Transmission Planning Technical Guide

System Planning

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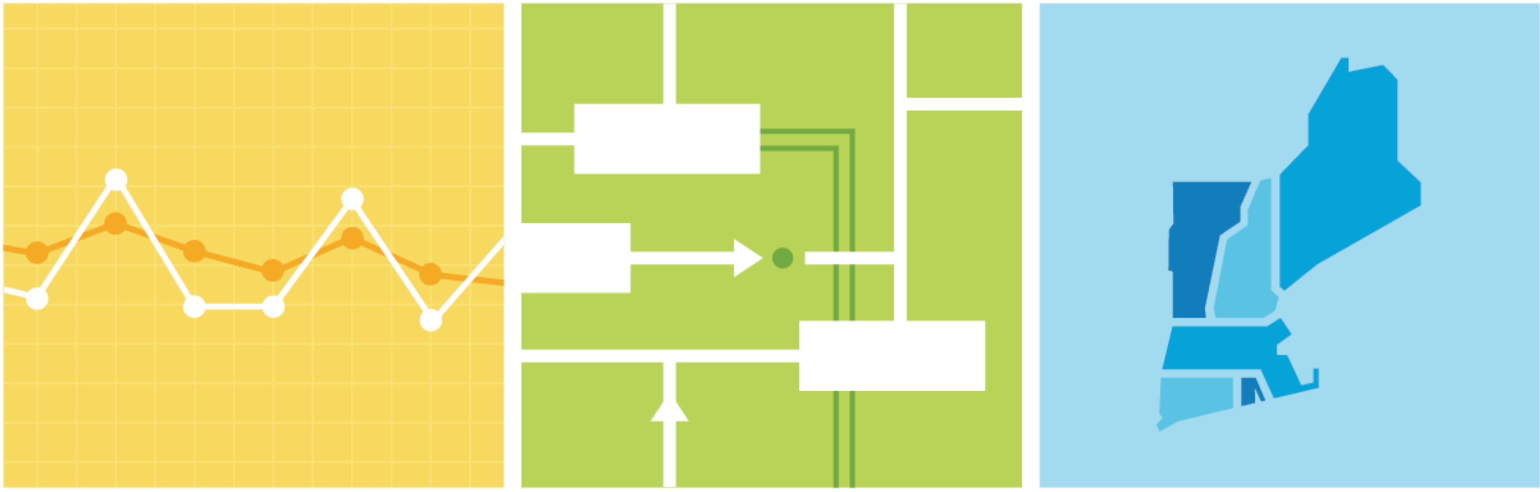
NOTE: Additional updates continuing to review the content of the guide in further detail to match current processes and procedures will follow.



Disclaimer

The provisions in this document are intended to be consistent with ISO New England's Tariff. If, however, the provisions in this planning document conflict with the Tariff in any way, the Tariff takes precedence as the ISO is bound to operate in accordance with the ISO New England Tariff.

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Section 1
Introduction

This Transmission Planning Technical Guide (the Guide) describes the current standards, criteria and assumptions used in various system planning studies in New England. An accompanying Transmission Planning Process Guide[1] provides additional detail on the existing regional system planning process as described in Attachment K of Section II of the ISO New England Transmission, Markets and Services Tariff (ISO Tariff).[2] This Technical Guide is not intended to address every assumption of system planning studies but to provide additional detail on certain assumptions not fully described in the ISO Planning Procedures.

The guide has been organized into four main sections. Section 1 describes its purpose, the source of the standards, criteria and assumptions used in system planning studies, and a description of the various types of studies that are conducted. Section 2 describes the modeling assumptions that are followed to create the network and system condition representations used in system planning studies. Section 3 describes the reliability criteria and standards that establish the bounds of acceptable system performance. They are applied to each analysis to determine if any violations exist. Section 4 defines the methodologies used to conduct various system planning studies.

Capitalized terms in this guide are defined in Section I of the ISO Tariff, in Section 1.3 of this guide, and Section 5.1, Appendices of this guide. Additional documents and white papers describing topics in further detail throughout this guide are listed in Section 5.

1.1 Purpose

The purpose of this guide is to clearly articulate the current assumptions used in planning studies of the transmission system consisting of New England Pool Transmission Facilities (PTF). Pursuant to Attachment K of the ISO New England Open Access Transmission Tariff (OATT),[3] ISO New England Inc. (the ISO) is responsible for the planning of the PTF portion of New England's transmission system. Pool Transmission Facilities are the transmission facilities owned by Participating Transmission Owners (PTO), over which the ISO exercises Operating Authority in accordance with the terms set forth in the Transmission Operating Agreement,[4] rated at 69 kV and above, except for lines and associated facilities that contribute little or no parallel capability to the PTF. The scope of PTF facilities is defined in Section II.49 of the OATT.

The PTOs are responsible for planning of the non-PTF and coordinating such planning efforts with the ISO. The PTOs establish the assumptions for planning of the non-PTF which does not impact the PTF. Section 6 of Attachment K to the OATT describes the responsibilities for planning the PTF and non-PTF transmission systems.

The planning assumptions in this guide also apply to studies of the impacts of system changes on the PTF transmission system, the Highgate Transmission System, Other Transmission Facilities, and

[1] https://www.iso-ne.com/system-planning/transmission-planning/transmission-planning-guides

[2] https://www.iso-ne.com/participate/rules-procedures/tariff

[3] https://www.iso-ne.com/participate/rules-procedures/tariff/oatt

[4] https://www.iso-ne.com/participate/governing-agreements/transmission-operating-agreements

Merchant Transmission Facilities. This includes studies of the impacts of Elective Transmission Upgrades and generator interconnections, regardless of the point of interconnection.

1.2 Applicable Reliability Standards

ISO New England establishes reliability criteria and procedures for the six-state New England region on the basis of authority granted to the ISO by the Federal Energy Regulatory Commission (FERC). Because New England is part of a much larger interconnected power system, the region also is subject to reliability standards established for the northeast and the entire United States by the Northeast Power Coordinating Council (NPCC) and the North American Electric Reliability Corporation (NERC), respectively.

The standards, criteria, and assumptions used in planning studies are guided by a series of reliability standards and criteria:

- North American Electric Reliability Corporation reliability standards for Transmission Planning (TPLs) which apply to North America. These standards can be found on the NERC website.[5]

- Northeast Power Coordinating Council, *Design and Operation of the Bulk Power Systems*, (Directory #1) and *NPCC Classification of Bulk Power System Elements*, (Document A-10) which describe criteria applicable to Ontario, Québec, Canadian Maritimes, New York and New England. These documents can be found on the NPCC website.[6]

- ISO New England Planning and Operating Procedures which apply to the New England transmission system, which excludes the northern section of Maine that is not directly interconnected to the rest of the United States transmission system but is interconnected to the New Brunswick system. These procedures can be found on the ISO website.[7]

NERC, NPCC, and the ISO describe the purpose of their reliability standards and criteria as:

- NERC describes the intent of the TPL standards as providing for system simulations and associated assessments that are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and that continue to be modified or upgraded as necessary to meet present and future system needs.

- NPCC describes the intent of its Directory #1 criteria as providing a "design-based approach" to ensure the Bulk Power System (BPS) is designed and operated to a level of reliability such that the loss of a major portion of the system, or unintentional separation of a major portion of the system, will not result from any design contingencies.

- ISO New England, in its Planning Procedure No. 3 (PP3), *Reliability Standards for the New England Area Pool Transmission Facilities*, describes that the purpose of the New England Reliability Standards is to assure the reliability and efficiency of the New England PTF through coordination of system planning, design, and operation.

[5] https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx
[6] https://www.npcc.org/program-areas/standards-and-criteria/regional-criteria
[7] https://www.iso-ne.com/participate/rules-procedures/planning-procedures and https://www.iso-ne.com/participate/rules-procedures/operating-procedures

The ISO planning standards and criteria, which are explained in this guide, are based on the NERC, NPCC, and ISO specific standards and criteria, and are set out for application in the region in the ISO Planning and Operation procedures. As the NERC registered Planning Authority, the ISO has the responsibility to establish procedures and assumptions that satisfy the intent of the NERC and NPCC standards.

1.3 Types of System Planning Studies

There are a number of different types of planning studies conducted in New England which assess or reflect the capability of the transmission system, including Market Efficiency upgrade studies, operational studies and reliability studies. The focus of this guide is on reliability studies.

The major types of studies addressed in this guide are:

- **Proposed Plan Application (PPA) Study** – Study done to determine if any addition or change to the New England transmission system has a significant adverse effect on stability, reliability, or operating characteristics of the PTF or non-PTF transmission system (See Section I.3.9 of the OATT).
  Note: This does not need to be an independent study but can be a submission or supplementation of another study such as a System Impact Study or transmission Solutions Study, as long as appropriate system conditions were included in that study.
- **System Impact Study (SIS)** – Study done to determine the system upgrades required to interconnect a new or modified generating facility (See Schedule 22, Section 7 and Schedule 23, Section 3.4 of the OATT), to determine the system upgrades required to interconnect an Elective Transmission Upgrade (See Schedule 25, Section 7 of the OATT), or to determine the system upgrades required to provide transmission service pursuant to the OATT. A Feasibility Study is often the first step in the interconnection study process and may be done as part of the System Impact Study or separately.
- **Transmission Needs Assessment** – Study done to assess the adequacy of the New England PTF (See Attachment K, Section 4.1 of the OATT).
- **Transmission Solutions Study** – Study done to develop regulated solutions to time-sensitive issues identified in a transmission Needs Assessment of the New England PTF (See Attachment K, Section 4.2[b] of the OATT).
- **Competitive Transmission Request for Proposal (RFP)** – Analysis of proposals submitted in order to resolve non-time-sensitive needs identified in a transmission Needs Assessment of the New England PTF (See Attachment K, Section 4.3 of the OATT).
- **Public Policy Transmission Study** – Study done to develop a rough estimate of the cost and benefits of high-level concepts that could meet transmission needs driven by Public Policy Requirements. While generally, the assumptions for a Public Policy Transmission Study would align with the assumptions for a Transmission Needs Assessment, the scope of the required studies is dependent upon specific and unique Public Policy Requirements (See Attachment K, Section 4A.3 of the OATT). The assumptions used for the Public Policy Transmission Study would also align with those of any competitive RFPs that are issued to resolve the needs identified in a Public Policy Transmission Study. Therefore, later sections of this document do not include specific assumptions for a Public Policy Transmission Study.
- **Longer-Term Transmission Study -** Study done to identify high-level concepts of transmission infrastructure and, if requested, high-level cost estimates that could meet State-identified Requirements specified in the request based on state-identified scenarios and timeframes, which may extend beyond the five-to-ten year planning horizon. While generally, the assumptions for a Longer-Term Transmission Study would align with the assumptions for a Transmission Needs Assessment, the scope of the required studies is dependent upon specific and unique New England States Committe on Electricity (NESCOE) request and assumptions (See Attachment K, Section 16 of the OATT). Therefore, later sections of this document do not include specific assumptions for a Longer-Term Transmission Study.

- **NPCC Area Transmission Review** – Study to assess reliability of the New England BPS (See NPCC Directory #1, Appendix B).
- **Bulk Power System (BPS) Testing** – Study done to determine if Elements should be classified as part of the Bulk Power System (See NPCC Document A-10).
- **Transfer Limit Study** – Study done to determine the range of megawatts (MW) that can be transferred across an interface under a variety of system conditions (See NERC Standard FAC-013).
- **Interregional Study** – Study involving two or more adjacent regions, for example New York ISO and ISO New England (See Section 6.3 of the OATT).
- **Overlapping Impact Study** – Optional study that an Interconnection Customer may select as part of its interconnection studies. This study provides information on the potential upgrades required for the generation project to qualify as a capacity resource in the Forward Capacity Market (FCM) (See Schedule 22, Section 6.2 or 7.3 and Schedule 25, Section 6.2 or 7.3 of the OATT).
- **FCM New Resource Qualification Network Capacity Interconnection Standard Analyses** – Study of the transmission system done to determine a list of potential Element or interface loading problems caused by a resource seeking to obtain a new or increased Capacity Supply Obligation (CSO). This study is done if an SIS for a generator interconnection is not complete (See ISO New England Planning Procedure No. 10 [PP10], Section 5.6).
- **FCM New Resource Qualification Overlapping Impact Analyses** – Study of the transmission system done to determine the deliverability of a resource seeking to obtain a new or increased CSO (See PP10, Section 5.8).
- **FCM Study for Annual Reconfiguration Auctions and Annual CSO Bilaterals** – Study of the transmission system done to determine the reliability impact of a resource seeking to obtain a new or increased CSO (See PP10, Sections 7 and 8).
- **FCM Delist Analyses** – Study of the transmission system done to determine the reliability impacts of delists (See PP10, Section 7).
- **Transmission Security Analyses** – Deterministic study done as part of the determination of the capacity requirements of import constrained load zones (See PP10, Section 6).
- **Non-Commercial Capacity Deferral Notifications** – Study done to determine the reliability impacts of non-commercial capacity deferral notifications (See PP10, Section 11).

Section 2
Modeling Assumptions

This Section describes the various modeling assumptions that are assembled to create the steady state, short circuit, and transient stability network representations used in system planning analyses.

2.1 Base Case Topology

Base case topology refers to how system Elements are represented and linked together for the year(s) to be studied. System Elements modeled in base cases include, but are not limited to transmission lines, transformers, series and shunt Elements in New England, generators on the New England transmission and distribution systems, merchant transmission facilities in New England, and similar topology for adjacent systems.

There are a number of Tariff and practical considerations that determine the topology used for various types of planning studies. For example, transmission Needs Assessments and Solutions Studies need to include the facilities that have a commitment to be available (e.g., an obligation in the Forward Capacity Market, a reliability upgrade with an approved PPA, or a merchant facility with an approved PPA and an associated binding contract) and need to exclude projects that are not committed to be available. For generation System Impact Studies, the studies need to include all active generators in the FERC section of the ISO interconnection queue that have earlier (higher priority) queue positions.

The starting point for the development of a base case is the ISO's Model on Demand database which includes a model of the external system from the Multiregional Modeling Working Group (MMWG). This Model on Demand data base is used to create the ISO's portion of the MMWG base case. However, the Model on Demand data base is updated periodically to include updates to existing Elements' modeling parameters and inclusion of newly approved projects. Table 2-1 summarizes the topology used in planning studies.

Table 2-1
Base Case Topology

Type of Study	Transmission in New England	Generation in New England	Merchant Facilities	Transmission outside New England	Generation outside New England
PPA Study of Transmission Project (Steady State and Stability)	In-Service, Under Construction, and Planned (1)	In-Service, Under Construction or has an approved PPA (1)(7)	In-Service, Under Construction or has an approved PPA	Models from recent MMWG base case	Models from recent MMWG base case
System Impact Study (Steady State and Stability)	In-Service, Under Construction, and Planned (1)	In-Service, Under Construction, or has an approved PPA or is included in FERC section of the ISO queue (1)(7)	In-Service, Under Construction or has an approved PPA	Models from recent MMWG base case	Models from recent MMWG base case

Type of Study	Transmission in New England	Generation in New England	Merchant Facilities	Transmission outside New England	Generation outside New England
Transmission Needs Assessment (Steady State and Stability)	In-Service, Under Construction, Planned, and Proposed (6)	In-Service, has a CSO, has been selected in a state sponsored RFP, or has a binding contract (4)(8)(9)(10)	In-Service, Under Construction, or has an approved PPA; and delivers an import with a CSO or a binding contract (4); and has a certain in-service date (ISD)	Models from recent MMWG base case	Models from recent MMWG base case
Transmission Solutions Study/ Competitive Transmission RFP (Steady State and Stability)	In-Service, Under Construction, Planned, and Proposed (6)	In-Service, has a CSO, has been selected in a state sponsored RFP, or has a binding contract (4)(8)(9)(10)(11)	In-Service, Under Construction, or has an approved PPA: and delivers an import with a CSO or a binding contract (4); and has a certain ISD	Models from recent MMWG base case	Models from recent MMWG base case
Area Review Analyses (Steady State and Stability)	In-Service, Under Construction, and Planned	In-Service, Under Construction, or has an approved PPA (9)	In-Service, Under Construction, or has an approved PPA	Models from recent MMWG base case	Models from recent MMWG base case
BPS Testing Analyses (Steady State and Stability)	In-Service, Under Construction, and Planned	In-Service, Under Construction, or has an approved PPA (9)	In-Service, Under Construction, or has an approved PPA	Models from recent MMWG base case	Models from recent MMWG base case
Transfer Limit Studies (Steady State and Stability)	In-Service, Under Construction, and Planned	In-Service, Under Construction or has an approved PPA (9)	In-Service, Under Construction or has an approved PPA	Models from recent MMWG base case	Models from recent MMWG base case
Interregional Studies	In-Service, Under Construction, and Planned (2)	In-Service, Under Construction or has an approved PPA (9)	In-Service, Under Construction or has an approved PPA	Models from recent MMWG base case	Models from recent MMWG base case
FCM New Resource Qualification Overlapping Impact Analyses (3)(5)	In-Service, or Under Construction, Planned, or Proposed with an ISD certified by the PTO	Existing resources and resources that have a CSO	In-Service, Under Construction, Planned, or Proposed with an ISD certified by the Owner	Models from recent MMWG base case	Models from recent MMWG base case and generators which represent flows to/from external areas
FCM New Resource Qualification Network Resource Interconnection Standard Analyses (5)	In-Service or Under Construction, Planned, or Proposed with an ISD certified by the PTO	Existing resources and resources that have a CSO	In-Service, Under Construction, Planned, or Proposed with an ISD certified by the Owner	Models from recent MMWG base case	Models from recent MMWG base case and generators which represent flows to/from external areas

Type of Study	Transmission in New England	Generation in New England	Merchant Facilities	Transmission outside New England	Generation outside New England
FCM Study for Annual Reconfiguration Auctions and Annual CSO Bilaterals (5)	In-Service or Under Construction, Planned, or Proposed with an ISD certified by the PTO	Existing resources and resources that have a CSO	In-Service, Under Construction, Planned, or Proposed with an ISD certified by the Owner	Models from recent MMWG base case	Models from recent MMWG base case and generators which represent flows to/from external areas
FCM Delist Analyses (5)	In-Service or Under Construction, Planned, or Proposed with an ISD certified by the PTO	Existing resources and resources that have a CSO (4)	In-Service, Under Construction, Planned, or Proposed with an ISD certified by the Owner	Models from recent MMWG base case	Models from recent MMWG base case and generators which represent flows to/from external areas
Transmission Security Analyses (5)	In-Service or Under Construction, Planned, or Proposed with an ISD certified by the PTO	Existing resources and resources that have a CSO	In-Service, Under Construction, Planned, or Proposed with an ISD certified by the Owner	N/A	N/A
Non-Commercial Capacity Deferral Notifications (5)	In-Service or Under Construction, Planned, or Proposed with an ISD certified by the PTO	Existing resources and resources that have a CSO (4)	In-Service, Under Construction, Planned, or Proposed with an ISD certified by the Owner	Models from recent MMWG base case	Models from recent MMWG base case and generators which represent flows to/from external areas

(1) Projects with a nearly completed PPA Study and that have an impact on this study are also considered in the base case. This includes transmission projects and generation interconnections to the PTF or non-PTF transmission system. Also generators without CSOs in the FCM are included in PPA Studies.
(2) Some interregional studies may include facilities that do not have approved PPAs.
(3) Base cases for preliminary, non-binding overlapping impact analysis done as part of a generation Feasibility Study or generation System Impact Study are developed with input from the Interconnection Customer.
(4) Section 4.1(f), Treatment of Market Responses in Needs Assessments, and Section 4A.3(b), Treatment of Market Solutions in Public Policy Transmission Studies, of Attachment K describe that resources that have cleared in a Forward Capacity Auction (have a CSO), are bound by a state-sponsored RFP, have a financially binding contract, or are in-service are represented in base cases.
(5) These studies are described in ISO New England Planning Procedure No. 10 (PP10), *Planning Procedure to Support the Forward Capacity Market*.
(6) Sensitivity analysis may also be done to confirm the proposed projects in the study area continue to be needed.
(7) Generators that have submitted a Non-Price Retirement Request are modeled out of service at the start of the Capacity Commitment Period (CCP) associated with their Non-Price Retirement Request and in subsequent years. Generators that have submitted a Retirement De-List Bid

(RDL) are modeled out of service as of the start of the CCP associated with the Forward Capacity Auction (FCA) for which the retirement has been confirmed (such as having cleared in the FCA or having a final price above the FCA starting price) and in subsequent years.

(8) In transmission Needs Assessments and Solutions Studies, additional generators are often considered unavailable. Generators that have a rejected Permanent De-list bid are considered unavailable (See Attachment K, Section 4.1(c)). Also, generators that have an accepted static or dynamic de-list bid for the full resource in the two most recent FCM auctions are considered unavailable. In addition, the ISO may consider generators unavailable because of circumstances such as denial of license extensions or being physically unable to operate.

(9) Generators that have submitted a Non-Price Retirement Request are modeled out of service at the start of the CCP associated with their Non-Price Retirement Request and in subsequent years. Generators that have submitted a RDL are modeled out of service as of the start of the CCP associated with the FCA for which they have submitted a Retirement De-List Bid and in subsequent years. Generators that have demand bids that cleared in a substitution auction are modeled out of service as of the start of the CCP associated with the substation auction for which they cleared and in subsequent years.

(10) The use of the status In-Service for generation in New England is equivalent to the use of existing resources found in Section 4.1(f) and Section 4A.3(b) of Attachment K.

(11) The cases used in a Transmission Solutions Study/Competitive Transmission RFP are the same cases used in a Needs Assessment and therefore the base case topologies are equivalent.

The base cases used for short circuit analysis originate from the Year N+5 Case that is created as part of the OP-16 Appendix K[8] process.

2.1.1 **Modeling Existing and Proposed Generation**

Generating facilities 5 MW and greater are listed in the Forecast Report of Capacity, Energy, Loads, and Transmission (the CELT Report) and are explicitly modeled in planning study base cases. The current exception to this is generators 5 MW and greater that are “behind-the-meter” and do not individually participate in the ISO New England energy market. Some of these generators are netted to load. However, as these generators could have an impact on system performance, future efforts will be made to model these resources in greater detail. The ISO is collecting load flow, stability and short circuit models for generators 5 MW and greater that are new or being modified. Additional models such as PSCAD models are collected as necessary. For example, a PSCAD model is often required for solar and wind generation connecting to the transmission system.

Generators less than 5 MW are modeled explicitly, either as individual units, the equivalent of multiple units, or netted to load. Generators connected to the distribution system are generally modeled at a low voltage bus connected to the transmission system through a load serving transformer.

2.1.2 **Base Cases for PPA Studies and System Impact Studies**

Similar topology is used in base cases for PPA Studies for transmission projects and System Impact Studies. Both types of studies include projects in the Planned status in their base cases. However, projects with a nearly completed PPA Study and that have an impact on a study area are also considered in the base case.

[8] OP-16 Appendix K, https://www.iso-ne.com/static-assets/documents/2015/11/op16k_rto_final.pdf.

Schedule 22, Section 2.3, of the OATT states that base cases for generation interconnection Feasibility and System Impact Studies shall include all generation projects and transmission projects, including merchant transmission projects, that are proposed for the New England Transmission System for which a transmission expansion plan has been submitted and approved by the ISO. This provision has been interpreted that a project is approved when it is approved under Section I.3.9 of the Tariff.

Schedule 22, Sections 6.2 and 7.3, of the OATT further state that on the date the Interconnection Study is commenced, the base cases for generation interconnection studies shall also include generators that have a pending earlier-queued Interconnection Request to interconnect to the New England Transmission System or are directly interconnected to the New England Transmission System.

2.1.3 **Coordinating Ongoing Studies**

At any point in time there are numerous active studies of the New England transmission system. The New England planning process requires study teams to communicate with other study teams to ascertain if the different teams have identified issues which may be addressed, in whole or in part, by a common solution, or if changes to the transmission system are being proposed that might impact their study. It is appropriate for a transmission Needs Assessment, a transmission Solutions Study or a Generator Interconnection Study to consider relevant projects that have nearly completed their PPA analyses.

