Transmission Planning Technical Guide

System Planning
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Contents

Section 1
Introduction

This guide describes the current standards, criteria and assumptions used in various transmission planning studies in New England.

Section 1 of this guide describes its purpose and the source of the standards, criteria and assumptions used in transmission planning studies. Section 2 describes the various types of transmission planning studies that use these standards, criteria and assumptions. Sections 3 and 4 discuss thermal and voltage ratings used in planning studies.

The remaining sections each describe the different assumptions that are utilized in transmission planning studies and the basis for these assumptions. The assumptions are presented in an order that is useful to a planner performing a transmission planning study.

Sections 5, 6 and 7 discuss modeling load in different types of transmission planning studies. Section 8 discusses the topology, transmission system and generators, used in different types of transmission planning studies. Sections 9-11 describe assumptions associated with generators. Section 12 discusses contingencies and Section 13 discusses interface stresses.

Sections 14-20 discuss modeling of specific types of equipment. The remaining sections describe specific parts of planning studies.

Capitalized terms in this guide are defined in Section I of the Tariff or in Section 2 or Appendix A of this guide.

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.

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, ISO New England ("the ISO" or "ISO-NE") 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 ("PTOs"), over which the ISO exercises Operating Authority in accordance with the terms set forth in the Transmission Operating Agreement, 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 ISO New England Open Access Transmission Tariff ("OATT" or "Tariff').

The PTO's are responsible for planning of the Non-PTF and coordinating such planning efforts with the ISO. The planning assumptions in this guide apply to the non-PTF transmission system when studying upgrades to the non-PTF transmission system which will result in new or modified PTF transmission facilities. The PTO's establish the planning 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 Merchant Transmission Facilities. This includes studies of the impacts of Elective Transmission Upgrades and generator interconnections, regardless of the point of interconnection.

1.2 Reliability Standards

ISO New England establishes reliability standards for the six-state New England region on the basis of authority granted to the ISO by the Federal Energy Regulatory Commission. Because New England is part of a much larger 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 and the North American Electric Reliability Corporation.

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

- North American Electric Reliability Corporation ("NERC") Reliability Standards for Transmission Planning ("TPLs") which apply to North America. These standards can be found on the NERC website at http://www.nerc.com/page.php?cid=2|20.

- Northeast Power Coordinating Council ("NPCC") 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, Quebec, Canadian Maritimes, New York and New England. These criteria can be found at the NPCC website at: https://www.npcc.org/Standards/Directories/Forms/Public%20List.aspx

- ISO New England Planning and Operating Procedures which apply to the New England transmission system except for the northern section of Maine that is not directly interconnected to the rest of the United States but is interconnected to New Brunswick. These standards can be found at the ISO-NE website at http://www.iso-ne.com/rules_proceds/index.html.

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

- NERC describes the intent of Transmission Planning Standards, its TPLs, 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 criteria as providing a "design-based approach" to ensure the Bulk Power System 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-NE, in its Planning Procedure No. 3 ("PP-3"), describes that the purpose of the New England Reliability Standards is to assure the reliability and efficiency of the New England bulk power supply system through coordination of system planning, design and operation.

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

Section 2
Types of Transmission 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 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 that this does not need to be an independent study but can be 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 ("SIS") Study - study done to determine the system upgrades required to interconnect a new or modified generating facility (See Schedule 22 of the OATT, Section 7 and Schedule 23 of the OATT, Section 3.4), to determine the system upgrades required to interconnect an Elective Transmission Upgrade (See Schedule 25 of the OATT, Section 7), 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 PTF system (See OATT Section II, Attachment K, Section 4)

- Transmission Solutions Study - study done to develop regulated solutions to issues identified in a Transmission Needs Assessment of the PTF system (See OATT Section II, Attachment K, Section 4.2 (b))

- NPCC Area Transmission Review - study to assess Bulk Power System reliability (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, Classification of Bulk Power System Elements)

- 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

- Interregional Study - study involving two or more adjacent regions, for example New York and New England

- 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. (See Schedule 22 of the OATT, Section 6.2 or 7.3 and Schedule 25 of the OATT, Section 6.2 or 7.3)

- 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. This study is done if a System Impact Study for a generator interconnection is not complete. (See Planning Procedure 10, 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 capacity supply obligation. (See Planning Procedure 10, 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 capacity supply obligation. (See Planning Procedure 10, sections 7and 8)

- FCM Delist/Non-Price Retirement Analyses - study of the transmission system done to determine the reliability impacts of delists and retirements. (See Planning Procedure 10, section 7)

- Transmission Security Analyses - deterministic study done to determine the capacity requirements of import constrained load zones. (See Planning Procedure 10, section 6)

- Non-Commercial Capacity Deferral Notifications - study done to determine the reliability impacts of non-commercial capacity deferral notifications. (See Planning Procedure 10, section 11)

Section 3
Transmission Element Ratings

Planning utilizes the following thermal capacity ratings for transmission facilities, as described in ISO-NE Operating Procedure No. 16 Transmission System Data - Appendix A - Explanation of Terms and Instructions for Data Preparation of NX-9A (OP-16A):

- Normal
  Normal is a continuous 24-hour rating

- Long Time Emergency ("LTE")
  LTE is a 12-hour rating in Summer and a 4-hour rating in Winter

- Short Time Emergency ("STE")
  STE is a 15-minute rating

Summer equipment ratings (April 1 through October 31) and Winter equipment ratings (November 1 through March 31) are applied as defined in ISO-NE Operating Procedure 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 ISO New England Planning Procedure 5-3 and in ISO New England Planning Procedure 7: 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 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. Drastic Action Limits are not used in testing the system adequacy in planning studies or for planning the transmission system.

Element ratings are calculated per ISO New England Planning Procedure 7, and are submitted to ISO New England per ISO New England Operating Procedure 16: Transmission System Data.

Section 4
Voltage Criteria

4.1 Overview

The voltage standards used for transmission planning have been established to satisfy three constraints: maintaining voltages on the distribution system and experienced by the ultimate 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. Note: This Transmission Planning Technical Guide does not address voltage flicker or harmonics.

The voltage standards prior to equipment operation apply to voltages at a location that last for seconds or minutes, such as voltages that occur prior to transformer load tap changer ("LTC") operation or capacitor 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.

The voltage standards apply to PTF facilities operated at a nominal voltage of 69 kV or above.

4.2 Pre-Contingency Voltages

The voltages at all PTF buses must be in the range of 0.95-1.05 per unit with all lines in service.

There are two exceptions to this standard. The first is voltage limits at nuclear units, which are described in Section 4.9. The second exception is that 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 as145 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 VAR 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 VAR 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.

4.3 Post-Contingency Low Voltages Prior to Equipment Operation

The lowest post-contingency voltages at all PTF buses must be equal to or higher than 0.90 per unit 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 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.

Also 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.

No contingency defined in Section 12.4 or 12.5 is allowed to cause a voltage collapse.

4.4 Post-Contingency Low Voltages After Equipment Operation

The lowest voltages at all PTF buses must be equal to or higher than 0.95 per unit after the switching of shunt or series capacitors and reactors, and operation of tap changers on transformers, autotransformers, phase-shifting transformers and shunt reactors.

There are two exceptions to this standard. The first is voltage limits at nuclear units. The other exception is that voltages as low as 0.90 per unit are allowed at a limited number of 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 ISO-NE to determine if the second exception applies to any buses in the study area.

4.5 Post-Contingency High Voltages Prior to Equipment Operation

The standard for high voltages prior to corrective action is under development.

4.6 Post-Contingency High Voltages After Equipment Operation

The highest voltages at all PTF buses must be equal to or lower than 1.05 per unit.

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 ISO-NE to determine if the exception applies to any buses in the study area.

4.7 Voltage Limits for 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.

4.8 Transient Voltage Response

NERC is has revised its transmission planning procedures to establish the requirement for transient voltage response criteria. This section will address those criteria once the new requirement becomes effective.

4.9 Voltage Limits at Buses Associated with Nuclear Units

The minimum 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 listed below. These limits apply whether or not the generation is dispatched in the study.

Table 4-1
Nuclear Unit Minimum Voltages

Critical Bus	Minimum Bus Voltage
Millstone 345 kV bus	345 kV
Pilgrim 345 kV bus	343.5 kV
Seabrook 345 kV bus	345 kV
Vermont Yankee 115 kV bus	112 kV[1]

[1] Due to the retirement of Vermont Yankee, the unique minimum voltage limit at Vermont Yankee 345 kV will be eliminated. The unique voltage limit at Vermont Yankee 115 kV will temporarily be 112 kV and will be eliminated within about three years dependent on NRC approval.

The minimum voltage requirements at buses serving nuclear units are provided in accordance with NERC Standard NUC-001 and documented in the appendices to Master Local Control Center Procedure MLCC 1.

Section 5
Assumptions Concerning Load

Load data is included in the power flow cases provided by ISO-NE. The following describes the make-up of the load data in those cases. Appendix J provides additional detail on how the load data is developed for power flow cases.

ISO New England's Planning Procedure 5-3: Guidelines for Conducting and Evaluating Proposed Plan Application Analyses states:

- Disturbances are typically studied at peak load levels in steady-state analysis since peak load levels usually promote more pronounced thermal and voltage responses within the New England Control Area than at other load levels. However, other load levels may be of interest in a particular analysis and, as appropriate, additional studies are conducted.

The following load levels are used in planning studies:

- Peak Load
- Intermediate Load
- Light Load
- Minimum Load

The Report of Capacity, Energy, Loads, and Transmission ("CELT") 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. These loads add approximately 1,464 MW of load that is not included in the CELT load forecast. About 1,100 MW of this is station service load and 364 MW is associated with the manufacturing loads. 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. Also specific large new 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 new load will come to fruition.

