminal structure.

2. 4” conduit from Eagle 345kV line 3195 terminal structure to cable trench.

3. Strain bus on phase B to connect high side and low side for 345kV line 3195 and 345kV line 367.

B. Civil Equipment

1. No major equipment to be installed.

C. Line Equipment

1. 48 fiber OPGW cable between 3195/103 and 3195/93, 3195/93 and Eagle 345kV terminal structure.

   - OPGW will tie into an existing fiber can on Structure 3195/93.

D. <u>P&C Equipment</u>

1. Cabinet #32, 345kV Secondary Line Relaying
   - SEL-311C Line Relay (21Z/LS-3195)
   - Electroswitch Control Switch (69/MAINT/LS-3195)

2. Cabinet #42, 345kV Primary Line Relaying
   - SEL-411L Line Relay (87/LP-367)
   - SEL-411L Line Relay (87/LP-3195)

E. <u>Telecommunications Equipment</u>

1. Fitzwilliam Comm Rack
   - SEL ICON SONET Multiplexer

2. Amherst Comm Rack
   - SEL ICON SONET Multiplexer

3. Eagle 345kV (Comm Rack?)
   - SEL ICON SONET Multiplexer
   - Fiber Backboard
   - Wall-mounted fiber patch panel

4. Busch (Comm Rack?)
   - WDM Module

V. CLARIFYING COMMENT & ASSUMPTIONS

List any additional information regarding the scope of the project. Include assumptions used.

A. S/S
B. P&C
C. Civil
D. Line

i This scope assumes that new fiber will be run on the 3195 line from 3195/103 Eagle SS Terminal Structure. Fiber from the terminal structure will be underground through conduit/cable trench to the substation control house.

ii Substation Engineering will be responsible for the design of the conduit and innerduct from the control equipment to the closest structure where fiber is installed. Substation Contractor/Engineering will complete the conduit riser above ground and install ADSS cable

iii No investigation has been complete on the availability of line outages for the fiber optic installation. Final fiber configuration may vary based on available outages.

REDACTED

[redacted]

CONFIDENTIAL
CIP
HANDLE PER
CIP-011 PRO-01

ADDITIONS

MATERIAL LISTS

(KAA) ORIGINAL CONTROL HOUSE MATERIAL LIST, DRAWING #002314012
(K01) 2003 CONTROL HOUSE ADDITION MATERIAL LIST, DRAWING #002316002

CONTRACT SERVICES

DWG REV	EPR/DESCRIPTION	CONT/PE#	DATE	DRN	CHKD	APPR
3	6891 – DFR INSTALLATION AS-BUILT		04/10	LAW	EME	LTW
2	6891 – DFR INSTALLATION I.C		09/09	DCG	EME	LTW
1	6840 – CIP AS-BUILT		05/09	LAW	EME	LTW

REDRAWN FOR REVISION 6891

EVERSOURCE ENERGY

CONTROL HOUSE
EQUIPMENT ARRANGEMENT PLAN
345/34.5KV
AMHERST S/S

D 3
LAW
EME
EME
LTW
04/10

1/4"=1'-0"

002315001

AMHERST AUTOMATION (LINES 367 & 3195)
FIBER MULTIPLEXER REMOVALS

REDACTED

[redacted]

AMHERST AUTOMATION (LINES 367 & 3195)
FIBER MULTIPLEXER ADDITIONS

[redacted]

EVERSOURCE
Project Authorization Form

Operations Program Level Project Authorization Form

Approved at March 06, 2019 EPAC
Link to Meeting Minutes

Date Prepared: February 5, 2019	**Project Title: Substation Animal Protection**
Company/ies: Eversource NH	**Project ID Number (by state): A19X22**
Organization: NH Operations	**Class(es) of Plant: Distribution Substation**
Project Initiator: Thelma Brown	**Project Category: Stations – Other**
Project Manager: TBD	**Project Type: Program**
Project Sponsor: John Zicko	**Project Purpose: Install animal protection systems in substations**
Estimated in service date: See associated Program Release Forms	**If Transmission Project: PTF? See associated Program Release Forms**
Eng. /Constr. Resources Budgeted? See associated Program Release Forms	**Capital Investment Part of Original Operating Plan? See associated Program Release Forms Yes**
Authorization Type: Program Approval	**O&M Expenses Part of the Original Operating Plan? See associated Program Release Forms**
Estimated Program Value (by State): $2.5M Projected unit cost $100K.	

Financial Requirements:

Project Authorization

ERM: ______________________________

FP&A: ______________________________

Executive Summary

Outages caused by animals in substations can affect the reliability to thousands of customers for a single event. A NH capital program has been identified in the five-year business plan to provide animal protection systems throughout substations.

This Program Project Authorization Form is to request funding for a five-year program identified at $500,000 per year for a total of $2,500,000. The estimated unit cost per station is $100K and it is expected that approximately five (5) stations will be equipped with animal protection systems per year.

This program is requesting program approval of $2,500,000 and identifies for information only projected unit costs. Dollar authorization for these costs shall be through submission of individual program releases. Program Release Form submissions shall occur in accordance with the locations and phases identified in this document. "Project Checklist – Transmission & Substation" will be submitted with each Program Release Form.

Financial Unit Cost Evaluation

The per-unit cost estimate is based on the animal protection installation at Tasker Farm SS estimate serving as a proxy for the general population since the effort required at Tasker Farm reflects the level of effort for a typical 34.5kV substation. The per-unit cost approaches $100K based on internal resources performing the work.

Note: Dollar values are in thousands and are unit level costs for Program PAFs

Direct Capital Costs	Year 1	Year 2	Year 3+	Total
Straight Time Labor	$25			
Overtime Labor	$0			
Outside Services	$0			
Materials	$35			
Total - Direct Spending	$60			
Other, including contingency amounts (describe)	$15			
Total Direct Costs	**$75**			

Indirect Capital Costs	Year 1	Year 2	Year 3+	Total
Indirects/Overheads (including benefits)	$22			
Capitalized interest or AFUDC, if any	$3			
Total Indirect Costs	**$25**			
Total Capital Costs	**$100**			
Less Total Customer Contribution	**$0**			
Total Capital Project Costs	**$100**			
Total O&M Project Costs	**$0**			

Note: Other costs include scheduling outages, temporary construction, equipment rental, vendor support during construction.

EVERSOURCE
Project Authorization Form

Future Financial Impacts:

Provide below the estimated future costs that will result from the project:
Note: Dollar values are in thousands:

Future Costs	Year 20__	Year 20__	Year20__	Year 20__+	Total Future Project Costs
Capital	$ -	$ -	$ -	$ -	$ -
O&M	-	-	-	-	-
Other	-	-	-	-	-
TOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Describe the estimated future Capital, O&M and/or Other costs noted above:
NA

What functional area(s) will these future costs be funded in? N/A

<u>If this is other than a Reliability Project, please complete the section below;</u>

Provide below the estimated financial benefits that will result from the project:
Note: Dollar values are in thousands:

Future Benefits	Year 20__	Year 20__	Year20__	Year 20__+	Total Future Project Benefits
Capital	$ -	$ -	$ -	$ -	$ -
O&M	-	-	-	-	-
Other	-	-	-	-	-
TOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Describe the estimated future Capital, O&M and/or Other benefits noted above:
NA

What functional area(s) will these benefits be reflected in? N/A

Asset Retirement Obligation (ARO) and/ or Environmental Cleanup Costs (Environmental Liabilities):

Is there an ARO associated with this project? If yes, please provide details:
No

Are there other environmental cleanup costs associated with this project? If yes, please provide details: No

Technical Justification:

Project Need Statement

Outages caused by animals in substations can affect the reliability to thousands of customers for a single event. A NH distribution capital program has been identified in the five-year business plan to provide animal protection systems throughout substations.

Project Objectives

Install animal protection systems in substations to improve reliability to customers.

Project Scope

This program is to provide an animal protection system for complete substations. This will include covering systems by Tyco or GreenJacket which are approved as capital assets when installed as a complete system. Another type of animal protection is an electrified fence inside the substation.

The systems being installed under this program are complete systems that are capital expenditures. Attached is a parts list (Attachment A) for the proposed systems for Tasker, Amherst, and Thornton SS as an example of the scope at a substation. The attached one-lines for Tasker, Amherst, Thornton, and Valley St. (Attachment B) highlight what parts of the system are covered. Note that animal protection systems will be included in the scope for some substations as part of the NH 34.5kV OCB Replacement Program. However, if a full coverage system is required sooner based on priority rating (such as at Amherst) prior to the OCB replacement project, the animal protection system will be done under this Program PAF.