For example, a study of New Hampshire might consider a 345 kV line from New Hampshire to Boston that is a preferred solution in a Solutions Study of the Boston area, or, when issues in both areas are considered, may suggest a benefit of modifying a solution that has already progressed to the Proposed or the Planned stage.

2.1.4 **Base Case Sensitivities**

Often in transmission planning studies, there is uncertainty surrounding the inclusion of a resource, a transmission facility, or a large new load in the base case for a study. These uncertainties are handled by doing sensitivity analysis to determine the impact the inclusion or exclusion of a particular resource, transmission project or load has on the study results.

For Needs Assessments,Solutions Studies, and competitive transmisison RFPs, sensitivity studies may be done to determine the impact of changes that are somewhat likely to occur within the planning horizon and may influence the magnitude of the need or the choice of the solution. Typically, stakeholder input is solicited at Planning Advisory Committee (PAC) meetings in determining the manner in which sensitivity results are factored into studies. Examples are resources that may retire or be added, and transmission projects that may be added, modified, or delayed. Sensitivity analysis usually analyzes a limited number of conditions for a limited number of contingencies.

2.1.5 **Modeling Projects with Different In-Service Dates**

In some situations it is necessary to do a study where the year of study is earlier than the in-service dates of all the projects that need to be considered in the base case. In such situations it is necessary to also include a year of study that is after the in-service dates of all relevant projects.

As an example, consider two generation projects in the ISO's queue. The first project has queue position 1000 and a Commercial Operation Date of 2018. The second project has queue position 1001 and a Commercial Operation Date of 2015. Schedule 22, Sections 6.2 and 7.3, of the OATT require that the study of the project with queue position 1001 to include the project with queue position 1000. To accomplish this, the study of the project with queue position 1001 would be done with a 2015 base case without the project with queue position 1000 and also with a 2018 base case that includes the project with queue position 1000 and any transmission upgrades associated with queue position 1000.

2.2 System Load

The following section describes the make-up of the load data in the cases provided by the ISO. Appendix J – Load Modeling Guide for ISO New England Network Model provides additional detail on how the load data is developed for the base case.

2.2.1 System Load Levels

The following load levels are used in planning studies:

- Summer Peak Load
- Winter Peak Load
- Intermediate Load
- Light Load
- Minimum Load

When assessing Summer peak load conditions, up to 100% of the projected 90/10 Summer Peak Load for the New England Control Area is modeled. When assessing Winter peak load conditions, up to 100% of the projected 90/10 Winter Peak Load for the New England Control Area is modeled. The Intermediate Load, Light Load, and Minimum Load levels were derived from actual measured load, which is total generation plus net flows on external tie lines. These load levels include transmission losses and manufacturing loads. The loads in the base cases provided by the ISO are adjusted to account for these factors. Since actual measured load includes the impacts of distributed resources and distributed generation, no adjustments to the ISO bases cases are needed to address these impacts. The Intermediate Load, Light Load, and Minimum Load will be reviewed periodically and may be adjusted in the future based on actual load levels.

2.2.1.1 *Summer Peak Load Level*

The Summer Peak Load level represents conditions that can be expected during the highest load levels of the summer season. Depending on the availability of DER, the highest load for New England and for each individual study area may occur at either a weekday mid-day or weekday evening hour. In certain types of studies, both conditions may need to be tested to ensure reliability during different levels of intermittent resource availability. The differences between the mid-day and evening peak hours are discussed further in Section 2.3.9.3. The Summer Peak Load is classified by the probability of occurrence such as 90/10 or 50/50. The 90/10 Summer Peak Load represents a load level that has a 10% probability of being exceeded due to variations in weather, the 50/50 represents a load level that has a 50% probability of being exceeded. In the studies described in this guide, the 90/10 Summer Peak Load is used.

Summer Peak Load values are obtained from the CELT Report. The exception is for planning studies that go beyond the last year of the CELT Report. For those studies, the percentage of load growth between the last two years of the CELT forecast is used to grow the load to the appropriate year of study. For example, the 2017 CELT report forecasts load until the Summer of 2026. For a study that will model the Summer of 2027, the growth rate between 2025 and 2026 is obtained and multiplied to the 2026 load to derive a 2027 value. See the following equation for details on how to calculate any future year load level beyond the end of the CELT forecast.

$$\boldsymbol{Year\ (X+n)\ Load\ Level} = \left(\frac{\boldsymbol{Year\ X\ Load\ Level}}{\boldsymbol{Year\ (X-1) Load\ Level}}\right)^{\boldsymbol{n}} \times \boldsymbol{Year\ X\ Load\ Level}$$

Where X represents the last year of the CELT forecast and n represents the number of years after the last year of the CELT forecast.

The CELT forecast includes losses of about 8% of the total gross load, which is comprised of 2.5% for transmission and large transformer losses, and 5.5% for distribution losses. Thus the amount of customer load served is typically slightly less than the gross forecast. The peak load level is additionally adjusted for modeling of demand resources and behind-the-meter solar photovoltaic (PV) as discussed in Sections 2.3.9.70 and 2.3.9 respectively. The target load level for Summer Peak Load is achieved by building a case with a recent CELT forecast and the study year being evaluated.

2.2.1.2 *Winter Peak Load Level*

The Winter Peak Load level represents conditions that can be expected during the highest load levels of the winter season. The target load level for Winter Peak Load is achieved by building a case with a recent CELT forecast and the study year being evaluated.

Similar to the Summer Peak, the Winter Peak Load is classified by the probability of occurrence such as 90/10 or 50/50. In the studies described in this guide, the 90/10 Winter Peak Load is used.

Winter Peak Load values are obtained from the CELT Report. The CELT forecast includes losses of about 8% of the total gross load, which is comprised of 2.5% for transmission and large transformer losses, and 5.5% for distribution losses. Thus, the amount of customer load served is typically slightly less than the gross forecast. The peak load level is additionally adjusted for modeling of demand resources, as discussed in Section 2.3.9.70. The load level is not adjusted for PV output, as the peak is assumed to occur after sunset. This assumption is discussed more in Section 2.3.9.

2.2.1.3 *Intermediate (Shoulder) Load Level*

The Intermediate Load level, also called the shoulder load level, represents both loads in off peak hours during the Summer and loads during peak hours in the Spring and Fall. The Intermediate Load level was developed by reviewing actual system loads for the three years (2011-2013) and approximating a value system loads were at or below 90% of the time (7,884 hours). The load level analysis used 500 MW increments and the current value was rounded down to account for the anticipated impact of continuing energy efficiency programs. The target load level for non-manufacturing load for Intermediate Load is 17,680 MW. The manufacturing loads are modeled in addition to the non-manufacturing loads (See Section 2.2.3 for more details on non-CELT loads).

2.2.1.4 *Light Load Level*

The Light Load level was developed by reviewing actual system loads for the last ten years and approximating a value system loads were at or below for 2,000 hours. The load level analysis used 500 MW increments and the current value was rounded down to account for the anticipated impact of continuing energy efficiency programs. The target load level for non-manufacturing load for Light Load is 12,180 MW. The manufacturing loads are modeled in addition to the non-manufacturing loads (See Section 2.2.3 for more details on non-CELT loads).

2.2.1.5 *Nighttime Minimum Load Level*

The Nighttime Minimum Load level was determined by reviewing actual minimum system gross loads, excluding data associated with significant outages such as after a hurricane. These low gross loads typically occur during overnight hours, between approximately 2 and 5 AM, on weekends in the spring or fall. The target load level for non-manufacturing load for Nighttime Minimum Load is 7,680 MW[9]. The manufacturing loads are modeled in addition to the non-manufacturing loads (See Section 2.2.3 for more details on non-CELT loads).

2.2.1.6 *Mid-day Minimum Load Level*

The Mid-day Minimum Load level was determined by reviewing actual power consumption during daytime hours. The target load level for non-manufacturing load for Mid-day Minimum Load is 12,000 MW[10], before reductions for behind-the-meter and distributed solar PV resources. This represents the power consumption observed near noon on weekends in the spring or fall. After accounting for reductions for behind-the-meter and distributed solar PV resources, this is the time period when the lowest net loads are expected to occur. The intent of examining a Mid-day Minimum Load level is to ensure reliability at lighter loads with higher levels of intermittent resources in-service. (See Section 2.3 for more detail on intermittent resources.)

2.2.2 **Load Levels Tested**

Steady state testing is done at the Summer Peak Load level because equipment ratings are lower in the Summer and loads are generally higher. Steady-state testing is also performed at the Winter Peak Load level, unless a study area's winter peak load is low enough that summer peak is expected to be most limiting.

Testing at the Intermediate Load level is typically done to test for the effects running the pumped storage facilities in pumping mode overnight during a heat wave, or high penetration of renewables during the Spring and Fall seasons. Testing at the Nighttime Minimum Load level is done to test for potential high voltages when line reactive losses may be low and fewer generators are dispatched resulting in lower availability of reactive resources. Testing in the Mid-Day Minimum Load level is also performed to examine the possibility of high steady-state voltages, and potentially other concerns, due to a lower net load.

Stability testing is always done at the Light Load level to simulate stressed conditions due to lower inertia resulting from fewer generators being dispatched and reduced damping resulting from reduced load. Stability testing at minimum load levels is also performed in certain types of studies to examine the performance of the system with fewer synchronous units online. Except where experience has shown it is not necessary, stability testing is also done at peak loads to bound potential operating conditions and test for low voltages.

The load levels generally used in different planning studies are shown in Table 2-2 and Table 2-3. This list should be used as a guide for typical load levels studied but it is ultimately up to the transmission planner performing the study to determine what is needed for each specific study.

[9] The process for arriving at this value is described in Appendix J.
[10] The process for arriving at this value is described in Appendix J.

Table 2-2
Typical Load Levels Tested in Needs Assessments, Solutions Studies, and Competitive Transmission RFP's

Type of Study	Steady State	Stability	Summer Mid-day Peak	Winter Evening Peak	Summer Evening Peak	Nighttime Minimum	Mid-day Minimum	Notes
Transmission Needs Assessments	X		Yes	Yes	Yes	Yes	Yes	7
		X	Yes	Yes	Yes	Yes	Yes	7
Transmission Solutions Studies	X		Yes	Yes	Yes	Yes	Yes	7
		X	Yes	Yes	Yes	Yes	Yes	7
Competitive Transmission RFPs	X		Yes	Yes	Yes	Yes	Yes	7
		X	Yes	Yes	Yes	Yes	Yes	7

Table 2-3
Typical Load Levels Tested in Other Planning Studies

Type of Study	Steady State	Stability	Summer Evening Peak	Winter Evening Peak	Intermediate	Light	Nighttime Minimum	Notes
PPA Study of Transmission Project	X		Yes	No	1	No	2	
		X	Yes	No	No	Yes	No	
System Impact Study	X		Yes	No	Yes	3	2	
		X	Yes	No	No	Yes	No	
Area Review Analyses	X		Yes	No	No	No	No	
		X	Yes	No	No	Yes	No	
BPS Testing Analyses	X		Yes	No	No	No	No	
		X	Yes	No	No	Yes	No	
Transfer Limit Studies	X		Yes	No	4	No	No	
		X	Yes	No	No	Yes	No	
Interregional Studies	X	X	Yes	No	No	No	No	
FCM New Resource Qualification Overlapping Impact Analyses	X		Yes	No	No	No	No	5
FCM New Resource Qualification Network Resource Interconnection Standard Analyses	X		Yes	No	No	No	No	5
FCM Study for Annual Reconfiguration Auctions and Annual CSO Bilaterals	X		Yes	No	No	No	No	5,6
FCM Delist Analyses	X		Yes	No	No	No	No	5
Transmission Security Analyses	X		Yes	No	No	No	No	5
Non-Commercial Capacity Deferral Notifications	X		Yes	No	No	No	No	5

(1) It may be appropriate to explicitly analyze Intermediate Load levels to assess the consequences of generator and transmission maintenance.

(2) Testing at a Nighttime Minimum Load level is done for projects that add a significant amount of charging current to the system, or where there is significant generation or other facilities such as conventional HVDC that do not provide voltage regulation.
(3) Testing at Light Load is done when generation may be limited due to Light Load export limits.
(4) Critical outages and limiting facilities may sometimes change at load levels other than peak, thereby occasionally requiring transfer limit analysis at Intermediate Load levels.
(5) These studies are described in PP10.
(6) Sensitivity analyses at load levels lower than peak are considered when such lower load levels might result in high voltage conditions, system instability or other unreliable conditions per PP10.
(7) Winter Evening Peak Load testing will not be required in Needs Assessments, Solutions Studies, or competitive RFPs in study areas where the winter peak is low enough that summer peak is expected to be most limiting.

2.2.3 **Non-CELT Loads**

The CELT Report is the primary source of assumptions for use in electric planning and reliability studies for the ISO New England Reliability Coordinator area. The CELT includes generators at their net output and customers with behind-the-meter generation at their net load or generation. In many planning studies, this generation is modeled at its gross output. When this is done, it is necessary to add generating station service loads and certain manufacturing loads, predominately mill load in Maine, to the CELT load forecast.

There is about 1,100 MW of station service load; however, the amount of station service represented will be dependent on the generation that is in service. Station service should be turned off if the generation it is associated with is out of service, with the exception of station service to nuclear plants. Due to the trend of retiring manufacturing load, the amount of manufacturing load that is modeled will be documented in study documents where it is relevant.

Also, specific large proposed loads, such as data centers and large green house facilities, are not generally included in the CELT load forecast, and may be included in the study depending on the degree of certainty that the large proposed load will come to fruition.

2.2.4 **Load Power Factor**

The power factor of the load is important in planning studies because it impacts the current flow in each transmission Element. For example, a 100 MW load causes about 500 amps to flow in a 115 kV line if it is at unity power factor and about 560 amps to flow if it is at 0.90 power factor. The larger current flow resulting from a lower power factor causes increased real power and reactive power losses and causes poorer transmission voltages. This may result in the need for replacing transmission Elements to increase their ratings, in the need for additional shunt devices such as capacitors or reactors to control voltages, or in a decreased ability to transfer power from one area to another.

Each Transmission Owner (TO) in New England uses a process that is specific and appropriate to their particular service area to determine the load power factor to be assumed for loads in its service territory. Table 2-4 summarizes the methods used by TOs within the New England Control Area to set the load power factor values to be used in modeling their systems at the 90/10 Summer Peak Load level.

Table 2-4
Load Power Factor Assumptions

Transmission Owner	Base Modeling Assumption
Avangrid (Maine)	Historical metered PF values (Long-term studies use 0.955 lagging)
Avangrid (SWCT)	0.995 lagging PF at Distribution Bus
Versant Power	Uses Historical Power Factor (PF) values
Eversource (Boston)	Individual Station 3 Year Average PF at Distribution Bus
Eversource (Cape Cod)	0.985 lagging PF at Distribution Bus
Eversource (CT, NH, WMA)	0.990 lagging PF at Distribution Bus
Municipal Utilities	Uses Historical PF values
National Grid	1.00 PF at Distribution Bus
VELCO	Historical PF at Distribution Bus provided by Distribution Companies

The power factor assumptions from Table 2-4 are also used in Intermediate Load and Light Load cases.

The power factor at the Nighttime Minimum Load level is set at 0.998 leading at the distribution bus for all scaling load in New England with the exception of:

1. Downtown Boston load served by Eversource is set to a power factor of 0.978 lagging at the distribution bus.
2. Suburban Boston load served by Eversource is set to a power factor of 1.00 at the distribution bus.

The power factor at the Mid-day Minimum Load level is set to unity for all loads with the exception of:

1. Downtown Boston load served by Eversource is set to a power factor of 0.978 lagging at the distribution bus.

The non-scaling load includes mill loads in Maine, Massachusetts Bay Transportation Authority (MBTA) loads in Boston, railroad loads in Connecticut, and other similar loads.

ISO New England Operating Procedure No. 17 (OP 17), *Load Power Factor Correction*, discusses load power factor in more detail and describes the annual survey done to measure compliance with acceptable load power factors.

2.2.5 **Load Models**

2.2.5.1 *Steady State*

In steady state studies, loads are modeled as constant MVA loads, comprised of active (real) P and reactive (imaginary) Q loads. The distributions of Transmission Owners' loads are based on historical and projected data at individual buses, modeling equivalent loads that represent line or transformer flows. These loads may be modeled at distribution, sub-transmission, or transmission voltages.

2.2.5.2 *Transient Stability*

Loads (including generator station service) are assumed to be uniformly modeled as constant impedances throughout New England and New York. The constant impedances are calculated using the P and Q values of the load. This representation is based on extensive simulation testing using various load models to derive the appropriate model from an angular stability point of view, as described in the 1981 New England Power Pool (NEPOOL) report, *Effect of Various Load Models on System Transient Response*.

For underfrequency load shedding analysis, other load models are sometimes used, such as either a polynomial combination of constant impedance, constant current and constant load; or a complex load model, including modeling of motors. The alternate modeling is based on the end use composition of the load. Voltage stability analysis is sometimes done using a complex load model, including modeling of motors.

2.3 System Resources

2.3.1 **Generator Maximum Power Rating Types**

Within New England, a number of different real power (MW) ratings for generators connected to the grid are published. Examples of the different generator ratings are summarized in Table 2-5. The detailed definitions of these ratings are included in Appendix A – Terms and Definitions. Capacity Network Resource Capability (CNRC) and Network Resource Capability (NRC) values for New England generators are published each year in the CELT Report.[11] Qualified Capacity (QC) values are calculated based on recently demonstrated capability for each generator. The Capacity Supply Obligation (CSO) value and QC values are published for each Forward Capacity Auction in the informational results filings to FERC.[12]

[11] http://www.iso-ne.com/trans/celt/index.html
[12] http://www.iso-ne.com/regulatory/ferc/filings/index.html

Table 2-5
Generator Real Power Ratings

Generator Maximum Value Type	Description
Capacity Network Resource Capability – Summer (CNRC Sum) (Maximum output at or above 90° F)	CNRC Summer is the maximum amount of capacity that a generator has interconnection rights to provide in Summer. It is measured as the net output at the Point of Interconnection and cannot exceed the generator's maximum output at or above 90° F.
Capacity Network Resource Capability – Winter (CNRC Win) (Maximum output at or above 20° F)	CNRC Winter is the maximum amount of capacity that a generator has interconnection rights to provide in Winter. It is measured as the net output at the Point of Interconnection and cannot exceed the generator's maximum output at or above 20° F.
Capacity Supply Obligation (CSO)	A requirement of a resource to supply capacity. This requirement can vary over time based on the resource's participation in the Forward Capacity Market.
Network Resource Capability – Summer (NRC Sum) (Maximum output at or above 50° F)	NRC Summer is the maximum amount of electrical output that a generator has interconnection rights to provide in Summer. It is measured as the net output at the Point of Interconnection and cannot exceed the generator's maximum output at or above 50° F.
Network Resource Capability – Winter (NRC Win) (Maximum output at or above 0° F)	NRC Winter is the maximum amount of electrical output that a generator has interconnection rights to provide in Winter. It is measured as the net output at the Point of Interconnection and cannot exceed the generator's maximum output at or above 0° F.
Qualified Capacity (QC)	QC is the amount of capacity a resource may provide in the Summer or Winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

2.3.2 Generator Models

In New England planning studies, except for the FCM studies, generators connected to the transmission system are generally modeled as a generator with its gross output, its station service load, and its generator step-up transformer (GSU). In FCM studies, except for Network Capacity Interconnection Standard studies, generation is generally modeled net of station service load at the low voltage side of the GSU and station service load is set to zero. This is done because the CSO, QC, and CNRC values are net values. One exception is made in FCM-related studies for nuclear resources, where the generator is modeled at its gross output, in order to capture the need to maintain supply to the generator's station service load if the generator is out of service.

Another exception is generating facilities composed of multiple smaller generators such as wind farms, solar PV, and small hydro units. These facilities are often modeled as a single equivalent generator on the low voltage side of the transformer that interconnects the facility with the transmission system.

The ratings and impedances for an existing GSU are documented on the NX-9 form for that transformer. The existing generator's station service load is documented on the NX-12 form for that generator. Similar data is available from the Interconnection Requests for proposed generators. The generator's gross output is calculated by adding its appropriate net output to its station service load associated with that net output. GSU losses are generally ignored in calculating the gross output of a generator. This data is used by the ISO to help create the base cases for planning studies.

In New England planning studies, generators connected to the distribution system are generally modeled as connected to a low voltage bus that is connected to a transformer that steps up to transmission voltage or netted to distribution load. Multiple generators connected to the same low voltage bus may be modeled individually or as an equivalent generator.

2.3.3 **Maximum Real Power Ratings**

Different studies are conducted to achieve a variety of transmission planning objectives. Therefore, it is necessary to anticipate different generator capabilities depending on the specific conditions being examined by each study type.

Most generators are usually dispatched to the maximum real power rating specified in Table 2-6 Maximum Real Power Ratings for Generation in Planning Studies. Exceptions include wind (Section 2.3.66), conventional hydro (Section 2.3.77), energy storage systems (Section 2.3.8), and solar PV (Section 2.3.9). Depending on study type, these units are often de-rated below their maximum power rating, as described later in this guide.

Table 2-6
Maximum Real Power Ratings for Generation in Planning Studies

Type of Study	Summer Peak	Winter Peak	Off-Peak (1)	Conventional Generation (2)	Renewable Generation (3)	Energy Storage Systems (4)
PPA Study of Transmission Projects	X			NRC Sum	NRC Sum	NRC Sum
			X	NRC Win	NRC Win	NRC Win
System Impact Studies	X			NRC Sum	NRC Sum	NRC Sum
			X	NRC Win	NRC Win	NRC Win
BPS Testing Analyses	X			NRC Sum	NRC Sum	NRC Sum
			X	NRC Win	NRC Win	NRC Win
Transfer Limit Studies	X			NRC Sum	NRC Sum	NRC Sum
			X	NRC Win	NRC Win	NRC Win
Interregional Studies	X			NRC Sum	NRC Sum	NRC Sum
			X	NRC Win	NRC Win	NRC Win
Transmission Needs Assessments	X			QC Sum (5)(6)	NRC Win (5)(7)	NRC Win (5)
		X	X	NRC Win (5)	NRC Win (5)(7)	NRC Win (5)
Transmission Solutions Studies	X			QC Sum (5)(6)	NRC Win (5)(7)	NRC Win (5)
		X	X	NRC Win (5)	NRC Win (5)(7)	NRC Win (5)
Competitive Transmission RFPs	X			QC Sum (5)(6)	NRC Win (5)(7)	NRC Win (5)
		X	X	NRC Win (5)	NRC Win (5)(7)	NRC Win (5)
NPCC Area Transmission Reviews	X			NRC Sum	NRC Sum	NRC Sum
			X	NRC Win	NRC Win	NRC Win
FCM New Resource Qualification Overlapping Impact Analyses	X			CNRC Sum	CNRC Sum	CNRC Sum
FCM New Resource Qualification Network Resource Interconnection Standard Analyses	X			NRC Sum	NRC Sum	NRC Sum
			X	NRC Win	NRC Win	NRC Win
FCM Study for Annual Reconfiguration Auctions and Annual CSO Bilaterals	X		X	Lower of QC Sum or CSO	Lower of QC Sum or CSO	Lower of QC Sum or CSO
FCM Delist Analyses	X			QC Sum	QC Sum	QC Sum
Transmission Security Analyses	X			QC Sum	QC Sum	QC Sum
Non-Commercial Capacity Deferral Notifications	X			Lower of QC Sum or CSO	Lower of QC Sum or CSO	Lower of QC Sum or CSO

(1) Off-peak load levels include intermediate load, light load and minimum load levels.

(2) The conventional generation column also includes some types of non-conventional generation, for example fuel cells, which aren't addressed in other sections of this document.
(3) The renewable generation column includes wind generation, conventional hydro generation, and solar PV generation. See sections 2.3.6, 2.3.7 and 2.3.9 for additional details.
(4) The energy storage systems column includes battery energy storage systems and pumped hydro. See Section 2.3.8 for more details.
(5) Generation will be dispatched down as necessary to avoid thermal loading violations that are unrelated to the ability to serve load.
(6) Existing generation that does not have a QC value will be modelled using their Summer Seasonal Claimed Capability (SCC) value. Future Resources that have been selected in a state sponsored RFP, or have a binding contract that do not have a QC value will be modeled at their contractual value.
(7) In transmission Needs Assessments, Solutions Studies, and Competitive Transmission RFPs, renewable generation is dispatched to a de-rated value of the maximum real power output. See sections 2.3.6, 2.3.7 and 2.3.9 for additional details.