When assessing peak load conditions, 100% of the projected 90/10 Summer peak load for the New England Control Area is used. The New England system experiences its peak load in the Summer. The 90/10 Peak Load represents a load level that has a 10% probability of being exceeded due to variations in weather. Summer peak load values are generally obtained from the CELT report. This forecast includes losses of about 8% of the total load, 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 forecast. The peak load level is adjusted for modeling of Demand Resources as discussed in Section 11.8. The target load level for Peak Load is achieved by requesting a case with the 90/10 CELT forecast year and the study year being evaluated.

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 ISO-NE are adjusted to account for these factors. Since actual measured load includes the impacts of distributed resources and distributed generation, no adjustments to ISO-NE 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.

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 (7884 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 of 18,000 MW for Intermediate Load is adjusted to 17,636 MW to properly account for the manufacturing loads.

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 2000 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 of 12,500 MW for Light Load is adjusted to 12,136 MW to properly account for the manufacturing loads.

In a similar fashion, the Minimum Load level was developed by reviewing actual minimum system loads, excluding data associated with significant outages such as after a hurricane. The original intent was to base the load level used on 500 MW increments and the value was rounded down to account for the anticipated impact of continuing energy efficiency programs. The original intent was to model 8,500 MW as the total of CELT load plus manufacturing loads. However, the concept was never clearly documented and most studies have been based on a CELT load of 8,500 MW plus the additional 364 MW of manufacturing load. This has been reviewed and is acceptable and therefore will be carried forward until such time that historic data shows that this value needs revision

Steady-state testing is done at Summer load levels because equipment ratings are lower in the Summer and loads are generally higher. 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. 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. Testing at the 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.

The following table lists the load levels generally used in different planning studies:

Table 5-1
Load Levels Tested in Planning Studies

Study	Peak Load	Intermediate Load	Light Load	Minimum Load
System Impact Study (Steady State)	Yes	Yes	(6)	(1)
System Impact Study (Stability)	Yes	No	Yes	No
PPA Study of Transmission (Steady State)	Yes	(2)	No	(1)
PPA Study of Transmission (Stability)	Yes	No	Yes	No
Transmission Needs Assessment (Steady State)	Yes	(2)	No	Yes
Transmission Needs Assessment (Stability)	Yes	No	Yes	No
Transmission Solutions Study (Steady State)	Yes	(2)	No	Yes
Transmission Solutions Study (Stability)	Yes	No	Yes	No
NPCC Area Review Analyses (Steady State)	Yes	No	No	No
NPCC Area Review Analyses (Stability)	Yes	No	Yes	No

Study	Peak Load	Intermediate Load	Light Load	Minimum Load
BPS Testing (Steady State)	Yes	No	No	No
BPS Testing (Stability)	Yes	No	Yes	No
Transfer Limit Studies (Steady State)	Yes	(3)	No	No
Transfer Limit Studies (Stability)	Yes	No	Yes	No
Interregional Studies	Yes	No	No	No
FCM New Resource Qualification Overlapping Impact Analyses (4)	Yes	No	No	No
FCM New Resource Qualification NCIS Analyses (4)	Yes	No	No	No
FCM Study for Annual Reconfiguration Auctions and Annual CSO Bilaterals (4) (5)	Yes	No	No	No
FCM Delist/Non-Price Retirement Analyses (4)	Yes	No	No	No
Transmission Security Analyses (4)	Yes	No	No	No
Non-Commercial Capacity Deferral Notifications (4)	Yes	No	No	No

(1) Testing at a 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.
(2) It may be appropriate to explicitly analyze intermediate load levels to assess the consequences of generator and transmission maintenance.
(3) Critical outages and limiting facilities may sometimes change at load levels other than peak, thereby occasionally requiring transfer limit analysis at intermediate loads.
(4) These studies are described in ISO New England Planning Procedure No. 10, Planning Procedure to Support the Forward Capacity Market.
(5) 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 ISO New England Planning Procedure No. 10.
(6) Testing at Light Load is done when generation may be limited due to Light Load export limits.

Section 6
Load Power Factor Assumptions

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 decrease in the ability to transfer power from one area to another.

Each transmission owner 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. The following summarizes the methods used by transmission owners within the New England area to set the load power factor values to be used in modeling their systems at the 90/10 Peak Load:

Table 6-1
Power Factor Assumptions

Company	Base Modeling Assumption
Emera Maine (formerly BHE)	Uses Historical Power Factor (PF) values
CMP	Historical metered PF values (Long term studies use 0.955 lagging)
Municipal Utilities	Uses Historical PF values
National Grid	1.00 PF at Distribution Bus
Eversource(Boston) (Formerly NSTAR North)	Individual Station 3 Year Average PF at Distribution Bus
Eversource (Cape Cod) (Formerly NSTAR South)	0.985 lagging PF at Distribution Bus
Eversource (CT,NH,WMA) (Formerly NU)	0.990 lagging PF at Distribution Bus
UI	0.995 lagging PF at Distribution Bus
VELCO	Historical PF at Distribution Bus provided by Distribution Companies

The above power factor assumptions are also used in Intermediate Load and Light Load cases. The power factor at the 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. Boston downtown load fed by Eversource that is set to a power factor of 0.978 lagging at the distribution bus
2. Boston suburban load fed by Eversource this is set to unity power factor at the distribution bus

The non-scaling load includes mill loads in Maine, MBTA loads in Boston, railroad loads in Connecticut and other similar loads.

ISO-NE Operating Procedure 17, Load Power Factor Correction, discusses load power factor and describes the annual survey done to measure compliance with acceptable load power factors.

Section 7
Load Models

7.1 Load Model for Steady-State Analysis

In steady-state studies, loads are modeled as constant MVA loads, comprised of active ("real") P and reactive ("imaginary") Q loads. They are modeled by the Transmission Owners 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.

7.2 Load Model for Stability Analysis

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 NEPOOL report, "Effect of Various Load Models on System Transient Response."

For under frequency 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.

Section 8
Base Case Topology

8.1 Summary of 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, other series and shunt Elements in New England, generators on the New England transmission system, generators on the New England distribution system, 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, 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 System Impact Studies for generation the studies need to include all active generators in the FERC section of the ISO-NE queue that have earlier (higher) queue positions. The starting point for the development of a base case is ISO-NE's Model on Demand database which includes a model of the external system from the Multi-regional Modeling Working Group ("MMWG"). This Model on Demand data base is used to create ISO-NE's portion of the MMWG base case. However, the Model on Demand data base is updated periodically to include updated ratings, updated impedances and newly approved projects. The following table summarizes the topology used in planning studies:

Table 8-1
Base Case Topology

Study	Transmission in New England	Generation in New England (7,8)	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)	In-Service, Under Construction or has an approved PPA	Models from recent Multiregional Modeling Working Group ("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-NE queue (1)	In-Service, Under Construction or has an approved PPA	Models from recent MMWG base case	Models from recent MMWG base case
Transmission Needs Assessment (Steady State)	In-Service, Under Construction, Planned, and Proposed (6)	Has a capacity supply obligation or a binding contract (4)	In-Service, Under Construction, or has an approved PPA; and delivers an import with a capacity supply obligation or a binding contract (4); and has a certain ISD	Models from recent MMWG base case	Models from recent MMWG base case

Study	Transmission in New England	Generation in New England (7,8)	Merchant Facilities	Transmission outside New England	Generation outside New England
Transmission Solutions Study (Steady State and Stability)	In-Service, Under Construction, Planned, and Proposed (6)	Has a capacity supply obligation or a binding contract (4)	In-Service, Under Construction, or has an approved PPA: and delivers an import with a capacity supply obligation 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	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	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	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	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) (4)	In-Service, or Under Construction, Planned, or Proposed with an In Service Date (ISD) certified by the Transmission Owner ("TO")	Existing resources and resources that have a capacity supply obligation	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 TO	Existing resources and resources that have a capacity supply obligation	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

Study	Transmission in New England	Generation in New England (7,8)	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 TO	Existing resources and resources that have a capacity supply obligation	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/Non-Price Retirement Analyses (5)	In-Service or Under Construction, Planned, or Proposed with an ISD certified by the TO	Existing resources and resources that have a capacity supply obligation	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 TO	Existing resources and resources that have a capacity supply obligation	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 TO	Existing resources and resources that have a capacity supply obligation	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 capacity supply obligations in the Forward Capacity Market are included in PPA Studies.
(2) Some interregional studies may include facilities that do not have approved Proposed Plan Applications.
(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 4.2 of Attachment K describes that resources that are bound by a state-sponsored RFP or financially binding contract are represented in base cases.
(5) These studies are described in ISO New England Planning Procedure No. 10, 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 considered to be retired in the year associated with their Non-Price Retirement Request and in subsequent years.
(8) In Transmission Needs Assessments and Transmission Solutions Studies, additional generators are often considered unavailable. Generators that have a rejected Permanent De-list bid are considered unavailable (See Attachment K 4.1.c). Also, generators that have delisted 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.

8.2 Modeling Existing and Proposed Generation

Generating facilities 5 MW and greater are listed in 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 or as the equivalent of multiple units, or are 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.

8.3 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.

Section 2.3 of Schedule 22 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.

Sections 6.2 and 7.3 of Schedule 22 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.

8.4 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 Needs Assessment, a 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.

8.5 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. Sensitivity studies are 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 PAC meetings in determining the manner in which sensitivity results are factored into studies. Examples are resources that may be retired or 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.

8.6 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. Sections 6.2 and 7.3 of Schedule 22 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 1001would be done with 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.