Attached is a Priority list (Attachment C) which identifies all the substations that have the potential need for animal protection systems based on MVA capacity or history of outages. Note that a recent animal strike at a substation will likely reprioritize the substations on this list. For example, if a station with no current history of hits and a priority rating #96 has an incident, it may move up to the top of the list. The determination for which type of system will be installed at any one facility, i.e. a coverup versus electric fence versus other system, has yet to be determined for other than the top priority facilities. Substations not on the list are those with secondary switchgear, existing systems, the potential for other project related solutions, and those being eliminated in the next few years.

The 2019 scope of work includes addressing a minimum of four substations. Program Releases will be presented for each facility for approval. The substations targeted for 2019 are:

Substation	Type of Protection	Estimated cost	# Customers
Tasker Farm SS	Covering System	$100,000	9,527
Amherst SS	Covering System	$120,000	24,023
Thornton SS	Covering System	$75,000	3,459
Valley St SS	Electric Fence	$100,000	6,802

These substations are targeted because they have a history of animal outages, the customer impact is high for an animal outage, or they have been identified as high risk for animal outages. The plan is to continue this program over five years to address the highest priority substations.

Background / Justification

Twenty-five (25) animal related outages have occurred in New Hampshire substations over the past ten (10) years. Each event can affect thousands of customers. The history of substation animal outages is provided below.

DATE	SUBSTATION	# CUSTOMERS	NOTES
09/21/2018	NEW RIMMON[1]	5,994	Raven on disconnect switch
07/27/2018	MERRIMACK	968	Squirrel contact on recloser
07/26/2018	WEARE	2051	Raven contacted the bus
06/01/2018	BEDFORD	5,490	Fisher Cat on 34.5 kV circuit breaker
05/30/2018	TASKER	7,732	Crow on the bus work
05/04/2018	NEW RIMMON[1]	2,674	Raven pecking LA
04/30/2018	NEW RIMMON[1]	10,015	Raven on station service
07/27/2017	NEW RIMMON[1]	10,138	Raven on bus 2
05/17/2017	NEW RIMMON[1]	10,138	Raven on bus 2
10/02/2016	NEW RIMMON[1]	2,351	Raven on bus 1
09/16/2016	NEW RIMMON[1]	9,890	Raven on station service
09/04/2016	NEW RIMMON[1]	9,890	Raven pecking LA
07/24/2016	NEW RIMMON[1]	4,037	Raven on disconnect switch
01/21/2016	PINE HILL	3,572	Hawk flew into disconnect
10/27/2014	ANHEUSER BUSCH	1	Squirrel on recloser
10/07/2014	RIMMON	2,057	Bird on breaker/bus
06/26/2013	VALLEY STREET	2,210	Squirrel on breaker
06/13/2013	VALLEY STREET	4,246	Squirrel on breaker
06/11/2013	MAMMOTH RD	608	Crow on station service bus
02/06/2013	ASHLAND	1	Squirrel on transformer
10/04/2012	PACKERS FALLS	407	Bird on station service bus
08/07/2011	VALLEY STREET	713	Animal(squirrel?) on transformer
09/03/2010	RIMMON	2,569	Squirrel on station service bus
09/30/2009	RIMMON	2,569	Raven on switch
08/20/2009	SCOBIE POND	1,856	Squirrel on buswork

[1] Note that the NEW RIMMON location is being addressed in a separate animal protection project A19C33.

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Project Authorization Form

Business Process and / or Technical Improvements:

Improve system reliability through prevention of unplanned outages caused by animal contacts.

Alternatives Considered with Cost Estimates

Alternative one – Do nothing. Station Operations has requested a proactive approach to addressing animal protection at substations, so this alternative does not meet that objective.

Project Schedule

Milestone/Phase Name	Estimated Completion Date
Program approval at EPAC	3/15/19
Complete Program – see Note	12/31/23

Note: This program is currently identified in the five-year business plan budget for $500K per year. Adjustments to the annual needs and spending will be made accordingly throughout each year.

Regulatory Approvals

None identified. If regulatory approvals are identified for a specific substation, it will be identified in that Program Release.

Risks and Risk Mitigation Plans

Weather and system related issues which do not allow outages for installation of animal protection.

- Schedule outages as soon as possible.
- Acquire materials and be prepared to do work as outages and schedules permit.

If additional risks are identified for a specific substation, they will be identified in that Program Release.

References

N/A

Attachments (One-Line Diagrams, Images, etc.)

- Attachment A - UPSC quotes for TYCO material for Tasker, Amherst, and Thornton Substations Priority List for Animal Protection

- Attachment B – One-Lines

  - Tasker Farm SS One-Line D-9845
  - Amherst SS One-Line D8134
  - Thornton SS One-Line D-9345
  - Valley Street SS One-Line D-7750
  - Valley Street General Arrangement

- Attachment C - Priority List for Animal Protection

Cost Estimate Backup Details

A detailed cost estimate backup summary will be provided with each Program Release.

UPSC

Eversource New Hampshire

February 7, 2019

We are pleased to provide you with follow quote on the requested TE/Raychem Raysulate line of products based for the Thornton Substation. All the material for the job would be skidded together and shipped complete. Where available stock codes for approved items are listed. Eversource MA East has been covering up their substations over the past 2-3 years with this material. We would kit all the material for this substation together and label all the box with material what station it is for.

TE Energy products are made from a premium grade, proprietary polymer blend that is non-tracking, extremely high temperature resistant, and designed to last 30+ years.

Training and Installation Assistance
Regarding training and installation assistance, TE - Energy and the Raysulate team stand ready to train Eversource crews, or any subcontractors picked by them, in the installation of our animal mitigation products. Again, we thank you for this opportunity to participate in your wildlife protection initiative. We feel confident that our 40+ years of experience can provide you a program that will exceed your expectations.

Tyco Product Description	Qty Req.	Device/ Location	EA.	EXT.	Product links
BISG-G-24-01 (Cat ID# unknown)	36	Hook Switches	$97.68	$3,516.48	BISG-G-24-01(B10): CR8834-000 Raychem | TE Connectivity
BCAC-G-IC-10.5D/20 (Cat ID# 25395)	3	Low Side Transformer	$75.00	$225.00	Not yet on website, see attached data sheet
BCAC-G-IC-8D/18 (Cat ID# 23523 & 21749)	36	Breaker Bushings	$45.35	$1,632.60	BCAC-G-IC-8D/18(B6): CR3053-000 Raychem | TE Connectivity
BCAC-G-IC-5D/6 (Cat ID# 24658)	18	Small Arresters / Station Transformers	$10.65	$191.70	BR3669-000 – Raychem – BCAC | TE Connectivity
BCIC-G-13D/13-HO (Cat ID# 24657)	3	Large Arresters	$204.95	$614.85	BCIC-13D/13-HO(B3): 953853-000 Raychem | TE Connectivity
BCIC-G-8.25D/8 (Cat ID# unknown)	12	PT's	$117.50	$1,410.00	Not yet on website, see attached drawing
BISG-G-100/400 (Cat ID# unknown)	108	Gang Switches / Bus Supports	$130.00	$14,040.00	Not yet on website, see attached drawing
MVCC-G-45/1.75x4 (Cat ID# 25904)	168 ft.	XLarge Bare Conductor Cover	$11.55	$1,940.40	MVCC-G-45/1.75X4(B24): CAT-MVCC, MVCC | TE Connectivity
MVCC-G-10/.40 (Cat ID# 25346)	100 ft.	Small Bare Conductor Cover	$5.95	$595.00	CP4754-000 Raychem Power Systems : MVCC | TE Connectivity
MVFT-G-2-12 (Cat ID# 24660	8 rolls	Fusion Tape (as needed)	$43.95	$351.60	Not yet on website, see attached data sheet

Continued $24,517.63

UPSC

Eversource New Hampshire

February 7, 2019

We are pleased to provide you with follow quote on the requested TE/Raychem Raysulate line of products based for the Amherst Substation. All the material for the job would be skidded together and shipped complete. Where available stock codes for approved items are listed. Eversource MA East has been covering up their substations over the past 2-3 years with this material. We would kit all the material for this substation together and label all the box with material what station it is for.

TE Energy products are made from a premium grade, proprietary polymer blend that is non-tracking, extremely high temperature resistant, and designed to last 30+ years.

Training and Installation Assistance
Regarding training and installation assistance, TE - Energy and the Raysulate team stand ready to train Eversource crews, or any subcontractors picked by them, in the installation of our animal mitigation products. Again, we thank you for this opportunity to participate in your wildlife protection initiative. We feel confident that our 40+ years of experience can provide you a program that will exceed your expectations.

