Northeast Utilities

CONFIDENTIAL - CRITICAL ENERGY INFRASTRUCTURE INFORMATION

New Hampshire 10 Year Reliability Project

Proposed Plan Application

REDACTED - PUBLIC VERSION

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1 Executive Summary

In 2010, ISO New England's (ISO-NE) New Hampshire/Vermont (NH/VT) Working Group including representatives from National Grid (NGRID), Vermont Electric Power Company (VELCO), Unitil, and Northeast Utilities (NU) performed reliability analyses on the New Hampshire and Vermont transmission systems. These analyses were used to develop a comprehensive NH/VT Needs Assessment report and Solutions Study report that have been vetted through the ISO-NE regional planning process including stakeholder input via the Planning Advisory Committee (PAC).

The NH/VT Needs Assessment report examined the steady-state thermal and voltage performance of the system under various dispatches and transfer scenarios, intended to stress the system at summer peak load conditions. The NH/VT Needs Assessment was the first step in the study process defined in accordance with the Regional Planning Process as outlined in Attachment K to the ISO-NE Open Access Transmission Tariff (ISO-NE OATT or ISO-NE Tariff). The results of the Needs Assessment are presented in the reports titled *"Vermont/New Hampshire Transmission System 2011 Needs Assessment"* dated November, 2011 and "*Follow-up Analysis to the 2011 New Hampshire/Vermont Needs Assessment*" dated April 2012.

A NH/VT Solutions Study was also conducted to develop and analyze potential transmission solutions and to identify the best solution alternatives for the New Hampshire and Vermont transmission system to address the needs identified in the needs Assessment report. The results of the Solutions Study are presented in the reports titled *"New Hampshire/Vermont Transmission Solution"* dated April 2011 and "*Follow-up Analysis to the 2011 New Hampshire/Vermont Solutions Study*" dated April 2012.

This study evaluates the reliability performance of the New Hampshire transmission system performed in accordance with national and regional reliability standards. The preferred solutions developed under the NH/VT Solutions Study for the New Hampshire area are the subject of this Proposed Plan Application (PPA) report. The assumptions, modeling and analyses are performed in accordance with the requirements contained in the ISO-NE Tariff and ISO-NE Planning Procedures. The Vermont preferred solutions will be the subject of a separate PPA study performed by VELCO.

The New Hampshire reliability projects listed below in the table are scheduled to be in service by 2017.

PPA No.	**Northern New Hampshire**
NU-12-T44	Install a second 230/115-kV autotransformer at the Littleton Substation. Connect the new autotransformer at Littleton to the C203 line. Install a 230-kV circuit switcher and two (2) 115-kV circuit breakers at the Littleton Substation.
NEP-12-T20	Tap the existing National Grid 230-kV Comerford-Moore C203 line into the Littleton Substation. Build a new 0.2 mile 230-kV transmission line between the tap point and the Littleton Substation.
PPA No.	**Central New Hampshire**
NU-12-T46	Install four (4) 26.6 MVAR 115-kV capacitor banks and two (2) 115-kV circuit breakers at the Webster Substation.
NU-12-T45	Install two (2) 25 MVAR 115-kV dynamic reactive devices and two (2) 115-kV circuit breakers at the Saco Valley Substation.
NU-12-X02	Retire the Saco Valley Under Voltage Load Shedding scheme
NU-12-X03	Retire the Beebe River Under Voltage Load Shedding scheme
PPA No.	**Southern New Hampshire**
NU-12-T47	Tap the 345-kV Scobie Pond – Amherst 380 line and build a new three (3) circuit breaker 345-kV ring bus and install a single 345/115 kV autotransformer at the Eagle Substation in Merrimack, New Hampshire. Install two (2) 115-kV circuit breakers at the Eagle Substation. BPS upgrades for Eagle 115-kV Substation. Install four (4) 26.6 MVAR 115-kV capacitor banks and two (2) circuit breakers at the Eagle Substation.
NU-12-T23	Eliminate the conductor clearance limitations on the 18 mile 345-kV Scobie Pond –NH/MA border 326 line (NU).
NEP-12-T19	Rebuild the 12 mile 345-kV NH/MA border - Sandy Pond 326 line (NGRID).
NU-12-T48	Install a new 345-kV series circuit breaker next to the existing 802 circuit breaker at the Scobie Pond Substation.
NU-12-T49	Build a new 6 mile 115-kV transmission line between the Scobie Pond and Huse Road Substations in parallel with the existing I158 line. Install two (2) 115-kV circuit breakers at the Huse Road Substation and one (1) 115-kV circuit breaker at the Scobie Pond Substation.
NU-12-T50	Eliminate terminal equipment and conductor clearance limitations on the 115-kV Garvins-Deerfield G146 line.
NU-12-T51	Eliminate terminal equipment and conductor clearance limitations on the 115-kV Oak Hill-Merrimack P145 line
NU-12-T52	Rebuild the existing 15 mile 115-kV Deerfield-Pine Hill D118 line
NU-12-T53	Rebuild the existing 3 mile 115-kV Merrimack-Garvins H137