Section 9
Generator Ratings

9.1 Overview of Generator Real Power Ratings

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 the table below. The detailed definitions of these ratings are included in Appendix A. CNRC and NRC values for New England generators are published each year in the CELT (Capacity, Energy, Loads, & Transmission) Report.[1] QC values are calculated based on recent demonstrated capability for each generator. The Capacity Supply Obligation value and QC values are published for each Forward Capacity Auction in the informational results filings to FERC.[2]

Table 9-1
Generator Real Power Ratings

Capacity Network Resource Capability ("CNRC") – Summer- (maximum output at or above 90 degrees Fahrenheit)	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 degrees Fahrenheit
Capacity Network Resource Capability ("CNRC") - Winter (maximum output at or above 20 degrees Fahrenheit)	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 degrees Fahrenheit
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 ("NRC") -Summer (maximum output at or above 50 degrees Fahrenheit)	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 degrees Fahrenheit
Network Resource Capability ("NRC") –Winter (maximum output at or above 0 degrees Fahrenheit)	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 degrees Fahrenheit
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

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

[1] http://www.iso-ne.com/trans/celt/index.html

[2] http://www.iso-ne.com/regulatory/ferc/filings/index.html

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 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-NE 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.

9.2 Generator Ratings in Steady-State Needs Assessments, Solutions Studies, and NPCC Area Review Analyses

The Summer Qualified Capacity value is used to represent a machine's maximum real power output (MW) for all load levels studied except for Light Load (when applicable) and Minimum Load Studies. QC is used in these studies because QC represents the recently demonstrated capability of the generation. The QC value is the maximum Capacity Supply Obligation that a resource may obtain in the Forward Capacity Market. Any requested reduction in obligation from a resource's QC is subject to a reliability review and may be rejected for reliability reasons. The Capacity Network Resource Capability acts as an approved interconnection capability cap within the Forward Capacity Market that limits how much a resource could increase its QC without an Interconnection Request. In other words, QC cannot exceed CNRC. Because QC corresponds to the recently demonstrated capability, as opposed to CNRC which is the upper limit of the capacity capability of a resource, using QC instead of CNRC does not overstate the amount of capacity that could potentially be obligated to provide capacity to the system.

For reliability analysis conducted at Light Load and Minimum Load Levels, the generator's Summer NRC value (maximum MW output at or above 50 degrees) is used. Some generators have higher individual resource capabilities at 50 degree ratings compared with 90 degrees. Therefore, using 50 degree ratings allows a smaller number of resources to be online to serve load. The fewer the number of resources online, the less overall reactive capability on the system to mitigate high voltage concerns. This value is also consistent with the expected ratings of machines at the temperatures that are typically experienced during lighter load periods in the Summer rating period.

9.3 Generator Ratings in PPA Studies and System Impact Studies

The generator's Summer NRC value is used to represent a machine's maximum real power output (MW) for all load levels. For generator System Impact Studies, using this value 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 to the system due to a project.

9.4 Generator Ratings in Stability Studies

The generator's Winter NRC value is used to represent a machine's maximum real power output (MW) for all load levels in all stability studies. Using the Winter NRC values ensures that stressed dispatches (in terms of limited inertia on the system and internal generator rotor angles) are studied and addressed, therefore ensuring reliable operation of the system in real-time. This operability is required because real-time power system analysis is unable to identify stability concerns or determine stability limits that may exist on the system. These limits are determined in offline operational studies performed in a manner that ensures that they are applicable over a wide range of system conditions, including various ambient temperatures and load levels.

9.5 Generator Ratings in 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 NCIS Analyses. This output represents the level of interconnection service that a generator has obtained for providing energy.

The generator's Summer QC value is used to represent a machine's maximum real power output (MW) for FCM Delist/Non-Price Retirement 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. This output represents the expected capacity capability of a generator during Summer peak periods.

9.6 Generator Reactive Ratings

This section is under development.

Section 10
Generators Out of Service in Base Case

In Transmission Needs Assessments and Transmission Solutions Studies, generally two generation resources are considered out of service in the study area. These resources can be individual generators or interdependent generating facilities such as combined-cycle units (see section 11.9). The most impactful generators, those whose outage creates the greatest stress on the portion of transmission system under study, are considered out of service. Identifying the most impactful generators may in itself require some analysis. Additional generators could be considered to be out of service if the area under study has a large population of generators or if examining Intermediate, Light or Minimum Load maintenance conditions. Often multiple base cases are required to assess the impact of different combinations of generators being out of service. In general, having several generators out in a base case addresses issues such as the following:

- Higher generator forced outage rates than other transmission system Elements
- Higher generator outages and limitations during stressed operating conditions such as a heat wave or a cold snap
- Past experience with simultaneous unplanned outages of multiple generators
- High cost of Reliability Must Run Generation
- Generator maintenance requirements
- Unanticipated generator retirements
- Fuel shortages

In some of the other transmission planning studies listed in Section 2, the most impactful single generators are considered out of service in the base cases and other generators may be turned off in order to create system stresses. For example, in FCM overlapping impact studies, the system is stressed by assuming that the most impactful helper is out of service. The most impactful helper is the generator that, when placed in service at its full output, will result in the most significant reduction in the flow on the limiting element.

Section 11
Determination of Generation Dispatch in Base Case

11.1 Overview

Different types of studies are conducted to achieve different transmission planning objectives. Therefore, it is necessary to consider the different range of anticipated generator capabilities which are appropriate to the objectives of study and the specific conditions which are being examined.

11.2 Treatment of Different Types of Generation

The following table lists the maximum generation levels generally used in different planning studies. Generators, when dispatched, are usually dispatched up to their maximum output in a study.

Table 11-1
Generator Maximum Power Output in Planning Studies

Study	Conventional Generation	Fast Start Generation	Hydro (1) Generation	Wind Generation	Solar Generation (3)
System Impact Study (Steady State)	Summer NRC	Summer NRC	Summer NRC	Summer NRC	Summer NRC
System Impact (Stability)	Winter NRC	Winter NRC	Winter NRC	Winter NRC	Winter NRC
PPA Study of Transmission (Steady State)	Summer NRC	Summer NRC	Summer NRC	Summer NRC	Summer NRC
PPA Study of Transmission (Stability)	Winter NRC	Winter NRC	Winter NRC	Winter NRC	Winter NRC
Transmission Needs Assessment (Steady State)	Summer QC	Summer QC	Historical Level	5% of nameplate for on-shore wind (2)	Summer QC
Transmission Solutions Study (Steady State)	Summer QC	Summer QC	Historical Level	5% of nameplate for on-shore wind (2)	Summer QC
Transmission Solutions Study (Stability)	Winter NRC	Winter NRC	Winter NRC	Winter NRC	Winter NRC
Area Review Analyses (Steady State)	Summer NRC	Summer NRC	Summer NRC	Summer NRC	Summer NRC
Area Review Analyses (Stability)	Winter NRC	Winter NRC	Winter NRC	Winter NRC	Winter NRC
BPS Testing Analyses (Steady State)	Summer NRC	Summer NRC	Summer NRC	Summer NRC	Summer NRC
BPS Testing Analyses(Stability)	Winter NRC	Winter NRC	Winter NRC	Winter NRC	Winter NRC
Transfer Limit Studies (Steady State)	Summer NRC	Summer NRC	Summer NRC	Summer NRC	Summer NRC
Transfer Limit Studies (Stability)	Winter NRC	Winter NRC	Winter NRC	Winter NRC	Winter NRC

(1) Table lists treatment on conventional hydro. The treatment of pumped storage hydro is described in Section 11.5.
(2) 20% of the nameplate for off-shore wind.
(3) Table lists treatment of solar generation 5 MW or greater that is in the ISO system model. See Section 11.7 for a complete description of treatment of solar generation.

Study	Conventional Generation	Fast Start Generation	Hydro (1) Generation	Wind Generation	Solar Generation (3)
Interregional Studies	Summer NRC	Summer NRC	Summer NRC	Summer NRC	Summer NRC
FCM New Resource Qualification Overlapping Impact Analysis	Summer CNRC	Summer CNRC	Summer CNRC	Summer CNRC	Summer CNRC
FCM New Resource Qualification Network Capacity Interconnection Standard Analyses	Summer NRC	Summer NRC	Summer NRC	Summer NRC	Summer NRC
FCM Delist/Non-Price Retirement Analyses	Summer QC	Summer QC	Summer QC	Summer QC	Summer QC
FCM Study for Annual Reconfiguration Auctions and Annual CSO Bilaterals	Lower of Summer QC or CSO	Lower of Summer QC or CSO	Lower of Summer QC or CSO	Lower of Summer QC or CSO	Lower of Summer QC or CSO
Transmission Security Analyses	Summer QC	Summer QC	Summer QC	Summer QC	Summer QC
Non-Commercial Capacity Deferral Notifications	Lower of Summer QC or CSO	Lower of Summer QC or CSO	Lower of Summer QC or CSO	Lower of Summer QC or CSO	Lower of Summer QC or CSO

(1) Table lists treatment on conventional hydro. The treatment of pumped storage hydro is described in Section 11.5.
(2) 20% of the nameplate for off-shore wind.
(3) Table lists treatment of solar generation 5 MW or greater that is in the ISO system model. See Section 11.7 for a complete description of treatment of solar generation.

11.3 Treatment of Wind Generation

Studies of wind generation in New England reveal that the output of on-shore (land-based) wind generation can be very low during Summer peak load hours.[3] In general, when it is needed to support area transmission requirements, on-shore wind generation is modeled at 5% of nameplate and off-shore wind is modeled at 20% of nameplate for Needs Assessment and Solutions Studies. If a wind farm's Qualified Capacity is lower than the above value, the Qualified Capacity will be used in Needs Assessments and Solutions Studies.