Tyco Product Description	Qty Req.	Device/ Location	EA.	EXT.	Product links
BISG-G-24-01 (Cat ID# unknown)	28	Hook Switches /Bus Supports	$97.68	$2,735.04	BISG-G-24-01(B10): CR8834-000 Raychem | TE Connectivity
BCAC-G-IC-10.5D/20 (Cat ID# 25395)	42	Low Side Transformer / Breaker Bushings	$75.00	$3,150.00	Not yet on website, see attached data sheet
BCAC-G-IC-7D/12 (Cat ID# 24544)	42	Small Arresters	$30.25	$1,270.50	http://www.te.com/usa-en/product-CS7743-000.html
BCAC-G-IC-5D/6 (Cat ID# 24658)	6	Station Transformers	$10.65	$63.90	BR3669-000 – Raychem – BCAC | TE Connectivity
BCIC-G-13D/13-HO (Cat ID# 24657)	36	Large Arresters/ Large Breakers	$204.95	$7,378.20	BCIC-13D/13-HO(B3): 953853-000 Raychem | TE Connectivity
BCIC-G-8.25D/8 (Cat ID# unknown)	30	PT's / CT's	$117.50	$3,525.00	Not yet on website, see attached drawing
BISG-G-100/400 (Cat ID# unknown)	132	Gang Switches / Bus Supports	$130.00	$17,160.00	Not yet on website, see attached drawing
MVCC-G-45/1.75x4 (Cat ID# 25904)	168 ft.	XLarge Bare Conductor Cover	$11.55	$1,940.40	MVCC-G-45/1.75X4(B24): CAT-MVCC, MVCC | TE Connectivity
MVCC-G-10/.40 (Cat ID# 25346)	100 ft.	Small Bare Conductor Cover	$5.95	$595.00	CP4754-000 Raychem Power Systems : MVCC | TE Connectivity
MVFT-G-2-12 (Cat ID# 24660)	8 rolls	Fusion Tape (as needed)	$43.95	$351.60	Not yet on website, see attached data sheet

Continued $38,169.64

UPSC

Eversource New Hampshire

February 7, 2019

We are pleased to provide you with follow quote on the requested TE/Raychem Raysulate line of products based for the Tasker Substation. All the material for the job would be skidded together and shipped complete. Where available stock codes for approved items are listed. Eversource MA East has been covering up their substations over the past 2-3 years with this material. We would kit all the material for this substation together and label all the box with material what station it is for.

TE Energy products are made from a premium grade, proprietary polymer blend that is non-tracking, extremely high temperature resistant, and designed to last 30+ years.

Training and Installation Assistance
Regarding training and installation assistance, TE - Energy and the Raysulate team stand ready to train Eversource crews, or any subcontractors picked by them, in the installation of our animal mitigation products. Again, we thank you for this opportunity to participate in your wildlife protection initiative. We feel confident that our 40+ years of experience can provide you a program that will exceed your expectations.

Tyco Product Description	Qty Req.	Device/ Location	EA.	EXT.	Product links
BISG-G-24-01 (Cat ID# unknown)	42	Hook Switches / Bus Supports	$97.68	$4,102.56	BISG-G-24-01(B10): CR8834-000 Raychem | TE Connectivity
BCAC-G-IC-10.5D/20 (Cat ID# 25395)	6	Low Side Transformer	$75.00	$450.00	Not yet on website, see attached data sheet
BCAC-G-IC-8D/18 (Cat ID# 23523 & 21749)	24	Breakers	$45.35	$1,088.40	BCAC-G-IC-8D/18(B6): CR3053-000 Raychem | TE Connectivity
BCAC-G-IC-5D/6 (Cat ID# 24658)	6	Station Transformers	$10.65	$63.90	BR3669-000 – Raychem – BCAC | TE Connectivity
BCIC-G-13D/13-HO (Cat ID# 24657)	18	Large Arresters	$204.95	$3,689.10	BCIC-13D/13-HO(B3): 953853-000 Raychem | TE Connectivity
BCIC-G-8.25D/8 (Cat ID# unknown)	22	PT's / CT's	$117.50	$2,585.00	Not yet on website, see attached drawing
BISG-G-100/400 (Cat ID# unknown)	134	Gang Switches / Bus Supports	$130.00	$17,420.00	Not yet on website, see attached drawing
MVCC-G-45/1.75x4 (Cat ID# 25904)	312 ft.	XLarge Bare Conductor Cover	$11.55	$3,603.60	MVCC-G-45/1.75X4(B24): CAT-MVCC, MVCC | TE Connectivity
MVCC-G-10/.40 (Cat ID# 25346)	300 ft.	Small Bare Conductor Cover	$5.95	$1,785.00	CP4754-000 Raychem Power Systems : MVCC | TE Connectivity
MVFT-G-2-12 (Cat ID# 24660	8 rolls	Fusion Tape (as needed)	$43.95	$351.60	Not yet on website, see attached data sheet

Continued $35,139.16

REDACTED

[redacted]

LAST REVISION DETAIL
CHANGE NORMAL AND ALTERNATE STATION SERVICE

EVERSOURCE ENERGY NEW HAMPSHIRE				EASTERN
TASKER FARM 34 MCKEAGNEY ROAD, MILTON, NH				
DRN. WNT	CHKD. CAB	APPR. CEC	5/22/18	D-9845

REDACTED

[redacted]

EVERSOURCE ENERGY NEW HAMPSHIRE			SOUTHERN	
AMHERST 2 HERTZKA DRIVE, AMHERST, NH 673-7832				
DRN. WNT	CHKD. CAB	APPR. CBC	6/9/16	D-6134

REDACTED

[redacted]

LAST REVISION DETAIL
UPDATE SUBSTATION ADDRESS

EVERSOURCE ENERGY				SOUTHERN
THORNTON S/S 239 D.W. HIGHWAY, MERRIMACK, NH				
DRN. WWT	CHKD. KR	APPR. CEC	7/10/17	D-9345

/d/021002/038129345

REDACTED

[redacted]

Electric Fence
Installation
Around all equipment shown.

EVERSOURCE ENERGY NEW HAMPSHIRE	CENTRAL
VALLEY STREET 629 BELL STREET, MANCHESTER, NH 603-625-5775	
DRN. WRT / CHKD. KR / APPR. CEC / 10/12/18	D-7750

REDACTED

[redacted]

IMAGE LIST

REVISIONS

SYSTEM PROJECTS – SUBSTATION ENGINEERING

SAS

GENERAL ARRANGEMENT
PLAN
VALLEY ST. 34.5/12.47/4.16KV S/S
MANCHESTER, NH

02891400

Public Service of New Hampshire
SUBSTATIONS
AN MAL PROTECTION PRIORITY

Substation	Primary (kV)	Secondary (kV)	Capacity (MVA)
Tasker Farm, Milton	115	34.5	45
Amherst, Amherst	345	34.5	280
Thornton, Merrimack	115	34.5	45
Valley Street, Manchester	34.5	12.47	13
Bedford, Bedford	115	34.5	90
Mammoth Road, Londonderry	115	34.5	90
Weare, Weare	115	34.5	45
Timber Swamp, Hampton	345	34.5	280
Huse Road, Manchester	115	34.5	93
Chester, Chester	115	34.5	90
Spring Street, Claremont	46	12.5	14
Sugar River, Claremont	46	12.5	14
Byrd, Claremont	46	12.5	13
Hudson, Hudson	115	34.5	90
Madbury, Madbury	115	34.5	90
North Road, Sunapee	115	34.5	90
Oak Hill, Concord	115	34.5	90
Ocean Road, Greenland	115	34.5	90
Rochester, Rochester	115	34.5	90
Jackman, Hillsboro	115	34.5	73
Beebe River, Campton	115	34.5	45
Brentwood, Brentwood	115	34.5	45
Great Bay, Stratham	115	34.5	45
Kingston, Kingston	115	34.5	45
North Woodstock, Woodstock	115	34.5	45
Saco Valley, Conway	115	34.5	45
South Milford, Milford	115	34.5	45
Whitefield, Whitefield	115	34.5	45
Chestnut Hill, Hindsdale	115	34.5	25
Lost Nation, Northumberland	115	34.5	25
Pemigeswasset, New Hampton	115	34.5	20
Portland Street, Rochester	34.5	12.47	16
Bristol, Bristol	34.5	12.47	13
Community St, Berlin	34.5	4.16	13
Malvern Street, Manchester	34.5	12.47	13
Millyard, Nashua	34.5	4.16	13
Pinardville, Goffstown	34.5	12.47	13
West Rye, Rye	34.5	12.47	13
Bridge Street, Nashua	115	4.16	11
Ash Street, Derry	34.5	12.47	11
Jackson Hill, Portsmouth	34.5	12.47	11
Meetinghouse Road, Bedford	34.5	12.47	11
Somersworth, Somersworth	34.5	13.8	11
South Manchester, Manchester	34.5	12.47	11
South Manchester, Manchester	34.5	4.16	11
Hanover Street, Manchester	34.5	12.47	9
North Rochester, Milton	34.5	12.47	9
Black Brook, Gilford	34.5	12.47	8
Foyes Corner, Rye	34.5	12.47	8
Center Ossipee, Ossipee	34.5	12.47	8
Front Street, Nashua	34.5	4.16	8
Littleworth Road, Dover	34.5	12.47	8
Lochmere, Tilton	34.5	12.47	8
Portland Pipe, She burne	34.5	4.16	8
Sanbornville, Sanbornville	34.5	12.47	8
Blue Hill, Nashua	34.5	4.16	6
Edgeville, Nashua	34.5	4.16	6
Franklin, Franklin	34.5	4.16	6
Hancock, Hancock	34.5	12.47	6
Loudon, Loudon	34.5	12.47	6
New London, New London	34.5	12.47	6
Long Hill, Nashua	34.5	12.47	5
Contoocook, Hopkinton	34.5	12.47	5
Great Falls Upper, Somersworth	13.8	2.4	5
High Street, Derry	34.5	12.47	5
Lafayette Road, Portsmouth	34.5	12.47	5