Further explanations of the decision to apply different maximum power ratings for certain types of system planning studies are described in the following subsections.

2.3.3.1 *Transmission Needs Assessments, Solutions Studies, and Competitive Transmisison RFP studies*

For these study types, maximum real power ratings vary by load level and resource type.

In summer peak load assessments, Summer QC is used to model the maximum real power output (MW) of conventional fuel resources that participate in the FCM. Conventional fuel resources include all fossil fuel, nuclear, and biomass generators. Summer QC is used for conventional fuel resources in peak load assessments because it represents recently demonstrated generation capability under summer peak load conditions for existing resources, and represents the maximum CSO a resource may obtain in the FCM. Any request to reduce an obligation below a resource's QC is subject to a reliability review and may be rejected for reliability reasons.

Existing conventional fuel generators that do not have QC values will be modeled using their summer seasonal claimed capability (SCC) value used to represent the available power under summer peak load conditions. Future conventional fuel generators that have been selected in a state sponsored RFP, or have a binding contract that do not have a QC value will be modeled at their contractual value.

A different method is used to set the maximum real power output of renewable and energy storage resources at peak load. These resources are typically dispatched at a de-rated percentage of their maximum real power capability. The de-rate values for renewable and energy storage resources are described in sections 2.3.6-2.3.9. Summer QC values are not appropriate because the output produced by the percentages of nameplate specified in high-renewable scenarios often exceeds the maximum power specified by Summer QC values.

For these units, maximum real power is best represented using Winter NRC values. Where applicable, Winter NRC values may be adjusted to account for station service load and/or transformation and collector system losses before being included in study models.

Future renewable and energy storage resources that have been selected in a state sponsored RFP, or have a binding contract that do not have an NRC value will be modeled at their contractual value.

In winter load assessments, Winter NRC values (maximum MW output at or above 0° F) are used to model the maximum real power output of all generators. The MW output at or above 0° F is reflective of typical New England Winter peak scenarios.

In Light Load and Minimum Load level assessments, Winter NRC values (maximum MW output at or above 0° F) are used to model the maximum real power output of all generators. Some generators have higher individual resource capabilities at 0° F than at higher temperatures, and Minimum Load conditions could feasibly occur at temperatures below those associated with other ratings. Therefore, using Winter NRC ratings allows a smaller number of resources to be online to serve load. Fewer resources online leads to less overall reactive capability on the system to mitigate high voltage concerns. Stability performance also degrades as the power output from a synchronous generator is increased. Additionally, a smaller number of conventional units dispatched at higher power output tends to be more conservative for transient stability concerns (in terms of limited inertia on the system and internal rotor angles).

2.3.3.2 *Other Transmission Planning Studies*

The generator's Summer NRC value is used to represent a machine's maximum real power output (MW) for all other transmission planning studies that are performed at summer peak load levels. The generator's Winter NRC value is used to represent a machine's maximum real power output (MW) for all other transmission planning studies that are performed at winter, Intermediate, Light and Minimum Load levels. There may be exceptions where an off-peak load study uses a different rating than Winter NRC. In that situation, the reason for the deviation will be noted as part of the study assumptions.

For generator System Impact Studies and generator PPA studies, using the NRC values ensures that studies match up with the level of service being provided. Studying Elective Transmission Upgrades and transmission projects with machines at these ratings also ensures equal treatment when trying to determine the adverse impact on the system due to a project.

2.3.3.3 *Forward Capacity Market Studies*

The generator's Summer CNRC value is used to represent a machine's maximum real power output (MW) for FCM New Resource Qualification Overlapping Impact Analyses. This output represents the level of interconnection service that a generator has obtained for providing capacity.

The generator's Summer NRC value is used to represent a machine's maximum real power output (MW) for FCM New Resource Qualification Network Resource Interconnection Standard Analyses at peak load. This output represents the level of interconnection service that a generator has obtained for providing energy. At off-peak load levels, Winter NRC values are used.

The generator's Summer QC value is used to represent a machine's maximum real power output (MW) for FCM Delist Analyses and Transmission Security Analyses. This output represents the expected output of a generator during Summer peak periods.

The lower of a generator's Summer QC value or Summer Capacity Supply Obligation is used to represent a machine's maximum real power output (MW) for FCM Study for Annual Reconfiguration Auctions and Annual CSO Bilaterals and the Non-Commercial Capacity Deferral Notifications. This output represents the expected capacity capability of a generator during Summer peak periods.

2.3.4 **Reactive Power Ratings**

This section is under development.

2.3.5 **Combined Cycle Generation**

For the purposes of modeling generating units in a base case and in generator contingencies, all generators of a combined cycle unit are considered to be in service at the same time or out of service together. The basis for this assumption is that many of the combustion and steam generators that make up combined cycle units cannot operate independently because they share a common shaft, they have air permit or cooling restrictions, or they do not have a separate source of steam. Other combined cycle units share a GSU or other interconnection facilities such that a fault on those facilities causes the outage of the entire facility. The ISO's operating history with combined cycle units has shown that even for units that claim to be able to operate in modes where one portion of the facility is out of service, they rarely operate in this partial mode.

2.3.6 **Wind Generation**

Analysis of historical wind data obtained from DNV[13] indicates onshore and offshore wind output can vary greatly despite relatively similar load levels and solar power availability. This creates the need to study both ends of the wind output spectrum as either may produce reliability issues on the system. To account for this variability, the average low wind output and the average high wind output (rounded within 5%) are both studied in Needs Assessments, Solutions Studies and Competitive RFPs for Summer Mid-day Peak load and for Nighttime Minimum load. For Summer Evening peak load scenarios, a fixed wind output of 5% for both onshore and offshore is assumed as this produces the most severe scenario for serving load, and DNV's data indicates that it is a realistic weather condition. For Winter Evening peak load scenarios, DNV's data indicates a realistic severe winter condition would have offshore wind at 40% of the maximum real power and onshore wind at 65% of the maximum real power specified in Table 2-6. For Mid-day Minimum load scenarios, 90% of the maximum real power output specified in Table 2-6 is assumed for offshore wind, and 65% is assumed for onshore wind. This produces the scenario with the least synchronous generation online, and DNV's data indicates that it is a realistic weather condition. The different wind levels discussed above are summarized in Table 2-7:

[13] The DNV data can be found here: https://www.iso-ne.com/system-planning/planning-models-and-data/variable-energy-resource-data/. The analysis referenced here was based on the 2021 Analysis of Stochastic Dataset.

Table 2-7
Wind Output Assumptions[14]

Scenario	Base Case	Onshore Wind (% of Maximum Real Power Output (1))	Offshore Wind (% of Maximum Real Power Output (1))
1	Nighttime Minimum (High Renewables)	65%	90%
2	Nighttime Minimum (Low Renewables)	5%	15%
3	Mid-Day Minimum	55%	90%
4	Summer Mid-Day Peak (High Renewables)	30%	90%
5	Summer Mid-Day Peak (Low Renewables)	5%	5%
6	Summer Evening Peak	5%	5%
7	Winter Evening Peak	65%	40%

(1) See Table 2-6 for details on maximum real power output employed in various study types.

The above percentages are estimates of the level of wind generation output that may occur during various scenarios. To ensure that the interconnection rights of wind resources are preserved, wind generation is dispatched in PPA studies at the maximum real power output described in Table 2-6.

2.3.7 Conventional Hydro Generation

There are two classifications of conventional hydro. The first category includes hydro facilities that have no control over water flow and no capability to store water. These facilities are listed as "hydro (daily cycle-run of river)" in the CELT report and are classified as intermittent resources in planning studies. The second category includes hydro facilities that control water flow using a reservoir or river bed that can store water. These facilities are listed as "hydro (weekly cycle)" or "hydro (daily cycle-pondage)" in the CELT report and are classified as non-intermittent resources.

For both classifications, the output of hydro generation at winter or summer peak load is set at the historic capability that can be counted on for reliability purposes, or at 10% of the maximum real power output reported in Table 2-6. The 10% value acts as an estimate of historic capability. At minimum load conditions, both classifications of hydro generation are set at the minimum flow rate capability, or to the historic capability that can be counted on for reliability purposes, or at 10% of the maximum real power output described in Table 2-6. Post contingency, conventional hydro that has the capability to control water flow and has sufficient water storage capability is dispatched up to 100% of maximum real power output to relieve criteria violations in transmission Needs Assessments, Solutions Studies, and Competitive Transmission RFP Studies. Hydro facilities that have no control over water flow or limited water storage capability are dispatched at the same output pre and post contingency.

[14] With the exception of Winter Peak, these assumptions were outlined at the Planning Advisory Committee (PAC) meeting on August 18, 2021: https://www.iso-ne.com/static-assets/documents/2021/08/a3_transmission_planning_for_the_clean_energy_transition_pilot_study_results_and_assumption_changes.pdf. Winter Peak assumptions were outlined at the Planning Advisory Committee (PAC) meeting on July 25, 2023: https://www.iso-ne.com/static-assets/documents/2023/07/a11_2023_07_25_tptg_update.pdf

2.3.8 Energy Storage Systems

Currently, the New England transmission system has two forms of energy storage systems: batteries and pumped storage hydroelectric facilities. For the purposes of this Transmission Planning Technical Guide, the ISO categorizes Energy Storage Systems (ESS) based on their participation or non-participation in the wholesale electricity market. ESS which participate in the wholesale electricity market are categorized as Market-facing. Market-facing ESS are expected to respond to the Locational Marginal Prices (LMP), and may provide capacity through the FCM and be exposed to Pay-for-Performance (PFP) penalties and incentives. ESS which do not participate in the wholesale electricity market are categorized as non-market facing. Non-market facing ESS are not expected to respond to LMPs or participate in the FCM. Additionally, some ESS installations are co-located with renewable resources, and may not have interconnection rights to charge from the grid in the absence of renewable resource production. There are three pumped storage hydroelectric facilities on the New England system, which are all market facing: J.Cockwell (Bear Swamp), Northfield Mountain, and Rocky River[15].

Within the two categories based on market participation, there are two subcategories based upon duration capabilities: short-duration and long-duration. For the purpose of Transmission Planning-related studies (Needs Assesments, Solutions Studies, and competitive tranmsission RFPs), short-duration Energy Storage Systems (ESS) are defined as having a ratio of MWh/MW less than 6 hours. Long-duration ESS are then defined as having a ratio of MWh/MW greater than or equal to 6 hours. Energy storage systems greater than or equal to six hour duration can be assumed to have enough energy capacity to charge through the entire mid-day minimum-load period.

For Needs Assessments, Solutions Studies, and competitive transmission RFPs, the output of ESS will vary based on the load scenario being studied. Table 2-8 describes the assumptions for both Market-Facing ESS and Non-Market-Facing ESS, for the six load scenarios studied in these types of assessments. (For all other load levels and studies, ESS will be modeled based on the study specific requirements. Additional details may be found in Table 2-6
Maximum Real Power Ratings for Generation in Planning Studies.)

Table 2-8
Energy Storage Systems (ESS) Assumptions

Scenario	Base Case	Short Duration		Long Duration	
		Market Facing ESS (1)	Non-Market Facing ESS (1)	Market Facing ESS (1)	Non-Market Facing ESS (1)
1	Nighttime Minimum (High Renewables)	Offline	Offline	Offline	Offline
2	Nighttime Minimum (Low Renewables)	Offline	Offline	Offline	Offline
3a	Mid-Day Minimum	Charging/pumping at the maximum consumption level based Interconnection Rights or historical performance	Charging/pumping at the maximum consumption level based Interconnection Rights or historical performance	Charging/pumping at the maximum consumption level based Interconnection Rights or historical performance	Charging/pumping at the maximum consumption level based Interconnection Rights or historical performance

[15] Rocky River is treated as a conventional hydro unit with ponding capability, due to restrictions on its pumping capability.

Scenario	Base Case	Short Duration Market Facing ESS (1)	Short Duration Non-Market Facing ESS (1)	Long Duration Market Facing ESS (1)	Long Duration Non-Market Facing ESS (1)
3b	Mid-Day Minimum	Offline	Offline	Charging/pumping at the maximum consumption level based Interconnection Rights or historical performance	Charging/pumping at the maximum consumption level based Interconnection Rights or historical performance
4	Summer Mid-Day Peak (High Renewables)	Co-located ESS- Charging/pumping at the maximum consumption level based Interconnection Rights or historical performance Stand-alone ESS- Offline	Charging/pumping at the maximum consumption level based Interconnection Rights or historical performance	Co-located ESS- Charging/pumping at the maximum consumption level based Interconnection Rights or historical performance Stand-alone ESS- Offline	Charging/pumping at the maximum consumption level based Interconnection Rights or historical performance
5	Summer Mid-Day Peak (Low Renewables)	Offline	Offline	Offline	Offline
6	Summer Evening	Discharging/generating at the lower of Winter NRC, or (MWh used to determine FCM Qualification, or nameplate MWh for energy-only resources, divided by 6)	Discharging/generating at the lower of Winter NRC, or (Nameplate MWh, divided by 6)	Discharging/generating at the lower of Winter NRC, or (MWh used to determine FCM Qualification, or nameplate MWh for energy-only resources, divided by 6)	Discharging/generating at the lower of Winter NRC, or (Nameplate MWh, divided by 6)
7	Winter Evening	Discharging/generating at the lower of Winter NRC, or (MWh used to determine FCM Qualification, or nameplate MWh for energy-only resources, divided by 6)	Discharging/generating at the lower of Winter NRC, or (Nameplate MWh, divided by 6)	Discharging/generating at the lower of Winter NRC, or (MWh used to determine FCM Qualification, or nameplate MWh for energy-only resources, divided by 6)	Discharging/generating at the lower of Winter NRC, or (Nameplate MWh, divided by 6)

(1) Details on maximum real power output can be found in Table 2-6
Maximum Real Power Ratings for Generation in Planning Studies, which varies by load level and study type.

For the Mid-Day Minimum, two scenarios may be evaluated, 3a and 3b, as seen in Table 2-8. Two scenarios are evaluated to account for conditions likely to occur in the future. The first scenario will assume that short-duration Market Facing and Non-Market Facing ESS are charging or pumping at the minimum of their Nameplate MWh or Interconnection Rights. This scenario is driven by the fact that Market-Facing ESS will see lower LMPs and Non-Market facing ESS are likely to charge when renewable energy is at its highest. The second scenario will assume all short-duration ESS are offline and only long-duration ESS will be charging or pumping. This scenario is driven by the fact that the short-duration ESS may already be fully charged, but long-duration ESS is assumed have enough energy capacity to charge through the entire minimum load window.

The only conditions where ESS are assumed to be discharging or generating is during the Summer and Winter Evening scenario. ESS are assumed to be discharging or generating at the lesser of either their Winter NRC rating or their MWh capacity divided by six. The division by six is to account for the fact that the summer evening peak period lasts for approximately five to six hours, with some margin for uncertainty of load shapes in the future. As more storage comes into the system and as electrification increases, the load curve will change and this assumption will need to be revisited.

2.3.9 **Solar Photovoltaic (PV) Generation**

Solar PV generation can be either large, transmission-connected installations, or smaller, distributed installations connected to the distribution system. These smaller, distribution-connected installations are covered by a forecast in the ISO-NE CELT Report. The CELT Report provides a forecast of the installed AC nameplate of solar PV at the end of each year and a table that lists the monthly growth of solar PV. Long-term planning studies will use the PV forecast for the end of the year prior to that being evaluated, plus the expected growth of PV through the end of May for the year being evaluated. As an example for a study in the year 2025, all the PV as of end of 2024 plus the expected growth of PV through May 2025 will be modeled.

As a part of the solar PV forecast, the data on solar PV is divided into the following three mutually exclusive groups:

- Group 1: Solar PV as a capacity resource in the FCM
    - Qualified for the FCM
    - Have CSOs
    - Size and location identified and visible to the ISO
    - May be supply or demand side resources
- Group 2: Non-FCM Settlement Only Resources (SOR) and Generators (per OP 14)
    - ISO collects energy output
    - Participate only in the energy market
- Group 3: Behind-the-Meter (BTM) Solar PV
    - Reduces system load
    - ISO has an incomplete set of information on generator characteristics
    - ISO does not collect energy meter data, but can estimate it using other available data
    - ISO calculates its value based on the difference between the total solar PV forecast and those resources that are in Groups 1 and 2.

For long-term transmission planning studies including generator interconnection studies, the solar PV will be modeled in the base cases to account for all three groups. See Section 6 of Appendix J – Load Modeling Guide for ISO New England Network Model for more details on how solar PV is modeled in the base cases.

The solar PV forecast is only on a state-wide basis. However, within a state, the solar PV does not grow uniformly, and study areas may have varying levels of PV penetration and varying levels of forecasted PV installations depending on the year of study. To account for this locational variation of solar PV, the locational data of existing solar PV that is in service as of the end of the previous year is utilized to obtain the percentage of solar PV that is in each Dispatch Zone. The New England Control Area is divided into 19 Dispatch Zones and the percentage of solar PV in each Dispatch Zone as a percentage of total solar PV in the state is available. This percentage is assumed to stay constant for future years to allocate future solar PV to the Dispatch Zones. The percentage of existing solar PV in each Dispatch Zone as of the end of each year that is used as a part of the solar PV forecast is based on Distribution Owner interconnection data.[16]

As an example, if the SEMA Dispatch Zone accounts for 20% of existing solar PV in Massachusetts, it will be assumed that 20% of any growth in solar PV as a part of the forecast will be in SEMA.

Once we have the solar PV data by Dispatch Zone, the solar PV within the Dispatch Zone falls into three categories:

- Category 1: Facilities greater than or equal to 5 MW
  - Locational data available
  - Will be modeled as aggregate generation representing the facility
  - See Appendix J for information on Category 1 modeling
- Category 2: Facilities greater than 1 MW[17] and less than 5 MW
  - Locational data available through the PPA notifications[18]
  - See Appendix K for information on Category 2 modeling
- Category 3: Existing facilities less than or equal to 1 MW and all future forecasted solar PV
  - Limited locational data available
  - Category 3 = Forecast – Category 1 – Category 2
  - See Appendix K for information on Category 3 modeling

2.3.9.1 *Load Levels Modeled*

Solar PV under Category 1 will be modeled in all the cases. The specific output of the unit will vary dependent on the study.

For Intermediate and Light Load levels, the ISO uses fixed load levels for studies based on historic data, which already includes the impacts of solar PV. Hence, no solar PV in Category 2 or 3 will be explicitly modeled in Intermediate and Light Load cases.

Peak conditions in the winter season are expected after sunset, and hence no solar PV in Category 2 or 3 will be modeled for Winter Peak Load cases. No solar PV in Category 2 or 3 will be modeled in Nighttime Minimum Load cases, because the condition being considered occurs after sunset. The only cases where solar PV under Category 2 and 3 will be explicitly modeled is for Summer Peak Load and Mid-Day Minimum Load conditions.

2.3.9.2 *Adjustment for Losses*

For solar PV in Categories 2 and 3, an adjustment to the AC nameplate will need to be made to account for avoided losses on the distribution system in summer peak and winter peak cases. Currently, the ISO assumption for distribution losses as a percentage of load is 5.5%. Hence the Category 2 and 3 PV generation output will be the AC nameplate solar PV injection at the bus on the low-side of the distribution transformer plus 5.5% to account for avoided distribution losses.

[16] https://www.iso-ne.com/system-planning/system-forecasting/distributed-generation-forecast

[17] There are instances of 1.0 MW facilities submitting PPA notifications even though they are not required to. Any facility that has notified the RC will be counted as a Category 2 facility.

[18] https://www.iso-ne.com/system-planning/transmission-planning/proposed-plan-applications

No adjustment for avoided losses will be applied in off-peak load cases. Under off-peak load conditions, the amount of distribution losses are generally lower. Additionally, it is more likely that total PV on a feeder would exceed load under off-peak load conditions, and under these conditions, additional distributed generation may increase losses. Consequently, no avoided loss factor will be applied for off-peak load conditions.

2.3.9.3 *Availability in Transmission Planning*

Based on a review of historic solar PV outputs, the ISO has determined a 26% availability factor to be appropriate for some transmission planning studies. The 26% level represents the output of solar PV during the Summer Peak Load period between 4 p.m. and 6 p.m. This is the time period when solar output begins to decrease due the angle of the sun and when loads are still at or near their peak levels.

For transmission PPA studies and generation System Impact Studies, the solar PV in Category 2 and 3 may be assumed to be up to 100% available.

For transmission Needs Assessments, Solutions Studies, and Competitive Transmission RFPs, all categories of solar PV will be modeled based on the specific scenario being analyzed. Table 2-9 summarizes the load conditions where PV output will be modeled. Any Nighttime Minimum Load study conditions will be assumed to have zero solar output.

Table 2-9
PV output levels for each Base Case Scenario

Base Case Scenario	Power Consumption (Before reductions due to behind-the-meter solar)	Solar PV Output
Mid-Day Minimum Load	12,000 MW	90%
Summer Mid-Day Peak Load (High Renewables)	100% of 90/10 Summer Peak Load	65%
Summer Mid-Day Peak Load (Low Renewables)	100% of 90/10 Summer Peak Load	40%
Summer Evening Peak Load	Evaluation of the highest net load, see Table 2-10	
Winter Evening Peak Load	100% of 90/10 Winter Peak Load	0%

The loads used in Table 2-9 are described in Section 2.2. The percent of solar output for each base case scenario is a percent of the maximum real power output described in Table 2-6. For Summer Evening Peak Load, in Needs Assessments, Solutions Studies, and Competitive Transmission RFPs, the net load for three cases will be evaluated to determine which one to select for system analysis. The power consumption level which results in the highest net load will be used for the study. Table 2-10 summarizes the three load conditions and the corresponding solar output.

Table 2-10
Summer Evening Peak Load Conditions

Peak Load Power Consumption (before reductions due to behind-the-meter solar PV)	Solar Output
100% of Summer 90/10	26%
95% of Summer 90/10	10%
92% of Summer 90/10	0%

By choosing the highest of the three net loads, studies will examine the most severe condition while accommodating variations in solar PV penetration. In study areas with uneven levels of solar PV penetration, more than one of these combinations may be used to fully evaluate the worst-case conditions for each portion of the study area. In addition, in study areas or portions of study areas with significant amounts of market-facing solar PV connected directly to the transmission system, the most severe conditions may be driven by low levels of transmission-connected solar PV rather than only distribution-connected and BTM solar PV. These situations will be evaluated on a case-by-case basis, and the transmission-connected solar PV may be included in the total solar PV in the study area when choosing one of these three Summer Evening Peak Load conditions.

For all other load levels, the Category 1 solar PV facilities will be modeled based on the study specific requirements. For transmission PPA studies and generation System Impact Studies, the Category 1 solar PV will be treated consistent with the treatment of conventional generators. In these studies, Category 2 and 3 solar PV installations will be modeled according to the first row of Table 2-10 (100% of 90/10 load, and 26% of maximum real power output).

2.3.9.4 *Modeling in FCM Studies*

Solar PV that has qualified in FCM will be treated consistent with the treatment of other intermittent generators that have qualified in FCM. Non-FCM solar PV that is participating in the ISO energy market will not be included in FCM studies because they have no obligation to generate. BTM solar PV will be modeled at a level based on the estimated median of its net output during the defined Intermittent Reliability Hours.

2.3.9.5 *Forecasting Beyond the Forecast Horizon*

Occasionally, transmission planning studies have to look beyond the 10 year solar PV forecast horizon. For these cases, the growth of the solar PV forecast from Year 9 to Year 10 will be used to obtain the Year 11 forecast. This process will be repeated to obtain Year 12 forecast from Year 11 forecast and Year 10 forecast and so on. This is the same methodology that is used to scale the Summer Peak Load and Mid-Day Minimum Load past the forecast horizon (See Section 2.2.1.1 for details).

2.3.9.6 *Impacts on Load Power Factor*

All DER, including Solar PV and ESS, when modeled in the base cases will be modeled with a 0 MVAR output. It is assumed that distribution companies will adjust their power factor correction programs to account for solar PV.