The above percentages are estimates of the level of wind generation output that can be counted on during Summer peak for reliability analysis. To ensure that the interconnection rights of wind resources are preserved, wind generation is modeled at its NRC value in PPA studies.

11.4 Treatment of Conventional Hydro Generation

There are two classifications of conventional hydro, those hydro facilities that have no control over water flow, for example no capability to store water, and those hydro facilities that can control water flow, for example those facilities with a reservoir or river bed that can store water. For the purpose of planning studies, hydro facilities listed as "hydro (weekly cycle)" or "hydro (daily cycle-pondage)" in the CELT report are considered to be able to control water flow. Hydro facilities listed as "hydro (daily cycle-run of river)" in the CELT report, are assumed to have no ability to control water flow and are classified as intermittent resources. Hydro facilities that can control water flow are classified as non- intermittent

[3] This was discussed at the Planning Advisory Committee meetings on September 21, 2011 and October 22, 2014.

resources. For both classifications the output of the hydro generation is set at its historic capability that can be relied on for reliability purposes or at 10% of nameplate, which is an estimate of that historic capability, in the base cases for Needs Assessments and Solutions Studies. Post contingency, conventional hydro that has the capability to control water flow and has sufficient water storage capability is dispatched up to 100% of its nameplate to relieve criteria violations in Needs and Solutions Analysis. Hydro facilities that have no control over water flow or limited water storage capability are dispatched at the same output pre and post contingency.

11.5 Treatment of Pumped Storage Hydro

There are three pumped storage-hydro plants connected to the New England Transmission System: Northfield Mountain and J. Cockwell (also known as Bear Swamp) in Massachusetts and Rocky River in Connecticut. Records indicate that these facilities historically have had limited stored energy during prolonged heat waves because limited time and resources are available to allow these units to refill their reservoirs during off-peak periods. Additionally J. Cockwell and Northfield are often used to provide reserve capacity. Based on this, the following generation levels are generally used in Needs Assessments and Solutions Studies.

Table 11-2
Pumped Storage Hydro Generation Levels

Generating Facility	MW Output
J. Cockwell	50% of Summer QC
Northfield Mountain	50% of Summer QC
Rocky River	Treated as conventional hydro with ponding capability

In Needs Assessments and Solutions Studies addressing the area that includes a pumped storage-hydro facility, the pumped storage-hydro facility in that area may also be dispatched at their maximum and/or minimum values to ensure that they can be utilized to serve load when they are available since they are often utilized in operations to provide reserve. In PPA studies, pumped storage-hydro plants are dispatched at their full output when necessary to show that their ability to supply load is maintained.

11.6 Treatment of Fast Start Generation

Fast start units are generally used as reserve for generation that has tripped off line, for peak load conditions, and to mitigate overloads or unacceptable voltage following a contingency, N-1 or N-1-1. Based on operating experience and analysis, 80% of fast start units in the study area are assumed to be available. However, it is not appropriate to rely on any one specific fast start unit as the solution to an overload.

For the purpose of transmission planning studies, fast start units are those combustion turbines or diesel generators that can go from being off line to their full Seasonal Claimed Capability in 10 minutes. A list of fast start units has been developed by reviewing market information such as notification times, start times and ramp rates. The list is included as Appendix B in the guide. The capacity included in the list is from Forward Capacity Auction 8. The capacity of any generator may have changed and needs to be confirmed. The unit does not need to participate in the 10-minute reserve market to be considered a fast start unit in planning studies.

For the steady-state portion of Transmission Needs Assessments and Solutions Studies at peak load, the fast start units can be turned on in the base cases. When using this approach, criteria violations that can be mitigated by turning off fast start generation can be disregarded.

For Transmission Needs Assessments and Solutions Studies at Intermediate or Light load level, fast start units are turned off in the base cases and turned on to mitigate post-contingency criteria violations.

One exception to the above is that fast start generation in Vermont is not dispatched in the base case in Needs Assessments and Solutions Studies due to their past poor performance, but they are may be turned on between the first and second contingency.

11.7 Treatment of Solar Generation

Solar generation will be represented in the power flow base cases that are provided by ISO-NE. ISO-NE includes a solar PV forecast in its annual CELT Report. This forecast includes the solar PV that has been installed as of the prior year as well as provides a forecast by state of the total PV (by AC Nameplate) that is expected to be in-service by the end of each forecast year for the next 10 years. As an example the 2015 PV forecast provides the PV that is in-service as of the end of 2014 as well as provides an annual forecast for the PV that will be in-service for end of 2015, end of 2016 and so on until the end of 2024.

The solar PV forecast is a part of the CELT Report and can be found at:

http://www.iso-ne.com/system-planning/system-plans-studies/celt

As a part of the 2015 PV forecast the data on solar PV was divided into the following four mutually exclusive groups:

1. PV as a capacity resource in the Forward Capacity Market (FCM)
   - Qualified for the FCM
   - Have capacity supply obligations
   - Size and location identified and visible to the ISO
   - May be supply or demand side resources
2. Non-FCM Settlement only Resources (SOR) and Generators (per OP-14)
   - ISO collects energy output
   - Participate only in the energy market
3. Behind-the-Meter (BTM) PV Embedded in Load (BTMEL)
   - 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
   - The portion of BTM that is captured in the historical load forecast and can be estimated via reconstitution of hourly historical BTM PV production
4. Behind-the-Meter (BTM) PV Not Embedded in Load (BTMNEL)
   - 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
   - The portion of BTM that is not captured in the historical load forecast (i.e., not embedded)

Of the four groups, the Behind-the-Meter PV Embedded in Load is already embedded in the CELT forecast and hence will not be modeled explicitly in any studies. The remaining three groups need to be considered when accounting for solar PV in studies.

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 that are not already included as part of the load forecast:

- PV as a capacity resource in FCM
- Settlement only Resources and Generators
- Behind-the-Meter PV Not Embedded in Load (BTMNEL)

The solar PV forecast only forecasts the PV values on a state-wide basis. However, within a state the PV does not grow uniformly, with some areas in the state having larger amounts of PV. To account for this locational variation of PV, the locational data of existing PV that is in-service as of the end of 2014 was utilized to obtain the percentage of PV that is in each dispatch zone. New England is divided into 19 dispatch zones and the percentage of PV in each dispatch zone as a percentage of total PV in the state is available. This percentage is assumed to stay constant for future years to allocate future PV to the dispatch zones. The percentage of existing solar 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 and the materials are located at:

http://www.iso-ne.com/system-planning/system-forecasting/distributed-generation-forecast

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

Once we have the solar PV data by dispatch zone the PV within the dispatch zone falls into three categories:

- Category 1 : Units greater than 5MW:
  - Location data available
  - Will be modeled as an individual generators
- Category 2 : Units greater than 1 MW and less than 5 MW
  - Location data available through the PPA notifications
  - Needs to be modeled as injections at specific locations – Negative loads similar to DR
- Category 3: Units below 1 MW
  - No location data available
  - Needs to be modeled by spreading the MWs across the dispatch zone – Negative loads similar to DR and spread across the load zone/dispatch zone like DR is spread

For PV in categories 2 and 3 the PV will be modeled as negative loads at the buses.

Load Levels at which PV will be modeled

For shoulder, light and minimum load levels the ISO uses fixed load levels for studies based on historic data, which already includes the impacts of PV. Hence, no PV in Category 2 or 3 will be explicitly modeled in shoulder, light and minimum load cases. The Winter peak conditions are expected after sunset and hence no solar PV in Category 2 or 3 will be modeled for Winter peak cases. The only case where PV under category 2 and 3 will be explicitly modeled is for Summer peak load conditions.

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

Further, since the PV data is available only as end of year installed AC nameplate, long term planning studies will use the forecast for the end of the year prior to that being evaluated. As an example for a study in the year 2018, all the PV as of end of 2017 will be modeled.

Adjustment for Losses

For PV in categories 2 and 3 an adjustment to the AC nameplate PV will need to be made to account for avoided losses on the distribution system. Currently, the ISO assumption for distribution losses as a percentage of load is 5.5%. Hence the negative loads will be the AC nameplate load at the bus + 5.5% avoided distribution losses.

Modeling Solar Generation in Transmission Planning

Based on a review of historic PV outputs ISO Transmission Planning has determined a 26% availability factor to be appropriate for transmission planning studies. The 26% level represents the output of solar generation during the peak load period between 4 p.m. and 6 p.m. in the Summer. This is the time period when solar output begins to go down due the angle of the sun and when loads are still at or near the peak level.

The PV in categories 2 and 3 will be assumed to be at 26% output for Needs Assessments and Solutions Studies. For transmission PPA studies and generation system impact studies, the PV in Category 2 and 3 may be assumed to be up to 100% available.

For Needs and Solutions studies the Category 1 PV will be modeled at 26% of their nameplate rating (50 degree rating) for peak load studies. For all other load levels the Category 1 PV generators will be modeled based on the study specific requirements. For transmission PPA studies and generation system impact studies, the Category 1 PV will be treated consistent with the treatment of conventional generators.

Modeling Solar Generation in FCM Studies (including the Transmission Security Analyses and Non-Commercial Capacity Deferral Notifications)

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

Forecasting Solar PV beyond the Solar PV forecast

Occasionally, transmission planning studies have to look beyond the 10 year PV forecast horizon. For these cases the growth of PV forecast from year 9 to year 10 will be used to obtain the year 11 PV forecast. This process will be repeated to obtain year 12 PV forecast from year 11 PV forecast and year 10 PV forecast and so on.