Public Service of New Hampshire
SUBSTATIONS
AN MAL PROTECTION PRIORITY

Substation	Primary (kV)	Secondary (kV)	Capacity (MVA)
Laskey's Corner, Milton	34.5	12.47	5
North Union Street, Manchester	34.5	4.16	5
Opechee Bay, Laconia	34.5	12.47	5
Ronald Street, Manchester	34.5	4.16	5
Simon Street, Nashua	34.5	12.47	5
Suncook, Allenstown	34.5	12.47	5
Whitefield, Whitefield	34.5	12.47	4
Colebrook, Colebrook	34.5	4.16	4
Cutts Street, Portsmouth	34.5	12.47	4
East Northwood, Northwood	34.5	12.47	4
Hollis, Hollis	34.5	12.47	4
Lancaster, Lancaster	34.5	12.47	4
Lowell Road, Hudson	34.5	12.47	4
Milford, Milford	34.5	12.47	4
Newmarket, Newmarket	34.5	4.16	4
Newport, Newport	34.5	4.16	4
North Dover, Dover	34.5	4.16	4
Rye, Rye	34.5	4.16	4
South Laconia, Laconia	34.5	4.16	4
South Peterborough, Peterborough	34.5	12.47	4
Tate Road, Somersworth	34.5	4.16	4
Somersworth, Somersworth	34.5	4.16	3
Chichester, Chichester	34.5	12.47	3
Dunbarton Road, Manchester	34.5	12.47	3
Jericho Road, Berlin	34.5	12.47	3
Tilton, Tilton	34.5	4.16	3
Jaffrey, Jaffrey	34.5	12.47	2
Milford, Milford	34.5	4.16	2
North Stratford, Stratford	34.5	12.47	2
Northwood Narrows, Northwood	34.5	12.47	2

EVERSOURCE
Project Authorization Form

Operations Program Level Project Authorization Form

Approved at August 7, 2019 EPAC
Link to Meeting Minutes

Date Prepared: July 26, 2019	**Project Title: 34.5kV Capacitor Bank Switch Replacement**
Company/ies: Eversource NH	**Project ID Number (by state): A19X35**
Organization: NH Operations	**Class(es) of Plant: Distribution Substation**
Project Initiator: Thelma Brown	**Project Category: Stations - Breakers**
Project Manager: TBD	**Project Type: Program**
Project Sponsor: John Zicko	**Project Purpose: Reliability/replace obsolete equipment**
Estimated in service date: Various: Q3 2020 through Q4 2026	**If Transmission Project: PTF? See associated Program Release Forms**
Eng. /Constr. Resources Budgeted? See associated Program Release Forms Yes	**Capital Investment Part of Original Operating Plan? Yes, See associated Program Release Forms**
Authorization Type: Program Approval	**O&M Expenses Part of the Original Operating Plan? Yes, See associated Program Release Forms**
Initial Funding Request: N/A	**Estimated Program Value (NH): $5.3M, Projected unit cost $756K**

Financial Requirements:

Project Authorization

ERM: ____

FP&A: ____

Executive Summary

*** NOTE: This program is requesting program approval of the 34.5kV Capacitor Bank Switch Replacement Program and identifies for information only, projected unit costs. Dollar authorization for these costs shall be through submission of individual program releases. Program Release Form submissions shall occur in accordance with the locations and phases identified in this document. "Project Checklist – Transmission & Substation" will be submitted with each Program Release Form.**

The plan for 34.5kV Capacitor Bank Switch Replacement Program was identified in 2008. There were 21 vacuum switches identified as needing replacement at that time and prioritized based on age, condition, operating problems and uniqueness. Twelve (12) capacitor switches have been removed and/or replaced since 2008. Nine (9) remain on the system scheduled for removal and replacement over the next ten years. Seven (7) of these Capacitor Switches are to be replaced as part of this program, the other two (2) are planned for replacement as part of other capital projects. The estimated unit cost per capacitor switch replacement is $756K for a total estimated program cost of $5.3M. The unitized cost per capacitor switch replacement is based on a recent estimate for replacing one (1) capacitor switch at the Long Hill SS in Nashua, NH, which will be the first release for this program.

Financial Unit Cost Evaluation (per Capacitor Switch)

Note: Dollar values are in thousands and are unit level costs for Program PAFs

Direct Capital Costs	Year 1	Year 2	Year 3+	Total
Straight Time Labor	$23	$29	$ -	$52
Overtime Labor	$ -	$ -	$ -	$ -
Outside Services	$60	$352	$ -	$412
Materials	$ -	81	$ -	81
Total - Direct Spending	$83	$462	$ -	$545
Other, including contingency amounts (describe)	$2	$22	$ -	$24
Total Direct Costs	**$85**	**$484**	$ -	**$569**

Indirect Capital Costs	Year 1	Year 2	Year 3+	Total
Indirects/Overheads (including benefits)	$42	$124	$ -	$166
Capitalized interest or AFUDC, if any	$3	$18	$ -	$21
Total Indirect Costs	**$45**	**$142**	$ -	**$187**
Total Capital Costs	**$130**	**$626**	$ -	**$756**
Less Total Customer Contribution	$ -	$ -	$ -	$ -
Total Capital Project Costs	**$130**	**$626**	$ -	**$756**
Total O&M Project Costs	$ -	$ -	$ -	$ -

Note: Explain unique payment provisions, if applicable.

Other/contingency includes Employee Expenses ($2K), Taxes ($4K), Expenses due to weather, OT and delays during construction ($10K), expenses due to design changes ($8K).

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Project Authorization Form

Future Financial Impacts:

Provide below the estimated future costs that will result from the project:
Note: Dollar values are in thousands:

Future Costs	Year 20__	Year 20__	Year20__	Year 20__+	Total Future Project Costs
Capital	$ -	$ -	$ -	$ -	$ -
O&M	-	-	-	-	-
Other	-	-	-	-	-
TOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Describe the estimated future Capital, O&M and/or Other costs noted above:
N/A

What functional area(s) will these future costs be funded in? N/A
A representative from the respective functional area is required to be included as a project approver.

If this is other than a Reliability Project, please complete the section below;

Provide below the estimated financial benefits that will result from the project:
Note: Dollar values are in thousands:

Future Benefits	Year 20__	Year 20__	Year20__	Year 20__+	Total Future Project Benefits
Capital	$ -	$ -	$ -	$ -	$ -
O&M	-	-	-	-	-
Other	-	-	-	-	-
TOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Describe the estimated future Capital, O&M and/or Other benefits noted above:
N/A

What functional area(s) will these benefits be reflected in? N/A
A representative from the respective functional area is required to be included as a project approver.

Asset Retirement Obligation (ARO) and/ or Environmental Cleanup Costs (Environmental Liabilities):

Is there an ARO associated with this project? If yes, please provide details: No

Are there other environmental cleanup costs associated with this project? If yes, please provide details: No

EVERSOURCE
Project Authorization Form

Technical Justification:

Project Need Statement

This program is to replace seven (7) 34kV Capacitor Bank Switches. This equipment has been recommended for replacement primarily because of age and condition. Some equipment has failed including cracked vacuum bottles. The Electric System Control Center (ESCC) uses the substation 34.5kV capacitor banks during high load periods to control the system losses and transmission voltage. It is important that these switches be available for energizing the substation capacitor banks on the system.

Project Objectives

This program will replace the capacitor bank switches targeted for replacement at Eversource substations in NH.

Project Scope

The scope of this program is to replace seven (7) Capacitor Switches in the prioritized list below. The two (2) shaded rows indicate where projects are already planned as a part of another project outside this program and are not included in the targeted switches for this program.