2.3.9.7 *Demand Resources*

Beginning June 1, 2018, certain resources, formerly classified as Demand Resources are allowed to participate in the ISO New England markets as energy-only resources. The change results in new terms that will be used to represent energy-only versus capacity resources. In this document the undefined term, demand resources (DR), will be used generically to generally mean demand-side resources while the proper terms will be referred to where appropriate.

Through the FCM, Demand Capacity Resources (DCR) can be procured to provide capacity and have future commitments similar to that of a generation resource. There are currently two categories of DCR in the FCM: passive Demand Capacity Resources (passive DCR) and Active Demand Capacity Resources (ADCR). Passive DCR consists of two types of resources: On-Peak Demand Resources and Seasonal Peak Demand Resources. ADCR consists of Demand Response Resources that reduce load based on ISO instructions under real-time system conditions. Demand Response Resources must be associated with an ADCR in order to be considered as a capacity resource in the FCM.

2.3.9.8 *Energy Efficiency beyond FCM Horizon*

In addition to the demand resources mentioned above that are procured through the FCM, the ISO forecasts Energy Efficiency as a part of the annual CELT forecast. This energy efficiency is a form of passive DR but is treated separately as it is forecasted beyond the FCM horizon. This demand resource is included for studies that analyze time periods beyond the FCM horizon.

2.3.9.9 *Modeling Demand Resources*

The modeling of demand resources in planning studies varies with the type of study and the load level being studied. Demand resources and their modeling are described fully in Appendix C – Guidelines for Treatment of Demand Resources in System Planning Analysis.

Demand resources will not be modeled explicitly in the Intermediate, Light, and Minimum Load level cases because the impact of demand resources was included in the actual measured load used to establish the fixed load levels (see Section 2.2.1).

2.3.10 **Behind-the-Meter Mill Generation**

Several industrial mill facilities in Maine have on-site generation that reduces their net load as experienced by the transmission system. This behind-the-meter generation is explicitly modeled in the ISO base case to account for a sudden load increase following the loss of this generation in steady state and transient stability analyses. Each industrial facility has a contractual load limit with the interconnecting transmission owner. For transmission planning studies under peak load conditions, the entire facility is modeled such that if the largest generator is lost, the net flow into the facility would be at the contractual limit. For transmission planning studies under minimum load conditions, all internal generation is modeled out-of-service, and the load inside the facility is adjusted such that the facility is interchanging 0 MW and 0 MVAR with the transmission system. This is reflective of the fact that the facility may cease its power consumption at any time, and the transmission system must not be designed in a way that relies on the facility's power consumption for its reliability. See Section 2.2.3 for a description of the manufacturing load.

2.4 Phase Shifting Transformers

A summary of each phase shifting transformer (PST) also known as phase angle regulators (PAR) in New England is described in this section (See Appendix G – Phase Shifting Transformers Modeling

Guide for ISO New England Network Model for a detailed description of each PST's operation). Modeling of phase shifting transformers in steady state power flow studies is also addressed in Section 2.11.3.

PSTs are used by system operators in the following locations within New England to control active (real) power flows on the transmission system within operating limits:

- **Saco Valley / Y138 Phase Shifter** – It is located along the New Hampshire – Maine border, and is used to control power flow along the 115 kV Y138 line into central New Hampshire.
- **Sandbar Phase Shifter** – It is located along the Vermont – New York border, and is used to control power flow along the 115 kV PV-20 line into the northwest Vermont load pocket from northeast New York.
- **Blissville Phase Shifter** – It is located along the Vermont – New York border, and is mainly used to prevent overloads on the New York side by controlling power flow on the 115 kV K7 line.
- **Granite Phase Shifters** – They are located in Vermont and are mainly used to control power flow on the 230 kV F206 line between New Hampshire and Vermont
- **Waltham Phase Shifters** – They are located in the Boston, Massachusetts area. They are adjusted manually to regulate the amount of flow into and through Boston on the 115 kV 282-520 and 282-521 lines.
- **Baker Street Phase Shifters** – They are located in the Boston, Massachusetts area. They are adjusted manually to regulate the amount of power flow into and through Boston on the 115 kV 110-510 and 110-511 lines.
- **Northport/Norwalk Harbor Cable (NNC) Phase Shifter** – It is located at the Northport 138 kV station in New York (controlled by Long Island Power Authority outside of ISO New England's control) and is used to control the power flow on the 138 kV Norwalk Harbor – Northport 601, 602, and 603 submarine cables.

2.5 Load Tap Changing Transformers

Many transformers connected to the New England transmission system have the capability of automatic load tap changing. This allows the transformer to automatically adjust the turns' ratio of its windings to control the voltage on the regulated side of the transformer. In transmission planning studies, load tap changers are allowed to operate when determining the system voltages and power flows after a contingency.

Modeling the operation of load tap changers on transformers that connect load to the transmission system generally produces conservative results because raising the voltage on the distribution system will reduce the voltage on the transmission system. Operation of load taps changers on autotransformers raises the voltage on the lower voltage transmission system (typically 115 kV) and reduces the voltage on the higher voltage transmission system (typically 230 kV or 345 kV).

In areas of the transmission system where there are known voltage concerns that occur prior to load tap changer operation, it is necessary to do sensitivity testing to determine if voltage criteria violations occur prior to load tap changer operation. This is further discussed in the voltage criteria section (See Section 3.1.2). Modeling of transformer load tap changers in steady state power flow studies is also addressed in Section 2.11.2.

2.6 Static Compensation Devices

2.6.1 **Series Devices**

2.6.1.1 *Reactors*

Series reactors serve many purposes on the New England transmission system. Some of these are permanently in service to limit short circuit duty, others may be switched to control flows on specific transmission elements. Table 2-11 lists these devices and briefly describes their purpose and operation in planning studies.

Table 2-11
Series Reactors Modeled in Planning Studies

Line	Station	State	kV	Ohms	Normal Operation	Purpose
1322	Breckwood	MA	115	5.55	Out of Service (By-passed)	Inserted to limit short circuit duty at Breckwood when 1T circuit breaker is closed
1556	Cadwell	MA	115	3.97	In Service	Limits short circuit duty at 115 kV East Springfield substation, not to be switched in planning studies
1645	Cadwell	MA	115	3.97	In Service	Limits short circuit duty at 115 kV East Springfield substation, not to be switched in planning studies
1497	East Devon	CT	115	1.32	In Service	Limits short circuit duty on 115 kV system, not to be switched in planning studies
1776	East Devon	CT	115	1.32	In Service	Limits fault duty on 115 kV systems, not to be switched in planning studies
F162	Greggs	NH	115	10.0	Out of Service (By-passed)	Controls flows on the 115 kV system, can be switched in to mitigate thermal overloads
1222	Hawthorne	CT	115	5.00	Out of Service (By-passed)	Controls flows on the 115 kV system, can be switched in to mitigate thermal overloads
1610	Mix Avenue	CT	115	7.50	In Service	Control flows on the 115 kV system and will normally be operated in service
1784	North Bloomfield	CT	115	2.65	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate thermal overloads
329-530	North Cambridge	MA	115	2.75	In Service	Limit flows and short circuit duty on 115 kV cables, not to be switched in planning studies
329-531	North Cambridge	MA	115	2.75	In Service	Limit flows and short circuit duty on 115 kV cables, not to be switched in planning studies
346	North Cambridge	MA	345	11.90	In Service	Controls flows on the 345 kV system, can be switched in to mitigate thermal overloads
365	North Cambridge	MA	345	11.90	In Service	Controls flows on the 345 kV system, can be switched in to mitigate thermal overloads
1637	Norwalk	CT	115	5.00	Out of Service (By-passed)	Controls flows on the 115 kV system, can be switched in to mitigate thermal overloads
115-10-16	Potter	MA	115	3.00	In Service	Limit flows on 115 kV cables, not to be switched in planning studies
PV-20	Sandbar	VT	115	30.0	Out of Service (By-passed)	Sandbar Overload Mitigation Reactor – Controls flows on the 115 kV system, can be switched in to mitigate thermal overloads
1910	Southington	CT	115	6.61	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate thermal overloads.
1950	Southington	CT	115	6.61	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate thermal overloads.
1465	Mystic	CT	115	1%	In Service	Controls flows on the 115 kV system, can be switched in to mitigate thermal overloads.
211-514	Woburn	MA	115	2.75	In Service	Limit flows and short circuit duty on 115 kV cables, not to be switched in planning studies
1346	Southwest Hartford	CT	115	2.65	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate thermal overloads
1704	Southwest Hartford	CT	115	3.97	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate thermal overloads
Southington Bus 1 to 2 Tie	Southington	CT	115	3%	In Service	Limit flows and short circuit duty on 115 kV, not to be switched in planning studies

2.6.1.2 *Capacitors*

This section is under development.

2.6.2 **Shunt Devices**

In transmission planning studies, switchable shunt devices are allowed to operate when determining the voltages and flows after a contingency.

In areas of the transmission system where there are known high or low voltage concerns that occur prior to operation of switchable shunt devices, it is necessary to do testing to determine if voltage criteria violations occur prior to operation of switchable shunt devices. This is further discussed in the voltage criteria Section 3.1.2.

Modeling of switchable shunt devices in power flow studies is also addressed in Section 2.11.4.

2.7 Dynamic Compensation Devices

This section is under development.

2.8 Interface Transfer Levels

Reliability studies begin with development of system models which must include definition of the initial or base conditions that are assumed to exist in the study area over the study horizon. These assumed initial conditions must be based on requirements as described within the applicable reliability standards and criteria as well as supplemental information that describe system operating conditions likely to exist.

2.8.1 **Methodology to Determine Transfer Limits**

In accordance with NERC standard FAC-013, *Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon*, the ISO documented the methodology used to determine transfer limits. This document is included as Appendix I – Methodology Document for the Assessment of Transfer Capability.

2.8.2 **System Conditions**

NPCC Directory #1 (Section 3.0, R7.1) requires planning entities include modeling of conditions that "stress" the system when conducting reliability assessments:

> *"Credible combinations of system conditions which stress the system shall be modeled including load forecast, inter-Area and intra-Area transfers, transmission configuration, active and reactive resources, generation availability and other dispatch scenarios. All reclosing facilities shall be assumed in service unless it is known that such facilities will be rendered inoperative."*

PP3 also states in Section 3, that studies be conducted assuming conditions that "reasonably stress" the system:

> *"The design shall assume power flow conditions with applicable transfers, loads, and resource conditions that reasonably stress the system."*

In each case, an assumption that considers stressed system conditions with respect to transfer levels must be included in reliability studies. The ISO has the primary responsibility for interpreting these general descriptions.

Additionally, these requirements are confirmed by PP5-3, which sets forth the testing parameters for the required PPA approval under Section I.3.9 of the Tariff. PP5-3 requires that "…intra-Area transfers will be simulated at or near their established limits (in the direction to produce 'worst cases' results)." Given the reliability standard obligations as well as the requirements for the PPA approval of any transmission upgrade, reasonably stressed transfer conditions that simulate interfaces at or near their defined limits are used in determining the transmission system needs.

2.8.3 **Modeling Procedures**

Interfaces associated with a study area must be considered individually as well as in combination with each other when more than one interface is involved. Transfer levels for defined interfaces are tested based on the defined capability for the specific system conditions and system configurations to be studied. Internal transfers not related to the study area can be set up based upon expected system conditions up to the limit and external transfers can be up to the limit depending on the type of study. Internal transfers within or related to the study area will be set based on the generation dispatch derived from the probabilistic methods. Each analysis type described in Section 4 will detail the methodology used to set up system transfers.

2.9 High Voltage Direct Current (HVDC) Lines

There are three existing high voltage direct current (HVDC) facilities on the New England transmission system: Highgate, Hydro Québec Phase II (Phase II), and the Cross Sound Cable (CSC). Table 2-12 lists the flows on these existing facilities generally and how they are used in the base cases for different planning studies. Imports on these facilities are considered Resources as discussed in ISO New England Planning Procedure No. 5-6 (PP5-6), *Interconnection Planning Procedure for Generation and Elective Transmission Upgrades*.

Table 2-12
Modeling Existing HVDC Lines in Planning Studies

Type of Study	Highgate	Phase II	Cross Sound Cable
PPA Study of Transmission Project	0 to 225 MW towards VT border	0 to 2000 MW towards NE	-330 to 346 MW towards Long Island
System Impact Study	0 to 225 MW towards VT border	0 to 2000 MW towards NE	-330 to 346 MW towards Long Island
Transmission Needs Assessment	0 to 225 MW towards VT border	0 to 2000 MW towards NE	0 to 346 MW towards Long Island
Transmission Solutions Study/Competitive Transmission RFPs	0 to 225 MW towards VT border	0 to 2000 MW towards NE	0 to 346 MW towards Long Island
Area Review Analyses	0 to 225 MW towards VT border	0 to 2000 MW towards NE	0 to 346 MW towards Long Island
BPS Testing Analyses	0 to 225 MW towards VT border	0 to 2000 MW towards NE	0 to 346 MW towards Long Island
Transfer Limit Studies	0 to 225 MW towards VT border	0 to 2000 MW towards NE	-330 to 346 MW towards Long Island
Interregional Studies	0 to 225 MW towards VT border	0 to 2000 MW towards NE	-330 to 346 MW towards Long Island
FCM New Resource Qualification Overlapping Impact Analyses	0 to 225 MW towards VT border	0 to 1400 MW towards NE	0 MW
FCM New Resource Qualification Network Resource Interconnection Standard Analyses	0 to 225 MW towards VT border	0 MW towards NE	0 MW
FCM Study for Annual Reconfiguration Auctions and Annual CSO Bilaterals	0 MW to cleared imports	0 MW to cleared imports	Cleared Administrative export to 0 MW
FCM Delist Analyses	0 MW to qualified existing imports	0 MW to qualified existing imports	Qualified Administrative export to 0 MW
Transmission Security Analyses	Qualified existing imports	Qualified existing imports	0 MW
Non-Commercial Capacity Deferral Notifications	0 MW to cleared imports	0 MW to cleared imports	Cleared Administrative export to 0 MW

Power flow solution settings for high voltage direct current lines in steady state studies are detailed in Section 2.11.5.

2.10 Special Protection Systems / Remedial Action Schemes

Special Protection Systems (SPS) may be employed in the design of the interconnected power system subject to the guidelines in the ISO New England Planning Procedure No. 5-5 (PP 5-5),*Requirements and Guidelines for Application of Remedial Action Schemes and Automatic Control Schemes*. Many SPS in New England are also classified as Remedial Action Schemes (RAS) according to the NERC RAS definition. All SPSs proposed for use on the New England transmission system must be reviewed by the NEPOOL Reliability Committee (RC) and NPCC and approved by the ISO. Some SPSs may also require approval by NPCC. The requirements for the design of SPSs are defined in NPCC Directory #4, *Bulk Power System Protection Criteria* and NPCC Directory #7, *Remedial Action Schemes*.

The owner of the SPS must provide sufficient documentation and modeling information such that the SPS can be modeled by the ISO, and other planning entities, in steady state and transient stability analyses. The studies that support the SPS must examine, among other things:

- System impact should the SPS fail to operate when needed
- System impact when the SPS acts when not needed
- Will the SPS function properly and acceptably during facility out conditions

Once an SPS is approved, its operation should be considered in all system planning studies.

2.11 Steady State Power Flow Solution Settings

This section describes the solution settings for running power flow analysis. The settings are summarized in Table 2-13 and more background for each setting is described in the following sub-sections.

Table 2-13
Steady State Power Flow Solution Settings

Case	Area Interchange Control	Tap Adjustments	Adjust Phase Shift	Switched Shunt Adjustments	DC Tap Adjustments
Emergency (Post-Contingency)	Disabled	Stepping	Disabled	Disabled	Disabled

2.11.1 **Area Interchange Control**

Enabling area interchange models is the normal operation of the power system in that it adjusts generation to maintain inter-area transfers at a pre-determined level. Each area defined in the power system network representation has one of its generators designated as the area-slack bus. Area interchange is implemented by setting an overall interchange with all neighboring areas and the power flow program adjusts the output of the area-slack bus generation to match that schedule.

Annually the Multiregional Modeling Working Group (MMWG) establishes the area interchange assumptions for different seasons, load levels, and years. These assumptions are included in base cases provided by the ISO. Requesting base cases from the ISO, which represent the scenarios that will be studied, ensures that area interchanges external to New England are appropriate.

In establishing a base case (N-0 or N-1) for a particular study, the planner selects the appropriate interchanges between New England and other areas. This should be done with area interchange enabled for tie lines and loads. This ensures that area interchanges external to New England are correct and that loads shared between New England and Québec are accounted for properly. The planner should re-dispatch generation in New England to obtain the desired interchanges with areas external to New England. The area-slack bus will adjust its output for the change in losses resulting from this re-dispatch. The planner should verify that the generation at the area-slack bus is within the operating limits of that generator.

For contingency analysis, area interchange is generally disabled. This causes the system swing bus output in the power flow model to increase for any generation lost due to a contingency. Following a loss of generation, each generator in the Eastern Interconnection increases its output in proportion to its inertia. About 95% of the total inertia for the Eastern Interconnection is to the west of New England. The system swing bus in the New England base cases is Browns Ferry in TVA. Using the system swing bus to adjust for any lost generation appropriately approximates post-contingency conditions on the power system prior to system-wide governors reacting to the disturbance and readjusting output.

2.11.2 Transformer Load Tap Changer Adjustment

Transformer load tap changers (LTCs) can exist on autotransformers, load serving transformers, and transformers associated with generation (e.g. transformers associated with wind parks). LTCs allow the ratio of the transformer to be adjusted while the transformer is carrying load so that voltage on low voltage side of the transformer can be maintained at a pre-determined level.

An LTC adjusts voltage in small steps at a rate of about 3-10 seconds per step. A typical LTC may be able to adjust its ratio by plus or minus ten percent may have sixteen 0.625% steps. Also the action of an LTC is delayed to prevent operations during temporary voltage excursions. For example, a 345 kV autotransformer might delay initiating tap changing by thirty (30) seconds. A load-serving transformer, which is connected to the 115 kV system near the autotransformer, might delay changing its tap by forty-five (45) seconds to coordinate with the autotransformer. The total time for an LTC to adjust voltage can be several minutes. For example, a LTC, which has thirty-two 0.625% steps, requires five (5) seconds per step and has a thirty (30) second initial delay, would require seventy (70) seconds to adjust its ratio by five (5) percent.

To model the actual operations of the system, LTC operation is typically enabled in the power system model to allow the LTCs to adjust post-contingency for steady state analysis. This generally represents the most severe condition because contingencies typically result in lower voltages and operation of LTCs to maintain distribution voltages result in higher current flow and lower voltages on the transmission system. Similarly operation of LTCs on autotransformers typically results in lower voltage on the high voltage side of the autotransformer.

In some portions of the transmission system, the voltage immediately following a contingency may be problematic because voltage collapse may occur. When instantaneous voltage is a concern, sensitivity analysis should be done with LTCs locked (not permitted to adjust) in the power flow model due to the amount of time required for the taps to move.

2.11.3 Phase Shifting Transformer Adjustments

The modeling of each phase shifting transformers (Phase Angle Regulator or PAR) is described in detail in Appendix G – Phase Shifting Transformers Modeling Guide for ISO New England Network Model.

2.11.4 Switched Shunt Adjustments

This section is under development by the ISO/TO study coordination group and will be sent out at a later date.

2.11.5 High Voltage Direct Current (HVDC) Lines Tap Adjustments

The flows in HVDC lines are not automatically adjusted after a contingency except where an adjustment is triggered by an SPS or RAS.

2.11.6 Series Reactive Devices

Section 2.6.1 of this guide describes the series reactive devices in the New England transmission system. The tables list those series devices that can be switched to resolve criteria violations. Those switchable devices that are out of service in the base case can be switched into service. Those switchable devices that are in service in the base case can be switched out of service. The switching can be done post-contingency, if the flow does not exceed the STE rating. When the post-contingency flow exceeds the STE rating, switching must be done pre-contingency and analysis must be done to ensure that the switching does not create other problems.

Section 3
Reliability Criteria and Guidelines

This Section describes the various reliability criteria and guidelines used in the evaluation of the New England transmission system in system planning steady state, transient stability, and short-circuit analyses.

3.1 Steady State Criteria and Guidelines

This section details the criteria used during steady state analysis. Criteria include thermal performance of all transmission elements, system voltage requirements, and guidelines for the interruption of load following a contingency event.

3.1.1 Thermal Criteria

System planning utilizes the thermal capacity ratings shown in Table 3-1 for New England transmission facilities, as described in ISO New England Operating Procedure No. 16 (OP 16), *Transmission System Data*, Appendix A, *Explanation of Terms and Instructions for Data Preparation of NX-9A*, (OP 16A).

Table 3-1
Steady State Thermal Ratings

Type	PSSE Rating	Summer Duration	Winter Duration
Normal	Rate 1	Continuous 24-hour	Continuous 24-hour
Long Time Emergency (LTE)	Rate 2	12-hour	4-hour
Short Time Emergency (STE)	Rate 3	15-min	15-min

Summer equipment ratings (April 1 through October 31) and Winter equipment ratings (November 1 through March 31) are applied as defined in OP 16. The twelve-hour and four-hour durations are based on the load shape for Summer and Winter peak load days.

The transmission element ratings used in planning studies are described in PP5-3 and in ISO New England Planning Procedure No. 7 (PP7), *Procedures for Determining and Implementing Transmission Facility Ratings in New England*. In general, element loadings up to normal ratings are acceptable for "All lines in" conditions. Element loadings up to LTE ratings are acceptable for up to the durations described above. Element loadings up to the STE ratings may be used following a contingency for up to fifteen minutes. STE ratings may only be used in limited situations such as in export areas where the Element loading can be reduced below the LTE ratings within fifteen minutes by operator or automatic corrective action.

There is also a Drastic Action Limit (DAL) that is only used as a last resort during actual system operations where preplanned immediate post-contingency actions can reduce loadings below LTE within five minutes. DALs are <u>not</u> used for testing the system adequacy in planning studies or for planning the transmission system.

Element ratings are calculated per PP7, and are submitted to the ISO per OP 16.

3.1.2 Voltage Criteria

The low voltage criteria used for transmission planning have been established to satisfy three constraints: maintaining voltages on the distribution system ultimately experienced by the customer within required limits, maintaining the voltages experienced by transmission equipment and equipment connected to the transmission system within that equipment's rating, and avoiding voltage collapse. Generally the maximum voltages are limited by equipment, and the minimum voltages are limited by customer requirements and voltage collapse.[19]

The voltage criteria prior to equipment operation apply to voltages at a location that last for seconds or minutes, such as voltages that occur prior to LTC operation or capacitor/reactor switching. The voltage standards prior to equipment operation do not apply to transient voltage excursions such as switching surges, or voltage excursions during a fault or during disconnection of faulted equipment. See Section 3.3 for more details on transient stability voltage criteria.

The voltage standards apply to PTF facilities operated at a nominal voltage of 69 kV or above. Voltages at all PTF buses must be in the range shown below in **Error! Reference source not found.**.[20]

[19] Note: This Transmission Planning Technical Guide does not address voltage flicker or harmonics.

[20] In a decimal number, a bar over one or more consecutive digits means that the pattern of digits under the bar repeats without end.