Solar Impacts on Power Factor

Solar generation will be represented in peak power flow cases such that it does not affect the net power factor of the load. It is assumed that distribution companies will adjust their power factor correction programs to account for solar generation. At peak load levels, solar generation generally should reduce distribution VAR losses, therefore modeling solar power such that it does not impact net load power factor should be a slightly conservative approach. If no load is present at the bus then a unity power factor will be assumed.

11.8 Treatment of Demand Resources

Through the Forward Capacity Market, Demand Resources (“DR”) can be procured to provide capacity and have future commitments similar to that of a generator. There are currently two categories of DR in the FCM: Passive Demand Resources (“Passive DR”) and Active Demand Resources (“Active DR”). Passive DR consists of two types of Resources: On-Peak and Seasonal Peak. Active DR reduces load based on ISO-NE instructions under real-time system conditions. Active DR consists of Real-Time Demand Response resources (“RTDR”) and Real-Time Emergency Generation resources (“RTEG”). After June 2017, RTDR will be replaced with Demand Response Capacity Resources (“DRCR”). 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 DR is included for studies that analyze time periods beyond the FCM horizon.

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 Analyses”.

Demand Resources will not be modeled explicitly in the fixed load level cases representing shoulder, light and minimum loads, because the impact of Demand Resources was included in the actual measured load used to establish the fixed load levels (see Section 5, “Assumptions Concerning Load”).

11.9 Treatment of 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. ISO New England’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.

11.10 Generator Dispatch in Stability Studies

At both Peak and Light load levels, generators are modeled at highest gross (maximum) MW output at 0^0 F or higher. Generators are generally dispatched either “full-on” at maximum capability, or “full-off.” If transmission transfers need to be adjusted, then the following is done:

- First, generators are re-dispatched by simulating them “full on” or “off”
- Second, adjust generators, if necessary, least critical to study results to obtain desired transfers (“off” or as close to “full on” as possible).

This is done to obtain generators’ maximum stressed internal angles in order to establish a stability limit under worst-case conditions. Generator reactive dispatch must also be considered for generators being evaluated for stability performance. Pre-fault reactive output is based on the Light Load voltage schedule in Operating Procedure OP-12.

Section 12
Contingencies

12.1 Basis for Contingencies Used in Planning Studies

The 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 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 contingencies 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 Long Time Emergency Rating is used as the emergency thermal limit. The Short Time Emergency Rating may be used as the emergency thermal limit when an area is exporting if generation can be dispatched lower to mitigate overloads. The Short Time Emergency Rating may be used as the emergency thermal limit in areas where phase-shifting transformers can be used to mitigate overloads. Voltage limits are discussed earlier in this guide.

Contingencies 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 contingencies

Planning criteria allow certain adjustments to the transmission system between the two initiating causes resulting in N-1-1 contingencies as described in Section 12.5.

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.

12.2 Contingencies in Steady-State Analysis

NERC and/or NPCC require that the New England Bulk Power System 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 Sections 12.4 and 12.5.

12.3 Contingencies in Stability Analysis

NERC and NPCC require that the New England Bulk Power System shall remain stable and damped and the Nuclear Plant Interface Coordinating Standard (NUC-001-2 approved August 5, 2009) shall be met. This requirement must be met during and following the most severe of the contingencies stated below "With Due Regard to Reclosing", and before making any manual system adjustments. 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.

New England's planning criteria defines a unit as maintaining stability when it meets the damping criteria in Appendix C of ISO-NE Planning Procedure No. 3 (also included as Appendix D to this guide). New England also uses the voltage sag guideline, which is included as Appendix E to this guide, to determine if it may be necessary to mitigate voltage sags.

Consistent with Operating Procedure OP-19, New England's planning procedures require generator unit stability for all Normal Design Contingencies as defined in Planning Procedure PP-3. 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 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 Attachment G to the ISO-NE Tariff. The low limit of 1,200 MW has historically been used for Design Contingencies in New England.

Table 12-1
Protection Modeling in Stability Studies

Station Type	Fastest Protection System Modeling for Normal Design Contingencies	
	Fastest Protection System In-Service	Fastest Protection System Out-of-Service
BPS	Not Tested	Tested
Non-BPS	Tested	Not Tested

12.4 N-1 Contingencies

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

a. A permanent three-phase fault with Normal Fault Clearing on any:
   - Generator
   - Transmission circuit
   - Transformer
   - Bus section
   - Series or shunt compensating device

b. Simultaneous permanent phase-to-ground faults on:
   - Different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower, with Normal Fault Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition and other similar situations can be excluded from ISO-NE testing on the basis of acceptable risk, provided that the ISO approves the request for an exclusion. For exclusions of more than five towers, the ISO and the NPCC Reliability Coordinating Committee need to specifically approve each request for exclusion.
   - Any two circuits on a multiple circuit tower

c. A permanent phase-to-ground fault, with Delayed Fault Clearing, on any:
   - Transmission circuit
   - Transformer
   - Bus section

   This Delayed Fault Clearing could be due to malfunction of any of the following:
   - Circuit breaker
   - Relay system
   - Signal channel

d. Loss of any Element without a fault (See Section 12.7)

e. A permanent phase-to-ground fault in a circuit breaker, with Normal Fault Clearing. (Normal Fault Clearing time for this condition may not be high speed.)

f. Simultaneous permanent loss of both poles of a direct current bipolar facility without an ac fault

g. The failure of any Special Protection System which is not functionally redundant to operate properly when required following the contingencies listed in "a" through "f" above.

h. The failure of a circuit breaker to operate when initiated by an SPS following: loss of any Element without a fault: or a permanent phase to ground with Normal Clearing, on any transmission circuit, transformer or bus section.

12.5 N-1-1 Contingencies

NERC and/or NPCC require that the N-1-1 contingencies 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 of events:

a. Loss of a generator

b. Loss of a series or shunt compensating device

c. Loss of one pole of a direct current bipolar facility

d. Loss of a transmission circuit

e. Loss of a transformer

Following the first initiating event, generation and power flows are adjusted in preparation for the next initiating event using units capable of ten-minute reserve, generator runback, generator tripping, phase angle regulators and high-voltage direct-current controls, transformer load tap changers, and switching series and shunt capacitors and reactors. Generator adjustments must not exceed 1,200 MW. The second events tested must include all of the contingencies in Section 12.4.

12.6 Extreme Contingencies

Consistent with NERC and NPCC requirements, New England tests extreme contingencies. This assessment recognizes that the New England transmission system can be subjected to events that exceed in severity the contingencies listed in Section 12.4 and 12.5. Planning studies are conducted to determine the effect of the following extreme contingencies on New England bulk power supply 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.

a. Loss of the entire capability of a generating station.

b. Loss of all transmission circuits emanating from a:
   - Generating station
   - Switching station
   - DC terminal
   - Substation (either all circuits at a single voltage level, or all circuits at any voltage level)

c. Loss of all transmission circuits on a common right-of-way.

d. Permanent three-phase fault on any:
   - Generator
   - Transmission circuit
   - Transformer or bus section

   with Delayed Fault Clearing and with due regard to reclosing

   This Delayed Fault Clearing could be due to malfunction of:
   - Circuit breaker
   - Relay system
   - Signal channel

e. The sudden dropping of a large load or major load center

f. The effect of severe power swings arising from disturbances outside of New England

g. Failure of a Special Protection System to operate when required following the normal contingencies listed in "a" through "f"

h. The operation or partial operation of a Special Protection System for an event or condition for which it was not intended to operate

i. Common mode failure of the fuel delivery system that would result in the sudden loss of multiple plants (i.e., gas pipeline contingencies, including both gas transmission lines and gas mains)

The following responses are considered unacceptable responses to an extreme contingency involving a three phase fault with Delayed Clearing 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, 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. 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 as Appendix F to this guide.

12.7 Line Open Testing

The requirement to evaluate a no-fault contingency (sometimes thought of as the opening of one terminal of a line) as a contingency event in transmission studies is described below. Additional detail is provided in the white paper that is included as Attachment H to this guide.

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

1. NERC BES facilities:
    a. Single contingency testing (N-1) - Evaluate the opening of the terminal of a line, independent of the design of the termination facilities.

    b. First or Second contingency in N-1-1 testing – Not required

2. NPCC BPS and New England PTF facilities:
    a. Single contingency testing (N-1) – Evaluate the opening of a single circuit breaker.

    b. Second contingency in N-1-1 testing – Evaluate the opening of a single circuit breaker as the second contingency, not as the first contingency in the pair

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

1. If voltage is within acceptance criteria and power flows are within the applicable emergency rating, operator action can be assumed as a mitigating measure.

2. 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 (“SPS”) 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 SPSs when evaluating this no fault contingency. An SPS may not operate for a line end open condition if its triggers are not satisfied, or may operate inappropriately if its triggers are satisfied but only one terminal of a line is open.

Generally, in New England, opening 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 13
Interfaces/Transfer Levels To Be Modeled

13.1 Overview

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.

It is important to note that study assumptions used for interface transfer level analysis must always be coordinated with generator outage assumptions. Specifically, unit unavailability is only relevant to generation inside the boundaries of a specific local study area. On the other hand, interface transfer levels are adjusted to target levels by only varying generation resources outside the boundaries of the local study area. This approach ensures interface transfer levels are tested at appropriate levels while maintaining a disciplined approach to unit unavailability consideration.

13.2 Methodology to Determine Transfer Limits

In response to NERC standard FAC-013-2, the ISO documented the methodology used to determine transfer limits. This document has been updated to reference this Guide and is included as Appendix I.