Switch Designation/Location		Manufacturer	Model	Age
C12	Long Hill	Allis Chalmers	VSC2-34	38
C13	Broad Street	Allis Chalmers	VSC-34	55
C11	Lost Nation	Allis Chalmers	VSC-34	55
C27	North Road	Allis Chalmers	VSC-34	52
C24	Rochester	Allis Chalmers	VSC-34	51
C36	Ocean Road 34.5	Allis Chalmers	VSC-34	51
C21	Packers Falls	Allis Chalmers	VSC-34	47
C18	White Lake	Allis Chalmers	VSC-34	43
C31	South Milford	Allis Chalmers	VSC-34	41

The Long Hill SS switch C12 is expected to be the first switch replaced. See attached One-Line Drawing D-8151. The typical capacitor bank switch replacement includes the following scope:

Major Equipment To Be Removed

1. One (1) Allis Chalmers Vacuum VSC-34 switch
2. One (1) Relay and Relay Cabinet (in SS Yard)
3. One (1) Potential Transformer
4. Three (3) fuse disconnect switches

Major Equipment To Be Added

1. One (1) 34.5kV Siemens Vacuum Circuit Breaker
2. Six (6) Current Transformers
3. One (1) Potential Transformer
4. Three (3) 34.5kV switches
5. One (1) Schweitzer SEL-351-7 relay, Device (50/51N/C25)
6. One (1) Relay Cabinet (in Control House)
7. Various insulators, wire, mounting brackets and connectors

Note that the existing SCADA functions will be rewired to the new equipment.

Background / Justification

The program for 34.5kV Capacitor Bank Switch Replacement is a specific program that was established in 2008 as project UB0830. 21 vacuum switches were identified as needing replacement at that time and prioritized based on age, condition, operating problems and obsolescence.

The 2008 program was funded annually in the NH distribution budget under project number UB0830. There is also funding in this project in 2019. Once the new program A19X35 is established, it will include funding for the distribution budget and UB0830 will be closed. There are currently no open work orders for project number UB0830.

Some of the capacitor bank switches have failed, including cracked vacuum bottles which are deteriorating and easily damaged. Replacement parts are not available. The capacitor switch at Monadnock SS failed in 2016. The switch at Laconia SS failed in 2017. The Long Hill switch has been sticking and there are no spare parts for these units. See the attached Monadnock SS Capacitor Bank Switch Photo. This switch failed in 2016 and was replaced in 2019.

Nine (9) capacitor switches remain on the system since this program started; 12 were replaced either with funding from project UB0830 or as a part of larger projects at the substations. This program includes seven (7) replacements; the other two (2) will be replaced as part of other capital projects. Capacitor bank switches are replaced unless the capacitor bank is removed from the system. These capacitor banks have been confirmed by System Planning to still be needed and there are no plans to retire these banks.

Business Process and / or Technical Improvements

Replacement of obsolete capacitor switches prior to failure will improve system reliability and decrease safety risk of failing equipment. This reduces the need to maintain spare parts for these obsolete switches that will be replaced with a standard vacuum breaker.

Alternatives Considered with Cost Estimates

The alternative to replacing these capacitor switches as a part of this program is to wait for another capital project and address capacitor switch replacement at that time.

The Siemens circuit breaker is the standard 34.5kV circuit breaker used. A Capacitor Switcher by Southern States could be used but it requires external CTs and is $60K more expensive than the Siemens circuit breaker.

Project Schedule

The tentative project schedule estimates one capacitor bank switch will be replaced per year beginning in 2020. The project schedule for each substation will be provided in the Release Forms.

Year	($)	Approx. # of Switches
2019	130K*	0
2020	756K	1
2021	756K	1
2022	756K	1
2023	756K	1
2024	756K	1
2025	756K	1
2026	626K	1

**The engineering for the Long Hill station capacitor switch will be completed in 2019.*

Regulatory Approvals

Local building permits as required by the City/Town.

Risks and Risk Mitigation Plans

Outage cancelled due to unplanned events on the system including weather events resulting in schedule delay and potential labor cost to remobilize.

- Be flexible – review with contractors to determine availability.
- Build float time into the construction schedule.

SCLL Conditions

- Schedule outages during light load period
- Proactively work with ESCC to address any SCLL concerns and mitigate restoration times.
- Replace fused switches with solid blades to reduce outage requirements, as applicable.

Any constructability issues, risks, and contingency costs will be provided in each specific program Release PAF.

References

N/A

Attachments (One-Line Diagrams, Images, etc.)

- Long Hill One-line D-8541 – a typical capacitor bank included in this program
- Monadnock SS Capacitor Bank Switch Photo

ESTIMATE SUMMARY

Project Title: Capacitor Switch Replacement Program - Long Hill
Project Mgr/Lead: Thelma Brown
Project Number: A19X35
Est. Revision # 00

Estimate By: D. PICCORELLI
Date of Estimate: 6/13/19
ISD: 12/31/20
Estimate # P-19-188

Templa e Revision # 0r

ESTIMATE SUMMARY

Estimate Type Planning

WBS		TOTAL	% of Total	Prior	2019	2020	2021	2022	2023	2024
7	Construction	$240,000	31.7%			$240,000				
5	Engineering / Design	$85,000	11.2%		$85,000					
2	Land									
6	Material	$76,000	10.1%			$76,000				
11	Project Mgmt. & Sppt.	$11,000	1.5%			$11,000				
8	Removal	$17,000	2.2%			$17,000				
9	Test	$108,000	14.3%			$108,000				
1	Risk / Contingency	$18,000	2.4%			$18,000				
	Escalation	$14,000	1.9%			$14,000				
12	Indirects	$166,000	22.0%		$42,000	$124,000				
12	AFUDC	$21,000	2.8%		$3,000	$18,000				
	Total Cost	**$756,000**	100.0%		**$130,000**	**$626,000**				

Estimate Range	**-25%**	**25%**
	$567,000	**$945,000**

COMMENTS:

Project Scope

The purpose of this estimate is to provide a program estimate for a unitized release cost for the new capacitor switch replacement at the Long Hill SS.
The Long Hill replacement is one (1) of seven (7) 34.5kV capacitor bank vacuum switches to be replaced as part of this program.
Specific removal scope includes 1ea Allis Chalmers Vacuum switch, 1ea relay and relay cabinet, 1ea potential transformer, and 3ea fuse disconnect switches.
Specific scope for new equipment includes 1ea 34.5kV Siemens Vacuum Circuit Breaker, 6ea current transformers, 1ea potential transformer, 3ea 34.5kV switches.
The protection and control work includes installation of a new Capswitcher and Cap Bank Protection and Control Equipment into a new P&C Cabinet., reconnect to existing bus differential schemes, connections to existing station annunciator and SCADA RTU for monitoring and remote control. Includes connection of the new SEL-351 relay to existing station communications equipment for remote engineering access.

The new Protection and Control equipment to be added to the existing control building includes the following: One Hoffman freestanding P&C cabinet which contains one Schweitzer SEL-351-7 relay (50/51N/C37), one Basler BE1-59NC relay (59N/C37), one 86LOR, one 52CS, one 43SL control switch, three ABB FT-19R test switches, various indicating lights and auxiliary relays.

Assumptions/Clarifications

Indirect rates based on 6D-NH, Station Work
Estimate includes $30,000 material cost for the Siemens Vacuum Circuit Breaker.
Complete design engineering to be outsourced to P&C Engineering & Design. $60,000 included in estimate.
Estimate includes $30,000 for mobile generator.
Replacement of a capacitor bank will not be required.
The Monadnock SS circuit switcher and capacitor bank replacement is used as a template for Long Hill SS.
All work will be done with the capacitor bank deenergized.
Only 1 day outage will be required on B2 Bus (to change fuses and install solid blades on the switch).
The PT to be replaced will be on existing stand.
The 6 new CT's are included / internal with the new breaker. t is assumed these are preinstalled at the factory.
The new switches shall be installed on existing stands.
LCE and testing to be outsourced and Construction Rep, P&C engineering to be in house.
This estimate is based on enginering scope description only, actual quantities may vary during detailed engineering.
Material estimates based on previous work, vendor quotes, and RS Means.
Labor estimates based on previous work, J. Bifulco S/S labor units, R.S. Means, and NECA labor units.
All new equipment will be installed within the confines of the existing fenced yard except for two suspension disconnects (no fence expansion required).
6D - NH , Station work

RISKS

Potential UG Obstructions	$ -
Severe Weather, Delays, OT	$ 10,000
Design development	$ 8,000

REDACTED

[redacted]