Table 3-2
Steady State Voltage Criteria

		Bus Voltage Limits (Per-Unit)		
Facility Owner	Voltage Level (kV)	Normal Conditions (Pre-Contingency)	Emergency Conditions (Post-Contingency)	
			Pre-Switching	Post-switching[21]
AVANGRID	115	0.950̅ -1.050̅	0.90̅ -1.050̅	0.950̅ -1.050̅
	345	0.950̅ -1.04920̅	0.900̅ -1.04920̅	0.950̅ -1.04920̅
Versant Power	115	0.950̅ -1.050̅	0.90̅ -1.050̅	0.950̅ -1.050̅
	345	0.950̅ -1.04920̅	0.900̅ -1.04920̅	0.950̅ -1.04920̅
Eversource	115 and 230	0.950̅ -1.050̅	0.90̅ -1.050̅	0.950̅ -1.050̅
	345	0.950̅ -1.04920̅	0.900̅ -1.04920̅	0.950̅ -1.04920̅
National Grid	115	0.950̅ -1.050̅	0.90̅ -1.050̅	0.950[22] -1.050̅
	230	0.980̅ -1.050̅	0.90̅ -1.050̅	0.950̅ -1.050̅
	345	0.980̅ -1.04920̅	0.90̅ -1.04920̅	0.950̅ -1.04920̅
	Sandy Pond HVDC Terminal[23] 345 kV	1.0̅ -1.04920̅	1.0̅ -1.04920̅	1.0̅ -1.04920̅
Vermont Electric Power Company	115	0.950̅ -1.050̅	0.920̅ -1.050̅	0.950̅ -1.050̅[24]
	230	0.980̅ -1.050̅	0.920̅ -1.050̅	0.950̅ -1.050̅[24]
	345	0.980̅ -1.04920̅	0.920̅ -1.04920̅	0.950̅ -1.04920̅[24]
Millstone/Seabrook[25]	345	1.0̅ -1.0490̅	1.0̅ -1.0490̅	1.0̅ -1.0490̅

Further explanation for these limits and their justification may be found in the following subsections.

3.1.2.1 *Pre-Contingency Voltages*

The high voltage limit for 345 kV buses is 1.04920̅ per unit to align with IEEE standard C37.06 which sets the maximum voltage level at 362 kV. In some cases, an exception can be made if higher voltages are permitted at buses where the Transmission Owner has determined that all equipment at those buses is rated to operate at the higher voltage. Often the limiting equipment under steady-state high voltage conditions is a circuit breaker. IEEE standard C37.06 lists the maximum voltage for 345 kV circuit breakers as 362 kV, the maximum voltage for 230 kV circuit breakers as 245 kV, the maximum voltage for 138 kV circuit breakers as 145 kV, the maximum voltage for 115 kV circuit breakers as 123 kV and the maximum voltage for 69 kV circuit breakers as 72.5 kV. Older 115 kV circuit breakers may have a different maximum voltage.

For testing N-1 contingencies, shunt reactive devices are modeled in or out of service pre-contingency, to prepare for high or low voltage caused by the contingency, as long as the pre-contingency voltage standard is satisfied. For testing of an N-1-1 contingency, shunt reactive

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[21] For contingencies where post contingency PAR adjustments are performed, the voltages observed prior to the PAR adjustment and after the PAR adjustment will be measured against the post-switching voltage criteria

[22] All non-BPS National Grid buses can have a voltage as low as 0.90̅ p.u. as long as the post contingency post adjustment voltage deviation is less than 10%.

[23] The voltage limits at the Sandy Pond HVDC terminal are only for conditions when the Sandy Pond HVDC terminal is in-service.

[24] Post-contingent switching out of VELCO capacitors to address VELCO system high voltage violations of the 1.050̅ p.u. criteria is permitted, provided voltages do not exceed 1.10̅ p.u. and the capacitor is at, or close to the location of the bus with high voltage.

[25] This is in compliance with NERC Standard NUC-001, *"Nuclear Plant Interface Coordination."*Further information is documented in the appendices to the Master Local Control Center Procedure 1 (MLCC 1).

devices are switched between the first and second contingencies to prepare for the second contingency as long as the post-contingency voltage standard is satisfied following the first contingency and prior to the second contingency.

3.1.2.2 *Post-Contingency Low Voltages*

Prior to Equipment Operation (Pre-Switching)

The post-contingency voltages at all PTF buses must be in the range shown in Table 3-2 prior to the automatic or manual switching of shunt or series capacitors and reactors, and operation of tap changers on transformers, autotransformers, phase-shifting transformers and shunt reactors. Dynamic compensation devices such as generator voltage regulators, STATCOMs, SVCs, DVARs, and HVDC equipment are assumed to have operated properly to provide voltage support when calculating these voltages.

Capacitor banks that switch automatically with no intentional time delay (switching time is the time for the sensing relay and the control scheme to operate, usually a few cycles up to a second) may be assumed to have operated when calculating these voltages.

Exceptions for voltages as low as $0.8\overline{0}$ per unit are allowed for a geomagnetic disturbance (GMD) event, which are described in section 3.1.2.6. No contingencies as defined in Section 3.4 are allowed to cause a voltage collapse.

After Equipment Operation (Post-Switching)

The voltages at all PTF buses must be in the range shown in Table 3-2 after the switching of shunt or series capacitors and reactors, and operation of tap changers on transformers, autotransformers, phase-shifting transformers and shunt reactors.

Exceptions for voltages as low as $0.9\overline{0}$ per unit are allowed at a limited number of 115 kV or 69 kV PTF buses where the associated lower voltage system has been designed to accept these lower voltages, and where the change in voltage pre-contingency to post-contingency is not greater than 0.1 per unit. The planner should consult with the Transmission Owner and the ISO to determine if the second exception applies to any buses in the study area. Exceptions for voltages as low as $0.8\overline{0}$ per unit are allowed for a GMD event, which are described in section 3.1.2.6.

3.1.2.3 *Post-Contingency High Voltages*

Prior to Equipment Operation (Pre-Switching)

The highest voltages at all PTF buses must be equal to or lower than the high voltage study limits shown in **Error! Reference source not found.**.

The only exception is that higher voltages are permitted where the Transmission Owner has determined that all equipment at those buses is rated to operate at the higher voltage. The planner should consult with the Transmission Owner and the ISO to determine if the exception applies to any buses in the study area.

After Equipment Operation (Post-Switching)

The highest voltages at all PTF buses must be equal to or lower than the high voltage study limits shown in **Error! Reference source not found.**.

The only exception is that higher voltages are permitted where the Transmission Owner has determined that all equipment at those buses is rated to operate at the higher voltage. The planner should consult with the Transmission Owner and the ISO to determine if the exception applies to any buses in the study area.

3.1.2.4 *Line End Open Contingencies*

There is no minimum voltage limit for the open end of a line if there is no load connected to the line section with the open end. If there is load connected the above standards for post-contingency low voltage apply.

The maximum voltage limit for the open end of a line is under development.

3.1.2.5 *Nuclear Units*

The minimum and maximum voltage limits at the following buses serving nuclear units, both for pre-contingency and for post-contingency after the switching of capacitors and operation of transformer load tap changers, are shown in **Error! Reference source not found.**. These limits apply whether or not the generation is dispatched in the study.

The minimum voltage requirements at buses serving nuclear units are provided in accordance with NERC Standard NUC-001, *Nuclear Plant Interface Coordination*, and documented in the appendices to the Master Local Control Center Procedure No. 1 (MLCC 1).

3.1.2.6 *Geomagnetic Disturbance (GMD) Event Voltages*

The New England system must meet the performance requirements of the NERC TPL-007 standard, which discusses the possible effects a GMD event may have on the tranmission system. These criteria are more permissive than the criteria for non-GMD events. This reflects the facts that major GMD events are rare and infrequent, and that the main goal during these events is avoiding widespread voltage collapse rather than maintaining acceptable voltage to individual customers. The steady state voltage criteria for a GMD event is shown in Table 3-3
GMD Event Voltage Criteriabelow.

Table 3-3
GMD Event Voltage Criteria

Facility	Voltage Level (kV)	Normal Conditions (N-0) (p.u.)	GMD Event (Post-Contingency)	
			Pre-Switching (p.u.)	Post-Switching (p.u.)
Transmission/Generation	200 and above and less than 345	$0.95\bar{0} - 1.05\bar{0}$	$0.8\bar{0} - 1.05\bar{0}$	$0.8\bar{0} - 1.05\bar{0}$
	345	$0.95\bar{0} - 1.0492\bar{0}$	$0.8\bar{0} - 1.0492\bar{0}$	$0.8\bar{0} - 1.0492\bar{0}$
Millstone/Seabrook	345	$1.\bar{0} - 1.0492\bar{0}$	$1.\bar{0} - 1.0492\bar{0}$	$1.\bar{0} - 1.0492\bar{0}$
Sandy Pond	345	$1.\bar{0} - 1.0492\bar{0}$	$1.\bar{0} - 1.0492\bar{0}$	$1.\bar{0} - 1.0492\bar{0}$

3.1.3 **Load Interruption Guidelines**

This section is under development.

Guidelines, which describe the amount of load that may be interrupted and the circumstances where load may be interrupted, were presented to the RC on November 17, 2010.[26] At the request of stakeholders, the ISO retransmitted this material to the RC on November 17, 2011 for comment and to the Planning Advisory Committee on November 21, 2011. The ISO has received comments on the guideline and is reviewing those comments.

3.2 Short Circuit Criteria

This Section details the criteria used for short circuit analysis.

In accordance with NERC TPL-001 Requirement 2.3, NPCC Directory 1 Requirement R10, and ISO PP3 Section 3, all equipment capabilities shall be adequate for all fault current levels with all transmission and generation facilities in service. This equates to all equipment having a fault current duty of less than or equal to 100% of their ratings.

3.3 Transient Stability Criteria and Guidelines

This Section details the criteria used during transient stability analysis. Criteria include post-fault unit stability, system voltage performance, system damping, and voltage sag.

3.3.1 Unit Stability Criteria

NERC and NPCC require that the New England Bulk Power System shall remain stable and damped and the NERC Standard, *Nuclear Plant Interface Coordinating Standard*, (NUC-001) shall be met.

These requirements must be met during and following the most severe of the contingencies defined "with due regard to reclosing", and before making any manual system adjustments. The ISO's planning defines a unit[27] as maintaining stability when it meets the damping criteria described in Section 3.3.3. The ISO also uses a voltage sag guideline (See Section 3.3.4) to determine if it may be necessary to mitigate voltage sags.

For each of the contingencies below that involves a fault, system stability and damping shall be maintained when the simulation is based on fault clearing initiated by the "system A" protection group, and also shall be maintained when the simulation is based on fault clearing initiated by the "system B" protection group where such protection group is required, or where there would otherwise be a significant adverse impact outside the local area. Table 3-4 describes which protection group is tested to evaluate BPS elements.

Table 3-4
Modeling of Protection Systems in Transmission Planning

NPCC Element Classification	Fastest Protection System Modeling for Normal Design Contingencies	
	In Service	Out of Service
BPS	Not Tested	Tested
Non-BPS	Tested	Not Tested

[26] https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/relblty_comm/relblty/mtrls/2010/nov172010/a13_load_interruption_guidelines.ppt

[27] A unit is defined as any single unit ≥ 5 MW or any set of units totaling more than 20 MW. For example, this includes a set of individual turbines within a wind plant. The performance of generating facilities that are ≥ 5 MW and ≤ 20 MW and that are connected to the system at a voltage less than 69 kV will be evaluated in accordance with the interconnection performance requirements of those generating facilities.

Consistent with ISO New England Operating Procedure No. 19 (OP 19), *Transmission Operations*, New England's planning procedures require generator unit stability for all Normal Design Contingencies as defined in PP3. This criterion applies when the fastest protection scheme is unavailable at any BPS substation involved in the fault clearing. This criterion applies if the fastest protection scheme is available at any non-BPS substation involved in the fault clearing. If the fastest protection scheme is unavailable at a non-BPS substation, unit instability is permitted as long as the net source loss resulting from the Normal Design Contingency is not more than 1,200 MW, and the net source loss is confined to the local area (i.e. no generator instability or system separation can occur outside the local area).

The 1,200 MW limit derives from the NPCC Directory #1 criteria which require that a Normal Design Contingency listed in Table 3 of the document have no significant adverse impact outside the local area. The maximum loss of source for a Normal Design Contingency has been jointly agreed upon by NYISO (formerly NYPP), ISO-NE (formerly NEPEX), and PJM to be between 1,200 MW and 2,200 MW depending on system conditions within NYISO and PJM. This practice is observed pursuant to a joint, FERC-approved protocol, which is described in Attachment C Section 5.2.2.1 of the OATT. The low limit of 1,200 MW has historically been used for Design Contingencies in New England.

3.3.2 **Voltage Criteria**

NERC has revised its transmission planning procedures to establish the requirement for transient voltage response criteria.

This section is under development.

3.3.3 **Damping Criteria**

Appendix C of PP3 contains the damping criteria used in stability studies of the New England transmission system. This guideline is duplicated below.

The purpose of the damping criterion is to assure small signal stability of the New England bulk power supply system. System damping is characterized by the damping ratio, zeta (ζ). The damping ratio provides an indication of the length of time an oscillation will take to dampen. The damping criterion specifies a minimum damping ratio of 0.03, which corresponds to a 1% settling time of one minute or less for all oscillations with a frequency of 0.4 Hz or higher. Conformance with the criterion may be demonstrated with the use of small signal eigenvalue analysis to explicitly identify the damping ratio of all questionable oscillations.

Time domain analysis may also be utilized to determine acceptable system damping. Acceptable damping with time domain analysis requires running a transient stability simulation for sufficient time (up to 30 seconds) such that only a single mode of oscillation remains. A 53% reduction in the magnitude of the oscillation must then be observed over four periods of the oscillation, measuring from the point where only a single mode of oscillation remains in the simulation.

As an alternate method, the time domain response of system state quantities such as generator rotor angle, voltage, and interface transfers can be transformed into the frequency domain where the damping ratio can be calculated.

A sufficient number of system state quantities including rotor angle, voltage, and interface transfers should be analyzed to ensure that adequate system damping is observed.

3.3.4 **Voltage Sag Guideline**

The minimum post-fault positive sequence voltage sag must remain above 70% of nominal voltage and must not exceed 250 milliseconds below 80% of nominal voltage within 10 seconds following a fault. These limits are supported by the typical sag tolerances shown in Figures C.5 to C.10 in IEEE Standard 1346-1998. These parameters are shown graphically in

Figure **3-1**. A more detailed description of the voltage sag guideline with references is in Appendix E – Dynamic Stability Simulation Voltage Sag .

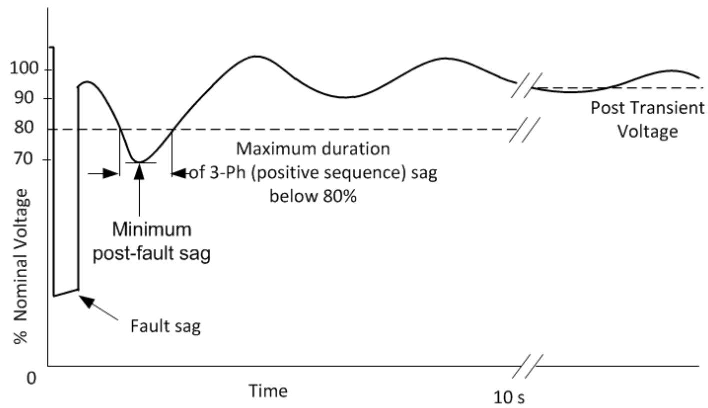

Figure 3-1: Voltage Sag Guideline

3.3.5 **Treatment for Transmission Element Loadings in Stability Simulations Following Tripping of Distributed Energy Resources (DER)**

Distributed Energy Resoources (DER), especially those interconnected before the adoption of Source Requirements Documents and IEEE 1547-2018, may be observed to trip during stability simulations. This tripping may result in power flow in transmission elements that exceeds their capability. For transmission element loading above STE limits, operators are required to immediately take action to reduce flow below LTE limits, likely through load shedding, in accordance with ISO-NE Operating Procedure-19. To prevent transmission element loading from reaching the STE limit, and to provide some margin for uncertainty in DER protection settings and distribution system voltages, transmission element loadings are limited to 95% of their STE limit following the conclusion of a stability simulation. For any element loading over 95% of STE following DER tripping, an upgrade is required. The upgrade could involve increasing the rating of the affected elements, or reducing the amount of DER that trips. This loading may be determined directly from a stability run, or from steady-state confirmation in situations where stability results are marginally acceptable (in the 90%-95% range).

The 95% of STE threshold would only be enforced in cases with non-zero DER tripping.
In addition, for any line loading over 100% of the applicable steady-state rating in steady-state simulation[28] without considering non-consequential DER tripping, an upgrade is required. This requirement would be enforced only in steady state simulation and not in stability simulations.

3.4 System Events (Contingencies)

The events (contingencies) that are tested in planning studies of the New England transmission system are defined in NERC, NPCC and ISO New England reliability standards and criteria. These

[28] Or 100% of STE, in limited Boston-area conditions where loading up to STE is allowed in post-contingency conditions

standards and criteria form deterministic planning criteria. The application of this deterministic criteria results in a transmission system that is robust enough to operate reliably for the myriad of operating conditions that occur on the transmission system.

These standards and criteria identify certain events that must be tested and the power flow in each element in the system must remain under the element's emergency limits following any specified contingency. In most of New England, the LTE rating is used as the emergency thermal limit. The STE rating may be used as the emergency thermal limit when an area is exporting and if generation can be dispatched lower to mitigate overloads. The STE rating may also be used as the emergency thermal limit in areas where phase-shifting transformers can be used to mitigate overloads. Voltage criteria limits are discussed in Section 3.

Planning Events used for the design of the transmission system can be classified as:

- N-1 – those Normal Contingencies (NCs) with a single initiating cause (a N-1 contingency may disconnect one or more transmission Elements)
- N-1-1 – those NCs with two separate initiating causes and where timely system adjustments are permitted between initiating causes
- Extreme events

Planning criteria allow certain adjustments to the transmission system between the two initiating causes resulting in N-1-1 contingencies as described in Section 3.4.2.

Steady state analysis focuses on the conditions that exist following the contingencies. Stability analysis focuses on the conditions during and shortly after the contingency, but before a new steady state condition has been reached.

3.4.1 **N-1 Events**

NERC and/or NPCC require that the following N-1 events be tested:

- A three-phase fault with Normal Fault Clearing on any:
  - Generator
  - Transmission circuit
  - Transformer
  - Bus section
  - Shunt compensating device
- Simultaneous phase-to-ground faults on:
  - Different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower, with normal fault clearing.
  - NERC TPL-001, in note 11 to Table 1, allows excluding circuits that share a common structure for one mile or less
  - NPCC Directory #1 in note vii to Table 1 allows excluding circuits that share a common tower if the multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station
  - For exclusions of more than five towers, the ISO and the NPCC Reliability Coordinating Committee need to specifically approve each request for exclusion.
- A phase-to-ground fault, with delayed fault clearing,[29] on any:

[29] Delayed fault clearing may result from a stuck breaker or a protective relay system failure.

  - Generator
  - Transmission circuit
  - Transformer
  - Bus section
  - Shunt compensating device
- Opening any circuit breaker or loss of any of the following without a fault (See Section 3.4.4)
  - Generator
  - Transmission circuit
  - Transformer
  - Bus section
  - Shunt compensating device
  - Single pole of a direct current facility
- A phase-to-ground fault in a circuit breaker, with normal fault clearing. (Normal clearing time for this condition may not be high speed.)
- Simultaneous permanent loss of both poles of a direct current bipolar facility without an AC fault
- The failure of a circuit breaker to operate when initiated by an SPS following: loss of any of the following without a fault:
  - Generator
  - Transmission circuit
  - Transformer
  - Bus section
  - Shunt compensating device
- The failure of a circuit breaker to operate when initiated by an SPS following a phase to ground with normal fault clearing, on any of the following:
  - Generator
  - Transmission circuit
  - Transformer
  - Bus section
  - Shunt compensating device

3.4.2 **N-1-1 Events**

NERC and/or NPCC require that the N-1-1 events be tested. These are events that have two initiating events that occur close together in time. The list of first initiating events tested must include events from all of the following possible categories:

- Loss of a generator
- Loss of a series or shunt compensating device
- Loss of one pole of a direct current facility
- Loss of a transmission circuit
- Loss of a transformer

Following the first initiating event, system adjustments are made in preparation for the next initiating event. These adjustments can consist of any combination of the following:

- Increasing resources available within ten minutes following notification
- Adjustments that can be achieved in thirty minutes such as:
  - Generator runback and/or generator tripping

- Reducing transfers on HVDC facilities
- Adjusting phase angle regulators, transformer load tap changers, and variable reactors
- Switching series and shunt capacitors and reactors.
- Reducing imports from external Areas

The total amount of resources that are turned online in New England must not exceed 1,200 MW.

3.4.3 **Extreme Events**

Consistent with NERC and NPCC requirements, New England tests extreme events. This assessment recognizes that the New England transmission system can be subjected to events that exceed in severity the contingencies listed in Sections 3.4.1 and 3.4.2. Planning studies are conducted to determine the effect of the following extreme events on New England PTF system performance as a measure of system strength. Plans or operating procedures are developed, where appropriate, to reduce the probability of occurrence of such contingencies, or to mitigate the consequences that are indicated as a result of the simulation of such contingencies.

Extreme events are listed in NERC Standard TPL-001 Table 1 and Table 2 of NPCC Directory #1.

The following responses are considered unacceptable responses to an extreme contingency involving a three phase fault with delayed clearing due to a stuck breaker and should be mitigated:

- Transiently unstable response resulting in wide spread system collapse
- Transiently stable response with undamped or sustained power system oscillations
- A net loss of source within New England in excess of 2,200 MW resulting from any combination of the loss of synchronism of one or more generating units, generation rejection initiated by a Special Protection System, tripping of the New Brunswick-New England tie, or any other system separation. The loss of source is net of any load that is interrupted as a result of the contingency.

The following response can be considered acceptable to an extreme contingency involving a three phase fault with delayed clearing:

- A net loss of source above 1,400 MW and up to 2,200 MW,[30] resulting from any combination of the loss of synchronism of one or more generating units, generation rejection initiated by a Special Protection System, or any other defined system separation, if supported by studies, on the basis of acceptable likelihood of occurrence, limited exposure to the pre-contingent operating conditions required to create the scenario, or efforts to minimize the likelihood of occurrence or to mitigate against the consequence of the contingency. The loss of source is net of any load that is interrupted as a result of the contingency.

3.4.4 **Line End Open Testing**

One of the NERC TPL-001 Category P2 planning events is described as the 'Opening of a line section w/o a fault.' The requirement to evaluate a no-fault contingency (sometimes thought of as the opening of one terminal/end of a line) as a contingency event in system planning studies is

[30] The 1,400 MW and 2,200 MW levels are documented in a NEPOOL Stability Task Force presentation to the NEPOOL Reliability Committee on September 9, 2000. This presentation is included in Appendix F – Stability Task Force Presentation to Reliability Committee – September 9, 2000, Section 5.6.

described below. Additional details are provided in the white paper that is included in Appendix H – Simulation of No-Fault Contingencies.

The following is a summary of the line open testing requirements:

- NERC BES facilities
    - N-1 Testing (Single Event) - Evaluate the opening of the terminal of a line, independent of the design of the termination facilities
    - N-1-1 Testing (First or Second Event) – Not required
- NPCC BPS or New England PTF facilities
    - N-1 Testing (Single Event) – Evaluate the opening of a single circuit breaker
    - N-1-1 Testing (First Event) – Not required
    - N-1-1 Testing (Second Event) – Evaluate the opening of a single circuit breaker

When evaluating the no-fault contingencies pursuant to implementation of NERC, NPCC, and ISO standards and criteria, the following will be used to establish the acceptability of post-contingency results and potential corrective actions:

- If voltage is within acceptance criteria and power flows are within the applicable emergency rating, operator action can be assumed as a mitigating measure.
- If voltage is outside of acceptance criteria or power flows are above the applicable emergency rating, operator action cannot be assumed as a mitigating measure. Mitigating measures may include, but are not limited to, transfer trip schemes detecting an open circuit breaker(s) or open disconnect switch(es), or, Special Protection Systems designed to trigger for specific system conditions that include the no-fault opening of a transmission line.

Special consideration must be given to the design and operation of the system when evaluating this no-fault contingency. Control schemes, transfer trip schemes, and Special Protection Systems may not operate for a line end open condition if their triggers are not satisfied, or may operate inappropriately if their triggers are satisfied but only one terminal of a line is open.

Generally, in New England, the opening of one end of a two terminal line is not a concern. However, in instances of long lines, high voltages may be a concern due to the charging associated with an unloaded line.

Section 4
Analysis Methodology

This section describes the details in the methodologies applied to conduct system planning studies. It is not intended to be an exhaustive description of all aspects of every study, but rather a description of some aspects that are specific to certain studies within New England.