13.3 Modeling Assumptions – System Conditions

NPCC's Regional Reliability Reference Directory #1 requires in Section 5.1.1 - Design Criteria, that planning entities include modeling of conditions that "stress" the system when conducting reliability assessments:

> "Design studies shall assume power flow conditions utilizing transfers, load and generation conditions that stress the system. Transfer capability studies shall be based on the load and generation conditions expected to exist for the period under study. All reclosing facilities shall be assumed in service unless it is known that such facilities will be rendered inoperative."

ISO-NE's Planning Procedure PP 3, " Reliability Standards for the New England Area Bulk Power Supply System" also states in Section 3 - Area Transmission Requirements, that studies be conducted assuming conditions that "reasonably stress" the system:

> "With due allowance for generator maintenance and forced outages, design studies will assume power flow conditions with applicable transfers, load, and resource conditions that reasonably stress the system. Transfers of power to and from another Area, as well as within New England, shall be considered in the design of inter-Area and intra-Area transmission facilities."

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

Additionally, these requirements are confirmed by ISO-NE's PP5-3, "Guidelines for Conducting and Evaluating Proposed Plan Application Analysis," which sets forth the testing parameters for the required PPA approval under Section I.3.9 of ISO-NE's 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.

13.4 Stressed Transfer Level Assumptions

The system is designed to preserve existing range of transfer capabilities. This is a requirement defined in ISO-NE Planning Procedure PP 5-3, the Reliability Standards for the New England Area Bulk Power Supply System 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. The most recent update of these studies now shows the need to move power from west to east, even prior to consideration of the retirement of Salem Harbor station in 2014.

13.5 Transfer Level 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.
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 following procedure is used when conducting system reliability assessments:

For the steady-state studies, the relevant interface transfer levels need to be determined up front for each dispatch in Needs Assessment studies. Solutions Study transfer levels are tested with the same transfer levels as tested in any associated Needs Assessment study as well as additional variations in transfer levels as determined to be appropriate to demonstrate that solution alternatives have not adversely affected any existing interface transfer capabilities.

In the past, Needs Assessments supported by ISO New England included base case conditions that simulated local generation outages simultaneously with power exports from New England to other Areas, such as New York. Simulation results that failed to meet system performance criteria (typically steady state thermal and voltage) would identify base case and contingency related system needs to be addressed.

In November, 2013, the ISO revised its practice with respect to Needs Assessments and Solutions Studies. Needs Assessments (steady state and dynamics) no longer model power exports to other Areas (New York, New Brunswick, and Quebec) in the base case conditions and N-1 contingency analysis 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, such as certain power exports across the Cross Sound Cable, which will be modeled with 100 MW from New England to Long Island due to the Administrative Export De-list bid associated with Bear Swamp.

However, testing required by NPCC Document A-10, Classification of Bulk Power System elements, as part of a Needs Assessment must consider the full range of potential operating conditions and therefore will continue to consider conditions where New England is exporting to other Areas.

Even with this decision by the ISO, planned system changes still need to respect Section I.3.9 of the Tariff, generally referred to as the PPA process. As part of the I.3.9 evaluation, the applicant must demonstrate that any proposed system changes do not have a significant adverse effect upon the reliability or operating characteristics of the Transmission Owner's transmission facilities, the transmission facilities of another Transmission Owner, or the system of a Market Participant, the Market Participant or Transmission Owner. In carrying out these responsibilities, testing must demonstrate that the project has not reduced transfer capability from pre-project levels.

Transfer level modeling when conducting a Needs Assessment are based on the dispatch conditions within the study area such that the transfer level = local load – local generation. The local area generation dispatch assumptions are consistent with stressed system modeling unit availability assumptions and provide the basis for the transfer level expected to exist for the area under study.

Transfer level modeling for Solutions Studies, in addition to modeling conditions as studied in any associated Needs Assessments, also includes modeling of system conditions that evaluate the ability to dispatch units with a capacity supply obligation within an area under heavy load conditions. ISO-NE may also determine that additional transfer level variations need to be tested in order to demonstrate that there is no adverse impact to existing interface transfer capabilities associated with any proposed solution alternatives.

Transfer level modeling for those cases in which more than one coincident interface (i.e. surrounding interfaces rather than an interface internal to the study area) can impact a study area is based on a set of transfer level combinations that includes the maximum and minimum values for each interface. This includes situations where the interface limits are not independent and for which simultaneous limits have been identified. For example, study of the Greater Boston area would consider the Boston Import interface as internal to the study and the North-South, SEMA/RI and East-West as coincident interfaces. Modeling of the Boston interface would be based on the procedures as described above. Modeling of the North-South, SEMA/RI and East-West interfaces would include those levels as shown in the table below.

Testing of coincident interfaces includes interface transfers modeled at high as well as low transfer levels. High transfer levels are modeled as close as possible to the defined maximum for an interface and low values are modeled as close as possible to the defined minimum for an interface. For example, if three interfaces can all affect a study area there will be eight variations in interface levels such that all combinations are tested:

Table 13-1
Example of Modeling Interface Flows in Planning Studies

Interface 1	Interface 2	Interface 3
High	High	High
High	High	Low
High	Low	High
High	Low	Low
Low	Low	High
Low	High	Low
Low	High	High
Low	Low	Low

If specific transfer level combinations cannot be achieved due to load and/or dispatch constraints an explanation of the conditions that prevented testing of the combination is provided.

Section 14
Modeling Phase Angle Regulators

The modeling of each Phase Shifting Transformers (Phase Angle Regulators) is described in ISO New England's ***Reference Document for Base Modeling of Transmission System Elements in New England.*** This document is located in the ISO New England Planning Procedures subdirectory of the Rules & Procedures directory, on the ISO New England web site and is included as Appendix G to this guide. Modeling of phase shifting transformers in power flow studies is also addressed in Section 26.

Phase Shifting Transformers 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.

- The Saco Valley / Y138 Phase Shifter is located along the New Hampshire – Maine border, and is used to control 115 kV tie flow along the Y138 line into central New Hampshire

- The Sandbar Phase Shifter is located along the Vermont – New York border, and is used to control power flow into the northwest Vermont load pocket from northeast New York

- The Blissville Phase Shifter is located along the Vermont – New York border, and is mainly used to prevent overloads on the New York side

- The Granite Phase Shifters are located in Vermont and are mainly used to control flow on the 230 kV line between New Hampshire and Vermont

- The three Waltham Phase Shifters and the two Baker Street Phase Shifters are located in the Boston, Massachusetts area. They are adjusted manually to regulate the amount of flow into and through Boston. One of the Waltham Phase Shifters will be removed as part of the Greater Boston project.

- The Sackett Phase Shifter is located in southwest Connecticut and will be replaced by a series reactor at Mix Avenue in late 2017. It is run in manual mode only and is normally set in the Raise 3 Tap Position (1,875^{o}) which tends to draw power from Grand Avenue towards Mix Avenue Substation.

- The Northport/Norwalk Harbor Cable (NNC) Phase Shifter, located at LILCO's Northport station (controlled by Long Island Power Authority) is used to control the power flow on the Norwalk Harbor – Northport 601, 602, and 603 submarine cables

Section 15
Modeling Load Tap Changers

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 voltages and 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. Modeling of transformer load tap changers in load flow studies is also addressed in Section 26.

Section 16
Modeling Switchable 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 4.

Modeling of switchable shunt devices in load flow studies is also addressed in Section 26.

Section 17
Modeling Series Reactors

There are 17 series reactors 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. The following table lists these devices and briefly describes their purpose and operation in planning studies.

Table 17-1
Modeling Series Reactors in Planning Studies

Device	Ohms	State	Normal Operation	Purpose
Breckwood series reactor in 1322 line	5.55 ohms	MA	Out of Service (Shorted)	Inserted to limit short circuit duty at Breckwood when 1T circuit breaker is closed
Cadwell Series Reactor in 1556 line	3.97 ohms	MA	In Service	Limits short circuit duty at 115 kV East Springfield substation, not to be switched in planning studies
Cadwell Series Reactor in 1645 line	3.97 ohms	MA	In Service	Limits short circuit duty at 115 kV East Springfield substation, not to be switched in planning studies
East Devon series reactor in 1497 line	1.32 ohms	CT	In Service	Limits short circuit duty on 115 kV system, not to be switched in planning studies
East Devon series reactor in 1776 line	1.32 ohms	CT	In Service	Limits fault duty on 115 kV systems, not to be switched in planning studies
Greggs series reactor in F162 line	10 ohms	NH	Out of Service (Shorted)	Controls flows on the 115 kV system, can be switched in to mitigate thermal overloads
Hawthorne series reactor in 1222 line	5 ohms	CT	Out of Service (Shorted)	Controls flows on the 115 kV system, can be switched in to mitigate thermal overloads
Mix Avenue series reactor in 1610	7.5 ohms	CT	In Service	Will be installed in late 2017 to control flows on the 115 kV system and will normally be operated in service
North Bloomfield series reactor in 1784 line	2.65 ohms	CT	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate thermal overloads
North Cambridge series reactor in 329-530 line	2.75 ohms	MA	In Service	Limit flows and short circuit duty on 115 kV cables, not to be switched in planning studies
North Cambridge series reactor in 329-531 line	2.75 ohms	MA	In Service	Limit flows and short circuit duty on 115 kV cables, not to be switched in planning studies
Norwalk series reactor in 1637 line	5 ohms	CT	Out of Service (Shorted)	Controls flows on the 115 kV system, can be switched in to mitigate thermal overloads
Potter series reactor in115-10-16 line	3 ohms	MA	In Service	Limit flows on 115 kV cables, not to be switched in planning studies
Sandbar Overload Mitigation Series reactor in PV-20 line	30 ohms	VT	Out of Service (Shorted)	Controls flows on the 115 kV system, can be switched in to mitigate thermal overloads
Southington series reactor in 1910 line(Existing)	3.97 ohms	CT	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate thermal overloads
Southington series reactor in 1910 line (ISD 12/2018 – replaces the existing reactor)	6.61 ohms	CT	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate thermal overloads
Southington series reactor in 1950 line (Existing)	3.97 ohms	CT	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate thermal overloads