** 1000 MCM RISER ABANDONED
‡ MOBILE S/S CONNECTION POINT SEE MOBILE S/S MANUAL FOR ADDITIONAL INFORMATION.

LAST REVISION DETAIL
ADD 350X3

EVERSOURCE ENERGY
NEW HAMPSHIRE

SOUTHERN

LONG HILL
81 D.W. HIGHWAY, SO. NASHUA, NH
888 1303

DRN.	CHKD.	APPR.		
WNT	CAB	CEC	10/12/18	D-8541

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Project Authorization Form

Operations Program Level Project Authorization Form

Approved at March 06, 2019 EPAC
Link to Meeting Minutes

Date Prepared: March 15, 2019	**Project Title: 34.5kV OCB Breaker and Ancillary Equipment Replacement Program**
Company/ies: Eversource NH	**Project ID Number (by state): A19X36**
Organization: NH Operations	**Class(es) of Plant: Distribution Substation**
Project Initiator: Thelma Brown	**Project Category: Stations - Breakers**
Project Manager: TBD	**Project Type: Specific**
Project Sponsor: John Zicko	**Project Purpose: Reliability/Replace obsolete circuit breakers**
Estimated in service date: December 2028	**If Transmission Project: PTF? See associated Program Release Forms**
Eng. /Constr. Resources Budgeted? See associated Program Release Forms	**Capital Investment Part of Original Operating Plan? See associated Program Release Forms**
Authorization Type: Initial Funding	**O&M Expenses Part of the Original Operating Plan? See associated Program Release Forms**
Total Request: $150K	**Estimated Program Value: $29.7M, Projected unit cost $450,000**

Financial Requirements:

Project Authorization

ERM: ______________________________

FP&A: ______________________________

*** This program is only being approved for initial funding of $150K. Below are the details of the program.**

Executive Summary

This program is requesting program approval for the replacement of 34.5kV Oil Circuit Breakers (OCBs) and identifies for information only, projected unit costs. Dollar authorization for these costs shall be through submission of individual program releases. Program Release Form submissions shall occur in accordance with the locations and phases identified in this document. "Project Checklist – Transmission & Substation" will be submitted with each Program Release Form.

A plan for a 34.5kV Substation Breaker Replacement Program was identified in 2007. Seventy-eight (78) OCBs have been removed from the system since then. There are ninety-one (91) OCBs remaining on the Eversource NH system scheduled for removal and/or replacement over

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the next ten years. This Program is to replace sixty-six (66) of the remaining OCBs not currently targeted by another project. The estimated unit cost per OCB replacement is $450K for a total estimated program cost of $29.7M. The unitized cost per OCB replacement is based on a recent estimate for replacing four (4) OCBs at Reeds Ferry SS.

Financial Unit Cost Evaluation (by per OCB)

Note: Dollar values are in thousands and are unit level costs for Program PAFs

Direct Capital Costs	Year 1	Year 2	Year 3	Total
Straight Time Labor	$40			
Overtime Labor	$ -			
Outside Services	$175			
Materials	$60			
Total - Direct Spending	$ -			
Other, including contingency amounts (describe)	$50			
Total Direct Costs	**$325**			

Indirect Capital Costs	Year 1	Year 2	Year 3	Total
Indirects/Overheads (including benefits)	$100			
Capitalized interest or AFUDC, if any	$25			
Total Indirect Costs	**$125**			
Total Capital Costs	**$450**			
Less Total Customer Contribution	$ -			
Total Capital Project Costs	**$450**			
Total O&M Project Costs	$ -			

Other/contingency:

- Potential delays in construction in the event of storms or other unplanned events $20K
- Installation of Mobile Substation $30K

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Future Financial Impacts:

Provide below the estimated future costs that will result from the project:
Note: Dollar values are in thousands:

Future Costs	Year 20__	Year 20__	Year20__	Year 20__+	Total Future Project Costs
Capital	$ -	$ -	$ -	$ -	$ -
O&M	-	-	-	-	-
Other	-	-	-	-	-
TOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Describe the estimated future Capital, O&M and/or Other costs noted above:
None

What functional area(s) will these future costs be funded in? N/A

<u>If this is other than a Reliability Project, please complete the section below;</u>

Provide below the estimated financial benefits that will result from the project:
Note: Dollar values are in thousands:

Future Benefits	Year 20__	Year 20__	Year20__	Year 20__+	Total Future Project Benefits
Capital	$ -	$ -	$ -	$ -	$ -
O&M	-	-	-	-	-
Other	-	-	-	-	-
TOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Describe the estimated future Capital, O&M and/or Other benefits noted above:
None

What functional area(s) will these benefits be reflected in? N/A

Asset Retirement Obligation (ARO) and/ or Environmental Cleanup Costs (Environmental Liabilities):

Is there an ARO associated with this project? If yes, please provide details: No

Are there other environmental cleanup costs associated with this project? If yes, please provide details: No

Technical Justification:

Project Need Statement

This Program is to replace 34.5kV Oil Circuit Breakers (OCBs). This equipment has been recommended for replacement for various reasons including:

- There is a need to remove all circuit breakers from the system which break fault current utilizing an oil insulating medium.
- Several are unique and old breakers that no longer have spare parts and are difficult to maintain.
- The elimination of Type U-Bushings from the system which have PCB oil and create an environmental risk.
- Station Operations has identified specific problems with the breaker that cannot be fixed.

Project Objectives

The overall program objectives are to replace obsolete equipment to increase system reliability, increase employee safety, and reduce maintenance intervals. This Program is to replace all 34.5kV OCBs on the Eversource NH system. There are currently ninety-one (91) OCBs remaining on the system. Sixty-six (66) will be addressed with this Program. The remaining OCBs are being replaced as part of larger projects at the substations. Cable and conduit that runs to the OCBs will be replaced as detailed in the Major Equipment to be Removed/Added sections of the Project Scope.

Project Scope

The scope of this program is to replace 66 OCBs at 18 substations in the prioritized list below. The shaded rows indicate where projects are already planned as a part of another project outside this program and are not included in this OCB Replacement Program PAF. There will be a SCLL review and constructability review for each site.

Priority #	Location	Model	Name	Age (Years)
1	Greggs Falls	FK-339-34.5-500-3	TB17	69
2	Garvins	FK-38-3600-1	TB39	44
3	Garvins	FK-38-3600-1	TB51	44
4	South Milford	FKA-34.5-5-1500-2	378	52
5	South Milford	FKA-34.5-5-1500-2	314	52
6	Reeds Ferry	FKA-38-22000-6	TB50	47

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Priority #	Location	Model	Name	Age (Years)
7	South Milford	FKA-34.5-5-1500-2	329	52
8	White Lake	FK-339-34.5-1000-3	TB82	68
9	Whitefield	FK-34.5-1500-1R	348	62
10	Reeds Ferry	FKA-38-22000-6	3164	47
11	Broad Street	FKA-38-22000-3	31770	46
12	White Lake	FK-339-34.5-1000-3	333	69
13	Madbury	FKA-38-22000-5	0399	48
14	Berlin Eastside	FKA-34.5-1500-2	TB83	52
15	Resistance	FZO-34-1500-1	339	58
16	Monadnock	FK-439-34.5-500	3525	66
17	Whitefield	FKA-34.5-1500-2	TB89	53
18	Portland Street	FK-34.5-1000-1	0371 - NO	63
19	White Lake	FK-439-34.5-1000	3116	63
20	Packers Falls	FKA-38-22000-5	3191	47
21	Huse Road	FK-34.5-1500	3250	63
22	Pemigewasset	FK-439-34.5-500	3114	68
23	Garvins	FKA-38-22000-5	396	48
24	Huse Road	FKA-38-22000-5	3184	48
25	Madbury	FKA-38-22000-5	0380	48
26	Packers Falls	FKA-38-22000-5	03162	47
27	Portland Street	FK-34.5-500	386	66
28	Broad Street	FK-439-34.5-500	31540 - NO	66
29	Pemigewasset	FK-439-34.5-500	3149	66
30	Broad Street	TDO-34-1500-1	32170 - NO	40
31	Resistance	FK-34.5-1500	367	63
32	Packers Falls	345GS1500	377	44
33	Packers Falls	345GS1500	03152	44
34	Saco Valley	345GS1500	3330	44
35	Saco Valley	345GS1500	TB60	44
36	South Milford	FK-34.5-1000	BT36	64
37	White Lake	FK-34.5-1000	TB76	63
38	Laconia	CG-38	310	42