4.1 Transmission Needs Assessments and Solutions Studies

4.1.1 Base Case Generation Dispatch

In the development of the base cases for transmission Needs Assessments and Solutions Studies, several standards and criteria describe the initial setup of the model prior to applying contingency outage events.

NERC Standard TPL-001[31] Requirement R1 states:

> *"…the Planning Assessment must vary one or more of the following conditions by a sufficient amount to **stress the System within a range of credible conditions** …" (emphasis added)*

NPCC Reliability Reference Directory #1[32] Requirement R7.1 states:

> *"**Credible combinations** of system conditions which **stress the system** shall be modelled including, **load forecast**, inter-Area and intra-Area transfers, transmission configuration, active and reactive resources, **generation availability** and other dispatch scenarios. …" (emphasis added)*

ISO Planning Procedure No. 3[33] Section 3 states:

> *"The design shall assume power flow conditions with applicable transfers, loads, and resource conditions that **reasonably stress** the system." (emphasis added)*

These standards describe the modeling of base system conditions that are 'credible' and 'reasonably stressed' before performing contingency analysis. To meet these requirements, a certain number of forced generator outages are included in the base case for transmission reliability studies. Typically, generator outages and high levels of interface transfers lead to higher stress on the system, especially in areas with more load than generation. Stressing the system to a high level ensures it can operate reliably under a wide range of conditions such as simultaneous unplanned generator outages, and unanticipated generator retirements.

Without modeling generator outages in base cases, the unavailability of generators on a peak load day could lead to transmission reliability issues. Moreover, a dynamic de-list bid or retirement bid from a generator may need to be rejected to avoid reliability concerns. Modeling generator outages

[31] https://www.nerc.com/pa/Stand/Pages/USRelStand.aspx
[32] https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx
[33] https://www.iso-ne.com/participate/rules-procedures/planning-procedures/

as a base system condition is therefore crucial to ensure peak load can be served reliably without dependence on specific generators.

Units modeled offline in base cases fall into one of four categories:

- Unavailable – Units that are out-of-service due to an unplanned outage and not available to system operators. More details can be found in Sections 4.1.2 and 4.1.3
- Reserves – Units that are offline as "reserves" are discussed in Section 4.1.4.
- Generation behind system constraints – Units that are located in an export constrained area and may need to be offline to avoid violating system constraints. These generators cannot count towards reserves because that may not be useful for required system adjustments after the first contingency.
- Offline for load-resource balance – Units that are offline to ensure that the supply is equal to demand.

The generator outage and interface transfer assumptions for Needs Assessments, Solutions Studies, and Competitive Transmission RFPs use transparent, public, and stable input data, and consider the economic dispatch of generators in the development of study conditions. Base interface transfers represent likely conditions, and reflect the fact that some units may be offline due to economics rather than outages. As transmission planners develop base case dispatches for use in transmission Needs Assessments and Solutions Studies, the guidelines described in the following sections are respected.

4.1.2 **Generation Outage Criteria at Peak Load**

Modeling generator outages ensures study area load can be served over a range of conditions at peak load. Summer peak load Needs Assessments, Solutions Studies, and competitive transmission RFPs are performed at 90/10 load levels, with a 90% chance that real system loads will be lower than the forecasted load being analyzed. Winter peak load conditions in Needs Assessments, Solutions Studies, and competitive transmission RFPs are similarly studied at 90/10 load levels. Likewise, generator outage criteria used to establish base system conditions are also designed to ensure the system can handle 90% of possible generator outage conditions. This provides a similar level of assurance that the transmission system can handle generator outages on a summer peak load day. These outage assumptions do not apply to wind, solar, hydroelectric, or ESS, which are subject to their own availability criteria as detailed in Sections 2.3.6 – 2.3.9.

To account for 90% of possible outage conditions, the number of generators in a study area is considered in conjunction with New England's system-wide weighted average EFORd value, adjusted to exclude energy storage and renewable units. The system-wide EFORd value is public and reasonably stable from year to year. The number of generators in a study area is combined with the weighted average EFORd value to calculate the probability that any given number of generators is out of service at peak load.

The following equations calculate the cumulative probabilities that result from studying all-generators-in, one generator out, two generators out, etc., assuming a constant EFORd (r) and number of generators (n) in the study area:

$$P_{0out} = (1-r)^n$$

$$P_{\leq 1out} = P_{0out} + r(1-r)^{n-1}{}_n\mathrm{C}_1$$

$$P_{\le 2out} = P_{\le 1out} + r^2(1-r)^{n-2}{}_n\mathrm{C}_2$$

etc.

If the calculation for $P_{\le 1out}$ produces a value below the 90% threshold, then studying two generators out-of-service is necessary. Similarly, if the calculation for $P_{\le 2out}$ is less than the desired threshold, then studying three generators out-of-service is necessary, etc. Calculations should be performed until a number of out-of-service generators is determined that meets the 90% threshold. Table 4-1 shows the threshold of units in a study area resulting in certain outage levels at different EFORd values.

Table 4-1
Peak Load Generator Outage Thresholds

EFORd	Two-Generators-Out Begins at:	Three-Generatorss-Out Begins at:
3%	18 generators in study area	38 generators in study area
4%	14 generators in study area	29 generators in study area
5%	11 generators in study area	23 generators in study area
6%	10 generators in study area	19 generators in study area
7%	8 generators in study area	17 generators in study area

With a weighted average EFORd of 7.0%[34], this leads to the outage assumptions described in Table 4-2. Again, the number of units taken out of service represent approximately 90% of possible outage conditions, dependent on the number of units in the study area. These values will be adjusted according to the formulas above as the system-wide weighted average EFORd changes in future years.

Table 4-2
Peak Load Generator Outage Criteria (7% EFORd)

Number of Units in Study Area	Number of Outages Applied
1-7 units in study area	Study 1 unit out of service
8-16 units in study area	Study 2 unit out of service
17-25 units in study area	Study 3 unit out of service
26-35 units in study area	Study 4 unit out of service

There are a several limitations on which units may be considered in the study area and placed out of service. All conventional generators (fossil fuel, nuclear and biomass units) over 5 MW are eligible to assume out of service, and are counted when determining the total number of units in the study area. Outages of units below 5 MW are not considered because they typically do not individually impact transmission system performance. Wind, solar, hydroelectric, and energy storage resources are already subject to different availability assumptions and are therefore excluded in the total number of study area units. Likewise, renewable resources and ESS are excluded from the number of units placed out of service as described in Table 4-2. Finally, combined-cycle units will be counted as a single unit when determining the number of units in a study area, due to demonstrated common-mode failures which render the entire unit unavailable.

[34] 7.0% represents the weighted average EFORd value for Forward Capacity Market (FCM) Capacity Commitment Period (CCP) 2026-2027, as reported in June 2022. This percentage is recalculated annually.

In addition to these assumptions, several ancillary limitations apply. These additional conditions are detailed below, and include considerations for unit location, unit size, and unit age.

Unit Location

In any smaller sub-area of a study area, the criteria reported in Table 4-2 still apply. In the case of sub-areas, the number of outages described in Table 4-2 serve as a *maximum limit* on the total number of units that may be taken out of service in each sub-area. This ensures the sub-area has a consistent number of units assumed out of service, independent of whether the sub-area is studied on its own or as part of a larger study area. This guarantees a consistent level of reliability.

Unit Size

In a study area with varying generator sizes, it is overly conservative to assume that all the largest generators are out of service at the same time. For example, in a study area with 20 generators, the chance of simultaneous outages on the three largest units is much lower than the total probability of simultaneous outages on all combinations of three units.

To account for this, no more than one of the largest seven units may be assumed out of service. This ensures the number of large generator outages is not inflated in an area with many small generators. The number 'seven' was selected based on the largest number of units for which only one unit may be assumed out of service as described in Table 4-2. Note this number is dependent on the system-wide weighted EFORd average (adjusted to exclude ESS and renewable resources), and is therefore subject to change if the EFORd average changes.

Unit Age

The application of generator outages in planning studies is also used to account for the risk of generator retirements. As such, unit age must be considered when determining which units to place out of service. By planning the transmission system to accommodate the retirement of older units, the region reduces the risk of denying retirement de-list bids due to transmission reliability concerns.

To account for the risk of unit retirement, only one conventional unit greater than 50 years old during the study year may be considered out-of-service in a study area. This is in addition to the other assumptions discussed already. When selecting this generator, no limitations are placed on geographic location within the study area or unit size. Generator age shall be determined using the in-service dates reported in the annual CELT report.

4.1.3 **Generator Outage Criteria at Minimum Load**

Assumptions for minimum load cover the following scenarios:

- Spring Daytime Minimum Load
- Spring Nighttime Minimum Load (high renewables)
- Spring Nighttime Minimum Load (low renewables)

In all three minimum load scenarios, all conventional generation in the selected study area is assumed to be offline. This prevents a 'must-run' condition where the system cannot be operated reliably without certain conventional fuel units online due to high voltage or stability criteria violations. 'Must-run' conditions in multiple study areas could create a system where the generation required to maintain reliability far outweighs the amount of load that needs to be served. Avoiding 'must-run' conditions for high voltage or stability criteria therefore ensures the system can be operated with a higher penetration of renewable energy resources during off-peak conditions.

4.1.4 **System Transfers**

The methodology to define system interface capability is described in Appendix I – Methodology Document for the Assessment of Transfer Capability. The following sections discuss how interface transfer levels are modeled in transmission Needs Assessments, Solutions Studies, and Competitive Transmission RFPs for external and internal interfaces.

External Inter-Area Transfers

In November 2013, the ISO revised its practice with respect to transmission Needs Assessments, Solutions Studies, and Competitive Transmission RFPs. Transmission Needs Assessments no longer model power exports to other Areas (New York, New Brunswick, and Québec) when evaluating transmission system needs. As a result, reliability based needs and their related backstop transmission solutions will not be identified and developed to support power exports out of New England. The only exception to this policy change would be long-term power exports realized through the Forward Capacity Market.

For transmission Needs Assessments, Solutions Studies, and competitive transmisison RFPs the base cases will not model exports to other areas unless there is a long-term export realized through the Forward Capacity Market. For imports on Inter-Area ties,[35] they can be tested from their minimum up to their maximum amounts listed in Table 4-.

Table 4-3
Inter-Area Import Levels Tested

Inter-Area Interface	Minimum Transfer Tested (MW)	Min Notes	Maximum Transfer Tested (MW)	Max Notes
New Brunswick – New England	0	1	700	2
New York – New England	0	3	1400	2
Phase II Imports	950	4	1400	2
Cross Sound Cable (CSC) Imports	0	1	0	2
Highgate Imports	225	5	225	2

(1) No long-term contracts for imports on this interface.
(2) The maximum import tested on these interfaces is the capacity import capability on the interface. The details of the capacity import capability are presented yearly at a PAC meeting typically in Q1 of each year for the next year's FCA.
(3) While there are currently 81.8 MW of long-term contracts in place over the NY to NE interface, they are due to expire on August 31, 2025, which is within the 10-year planning horizon and therefore cannot be relied upon for entire planning horizon. The 81.8 MW of long-term contracts is bounded by the proposed transfer levels of 0 and 1,400 MW.
(4) The 950 MW value is based on a review of the Hydro Québec Interconnection Capability Credit (HQICC) in past auctions. When conducting an analysis based on winter peak, the ISO may

[35] Section 4.1(f) and Section 4A.3(b) of Attachment K state "Imports across future or existing external tie lines will not be relied upon unless such imports have a Capacity Supply Obligation corresponding to the year of study, have been selected in, and are contractually bound by, a state-sponsored request for proposals, have a financially binding obligation pursuant to a contract, or may be represented by a minimum flow based on HQ Interconnection Capability Credits".

consider 0 MW across Phase II as the Hydro Québec system is a winter peaking system and there may not be power available to export to New England.

(5) Highgate is modeled at its capacity import capability based on a long-term contract to import power.

Phase II has historically been treated differently than other import interfaces in New England. In the New England East-West Solution Interstate Needs Assessment, Phase II was considered as one of the two largest resources out-of-service in eastern New England in addition to Seabrook. Turning off Phase II with two largest generators in eastern New England was considered to be too stressed for the study. On this basis, setting the minimum value on Phase II to 0 MW did not seem appropriate for use in future transmission Needs Assessments. HQICCs are compensated through the FCM and therefore the HQICC MW value was considered a reasonable minimum amount that can be relied upon, similar to other capacity resources.

Depending on the proximity of the study area to the external interfaces, the external interfaces that are relevant to the study area will be modeled at both maximum and minimum levels to assess the impact of the range of possible import conditions.

Internal Intra-Area Transfers

Studying a range of transfer conditions on major intra-area interfaces ensures that the system remains operable and reliable under a variety of conditions. Depending on the location of the study area, stress conditions are selected as needed.

Summer and Winter Evening Peak Load

Interface transfers are primarily driven by the generation dispatch on each side of the interface. Typically, units are on or off due to economic conditions and unplanned outages. The intra-area transfers described here will be calculated for one major interface at a time. Many study areas are only affected by one major interface, so calculations only need to be performed once. For study areas affected by multiple major interfaces, the calculations should be repeated separately for each interface being studied.

In the summer and winter evening peak conditions, the greatest amount of conventional generation is expected to be online to serve load. The base dispatch determined for the summer evening peak condition represents a reasonabe generation dispatch based on economic conditions. The main driver for variations in transfer conditions in the evening peak condition is the forced outage of generators.

To set up the base dispatch for summer and winter evening peak conditions, a study area and interface are selected. Generation within the study area is dispatched according to the generator outage assumptions outlined in Section 4.1.2. Outside the study area, generating units are dispatched in the following pseudo-economic order until all load is served:

1) Wind, solar, hydroelectric and ESS *(dispatched according to the availability assumptions outlined in Sections 2.3.6 – 2.3.9)*
2) Biomass and nuclear units
3) Natural gas combined-cycle units
4) Imports from neighboring areas *(up to the maximum values specified in Table 4-3)*
5) Natural gas simple-cycle units

6) Coal units
7) Oil units

This order reflects typical summer and winter economic dispatches, and therefore suitably approximates typical summer and winter evening peak load transfer conditions. Within each of the categories listed above, units are dispatched from newest to oldest according to the in-service dates reported in the annual CELT report.

Most conventional fuel units should be dispatched up to their maximum real power output as described in Table 2-6. The only exception is the final unit placed into service, which may be partially dispatched so that load is fully served. In addition, combined cycle units should be dispatched so the entire plant is online or offline. If the final unit placed into service is part of a combined cycle unit, the required megawatts should be proportionally distributed across all units within the combined cycle plant, or otherwise assigned in a manner that matches the unit's typical physical operation.

Next, one side of the interface is chosen to be the 'receiving end'. On the receiving end, the planner shall add up the total amount of conventional generation online in megawatts. If the study area is on the receiving end of the interface, units in the study area shall be excluded from the total amount of conventional generation considered online. This is because outages of study area units are already accounted for in the outage assumptions described in Section 4.1.2. The total number of conventional megawatts online on the receiving end is then multiplied by the fleet-wide weighted average EFORd for conventional units to approximate the number of unavailable megawatts.

Units shall be taken out of service on the receiving end until the amount of megawatts taken out of service equals the number of unavailable megawatts determined in the previous step. Note that units taken out of service on the receiving end should not be clustered in one location, but rather distributed across the receiving end. As these units are taken out of service, they should be replaced with units on the sending end of the interface (the side opposite the receiving end), as long as units in the same pseudo-economic "class" as the last unit online (as listed above) are available. If all of the units in the same pseudo-economic class on the sending end of the interface are already online, units in the same pseudo-economic class on the receiving end of the interface may be turned on to replace the outaged units. If all units in the same pseudo-economic class on both sides of the interface are already online at full power, then units in a lower economic class may be turned on. This step reflects the potential need to replace unavailable megawatts on one side of the interface with megawatts from the opposite side. If units on the opposite side are likely to be significantly more expensive, and more economic units remain offline on the receiving end of the interface, then it may be assumed that the more economic units would be used to replace the power from the outaged units.

The final step is to set imports from external areas on the receiving end to the minimum values specified in Table 4-3. Note that the resulting primary interface flows should be capped at the applicable N-1 interface transfer limits described in Appendix I – Methodology Document for the Assessment of Transfer Capability. If the N-1 transfer limit is exceeded for the primary interface under analysis, non-outaged units may be redispatched (turned on on the receiving end and turned off on the sending end) to remain within transfer limits, following the same pseudo-economic order. Finally, reserves are established as described in the "Establishment of Reserves" section below.

Summer Daytime Peak Load

Summer daytime peak conditions likely occur on the same day as summer evening peak conditions. Mid-day conditions include higher solar output, and possibly higher wind output, so less power is needed from conventional fuel units (fossil fuel, biomass, and nuclear). Moreover, the greater availability of renewable resources in the mid-day dispatch will cause offline units to be driven more by economic considerations than by unplanned outage risks.

Conventional generators can either be offline at mid-day and start up later to serve evening peak load, or operate at partial output during mid-day periods. In daily operation of the system, this is determined through the unit commitment process in the clearing of the day-ahead energy market. Since bid parameters like minimum down time, minimum run time, and ramp rates are confidential and subject to change, they are not suitable for long-term planning studies. It is typically more conservative to simply assume units will be offline rather than operating at partial output. This is because voltage control is unavailable for fully-offline units, and stability performance tends to be worse with more units offline. This assumption is reasonable as units have already been observed to start up to meet evening peak load in present-day operations.

The daytime peak dispatch begins with renewable units dispatched to match Summer Daytime Peak assumptions outlined in Sections 2.3.6-2.3.9. Next, any non-renewable units are dispatched according to the pseudo-economic dispatch order described in the Summer Evening Peak Load section above. All natural gas simple-cycle units should be kept offline because they typically have short start-up times, and thus are more likely to be offline at mid-day and brought online to meet peak net loads during the evening. Additionally, any units that were assumed to be outaged in the evening peak case, as described above, should be kept offline as well.

An interface and 'receiving end' are then selected. Imports from external areas on the receiving end should be reduced to the minimum values specified in Table 4-3, with imports replaced by generation within New England turned on in the same pseudo-economic order. On the receiving end of the interface, units should be turned off according in the pseudo-economic order described above until one of the following occurs:

- Load/generation balance is reached
- The all-lines-in interface limit is reached
- All units in the "class" of units being reduced (for example, natural gas combined cycle) are offline on the receiving end of the interface

If more megawatts of generation are online than needed to serve load, units on the sending end of the interface shall be reduced in the same order. From this transfer level, transfers can be further reduced to eliminate any N-1 thermal issues which could be easily addressed through a different set of unit commitments during daily operation of the system, and to stay within applicable existing interface N-1 transfer limits.

These conditions produce reasonable Summer Daytime Peak stresses for several reasons. Bid data, start-up times, and minimum run/down times are variable enough that any combination of units with the same fuel type could feasibly be online. Stopping when all units in the marginal class are off prevents scenarios where units most likely to run are offline while other units less likely to run are online. Finally, it ensures that the system can be operated at peak loads under a wide range of transfer conditions while still reflecting reasonably likely dispatches, which will become increasingly important as higher amounts of variable resources are incorporated into the New England system.

Minimum Load

Assumptions for minimum load internal area transfers cover the following scenarios:

- Spring Daytime Minimum Load
- Spring Nighttime Minimum Load (high renewables)
- Spring Nighttime Minimum Load (low renewables)

In both nighttime minimum load scenarios, dispatchable generators shall be adjusted outside the study area such that major interfaces relevant to the study area are as close to 0 MW as possible. This is because lower transmission flows are more impactful for high voltages. Designing the system to accommodate low to zero flows on major interfaces therefore avoids the need to keep conventional generation online, out of merit, to control high voltages or meet stability criteria.

In the daytime minimum load scenario, units outside the study area shall be dispatched according to the pseudo-economic dispatch order described for setting evening peak load interface transfers. Due to low spring mid-day loads and high penetration of renewables, very little conventional generation is required during daytime minimum load conditions. In some circumstances, renewable generators in the study area may need to be backed down due to excess generation.

Establishment of Reserves

The term “reserves” described in this section refers to the “resources available within ten minutes following notification” as described in PP3. A transmission Needs Assessment, Solutions Study, an Competitive Transmission RFP base case will model 1,200 MW of reserves to account for generation adjustments after the first contingency. These resources are available after the first contingency to: 1) Keep load-resource balance in the base case if the first contingency involves the loss of a resource (generator/inter-Area tie); and 2) Make system adjustments in preparation for the next contingency while maintaining load-resource balance in the base case. The reserves in a base case may include hydro generation and conventional generation.

Reserves in the peak load base case can be procured from the following sources:

- Energy storage systems in charging/pumping mode may be dispatched to 0 MW to reduce effective load on the system.(Battery systems cannot be guaranteed to have MWh available to discharge in order to provide reserves, and thus will not be dispatched to provide reserves above 0 MW.)
- Weekly Cycle Hydro Units – These generators may be dispatched up to their maximum power output, as defined in Table 2-6, from their historical de-rated output in the base case after the first contingency.
- Offline Fast Start[36] Units – These generators may be dispatched up to their maximum power output, as defined in Table 2-6, after the first contingency.
- Energy storage systems that are discharging energy (for example, in a Summer Evening Peak case) may be reduced to below the output level specified in Section 2.3.8, with the amount of the reduction designated as reserves.

[36] For the purpose of transmission Needs Assessments and Solutions Studies, fast start units are that can go from being offline to at least 90% of their Pmax rating, as specified in Section 2.3.3, in 10 minutes.

- Online Conventional Generators – If weekly cycle hydro and offline fast start units do not provide 1,200 MW of reserves, then generators capable of ramping up after the first contingency will be assigned reserves equal to their 10 minute ramp capability.

For a particular system stress selected, an attempt is made to establish reserves on the receiving end of the system stress. However, interface limits must not be violated when establishing reserves on the receiving end. If an interface limit is violated, the remaining reserves will be established on the sending end of the stress.

If the study area is on the receiving end of the system stress, additional generation may not be turned off in the study area or adjacent area to establish reserves. If the study area is part of a Load Zone, additional generation in the Load Zone containing the study area may not be turned offline to establish reserves. An exception to this rule is the available weekly cycle hydro units in the study area which may be used to establish reserves in the receiving end.

Reserves are established in the base case relying on the following types and using the priority listed in parenthesis:

- Receiving end weekly cycle hydro units (Priority 1)
- Study area weekly cycle hydro units (Priority 1)
- Reductions in receiving end energy storage systems, in cases where storage is assumed to be charging/pumping (Priority 2)
- Receiving end offline fast start units (Priority 2)
- Receiving end online energy storage systems, in cases where storage is assumed to be discharging/generating (Priority 3)
- Receiving end online conventional units (Priority 3)
- Sending end units outside the study area (Priority 4)
    - Sending-end units outside the study area should only be turned on if they are in the same pseudo-economic class as other online units in New England, or if all such units in New England are already online.

4.1.5 **Steady State Thermal and Voltage Analysis**

This section details the setup and analysis of the steady state thermal loadings and system voltages on the New England transmission system for transmission Needs Assessments and Solutions Studies.

4.1.5.1 *Contingencies Tested*

NERC, NPCC, and the ISO require that the New England BES, BPS, and PTF (respectively) shall maintain equipment loadings and voltages within normal limits for pre-disturbance conditions and within applicable emergency limits for the system conditions following the contingencies described in Section 3.4.

4.1.5.2 *Critical Load Level Analysis*

Based on stakeholder feedback at the March 15, 2018 PAC meeting, the ISO has discontinued performing critical load level (CLL) analysis as part of transmission Needs Assessments.

4.1.6 **Transient Stability Analysis**

This section details the contingency analysis of the transient stability of the New England transmission system for transmission Needs Assessments and Solutions Studies.

4.1.6.1 *Contingencies Tested*

NERC and NPCC require that the New England BES and BPS systems shall remain stable and damped and the NERC Standard NUC-001 shall be met. The ISO's PP3 requires:

> *"Individual generating units ≥ 5 MW or any set of units totaling more than 20 MW shall not lose synchronism or trip during and following the most severe of the contingencies with due regard to reclosing, and before making any manual system adjustments."*

This applies for all N-1 and N-1-1 Contingencies as defined Table 1 and 2 of the procedure.