Device	Ohms	State	Normal Operation	Purpose
Southington series reactor in 1950 line(ISD 12/2018 – replaces the existing reactor)	6.61 ohms	CT	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate thermal overloads
Woburn series reactor in 211-514 line	2.75 ohms	MA	In Service	Limit flows and short circuit duty on 115 kV cables, not to be switched in planning studies
Southwest Hartford series reactor in 1346 line (ISD 12/2018)	2.65 ohms	CT	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate thermal overloads
Southwest Hartford series reactor in 1704 line (ISD 12/2018)	3.97 ohms	CT	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate thermal overloads

Section 18
Modeling High Voltage Direct Current Lines

There are three existing high voltage direct current facilities on the New England Transmission System, Highgate, Hydro Quebec Phase 2 and the Cross Sound Cable. There are no future high voltage direct current facilities with an approved PPA. The following tables list the flows on these facilities generally used in the base cases for different planning studies. Table 18-1 addresses existing facilities and table 18-2 is a placeholder for future facilities that have obtained an approved PPA.

Table 18-1
Modeling Existing DC Lines in Planning Studies

Study[1]	Highgate	Phase 2	Cross Sound Cable
PPA Study (I.3.9) of transmission project (Steady State and Stability)	0 to 225 MW towards Vermont at border	0 to 2000 MW towards New England	-330 to 346 MW towards Long Island
System Impact Study (Steady State and Stability)	0 to 225 MW towards Vermont at border	0 to 2000 MW towards New England	-330 to 346 MW towards Long Island
Transmission Needs Assessment (Steady State)	0 to 225 MW towards Vermont at border	0 to 2000 MW towards New England	0 to 346 MW towards Long Island
Transmission Solutions Study (Steady State and Stability)	0 to 225 MW towards Vermont at border	0 to 2000 MW towards New England	0 to 346 MW towards Long Island
Area Review Analyses (Steady State and Stability)	0 to 225 MW towards Vermont at border	0 to 2000 MW towards New England	0 to 346 MW towards Long Island
BPS Testing Analyses (Steady State and Stability)	0 to 225 MW towards Vermont at border	0 to 2000 MW towards New England	0 to 346 MW towards Long Island
Transfer Limit Studies (Steady State and Stability)	0 to 225 MW towards Vermont at border	0 to 2000 MW towards New England	-330 to 346 MW towards Long Island
Interregional Studies	0 to 225 MW towards Vermont at border	0 to 2000 MW towards New England	-330 to 346 MW towards Long Island
FCM New Resource Qualification Overlapping Impact Analyses	0 to 225 towards Vermont at border	0 to 1400 MW towards New England	0 MW
FCM New Resource Qualification NCIS Analyses	0 to 225 towards Vermont at border	0 MW towards New England	0 MW
FCM Delist/Non-price Retirement Analyses	0 to qualified existing imports	0 to qualified existing imports	Qualified Administrative export to 0 MW
FCM Study for Annual Reconfiguration Auctions and Annual CSO Bilaterals	0 to cleared imports	0 to cleared imports	Cleared Administrative export to 0 MW
Transmission Security Analyses	Qualified existing imports	Qualified existing imports	0 MW
Non-Commercial Capacity Deferral Notifications	0 to cleared imports	0 to cleared imports	Cleared Administrative export to 0 MW

[1] Imports on these facilities are considered Resources as discussed in Planning Procedure PP5-6.

Table 18-2
Modeling Future DC Lines in Planning Studies

Study[1]	Future DC Line
PPA Study (I.3.9) of transmission project (Steady State and Stability)	To Be Determined
System Impact Study (Steady State and Stability)	To Be Determined
Transmission Needs Assessment (Steady State)	To Be Determined
Transmission Solutions Study (Steady State and Stability)	To Be Determined
Area Review Analyses (Steady State and Stability)	To Be Determined
BPS Testing Analyses (Steady State and Stability)	To Be Determined
Transfer Limit Studies (Steady State and Stability)	To Be Determined
Interregional Studies	To Be Determined
FCM New Resource Qualification Overlapping Impact Analyses	To Be Determined
FCM New Resource Qualification NCIS Analyses	To Be Determined
FCM Delist/ Non-price Retirement Analyses	To Be Determined
FCM Study for Annual Reconfiguration Auctions and Annual CSO Bilaterals	To Be Determined
Transmission Security Analyses	To Be Determined
Non-Commercial Capacity Deferral Notifications	To Be Determined

[1] Imports on these facilities are considered Resources as discussed in Planning Procedure PP5-6.

Modeling of high voltage direct current lines in load flow studies is also addressed in Section 26.

Section 19
Modeling Dynamic Reactive Devices

This section is under development.

Section 20
Special Protection Systems (Remedial Action Schemes)

Special Protection Systems ("SPSs") may be employed in the design of the interconnected power system subject to the guidelines in the ISO New England Planning Procedure 5-6 "Special Protection Systems Application Guidelines." All SPSs proposed for use on the New England system must be reviewed by the Reliability Committee 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 the NPCC Directory #4 "Bulk Power System Protection Criteria" and the NPCC Directory #7 "Special Protection Systems".

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 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 transmission planning studies.

Section 21
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 Reliability Committee ("RC") on November 17, 2010. At the request of stakeholders, ISO-NE retransmitted this material to the RC on November 17, 2011 for comment and to the Planning Advisory Committee on November 21, 2011. ISO-NE has received comments on the guideline and is reviewing those comments.

Section 22
Short Circuit Studies

This section is under development.

NPCC requires that the transmission system be designed such that equipment capabilities are adequate for fault levels with all transmission and generating facilities in service. In New England, the base case for short circuit studies include transmission projects that are In-Service, Under Construction, and Planned and generators that are In-Service, Under Construction, are included in FERC section of the ISO-NE queue at the time the study begins, or have an approved Proposed Plan Applications. Projects with a nearly completed PPA Study and that have an impact on this study are also considered in the base case.

The voltage values that are used in short circuit studies are:

EM (formerly BHE)-1.05 per unit
CMP -1.05 per unit
NGRID - 1.03 per unit
Eversource (Boston, Cape Cod) -1.03 per unit
Eversource (CT, W.MA, NH) -1.04 per unit
UI - 1.04 per unit
Vermont- 1.05 per unit

Section 23
Critical Load Level Analysis

The Critical Load Level is the lowest load level at which the criteria violation occurs. One technique used to estimate Critical Load Level ("CLL") for overloads is linear extrapolation. Other methods are also acceptable.

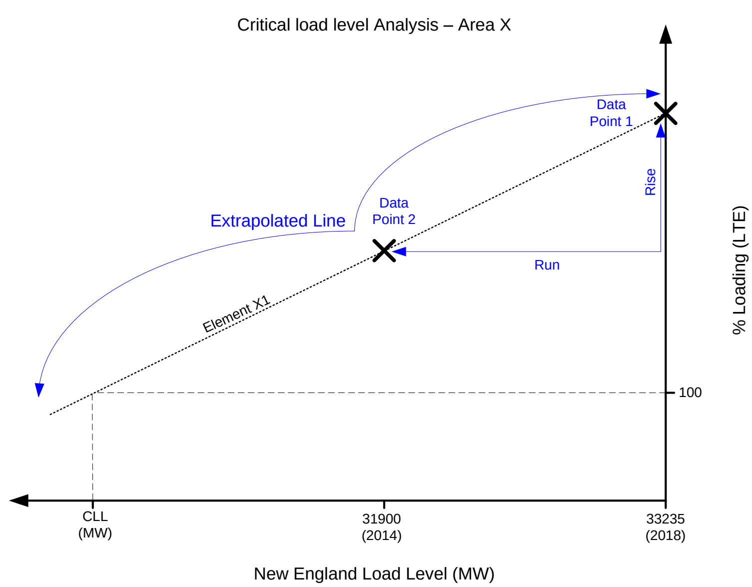
The linear extrapolation method is an approximation and provides a reasonable estimate with a minimum of additional analyses. The method requires that level of the loading on a transmission Element be determined at two load levels for the contingency or contingencies that have the largest impact on that transmission Element. This is done for each transmission Element that is overloaded. The load level in each base case is plotted on the x axis of a graph and percentage of the overload is plotted on y-axis. A straight line is drawn to connect these two points. The critical load level is the load level (x axis value) associated with 100 percent on the y axis.

An example of the use of linear extrapolation from a study of southwest Connecticut follows:

The initial base case was a 2018 base case. A second base case was developed by adjusting loads in the first case to 2014 year load levels taking into account the following:

- Loads plus losses in ISO-NE adjusted to 2009 CELT year 2014 levels (31,900 MW)
- Generation outside of CT was used to adjust to the new 2014 load levels
- Connecticut loads scaled according to 2009 RSP to 2014 levels (8,455 MW)
- Loads adjusted to account for FCA 3 cleared DR

No transmission topology changes were made to the adjusted 2014 cases. The highest overload per Element was identified in 2018 and the same Element's loading was obtained from the 2014 case results. This was done for the same single contingency (N-1) or line-out plus contingency pair (N-1-1) for every case. That is, both N-1 and N-1-1 analysis were performed in order to obtain two data points (2018 and 2014). Using the two data points available, linear extrapolation was used to form a line loading equation (slope = rise / run, y = mx + b, etc.) for each monitored Element which can then provide the loading of a particular line for different New England load levels. As an example, below shows the extrapolated line for Element X1 in Area X for a thermal violation.