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Priority #	Location	Model	Name	Age (Years)
39	Laconia	CG-38	TB-125	42
40	Saco Valley	345GS1500	395	44
41	Saco Valley	345GS1500	3470	44
42	Reeds Ferry	FKA-38-22000-6	3230	47
43	Laconia	CG-38	3222	42
44	Laconia	CG-38	3980	42
45	Dover	FKA-38-22000-3	3148	49
46	Broad Street	FK-34.5-1000	03168X	63
47	Messer Street	CG-38	368	42
48	Messer Street	CG-38	338	42
49	Beebe River	FKA-38-22000-6	342A	46
50	Beebe River	FKA-38-22000-6	342B	45
51	South Milford	FKA-38-22000-6	3217	41
52	White Lake	FK-34.5-1000	347 - NO	53
53	Portland Street	FK-34.5-1000-1	032 - NO	63
54	South Milford	FKA-34.5-1500-2	32120	49
55	Huse Road	FK-34.5-1500	3210	64
56	Beebe River	FK-34.5-1500	TB-70	63
57	South Milford	FKA-34.5-5-1500-2	TB86	52
58	Madbury	345GS1500	3137	44
59	North Road	FKA-38-22000-6	3160	44
60	Madbury	FKA-38-22000-6	TB74	41
61	Monadnock	FK-34.5-1000	BT20	63
62	South Manchester	FK-34.5-1000	03142	63
63	Reeds Ferry	FKA-38-22000-6	3197	47
64	Rochester	FKA-34.5-1500-2	TB53	51
65	Beebe River	FKA-38-22000-6	TB62	45
66	Madbury	FKA-38-22000-5	TB65	48
67	Rochester	FKA-34.5-1500-2	0340	51
68	Rochester	FKA-34.5-1500-2	386A	51
69	South Manchester	FKA-34.5-1500-2	320	51
70	Packers Falls	FKA-38-22000-5	380	47

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Priority #	Location	Model	Name	Age (Years)
71	Laconia	CG-38	3680	42
72	Laconia	CG-38	TB24	42
73	Timber Swamp Road	CG-38	31650	35
74	North Road	FKA-38-22000-6	TB49	44
75	Amherst	CG-38	3143	32
76	Amherst	CG-38	3212	32
77	Oak Hill	CG-38	3122	32
78	South Milford	CG-38	31430	32
79	Resistance	FKA-38-22000-6	TB79	45
80	Timber Swamp Road	CG-38	31120	35
81	Amherst	CG-38	3159	32
82	Amherst	CG-38	3445	32
83	Huse Road	CG-38	3130	32
84	Huse Road	FKA-38-22000-6	3930	45
85	North Road	FKA-38-22000-6	341	44
86	Amherst	CG-38	3110	32
87	Broad Street	CG-38	03110 - NO	32
88	Broad Street	CG-38	3290 - NO	32
89	Broad Street	CG-38	03445 - NO	32
90	Garvins	CG-38	3320	32
91	Broad Street	FKA-38-22000-6	3530	40

Note: No notation indicates the OCB is operated Normally Open.

A typical project scope for an OCB replacement includes:

Major Equipment To Be Removed

1. 34.5kV Oil Circuit Breakers
2. 34.5kV Potential Transformers (PTs)
3. 34.5kV Lightning Arresters (LAs)
4. 34.5kV Breaker disconnect switches
5. Control Cables and conduit, as determined by field conditions
6. Bus tie switch

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Major Equipment To Be Added

1. 34.5kV Vacuum Breakers
2. PTs
3. LAs
4. Disconnect Switches
5. Control Cables and conduit, as determined by field conditions
6. Bus tie switch
7. Conduits, as required
8. Various wire, mounting brackets and connectors
9. Ground grid upgrades and modifications, as required.
10. 34kV Breaker foundation modifications, as required.
11. Labeling of new and existing equipment
12. A complete animal protection system on the 34.5kV bus.

Background / Justification

A plan for 34.5kV Substation OCB Replacements was established in 2007. Seventy-eight (78) OCBs have been removed from the system since then either as targeted OCB projects or as a part of larger projects at the substations. There are ninety (91) OCBs remaining on the Eversource NH system scheduled for removal and/or replacement over the next ten years.

There has been a focus on removing OCBs from the Eversource system. The oldest 34.5kV OCB is 69 years old with the youngest OCB at 32 years old. Some of the breakers are one of a kind on the system and the maintenance and repair of older breakers can be problematic.

When the program was started several things were examined to evaluate and prioritize the replacement of the breakers. In addition to age, each breaker was rated based on: 1) the number of same unit models or uniqueness; 2) if there are issues with maintenance such as no parts available because of age; 3) known maintenance issues particular to the unit; and 4) number of customers fed from the breaker which would lose power in the event of a failure. An additional emphasis has been placed on the removal of type U-Bushings from the system. This is due to the amount of environmental damage and the associated cost the company would be exposed to by a PCB bushing/breaker failing catastrophically.

Based on ranking, this program prioritizes the replacement of OCBs. Another consideration is whether there is a major project planned in the substation which can include OCB replacements. Additionally, Station Operations and Engineering review the list annually to identify any specific station needs when determining which breakers to replace next.

Business Process and / or Technical Improvements

Replacement of obsolete OCB equipment prior to failure will improve system reliability and decrease environmental risk while benefiting customers. This benefit will be realized by replacing aging oil filled equipment, which presents an environmental concern. The maintenance on the OCBs is more than on vacuum OCBs thereby resulting in new equipment with less maintenance costs. This reduces the need to maintain spare parts for multiple types of breakers.

Alternatives Considered with Cost Estimates

The alternative to replacing OCBs as a part of this program is to wait for another capital project and address OCB replacement at that time.

Project Schedule

Note: A tentative program schedule to establish cash flow shall be developed from the Project Release through a collaboration of Asset Management and Project Management.

Year	($)	Approx. # of OCB
2019	1.0M *	2
2020	1.0M *	2
2021	1.5M *	3
2022	2.5M *	6
2023	2.5M *	6
2024	5.0M	11
2025	5.0M	11
2026	5.0M	11
2027	5.0M	11
2028	2.9M	3

** Identified in the 5-year business plan budget*

Regulatory Approvals

Local Building Permits as required by the City/Town.

Risks and Risk Mitigation Plans

Outage cancelled due to unplanned events on the system resulting in schedule delay and potential labor cost to remobilize.

- Be flexible – review with contractors to determine availability.

- Build float time into the construction schedule.

SCLL Conditions

- Utilize existing circuit ties or build new ones as part of project scope
- Schedule outages during light load period
- Keep schedule flexible to work with ESCC and limit restoration times

Any constructability issues, risks, and contingency costs will be provided in each specific program release PAF.

References

N/A

Attachments (One-Line Diagrams, Images, etc.)

Reeds Ferry One-line D-8676 - A typical substation to be targeted

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Project Authorization Form

Cost Estimate Backup Details

The existing Ocean Road SS OCB breaker replacement project is ongoing and was used to estimate a proposed Reeds Ferry SS project. The unitized cost per OCB replacement is based on a recent estimate for replacing 4 OCBs at Reeds Ferry SS as follows:

Note: Dollars are in Thousands

Direct Capital Costs	2019	2020	2021	Totals
Straight Time Labor	$94	$0	$0	$94
Overtime Labor	$0	$0	$0	$0
Outside Services	$469	$526	$0	$994
Materials	$196	$25	$0	$221
Other, including contingency amounts (describe)	$86	$26	$0	$112
Total Direct Costs	**$845**	**$576**	**$0**	**$1,422**
Indirect Capital Costs	2019	2020	2021	Totals
Indirects/Overheads (including benefits)	$272	$131	$0	$403
Capitalized interest or AFUDC, if any	$34	$59	$0	$93
Total Indirect Costs	**$306**	**$190**	**$0**	**$496**
Total Capital Costs	**$1,152**	**$766**	**$0**	**$1,918**
Less Total Customer Contribution	$0	$0	$0	$0
Total Capital Project Costs	**$1,152**	**$766**	**$0**	**$1,918**
Total O&M Project Costs	$0	$0	$0	$0

Other/Contingency includes:

- Building Permits & fees $5K
- Potential delays in construction in the event of storms or other unplanned events $25K
- Temporary construction to limit exposure to SCLL conditions $70K
- Real Estate Taxes $12K

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Request for Initial Funding

Initial Funding Request Form

Approved by EPAC Chairmen external to meeting on 09/9/2020

Link to 9/16/2020 EPAC Meeting Minutes

Date Prepared: 08/27/2020	**Project Title: Spare 345-34.5kV Transformer**
Company/ies: Eversource NH	**Project Number: A20X26**
Organization: System Planning	**Class(es) of Plant: D SS**
Project Initiator: Yassine Mhandi	**Project Category: Stations - Transformers**
Project Manager: Thelma Brown	**Project Type: Specific**
Project Sponsor: Digaunto Chatterjee	**Project Purpose: Provide a spare transformer for the existing five (5) unique transformers on the system.**
Estimated in service date: 12/31/2021	**If Transmission Project (check all that apply): NA**
Authorization Type: Initial Funding	**PTF ☐ Non-PTF ☐**
Total Request: $129K	

Project Need Statement:

This initial funding request of $129K is to develop a Solution Selection Form (SSF) for presentation to the Solution Design Committee (SDC) to install a spare mobile 345-34.5kV transformer and evaluate other alternatives. Eversource NH has five (5) 140MVA 345-34.5kV transformers on their system. There are two (2) at Timber Swamp SS, two (2) at Amherst SS, and one (1) at Lawrence Road SS. For the failure of one (1) of these units it would take over a year to replace it because there are no spares on the system. The failure would rely on the 115-34.5kV system to back up the load. This not only puts load on the 115kV system, but subjects the load to isolation in the event of the loss of a 115-34.5kV transformer for over a year.