4.1.7 **Short Circuit Analysis**

This section details the setup for short circuit analysis of the New England transmission system for transmission Needs Assessments, Solutions Studies, System Impact Studies and PPA studies.

4.1.7.1 *Short Circuit Base Case Generation Dispatch*

The system condition most critical for short circuit assessment is all available generation in service[37] and should be modeled as such in the base case used for the study.

4.1.7.2 *Short Circuit Assumptions for Transmission Circuit Breaker Duty Assessment*

This section summarizes the solution parameters that shall be used for fault current and breaker duty evaluation of transmission circuit breakers when conducting a short circuit assessment. ISO New England recommends using ASPEN OneLiner Breaker Rating Module (BRM) and the relevant ISO short circuit base cases for short circuit studies.

Table 4-4 shows the system-wide solution parameters that shall be used for ISO short circuit analyses.

Table 4-4
ASPEN OneLiner Solution Parameters

ASPEN OneLiner Short Circuit Assessment Assumptions		
Fault Simulation Options		**Standardized Value**
Switch impedance		R = 0.00001 p.u. X = 0.0001 p.u.

[37] If an inverter based resource is modeled as a voltage-controlled current source (VCCS), the breaker duty may decrease under certain circumstances if the VCCS based resource is online. If a breaker in the vicinity of a VCCS based resource is at or above its rated capability, further assessment may be necessary to confirm the observed overduty.

Pre-fault voltage	From a linear network solution	Operating kV of circuit breaker set to voltages per Table 4-5
Ignore in Short Circuits	Loads	Selected
	Transmission line G+jB	Selected
	Shunts with + sequence values	Selected
	Transformer line shunts	Selected
Generator Impedance		Subtransient
MOV-protected series capacitor	Iterate short circuit solutions	Selected
	Acceleration Factor	0.4
Define Fault MVA As Product of		Current & pre-fault voltage
Ignore Mutuals < This Threshold		0 pu
Current Limited Generators		Enforce current limit A
Simulate voltage-controlled current sources		Selected[38]
Simulate type-3 wind plants		Selected**Error! Bookmark not defined.**
Simulate converter-interfaced sources		Selected**Error! Bookmark not defined.**
X/R Options		**Standardized Value**
Compute ANSI x/r ratio		Selected
Assume Z2 equals Z1 for ANSI x/r calculation		Selected
X-only calculation	If X is 0 use	X=0.0001 p.u.

[38] The “Simulate voltage-controlled current source”, “simulate converter-interfaced resources”, and “Simulate type-3 wind plants” options require the use of the Prefault Voltage option “From a linear network solution” method.

R-only calculation	If R is 0 use	Method 1
		Rc=0.0001 p.u.
	Typical X/R ratio (g)[39]	80 for generators
		60 for transformers
		80 for reactors
		10 for all others
ANSI/IEEE Breaker Checking Options[40]		**Standardized Value**
Fault Types		3LG, 2LG, 1LG, LL
For X/R Calculation	Separate X-only, R-only networks	Selected
In 1LG faults, allow up to 15% higher rating for	Symmetrical current rated	Selected
Force voltage range factor K=1 in checking	Symmetrical-current rated breakers with max design kV 121 or higher	Selected
Miscellaneous options	Treat all sources as “Remote”[41]	Selected
Network Options		Standardized Value
Ignore phase shift of transformers and phase shifters		Not selected

Table 4-5 shows the pre-fault voltage values that shall be used in short circuit studies:

[39] Values derived from IEEE Std C37.010-1999

[40] For IEC rated circuit breakers, all necessary modeling data and supporting analysis methodology should be obtained from the equipment owner or their designated entity.

[41] For circuit breakers in the vicinity of a generating station, this is a conservative approach and should be used during a breaker duty assessment. If warranted, further analysis should be conducted without using this option to obtain a more accurate breaker duty for circuit breakers in the vicinity of a generating station.

Table 4-5
Pre-fault Voltage by Transmission Owner

Transmission Owner	Voltage (p.u.)
Versant Power	1.05
Avangrid (ME)	1.05
National Grid	1.05
Eversource (Boston, Cape Cod)	1.03
Eversource (CT, WMA, NH)	1.04
Avangrid (CT)	1.04
Vermont Electric Power Company (VELCO)	1.05

For facilities that are not owned by the Transmission Owner listed in Table 4-5, the pre-fault voltage for the adjacent Transmission Owner listed in Table 4-5 will be used.

4.1.7.3 *Evaluation of Generator Breakers*

ASPEN OneLiner BRM evaluates IEEE symmetrical current rated breakers based on guidance found in IEEE C37.010 – IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis[42] and currently does not include a function that is directly applicable to Generator Circuit Breakers rated in accordance with IEEE C37.013 – IEEE Standard for AC High-Voltage Generator Circuit Breakers Rated on a Symmetrical Current Basis[43]. The determination of ac and dc decrement documented in IEEE C37.010 and used by ASPEN OneLiner BRM are not necessarily relevant for Generator Circuit breakers, given the different conditions each type of breaker is expected to be exposed to. However, ASPEN OneLiner BRM may be used to screen generator breaker duty using the methodology discussed in Section 4.1.7.2. If the screening demonstrates a generator breaker at or above its rated capability, considerations should be made to determine if the respective generator circuit breaker has been modeled accurately within ASPEN in conjunction with the Generator Owner.

4.1.7.4 *Contingencies Tested*

4.1.8 **Time-Sensitive Needs and Need-by Date Determination**

4.1.8.1 *Introduction*

At the conclusion of a Needs Assessment, a decision must be made with regard to developing regulated transmission upgrades (solutions) to resolve the needs. The development of the solution(s) shall be accomplished by either the Solutions Study process or the Competitive Solution process. The initial determining factor of the decision for Reliability Transmission Upgrades is based on the time-sensitivity of each identified need in the Needs Assessment. Time-sensitive needs

[42] IEEE C37-010
[43] IEEE C37-013

are those that occur in three years or less from the completion of the Needs Assessment report. If any of the needs identified are deemed to be time-sensitive and the requirements of Section 4.1(j) of Attachment K of the OATT have been met, then the Solutions Study process will be initiated.

Additionally, for all needs that are identified as a part of the Needs Assessment, a need-by date (NBD) is determined.

4.1.8.2 *Short-circuit Needs*

The time-sensitivity of the short circuit need(s) is based on the expected in-service date of the future project that causes the equipment to exceed its capabilities.

- If the equipment is found to exceed its capabilities in greater than three years from the completion of the Needs Assessment report, the need would be considered non-time-sensitive.
- If the equipment is found to exceed its capabilities within three years or less from the completion of the Needs Assessment report, the need would be considered time-sensitive.

The NBD for time-sensitive needs observed as a part of the short circuit analysis will be set to June 1st of the time-sensitive year.

The NBD for non-time-sensitive needs will be set to the expected in-service date of the future project that causes the equipment to exceed its capabilities.

4.1.8.3 *Minimum Load Level Needs*

All needs identified in nighttime minimum load conditions are assumed to be time-sensitive, due to the fact that the nighttime minimum load conditions studied can occur at present.

Needs identified in Mid-day Minimum load conditions may be driven by increasing levels of PV integration. For these needs, new base cases will be created. These cases will be called the time-sensitive base cases. The year represented in these newly created base cases is determined by the date of publishing of the Needs Assessment report[44] and is called the time-sensitive year.

For purposes of establishing time-sensitivity, the Minimum Load period is assumed to begin on March 1st of each year. Therefore, the time-sensitive year will vary depending on whether the completion date of the Needs Assessment report occurs before March 1 versus on March 1 or later. Table 4-6 **Error! Reference source not found.Error! Reference source not found.Error! Reference source not found.**provides a summary of the correct Mid-day Minimum loads to be represented in the time-sensitive year.

Table 4-6
Determination of Time-Sensitive Year for Mid-Day Minimum Load Needs

Publishing Date of Final Needs Assessment Report	Time-Sensitive year
Between January 1st and February 28th of Year N	Spring of Year N+2
Between March 1st and December 31st of Year N	Spring of Year N+3

[44] The date of publishing of the Needs Assessment report is the date when the final Needs Assessment report is posted to the PAC website.

The steps to create time-sensitive base cases are discussed below.

- The study horizon base cases are used as a starting point.
- The level of PV is scaled to a level that matches the PV forecast for March 1st of the identified time-sensitive year.
- The study horizon base case transmission topology is not changed[45] .
- The dispatch of study area generators in the study horizon base cases is maintained in the time-sensitive year base cases.
- The only exception to this practice is if there are study area generators that are assumed to be retired in the study horizon base cases but are expected to be available in the time-sensitive year. If these generators are likely to run under minimum load conditions, they may be assumed online in the time-sensitive base cases. Additional dispatches may be considered in the time-sensitive year with these generators unavailable[46]. If a generator was assumed out of service in the study horizon base cases based on having accepted dynamic or static de-list bids for the full resource in the two most recent FCM auctions, the generator will be assumed OOS in the time-sensitive year. When creating the new dispatches, the same methodology that was used to establish the dispatches in the study horizon base cases is used.

Once the time-sensitive base cases are created, steady state thermal and voltage analysis is performed on these base cases.

All needs identified in the study horizon base case that still appear as a result of the analysis using the time-sensitive base cases are considered time-sensitive needs. The NBD for time-sensitive needs observed under Mid-day Minimum load conditions will be set to March 1st of the time-sensitive year.

All needs that were observed in the analysis using the study horizon base cases but are no longer present in the analysis using the time-sensitive base cases are considered non-time-sensitive needs. If non-time-sensitive needs are observed as a part of a Needs Assessment, a NBD will not be determined if there were time-sensitive needs that were also identified as a part of the same Needs Assessment.

4.1.8.4 *Peak Load Level Needs*

For needs observed at peak load levels, additional analysis is performed to determine time sensitivity. Typically, a Needs Assessment is conducted over a 10-year study horizon with initial study base cases created for a time period 10 years into the future. These base cases will be referred to as the study horizon base cases.

To determine the time-sensitive needs new base cases will be created. These cases will be called the time-sensitive base cases. The year represented in these newly created base cases is determined by the date of publishing of the Needs Assessment report[47] and is called the time-sensitive year.

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[45] This assumption avoids identifying a need using the time-sensitive base cases which would be solved by a previously identified project that would be placed in-service in the future beyond the time sensitive-year.

[46] While the generator is not assumed to have been retired in the time-sensitive year, the possibility of unavailability due to a forced outage still exists. Therefore, additional dispatches with the generator assumed to be unavailable may be considered.

For purposes of establishing time-sensitivity, the Summer Peak Load period is assumed to begin on June 1st of each year. Therefore, the time-sensitive year will vary depending on whether the completion date of the Needs Assessment report occurs before June 1 versus on June 1 or later. Table 4-7 provides a summary of the correct summer peak loads to be represented in the time-sensitive year.

Table 4-7
Determination of Time-Sensitive Year for Summer Peak Load Needs

Publishing Date of Final Needs Assessment Report	Time-Sensitive year
Between January 1st and May 31st of Year N	Summer Peak of Year N+2
Between June 1st and December 31st of Year N	Summer Peak of Year N+3

The Winter Peak Load period is assumed to begin on December 1st of each year. Therefore, the time-sensitive year will vary depending on whether the completion date of the Needs Assessment report occurs before December 1 versus on December 1 or later. Table 4-8 provides a summary of the correct summer peak loads to be represented in the time-sensitive year.

Table 4-8
Determination of Time-Sensitive Year for Winter Peak Load Needs

Publishing Date of Final Needs Assessment Report	Time-Sensitive year
Between January 1st and November 30th of Year N	Winter Peak of Year N+2
Between December 1st and December 31st of Year N	Winter Peak of Year N+3

The steps to create time-sensitive base cases are discussed below.

- The study horizon base cases are used as a starting point.
- The load is scaled to a load that matches the peak load conditions in the identified time-sensitive year.
- The study horizon base case transmission topology is not changed[48] .
- The dispatch of study area generators in the study horizon base cases is maintained in the time-sensitive year base cases.
- The only exception to this practice is if there are study area generators that are assumed to be retired in the study horizon base cases but are expected to be available in the time-sensitive year. These generators are assumed online in the time-sensitive base cases. Additional dispatches may be considered in the time-sensitive year with these generators unavailable[49]. If a generator was assumed out of service in the study horizon base cases based on having accepted dynamic or static de-list bids for the full resource in the two most recent FCM auctions, the generator will be assumed OOS in the time-sensitive year. When creating the new dispatches, the same methodology that was used to establish the dispatches in the study horizon base cases is used.

[48] This assumption avoids identifying a need using the time-sensitive base cases which would be solved by a previously identified project that would be placed in-service in the future beyond the time sensitive-year.

[49] While the generator is not assumed to have been retired in the time-sensitive year, the possibility of unavailability due to a forced outage still exists. Therefore, additional dispatches with the generator assumed to be unavailable may be considered.

Once the time-sensitive base cases are created, steady state thermal and voltage analysis is performed on these base cases.

All needs identified in the study horizon base case that still appear as a result of the analysis using the time-sensitive base cases are considered time-sensitive needs. The NBD for time-sensitive needs observed at peak load will be set to June 1st of the time-sensitive year.

All needs that were observed in the analysis using the study horizon base cases but are no longer present in the analysis using the time-sensitive base cases are considered non-time-sensitive needs. If non-time-sensitive needs are observed as a part of a Needs Assessment, a NBD will not be determined if there were time-sensitive needs that were also identified as a part of the same Needs Assessment.

NBD for Non-Time-Sensitive Needs

If non-time-sensitive needs are identified as a part of a study, the first step is to review the variation of New England net load during the years between the time-sensitive year and the study horizon year. The following formula shows how the New England net load is calculated for a given summer or winter peak load period.

$$\textbf{\textit{NE Net Load}}_{year\ x} = \boldsymbol{A}_{year\ x} - \boldsymbol{B}_{year\ x} - \boldsymbol{C}_{year\ x} - \boldsymbol{D}_{year\ x}$$

Where:

- $\boldsymbol{A}_{year\ x}$ - 90/10 Summer Peak Load for year x,
- $\boldsymbol{B}_{year\ x}$ - Available EE forecast for year x,
- $\boldsymbol{C}_{year\ x}$ - Available Active DR (de-rated) acquired via the FCM for year x, and
- $\boldsymbol{D}_{year\ x}$ - Available PV (de-rated) for year x.

The following formula shows how the New England net load is calculated for a given Mid-day Minimum load period:

$$\textbf{\textit{NE Net Load}}_{year\ x} = \boldsymbol{A} - \boldsymbol{D}_{year\ x}$$

Where:

- $\boldsymbol{A}$ - 12,000 MW power consumption, regardless of year of study,
- $\boldsymbol{D}_{year\ x}$ - Available PV (de-rated) for year x.

If the net New England loads in the study horizon year are lower (for Summer or Winter Peak load conditions) or higher (for Mid-day Minimum load conditions) than the time-sensitive year, or the change in net New England load between the time-sensitive year and the study horizon year is negligible, then the non-time sensitive needs observed under the study horizon conditions are caused by a system change, such as a resource retirement, that occurs in the period between the time-sensitive year and the study horizon year. In these instances, June 1 (for Summer Peak loads), December 1 (for Winter Peak loads), or March 1 (for Mid-day Minimum loads) of the first year following the date associated with the system change is used to determine the NBD. As an example, if a system change occurs in December 2025, then the NBD for Summer Peak load needs will be set to June 1, 2026. In these instances, additional analysis will not be performed.

In situations where net New England loads are appreciably higher (for Summer or Winter Peak load conditions) or lower (for Mid-day Minimum load conditions) in the study horizon year than the time-sensitive year, the method to approximate NBD for non-time-sensitive needs is the slope-intercept equation from two points. This method is an approximation that provides a reasonable estimate with minimum additional analysis. The NBD analysis requires the level of the loading or voltage on a transmission element[50] to be determined at two system load levels for the contingency or contingencies that have the largest impact on that transmission element. An NBD analysis is done for each transmission element that is overloaded or experiences a voltage violation in the study horizon base cases that is categorized as a non-time-sensitive need.

The load or voltage level in each base case is plotted[51] on the x-axis of a graph and percentage of the overload or per unit of the voltage violation is plotted on the y-axis. A straight line is then drawn to connect these two points. The NBD load level is the load level (x-axis value) associated with the 100 percent value for thermal overloads or the lowest acceptable per unit voltage[52] on the y-axis.

The two data points adhere to the following requirements:

- The dispatch of generators critical to the study area should be the same for the two points considered
- The two points must correspond to the same contingency or contingency pair

One data point corresponds to the study horizon base case. The second data point could be any year between the time-sensitive year and the study horizon year. The use of the first year after the time-sensitive year is considered a good choice for the 2nd data point because any generation retirements in the study horizon year that were not in the time-sensitive year would generally be effective in the year after the time-sensitive year. Any study that uses a different year for the second data point will include an explanation for the choice of the second data point.

The thermal loads and voltage levels are obtained from the analysis results.

Using the two data points available, a line is drawn using the slope/intercept method[53]. For each monitored element, the line can be used to determine the loading or voltage of an element for different system load levels. As an example, the line for Element X1 for a thermal violation is shown in Figure 4-1 below.

[50] An element is any electric device with terminals which may be connected to other electric devices. Some examples of an element are a generator, transformer, circuit breaker, bus section, or transmission line.

[51] While this document refers to actions such as plotting and drawing, these actions are to help the reader understand the concept. In practice, the math is performed without actually creating such plots.

[52] The voltage threshold depends on the transmission owner or the Nuclear Plant Interface Requirements (NPIRs). See section 3.1.2.5 for additional details.

[53] Slope (m) = Rise divided by Run and the line equation is $y = m(x) + b$ where b is the y-intercept.

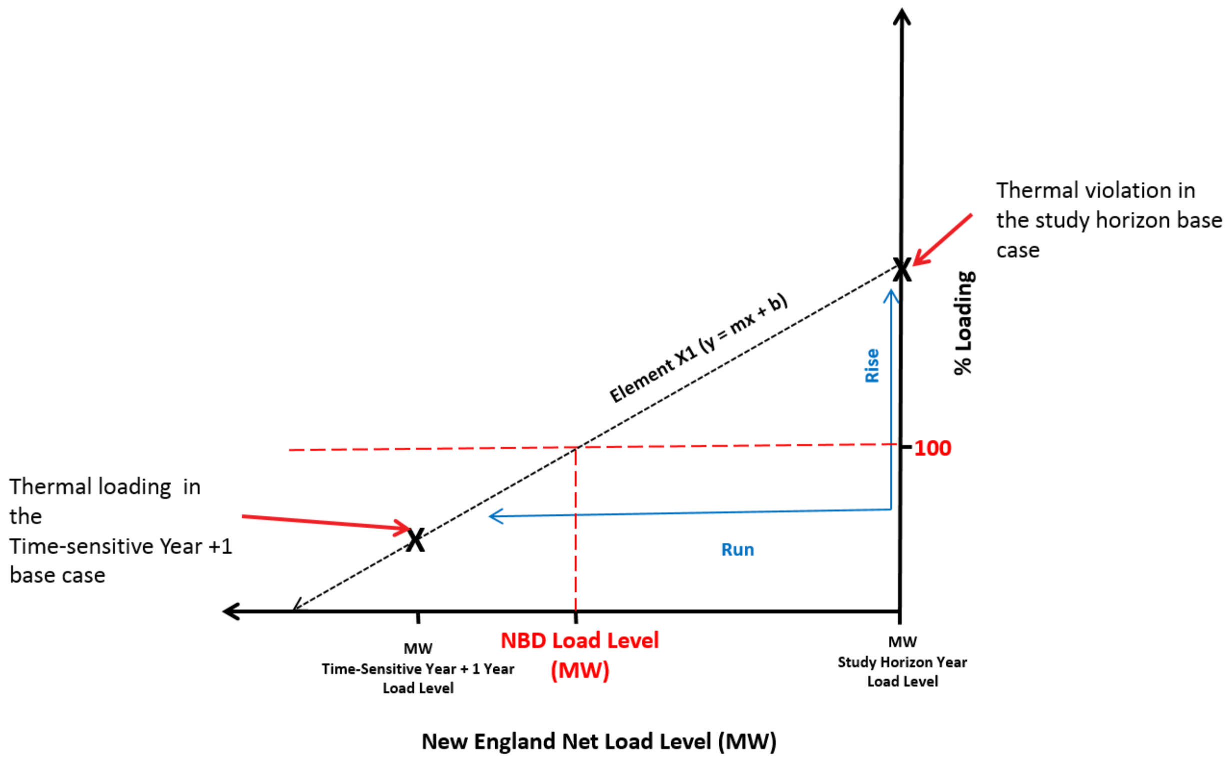

Figure 4-1: NBD Analysis for Non-Time-Sensitive Need on Element X1

The NBD load level for thermal violations is determined from the point on the line which corresponds to the 100 percent value on the y-axis. The NBD load level for voltage violations is determined from the point on the line which corresponds to the lowest acceptable per unit voltage level on the y-axis.

For a given NBD load level, the NBD represents June 1 (for Summer Peak loads), December 1 (for Winter Peak loads), or March 1 (for Mid-day Minimum loads) of the year that corresponds to the closest New England net load that is greater than or equal to the calculated NBD load level. In the example in Figure 4-2 , the NBD would be June 1, 2025.

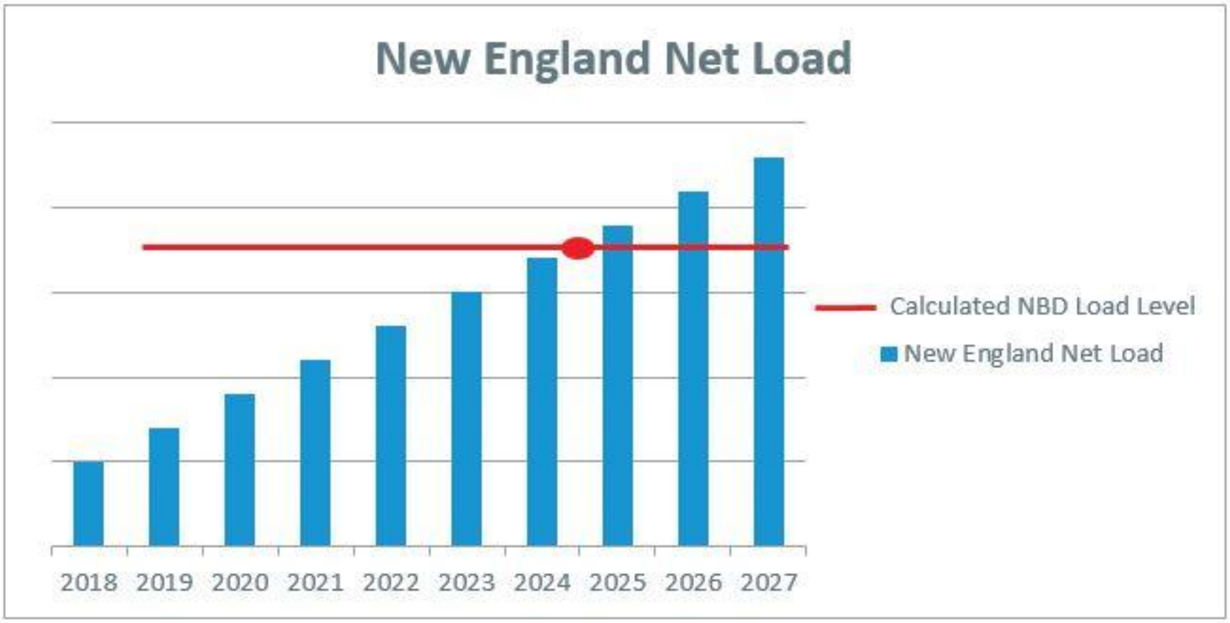

Figure 4-2: Calculating Need-By Date using NBD Load Level

4.1.8.5 *Summary of Time-sensitivity and Need-By Date Determination*

Table 4-9 provides a summary of the methodology used to determine the time-sensitivity of needs and the NBD associated with needs that are identified as a part of a Needs Assessment.