Section 24
Bulk Power System Testing

This section is under development.

Section 25
Treatment on Non-Transmission Alternatives

This section is under development.

Section 26
Power Flow Study Solution Settings

26.1 Area Interchange

Enabling area interchange models 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 model 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 machines to match that set point. The area-slack bus for the New England Area is generally Canal 2. For studies of the area near Canal 2, a remote generator such as Seabrook in New Hampshire or Yarmouth 4 in Maine (also referred to as Wyman 4) is typically chosen as the area-slack bus.

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 Quebec 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.

26.2 Phase-Angle Regulators

The modeling of each Phase Shifting Transformers (Phase Angle Regular) is described in ISO New England's ***Reference Document for Base Modeling of Transmission System Elements in New England.*** This document is located in the ISO New England Planning Procedures subdirectory of the Rules & Procedures directory, on the ISO New England web site and is included as Appendix G to this guide.

26.3 Transformer Load Tap Changers

Transformer load tap changers ("LTC's") can exist on autotransformers, load serving transformers and transformers associated with generation (e.g. transformers associated with wind parks). LTC's 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 5/8% 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 seconds. A load-serving transformer, which is connected to the 115 kV system near the autotransformer, might delay changing its tap by forty-five 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 5/8% steps, requires five seconds per step and has a thirty second initial delay, would require seventy seconds to adjust its ratio by five percent.

To model the actual operations of the system, LTC operation is typically enabled in the power system model to allow the LTC's to adjust after contingencies for Steady State analysis. This generally represents the most severe condition because contingencies typically result in lower voltages and operation of LTC's to maintain distribution voltages result in higher current flow and lower voltages on the transmission system. Similarly operation of LTC's 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 LTC's locked (not permitted to adjust) in the power flow model due to the amount of time required for the taps to move.

26.4 Shunt Reactive Devices

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

26.5 Series Reactive Devices

Section 17 of this guide describes the series reactive devices in the New England transmission system. The following table lists those series reactive devices that can be switched to resolve criteria violations. Those devices that are out-of service in the base case can be switched into service. Those devices that are in-service in the base case can be switched out of service. The switching can be done post contingency if flows do not exceed STE ratings. When post contingency flows exceed STE ratings, switching must be done pre-contingency and analysis must be done to ensure that the switching does not create other problems.

Table 26-1
Modeling Series Reactors in Planning Studies

Device	Base Case	Adjustments
Greggs series reactor in F162 line	Out of Service (Shorted)	Controls flows on the 115 kV system, can be switched in to mitigate criteria violations
Hawthorne series reactor in 1222 line	Out of Service (Shorted)	Controls flows on the 115 kV system, can be switched in to mitigate criteria violations
Mix Avenue series reactor in 1610	In Service	Controls flows on the 115 kV system, can be bypassed to mitigate criteria violations
North Bloomfield series reactor in 1784 line	In Service	Controls flows on the 115 kV system, can be bypassed to mitigate criteria violations
Norwalk series reactor in 1637 line	In Service	Controls flows on the 115 kV system, can be bypassed to mitigate criteria violations
Sandbar Overload Mitigation Series reactor in PV-20 line	Out of Service (Shorted)	Controls flows on the 115 kV system, can be switched in to mitigate criteria violations. This reactor is controlled by a Special Protection System
Southington series reactor in 1910 line (existing or new)	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate criteria violations
Southington series reactor in 1950 line (existing or new)	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate criteria violations
Southwest Hartford series reactor in 1346 line (ISD 12/2018)	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate criteria violations
Southwest Hartford series reactor in 1704 line (ISD 12/2018)	In Service	Controls flows on the 115 kV system, can be by-passed to mitigate criteria violations

26.6 High Voltage Direct Current Lines

The flows in higher voltage direct current lines are not automatically adjusted after a contingency except where an adjustment is triggered by a Special Protection System.

Appendix A – 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 Bulk Power Supply 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
An Area (when capitalized) refers to one of the following: New England, New York, Ontario, Quebec 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 NPCC Directory #1, Appendix B)
A study to assess bulk power system reliability

BULK ELECTRIC POWER SYSTEM (as defined in the NERC Glossary of Terms Used in Reliability Standards)
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, Classification of Bulk Power System Elements)
A study done to determine if Elements are classified as part of the Bulk Power System

BULK POWER SYSTEM (as defined in NPCC Glossary of Terms Used in Directories)
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 Document A-7)
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. degrees for Summer and at or above 20 degrees 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 degrees F. for Summer and at or above 20 degrees F. for Winter. The CNR 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.

DELAYED FAULT CLEARING (as defined in NPCC Document A-7)
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 NPCC Document A-7)
Any electric device with terminals which may be connected to other electric devices, usually limited to a generator, transformer, circuit, circuit breaker, or bus section.

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/NON-PRICE RETIREMENT ANALYSES
The FCM Delist/Non-Price Retirement Analyses is the analysis of de-list bids, demand bids and non-price retirement requests as described in Section 7.0 of Planning Procedure PP-10.

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 Planning Procedure PP-10. 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 Planning Procedure PP-10. 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 Document A-7)
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

NR 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 degrees Fahrenheit for Summer and at or above 0 degrees Fahrenheit 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 degrees Fahrenheit for Summer and at or above 0 degrees Fahrenheit 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 Used in Reliability Standards)
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 Used in Reliability Standards)
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 Section II of the ISO-NE Tariff)
A transmission upgrade the ISO has approved under Section I.3.9 of the tariff. (Both a Needs Assessment and a Solutions Study have been completed for planned projects.)

PROPOSED (as defined in Attachment K of Section II of the ISO-NE Tariff)
A regulated transmission solution that (1) has been proposed in response to a specific identified needs in a needs assessment or the 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-NE 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 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 Document A-7)
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:

1. 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.
2. Pilot protection is considered to be one protection group.

PROTECTION SYSTEM (as defined in NPCC Document A-7)
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 ISO-NE Tariff)
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 ISO-NE Tariff)
Resource means a generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction.

SIGNIFICANT ADVERSE IMPACT (Based on Section I.3.9 of the Tariff and Planning Procedure 5-3)
A change to the transmission system that increases the flow in an Element by at least two percent of the Element's rating and that causes that flow to exceed that Element's appropriate thermal rating by more than two percent. 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).

A change to the transmission system that causes at least a one percent 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 4).

A change to the transmission system that causes at least a one percent 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 22)

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 Planning Procedure PP-3
- 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 Document A-7)
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. Automatic under frequency load shedding, as defined in NPCC Emergency Operation Criteria A-3, is not considered an SPS. Conventionally switched, locally controlled shunt devices are not SPSs.

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 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 ISO-NE OP-16 Appendix A)
The Summer period is April 1 to October 31.

TEN-MINUTE RESERVE (as defined in NPCC Document A-7)
The sum of synchronized and non-synchronized reserve that is fully available in ten minutes.

VOLTAGE COLLAPSE
The situation which results in a progressive decrease in voltage to unacceptable low levels, levels at which power transfers become infeasible. Voltage collapse usually leads to a black-out.

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

WITH DUE REGARD TO RECLOSING (as defined in NPCC Document A-7)
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.

Appendix B – Fast Start Units

The list of fast start units referenced in Section 11.6 is listed separately on the ISO-NE website at:

http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/plan_guides/plan_tech_guide/technical_planning_guide_appendix_b_reference_document.pdf

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

This document referenced in Section 11.8 is listed separately on the ISO-NE website at:

http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/plan_guides/plan_tech_guide/technical_planning_guide_appendix_c_guidelines_for_treatment_of_demand_resources_in_system_planning_analysis.pdf

Appendix D – Dynamic Stability Simulation Damping Criteria

The damping criteria referenced in Section 12.3 is listed separately on the ISO-NE website at:

http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/plan_guides/plan_tech_guide/technical_planning_guide_appendix_d_damping_criteria.pdf

Appendix E – Dynamic Stability Simulation Voltage Sag Criteria

This document referenced in Section 12.3 is listed separately on the ISO-NE website at:

http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/plan_guides/plan_tech_guide/technical_planning_guide_appendix_e_voltage_sag_guideline.pdf

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

This document referenced in Section 12.6 is listed separately on the ISO-NE website at:

http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/plan_guides/plan_tech_guide/technical_planning_guide_appendix_f_stabiliy_task_force_presentation.pdf

Appendix G – Reference Document for Base Modeling of Transmission System Elements in New England

This document, referenced in Sections 14 and 26.2, is listed separately on the ISO-NE website at:

http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/plan_guides/plan_tech_guide/technical_planning_guide_appendix_g_reference_document.pdf

Appendix H – Position Paper on the Simulation of No-Fault Contingencies

This document, referenced in Section 12.7, is listed separately on the ISO-NE website at:

http://www.iso-ne.com/static-assets/documents/2014/12/technical_planning_guide_appendix_h_reference_document.pdf

Appendix I – Methodology Document for the Assessment of Transfer Capability

This document, referenced in Section 13.2, is listed separately on the ISO-NE website at:

http://www.iso-ne.com/static-assets/documents/2016/01/technical_guide_appendix_i_2016_01_14.pdf

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

This document, referenced in Section 5, is listed separately on the ISO-NE website at:

http://www.iso-ne.com/static-assets/documents/2016/01/technical_guide_appendix_j_2016_01_14.pdf