Project Objectives:

The objective of the initial funding is to evaluate the location and scope to place a spare 345-34.5kV transformer. The following five (5) alternatives have been identified, but only Alternative 1 meets the immediate needs to have a spare transformer on the system.

Alternative 1 **(This is the chosen alternative at this time)**

Procure a spare 140MVA 345-34.5kV transformer and design and install it in a location which would include a new foundation, oil containment, status alarms, and AC power to the transformer. The preliminary estimate for this alternative is **$3.0M**. This is based on HICO's budgetary quote of $2.05M for the transformer.

Alternative 2 **(This is not the preferred alternative).**

Rebuild South Milford SS with two (2) 62.5MVA transformers ($20M)

Build a 115kV line from Long Hill SS to South Milford SS

- 4.6 miles of the 34.5kV 3154 line will be converted to 115kV ($2M)
- 10.7 miles of the line from Broad St. SS to South Milford SS will be built in the 329 line right-of-way (ROW) requiring Site Evaluation Committee approval. ($35M)

Rebuild Ocean Road SS with two (2) 62.5MVA transformers ($15M)

Rebuild Great Bay Substation with two (2) 62.5 MVA transformers ($15M)

Timber Swamp and Great Bay SS feed the Unitil Energy System (UES). UES has studied upgrades required on their 34.5kV system ($20M)

This solution will eliminate the need for a spare 345-34.5kV transformer as it provides adequate support from the 115-34.5kV stations to back up for the loss of an existing 345-34.5kV transformer.

Alternative 2 Estimated Cost: **$107M**. Additional transmission system solutions will be required.

Estimate ISD: 12/31/2025

Alternative 3 **(This is not the preferred alternative)**.

Rebuild Amherst SS to a 115-34.5kV substation with two (2) 62.5MVA transformers ($20M)

Rebuild South Milford SS with one (1) 62.5MVA transformer ($15M)

Build a 115kV line from Long Hill SS to South Milford SS

- 4.6 miles of the 34.5kV 3154 line will be converted to 115kV ($2M)
- 10.7 miles of the line from Broad St. SS to South Milford SS will be built in the 34.5kV 329 line ROW requiring Site Evaluation Committee approval. ($35)

Build a four (4) mile 115kV line from South Milford SS to Amherst SS ($13M)

Build a 6.5 mile 115kV line from Amherst SS to Eagle SS in the 345kV 3195 ROW ($21M)

This solution will eliminate two (2) 345-34.5kV transformers on the system that can then be designated as system spares.

Alternative 3 Estimated Cost: **$106M.** Additional transmission system solutions will be required.

Estimate ISD: 12/31/2025

Alternative 4 **(This is not the preferred alternative)**.

Rebuild Timber Swamp SS to a 115-34.5kV substation with three (3) 62.5MVA transformers ($30M)

Install a 345-115kV autotransformer at Timber Swamp ($30M)

Build a 7.5 mile 115kV line from Ocean Road SS to Timber Swamp SS ($25M)

This solution will eliminate two (2) 345-34.5kV transformers on the system that can then be designated as system spares.

Alternative 4 Estimated Cost: **$85M**

Estimate ISD: 12/31/2025

Alternative 5 **(This is not the preferred alternative)**.

Rebuild Lawrence Road SS to a 115-34.5kV substation with one (1) 62.5MVA transformer ($10M)

Re-terminate the Y135N line into the Lawrence Road SS ($5M)

This solution will eliminate one (1) 345-34.5kV transformer on the system that can then be designated as a system spare.

Alternative 5 Estimated Cost: **$15M.** Additional transmission system solutions may be required.

Estimate ISD: 12/31/2023

Funding Request Explanation (total request, amount per task, deliverables):

This $129K in initial funding will be used to develop scope documents and engineering deliverables for the Preferred Alternative 1 and development of an SSF for presentation at SDC. This will allow for a site selection either at Amherst SS, Lawrence Road SS, or Timber Swamp SS. Engineering will be completed to proceed to EPAC for a full funding project authorization form (PAF).

The Eversource NH Distribution capital budget is available for initial funding. The remainder of the project cost will be funded in 2021 and/or 2022, depending on the order date and delivery of the transformer.

Plant Accounting has confirmed that this spare transformer can be capitalized.

Preliminary Schedule:

The preliminary schedule is based on choosing Alternative 1, which is to procure a spare 140MVA 345-34.5kV transformer.

If a different alternative is chosen, it will be a much larger project and will take several years to complete the construction. The schedule below does not represent the alternative solutions 2-6 described above.

Milestone/Phase Name	Estimated Date
SDC Review of Preferred Solution and Initial Funding request	9/16/20
70% Engineering Completion	10/30/20
Full Funding request at EPAC	11/10/20
Order a spare transformer	12/1/20
Site Construction Start	9/1/21
In Service Date	12/31/21

Initial Funding Request Form

Date Prepared: 07/16/2020	**Project Title:** Manchester Network Cable Replacement
Company/ies: Eversource NH	**Project Number:** A20C40
Organization: Asset Management	**Class(es) of Plant:** D Line
Project Initiator: Robert Krewson	**Project Category:** Lines - UG Cable
Project Manager: Marc Pilotte	**Project Type:** Specific
Project Sponsor: Russel Johnson	**Project Purpose:** Replace primary cables in Manchester network
Estimated in service date: 12/31/20	**If Transmission Project** (check all that apply)**:** n/a **PTF** ☐ **Non-PTF** ☐
Authorization Type: Initial Funding	
Total Request: $183,000	

Project Need Statement:

While the network has historically been a highly reliable distribution system due to its inherent redundancy, it has recently experienced a significant number of primary circuit outages. Since December 2018, there have been ten instances of cable or splice failures. The cabling on the four 13.8 kV circuits is primarily Paper Insulated Lead-sheathed Cable (PILC), and dates to the 1950s.

Hooksett Field Engineering is proposing the replacement of the four network primary circuits due to the poor reliability experienced recently. Construction work is expected to take place over a period of four years. Cable sections recently installed as replacements due to failures will not be replaced.

This initial funding request is for surveying the first of four zones identified for the replacement of primary conductor on all four network circuits. The survey is intended to create a pull plan for circuit cable routing as well as identify in advance issues needing to be addressed during construction. Additional PAFs will be submitted for subsequent surveys and cable replacement projects. Full cost of the project is not known at this time but is estimated at approximately $8 million and is planned to be completed over a four-year time frame. Total estimated project cost will be revised based on experience as the project proceeds.

Project Objectives:

Replace the 13A, 13B, 13C, and 13D network primary cables over a four-year period. The project will be broken up into four zones, one per year for the duration of the project, with cable replacements of all four circuits undertaken within each particular zone. The network primary cables are 15 KV oil impregnated PILC cables which were installed approximately 60-65 years ago. There are two cable sizes: 350 MCM copper for the mainline, and 1/0 copper for the transformer taps. The original lead cables require specialized lead (transition) splicing to plastic replacement cables. The PILC type cable is very reliable, with failures occurring only when the lead sheath is compromised, which allows water ingress. Historically there have been a limited number of cable failures, and a system of five fault indicators per circuit (designed specifically for PILC application) has enabled quick fault location. Recently there has been an increased rate of primary cable failure, with ten failures since December 2018.

Funding Request Explanation (total request, amount per task, deliverables):

Note: Dollar values are in thousands

Direct Capital Costs		
Straight Time Labor	82	Eversource labor required is to develop a pull plan, rod, rope, and mandrel ducts, and to identify manhole issues needing correction in the 23 vaults to be inspected in zone 1 and to develop preliminary engineering plans for replacing the cable in zone 1.
Outside Services	45	Outside Services is contractor labor is for the anticipated work by Clean Harbors to pump and clean the vaults being surveyed.
Total Direct Costs	**127**	
Indirect Capital Costs		
Indirects/Overheads	56	
Total	**183**	

Preliminary Schedule:

Milestone/Phase Name	Estimated Date
Perform survey of Zone 1 (Nutfield Lane)	8/1/2020
Design Complete for Zone 1	9/15/2020
Start of Zone 1 construction	10/15/2020
Zone 1 construction complete	12/15/20