Table 4-9
Summary of Time-sensitivity and NBD Analysis

Load Level Studied	Time-Sensitivity of Need	Need-by Date
Short-circuit	Time-Sensitive	June 1 of the time sensitive year
	Non-Time-Sensitive	Date associated with the expected in-service date of the future project that causes the equipment to exceed its capabilities
Off-peak (except for Mid-day Minimum)	Time-Sensitive (All needs at off peak load levels are time-sensitive)	Publishing Date of the final Needs Assessment Report
Summer Peak	Time-Sensitive	June 1 of time-sensitive year
	Non-Time-Sensitive	Date obtained using linear method if study horizon year NE loads are appreciably higher than time-sensitive year NE loads June 1 of the first year following the date associated with critical system change affecting the study area for all other scenarios of load change between the time-sensitive year and the study horizon year
Mid-Day Minimum	Time-Sensitive	March 1 of time-sensitive year
	Non-Time-Sensitive	Date obtained using linear method if study horizon year NE loads are appreciably lower than time-sensitive year NE loads March 1 of the first year following the date associated with critical system change affecting the study area for all other scenarios of load change between the time-sensitive year and the study horizon year

4.2 Proposed Plan Application Testing and System Impact Study Testing

This section details the setup and analysis of the New England transmission system for Proposed Plan Application testing under Section I.3.9 of the Tariff.

4.2.1 Stressed Transfer Levels

Transfer levels are also adjusted as appropriate for the load levels that are to be studied. Transfer level testing may require thermal, voltage, and/or stability testing to confirm no adverse impact on transfer limits. Interface transfer levels are tested up to their capability in order to sustain the economic efficiency of the electric system and reliable operation and transmission service obligations of the New England transmission system.

The system is designed to preserve existing range of transfer capabilities. This is a requirement defined in PP5-3 and is a fundamental objective of the minimum interconnection standard. In order to meet this requirement, interfaces that may affect the area under study are modeled with transfer levels that cover the full range of existing capabilities. The review of interface stresses includes an evaluation of each interface internal to New England as well as interfaces between New England and adjacent Control Areas to determine the set of interfaces that may have a significant impact on the results of studies for the study area. Interfaces that are not directly connected to a study area but may have a significant effect on the study area interface are considered “coincident interfaces”. The procedures for selecting transfer levels for study area interfaces and coincident interfaces are provided below.

There may be a need to increase transfer capabilities as generation patterns shift across the system. General system trends in the direction of flow and magnitude may change dramatically over time. Some examples of conditions in which transfer capabilities requirements have changed include:

- The Connecticut area used to export across the Connecticut interface to eastern New England over many hours, but significant load growth and the outage of the nuclear units changed this to an import.
- Whether the New Brunswick Control Area is an exporter to New England or an importer from New England can vary and depends on many factors including the availability of generation in New Brunswick.
- There has been an increase of “in-merit” natural gas generation being sited adjacent to existing gas pipelines in southern New England.
- Studies associated with the New England East West Solution have in the past been focused on the need to move power from across New England from east to west. As the project progressed, the studies demonstrated a need to move power from west to east, even prior to consideration of the retirement of Salem Harbor station in 2014, Brayton Point station in 2017, or retirement of Pilgrim Nuclear station in 2019.

4.2.2 Contingencies Tested

NERC, NPCC, and the ISO require that the New England BES, BPS, and PTF (respectively) shall maintain equipment loadings and voltages within normal limits for pre-disturbance conditions and within applicable emergency limits for the system conditions following the contingencies described in Section 3.4.

4.3 Bulk Power System Testing

This section is under development.

4.3.1 **Base Case Generation Dispatch**

4.3.2 **Contingencies Tested**

Section 5
Appendices

5.1 Appendix A – Terms and Definitions

50/50 PEAK LOAD
A peak load with a 50% chance of being exceeded because of weather conditions, expected to occur in New England at a temperature of 90.4°F.

90/10 PEAK LOAD
A peak load with a 10% chance of being exceeded because of weather conditions, expected to occur in New England at a temperature of 94.2°F.

ADVERSE IMPACT
See Significant Adverse Impact.

APPLICABLE EMERGENCY LIMIT

- These Emergency limits depend on the duration of the occurrence, and are subject to New England standards.
- Emergency limits are those which can be utilized for the time required to take corrective action, but in no case less than five minutes.
- The limiting condition for voltages should recognize that voltages should not drop below that required for suitable system stability performance, meet the Nuclear Plant Interface Requirements and should not adversely affect the operation of the New England PTF System.
- The limiting condition for equipment loadings should be such that cascading outages will not occur due to operation of protective devices upon the failure of facilities.

AREA (as defined in NPCC Glossary of Terms)
An Area (when capitalized) refers to one of the following: New England, New York, Ontario, Québec or the Maritimes (New Brunswick, Nova Scotia and Prince Edward Island); or, as the situation requires, area (lower case) may mean a part of a system or more than a single system.

AREA TRANSMISSION REVIEW (see Appendix B of NPCC Directory #1)
A study to assess the reliability of the bulk power system

BULK ELECTRIC SYSTEM / BES (as defined in the NERC Glossary of Terms)
As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

BULK POWER SUPPLY SYSTEM
The New England interconnected bulk power supply system is comprised of generation and transmission facilities on which faults or disturbances can have a significant effect outside of the local area.

BULK POWER SYSTEM TESTING (see NPCC Document A-10)
A study done to determine if Elements are classified as part of the Bulk Power System

BULK POWER SYSTEM / BPS (as defined in NPCC Glossary of Terms)
The interconnected electrical system within northeastern North America comprised of system elements on which faults or disturbances can have significant adverse impact outside the local Area.

CAPACITY SUPPLY OBLIGATION (as defined in Section I of the Tariff)
This is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

CONTINGENCY (as defined in NPCC Glossary of Terms)
An event, usually involving the loss of one or more Elements, which affects the power system at least momentarily

CAPACITY NETWORK RESOURCE CAPABILITY (as defined in Schedule 22 of the OATT)
Capacity Network Resource Capability (CNR Capability) is defined in Schedule 22 of the Tariff and means (i) in the case of a Generating Facility that is a New Generating Capacity Resource pursuant to Section III.13.1 of the Tariff or an Existing Generating Capacity Resource that is increasing its capability pursuant to Section III.13.1.2.2.5 of the Tariff, the highest MW amount of the Capacity Supply Obligation obtained by the Generating Facility in accordance with Section III.13 of the Tariff, and, if applicable, as specified in a filing by the System Operator with the Commission in accordance with Section III.13.8.2 of the Tariff, or (ii) in the case of a Generating Facility that meets the criteria under Section 5.2.3 of this LGIP, the total MW amount determined pursuant to the hierarchy established in Section 5.2.3. The CNR Capability shall not exceed the maximum net MW electrical output of the Generating Facility at the Point of Interconnection at an ambient temperature at or above 90° F for Summer and at or above 20° F for Winter. Where the Generating Facility includes multiple production devices, the CNR Capability shall not exceed the aggregate maximum net MW electrical output of the Generating Facility at the Point of Interconnection at an ambient temperature at or above 90° F for Summer and at or above 20° F for Winter. The CNR Capability of a generating facility can be found in the Forecast Report of CELT Report which is produces annually by ISO New England.

DELAYED FAULT CLEARING (as defined in NERC Glossary of Terms)
Fault clearing consistent with correct operation of a breaker failure protection group and its associated breakers, or of a backup protection group with an intentional time delay.

ELEMENT (as defined in NERC Glossary of Terms)
Any electric device with terminals which may be connected to other electric devices such as a generator, transformer, circuit, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.

FCM STUDY FOR ANNUAL RECONFIGURATION AUCTIONS AND ANNUAL BILATERALS
The FCM study as part of the annual reconfiguration auction or annual evaluation of Capacity Supply Obligations as described in Sections 13.4 and 13.5 of Market Rule 1.

FCM DELIST ANALYSES
The FCM Delist Analyses is the analysis of de-list bids, and demand bids as described in Section 7.0 of PP10.

FCM NEW RESOURCE QUALIFICATION OVERLAPPING IMPACT ANALYSES

The FCM New Resource Qualification Overlapping Analyses is the analysis of overlapping interconnection impacts as described in Section 5.7 of PP10. This study is similar in scope as the thermal analyses performed in a System Impact Study associated with a generator interconnection request.

FCM NEW RESOURCE QUALIFICATION NCIS ANALYSES

The FCM New Resource Qualification NCIS Analyses is the initial interconnection analysis under the Network Capability Interconnection Standard as described in Section 5.6 of PP10. This study is similar in scope as the thermal analyses performed in a System Impact Study associated with a generator interconnection request.

NORMAL FAULT CLEARING (as defined in NPCC Glossary of Terms)

Fault clearing consistent with correct operation of the protection system and with the correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that protection system.

NETWORK RESOURCE CAPABILITY

Network Resource Capability (NR Capability) is defined in Schedule 22 of the Tariff and means the maximum gross and net MW electrical output of the Generating Facility at the Point of Interconnection at an ambient temperature at or above 50° F for Summer and at or above 0° F for Winter. Where the Generating Facility includes multiple energy production devices, the NR Capability shall be the aggregate maximum gross and net MW electrical output of the Generating Facility at the Point of Interconnection at an ambient temperature at or above 50° F for Summer and at or above 0° F for Winter. The NR Capability shall be equal to or greater than the CNR Capability. The NR Capability of a generating facility can be found in the Forecast Report of Capacity, Energy, Loads and Transmission (CELT Report) which is produces annually by ISO New England.

NUCLEAR PLANT INTERFACE REQUIREMENTS (as defined in the NERC Glossary of Terms)

The requirements based on Nuclear Plant Licensing Requirements (NPLRs) and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable Transmission Entities.

NUCLEAR PLANT LICENSING REQUIREMENTS (NPLRs) (as defined in the NERC Glossary of Terms)

Requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for:

1. Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and
2. Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.

PLANNED (as defined in Attachment K of the OATT)

A transmission upgrade the ISO has approved under Section I.3.9 of the Tariff (Both a transmission Needs Assessment and a Solutions Study have been completed for planned projects).

PROPOSED (as defined in Attachment K of the OATT)
A regulated transmission solution that (1) has been proposed in response to a specific identified needs in a transmission Needs Assessment or the Regional System Plan (RSP) and (2) has been evaluated or further defined and developed in a Solutions Study, as specified in the OATT, Attachment K, Section 4.2(b) but has not received ISO approval under Section I.3.9 of the Tariff. The regulated transmission solution must include analysis sufficient to support a determination by the ISO, as communicated to the PAC, that it would likely meet the identified need included in the transmission Needs Assessment or the RSP, but has not received approval by the ISO under Section I.3.9 of the Tariff.

PROTECTION GROUP (as defined in NPCC Glossary of Terms)
A fully integrated assembly of protective relays and associated equipment that is designed to perform the specified protective functions for a power system Element, independent of other groups.

Notes:
- Variously identified as Main Protection, Primary Protection, Breaker Failure Protection, Back-Up Protection, Alternate Protection, Secondary Protection, A Protection, B Protection, Group A, Group B, System 1 or System 2.
- Pilot protection is considered to be one protection group.

PROTECTION SYSTEM (as defined in NPCC Glossary of Terms)
Element Basis
One or more protection groups; including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities; installed at all terminals of a power system Element to provide the complete protection of that Element.

Terminal Basis
One or more protection groups, as above, installed at one terminal of a power system Element, typically a transmission line.

QUALIFIED CAPACITY (as defined in Section I of the Tariff)
a. Qualified Capacity is the amount of capacity a resource may provide in the Summer or Winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

RESOURCE (as defined in Section I of the Tariff)
Resource means a generating unit, a Dispatchable Asset Related Demand, an External Resource, or an External Transaction. For Capacity Commitment Periods commencing on or after June 1, 2018, it also means to include a Demand Response Resource.

SIGNIFICANT ADVERSE IMPACT (Based on Section I.3.9 of the Tariff and PP5-3)
A change to the transmission system that increases the flow in an Element by at least two percent (2%) of the Element's rating and that causes that flow to exceed that Element's appropriate thermal rating by more than two percent (2%). The appropriate thermal rating is the normal rating with all lines in service and the long time emergency or short time emergency rating after a contingency (See Section 3.1.1).

A change to the transmission system that causes at least a one percent (1%) change in a voltage and causes a voltage level that is higher or lower than the appropriate rating by more than one percent (See Section 3.1.2).

A change to the transmission system that causes at least a one percent (1%) change in the short circuit current experienced by an Element and that causes a short circuit stress that is higher than an Element's interrupting or withstand capability (See Section 3.2).

With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from faults or disturbances, shall be deemed as having significant adverse impact:

A fault or a disturbance that cause:

- Any loss of synchronism or tripping of a generator
- Unacceptable system dynamic response as described in PP3
- Unacceptable equipment tripping: tripping of an un-faulted bulk power system element (element that has already been classified as Bulk Power System) under planned system configuration due to operation of a protection system in response to a stable power swing or operation of a Type I or Type II Special Protection System in response to a condition for which its operation is not required

SPECIAL PROTECTION SYSTEM / SPS (as defined in NPCC Glossary of Terms)
A protection system designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted Elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages or power flows.

However, the following are not considered SPS's:

- Automatic under frequency load shedding:
- Automatic under voltage load shedding, and
- Manual or automatic locally controlled shunt devices.

STEADY STATE (as defined in ANSI/IEEE Standard 100)
The state in which some specified characteristic of a condition such as value, rate, periodicity, or amplitude exhibits only negligible change over an arbitrary long period of time. In this guide, the term steady state refers to sixty hertz (60 Hz) currents and voltages after current and voltages deviations caused by abnormal conditions such as faults, load rejections and the like are dissipated.

SUMMER (as defined in OP 16 Appendix A)
The Summer period is April 1 to October 31.

VOLTAGE COLLAPSE
Situations which result in a progressive decrease in voltage to unacceptable low levels, levels at which power transfers become infeasible. Voltage collapse usually leads to a system blackout.

WINTER (as defined in OP 16 Appendix A)
The Winter period is November 1 to March 31.

WITH DUE REGARD TO RECLOSING (as defined in NPCC Glossary of Terms)
This phrase means that before any manual system adjustments, recognition will be given to the type of reclosing (i.e., manual or automatic) and the kind of protection.

5.2 Appendix B – Retired

This appendix was retired on November 14, 2017.

5.3 Appendix C – Guidelines for Treatment of Demand Resources in System Planning Analysis

This document referenced in Section 2.3.9.9 is listed separately on the ISO website at:

https://www.iso-ne.com/system-planning/transmission-planning/transmission-planning-guides/

5.4 Appendix D – Retired

This appendix on dynamic stability simulation damping criteria was retired on November 14, 2017. The contents of this appendix are now described in Section 3.3.3.

5.5 Appendix E – Dynamic Stability Simulation Voltage Sag Guideline

This document referenced in Section 3.3.4 is listed separately on the ISO website at:

https://www.iso-ne.com/system-planning/transmission-planning/transmission-planning-guides/

5.6 Appendix F – Stability Task Force Presentation to Reliability Committee – September 9, 2000

This document referenced in Section 3.4.3 is listed separately on the ISO website at:

https://www.iso-ne.com/system-planning/transmission-planning/transmission-planning-guides/

5.7 Appendix G – Phase Shifting Transformers Modeling Guide for ISO New England Network Model

This document, referenced in Sections 2.4 and 2.11.3, is listed separately on the ISO website at:

https://www.iso-ne.com/system-planning/transmission-planning/transmission-planning-guides/

5.8 Appendix H –Simulation of No-Fault Contingencies

This document, referenced in Section 3.4.4, is listed separately on the ISO website at:

https://www.iso-ne.com/system-planning/transmission-planning/transmission-planning-guides/

5.9 Appendix I – Methodology Document for the Assessment of Transfer Capability

This document, referenced in Section 2.8.1, is listed separately on the ISO website at:

https://www.iso-ne.com/system-planning/transmission-planning/transmission-planning-guides/

5.10 Appendix J – Load Modeling Guide for ISO New England Network Model

This document, referenced in Sections 2.2 and 2.3.9, is listed separately on the ISO website at:

https://www.iso-ne.com/system-planning/transmission-planning/transmission-planning-guides/

5.11 Appendix K – DER Modeling Guide for ISO New England Planning Studies

This document is listed separately on the ISO website at:

https://www.iso-ne.com/system-planning/transmission-planning/transmission-planning-guides/

Section 6
Revision History

This revision history reflects all changes after re-organization of Version 1 of the Transmission Planning Technical Guide, last updated on March 24, 2017. For revisions made to Version 1, PAC presentations, and stakeholder comments, they are posted on the ISO website.

https://www.iso-ne.com/system-planning/transmission-planning/transmission-planning-guides#

Rev. No.	Date	Reason
8.1	9/12/2023	• Added Section 2.2.1.2, Winter peak study condition. Added language throughout the guide to account for having a winter peak study condition • Updated Section 2.3.8 and Table 2-8 to reflect long-duration energy storage • Updated Section 2.3.9.2 to not include DER loss gross-up for non-peak conditions • Update Section 2.3.9.6 to reflect that DER will be modeled at a unity power factor • Update Table 3-2 to reflect updated National Grid Steady-State voltage criteria • Updated Section 4.1.2 to clarify the 50-year generator outage retirement risk rule

8.0	3/24/2023	• Updated Sections 2.3.3, 2.3.6 – 2.3.9, and Tables 2-6 to reflect new maximum real power output assumptions. Assumption changes apply to Transmission Needs Assessments, Solutions Studies, Competitive RFPs, Public Policy Studies, and System Impact Studies
		• Table 2-6 and 2-7 were combined into a single table
		• Added note (1) to Tables 2-7 and 2-8
		• Updated treatment of hydro units at minimum load condtions in section 2.3.7
		• Removed section related to generator unavailability probability (previously 2.3.5)
		• Removed the section related to pumped storage (previously 2.3.8)
		• Battery Energy Storage System language changed to Energy Storage Systems in section 2.3.9 (now 2.3.8). Includes information about pumped hydro units
		  o Table 2-8 updated to include pumped hydro units
		  o Footnotes added for table 2-8 updated
		  o Footnotes added for language around pumped hydro units
		• Removed section related to probabilistic threshold guidelines (previously 3.1.3)
		• Table 3-2 updated to include all voltage criteria, listed by Transmission Owner
		  o Table 3-2 moved to section 3.1.2
		  o Footnotes added for updated Table 3-2
		  o Sunsequent sections updated to coordinate with updated Table 3-2
		  o Former Table 3-3 removed
		• Section 3.1.2.3 updated to discuss post-contingecy, pre-swithcing high voltage criteria
		• New Table 3-3 and Section 3.1.2.6 added for GMD voltage criteria
		  o Subsequent Table numbers in Section 3 updated
		• New Section 3.3.5 Treatment for Line Loadings in stability simulations after DER disturbances
		• Updated Section 4.1.1.1 – 4.1.1.4 to reflect new generator outage and intra-area transfer assumptions for steady state thermal and voltage analysis
		• Added Tables 4-1 and 4-2 to describe new generator outage assumptions for steady state thermal and voltage analysis
		• Updated appendix J to reflect load distribution at minimum load conditions
		  o Added footnotes in section 2.2.1.4 and 2.2.1.5 with refrences to appendix J
		• New appendix, DER Modleing and Protection settings

		○ Includes DER locational mapping ○ Includes DER lifecycle data • Minor editorial changes throughout
7.3	4/4/2022	• Section 1.3 added definition for Longer-Term Transmission Study • Table 4-3 updated to reflect changes in ASPEN Oneliner solution parameters for short circuit analyses
7.2	2/28/2022	• Table 2.1 updated to add in-service resources to be included in Transmission Needs Assessments, Solutions Studies/Competitive RFPs, and Public Policy Transmission Studies per Section 4.1(f) and Section 4A.3(b) of Attachment K ○ Table 2-1, note 4 updated ○ Table 2-1, note 10 added to state that the terms existing resource and in-service resource are equivalent ○ Table 2-1, note 11 added to state that the base case topologies of a Needs Assessment and Solutions Studies/Competitive RFPs are equivalent • Table 2-2, Table 2-6, Table 2-7, and Table 2-15 updated to include Public Policy Transmission Studies • Notes added to Table 2-6 ○ Note 4 added to show that non-conventional generators, like fuel cells, are included in the conventional generation column ○ Note 5 added to show that summer SCC values are used for existing generation that does not have a QC value • Section 4.1.1.3 updated to show the reliance on Inter-Area ties through new footnote 26 which refers to Section 4.1(f) and Section 4A.3(b) of Attachment K • Table 4-1 updated to show the Highgate Imports level at 225 MW • Table 4-1, note 4 updated to consider 0 MW from Phase II during winter peak analysis in New England
7.1	12/10/2021	• Section 2.2.1.1 clarified that the 90/10 summer peak load is used in all studies in the guide, rather than just needs assessments and solutions studies • Section 2.2.2 deleted language regarding probabilistic calculations because the topic is different than the subject of the rest of the paragraph • Section 2.3.13 added language to reflect current assumptions under minimum load conditions previously discussed with the PAC in June 2019 • Table 2-14 updated the status of the North Cambridge, Southington, Mystic and Southwest Hartford reactors • Sections 3.1.2.1, 3.1.2.2, and 3.1.2.3 updated to incorporate the change in high and low voltage limits. Rounding of voltage results is not acceptable • Minor editorial changes throughout
7.0	09/30/2021	• Sections 2.2, 2.3, and 4.1 updated, along with other minor editorial updates in other sections, to reflect the results of the Transmission Planning for the Clean Energy Transition effort (including updates to assumptions for load, solar output, wind output, and battery behavior in Needs Assessments, Solutions Studies, and Competitive Transmission RFPs)
6.1	06/15/2020	• Table 4-4 – Updated National Grid voltage
6.0	10/10/2019	• Section 2.1 – Added language to reflect the base case used for short circuit analysis • Section 3.2 – Updated language to clarify the short circuit criteria

		• Section 4.1.3 – Updated to reflect the current process for short circuit analysis • Section 4.1.4.4 – Editorial change to improve clarity
5.0	09/13/2019	• Section 2.1 – Footnote 8 of Table 2-1 updated to clarify the treatment of units with successive accepted static or dynamic de-list bids • Section 3.1.2.5 – Table 3-2 updated to reflect the removal of the Pilgrim nuclear unit voltage limits based on the retirement of the Pilgrim station • Section 4.1.4 – New Section 4.1.4 to reflect the methodology for determining time-sensitive needs and the need-by date as a part of Needs Assessments
4.2	04/09/2019	• Updated sections 2.2.1.2, 2.2.1.3, 2.2.1.4, to separate the handling of Maine paper mill load from the rest of New England load.
4.1	01/30/2019	• Section 2.1 – Note 9 updated to reflect CASPR conforming changes.
4.0	07/03/2018	• Section 2.2.3 – The language has been made more generic to remove specific MW values of manufacturing load and refers to study documents for the amount. • Section 2.3.5 – Language about resources participating in the FCM has been removed. The language describing which resources that are to be used in each study are already documented in Table 2-1 of Section 2.1. Footnote 2 of Table 2-6 was also removed for the same reason. • Section 3.1.2.5 – Table 3-2, an error was corrected in the minimum bus voltage limit for Pilgrim; it should be 343.5 kV not 345.5 kV.
3.0	05/18/2018	• Updated guide to reflect changes to terminology associated with Price Responsive Demand (PRD) • Updated to reflect current process for Needs Assessments and Solutions Studies base case dispatch (Section 4.1.1.1) and system transfers (Section 4.1.1.2). • Created new Section 4.2 – Proposed Plan Application Testing, to include stressed transfer language originally contained in Section 2.8. • Moved power flow solutions settings from Section 4 to Section 2 to apply more generically to system studies and avoid repeating same section for each study type in Section 4.
2.0	11/14/2017	• Re-organized original Technical Guide to group together similar topics and allow for future additions to be more logically placed within the document outline. • Updated report format to latest ISO document template. • Updated formatting throughout to be consistent with ISO New England Style Guide. • Removed section concerning two generators out in the base case (Section 10 of Rev 1.0) of transmission Needs Assessments and replaced with base case dispatch probabilistic methods (New Sections 2.2.2, 2.3.5, 2.3.12, 3.1.3, and 4.1.1 of Rev 2.0). • Retired Appendices B and D of the guide.
1.0	03/24/2017	• Latest version of the Technical Guide prior to re-organization in Rev 2.0.