	line.
NU-12-T54	Eliminate terminal equipment and conductor clearance limitations 115-kV Greggs-Rimmon J114 line.
NU-12-T55	Tap the 115-kV Garvins – Webster V182 line into the Oak Hill Substation and build a new six (6) 115-kV circuit breaker substation in a "breaker & half" configuration.
NU-12-T08[1]	Install a 115-kV circuit breaker in series with each of the BT12 and BT23 circuit breakers at the Merrimack Substation.
NU-12-T56	At the Merrimack Substation relocate the existing (2) 36.7 MVAR 115-kV capacitor banks from Bus 2, installing one bank onto Bus 1 and the other onto Bus 3. Replace the existing Q171 circuit breaker at Merrimack Substation.
NU-12-T57	Rebuild the existing 5 mile 115-kV Eagle - Bridge Street - Power Street K165 line.
NU-13-T02	BPS upgrades for Power Street 115-kV Substation.
PPA No.	**Seacoast New Hampshire**
NU-12-T58	Build a new 13 mile 115-kV transmission line between the Madbury and Portsmouth Substations. Install one (1) 115-kV circuit breaker at both substations.
NU-12-T59	Build a new 6 mile 115-kV transmission line between the Scobie Pond and Chester Substations. Build a new five (5) 115-kV circuit breaker substation in a "breaker & half" configuration at the Chester Substation and install one (1) 115-kV circuit breaker at the Scobie Pond Substation.
NU-12-T60	Install six (6) 13.3 MVAR 115-kV capacitor banks at the Schiller Substation and install a 115-kV circuit breaker in series with the BT10 circuit breaker. Relocate the 115-kV Schiller – Portsmouth Z156 line terminal from bus A to bus B.
NU-12-T61	Eliminate terminal equipment and conductor clearance limitations on the 115-kV Chester - Great Bay H141 line.
NU-12-T62	Eliminate terminal equipment and conductor clearance limitations on the 115-kV Scobie – Kingston Tap R193 line.
NU-12-T63	Install a new 115-kV circuit breaker in series with the R1690 circuit breaker at the Three Rivers Switching Station.
PPA No.	**Western New Hampshire**
NU-12-T64	Build a new 2 mile 115-kV line between the Fitzwilliam and Monadnock Substations. Install two (2) 115-kV circuit breakers at the Fitzwilliam Substation and one (1) 115-kV circuit breaker at the Monadnock Substation.
NU-12-T65	Install two (2) 26.6 MVAR 345-kV capacitor banks and one (1) 345-kV circuit breaker at the Amherst Substation.
NU-12-T66	Eliminate terminal equipment and conductor clearance limitations on the 115-kV Keene-Monadnock T198 line.
NU-12-T67	Install two (2) 13.3 MVAR 115-kV capacitor banks and one (1) 115-kV circuit breaker at the Weare Substation.
NU-12-T68	Rebuild the 13 mile 115-kV Chestnut Hill – Westport - Swanzey A152 line.
NU-12-T69	Rebuild the 1 mile 115-kV NH/VT Border - Chestnut Hill N186

[1] These system upgrades were approved May 2012, in support of the generator interconnection for the Groton Wind Project (QP345).

	line.
NU-12-T41[2]	Eliminate conductor clearance limitations on the 345-kV Line 381, MA/NH border to NH/VT border, 11 miles.

This study, performed in accordance with Section I.3.9 of the ISO-NE Tariff, evaluated the New Hampshire reliability projects to ensure that the proposed additions and upgrades do not have a significant adverse system impact on the reliability, stability and operating characteristics of the interconnected bulk power transmission system or the system of a NEPOOL Market Participant. The reliability analyses were performed in accordance with applicable NERC, NPCC and ISO-NE reliability standards and criteria.

Steady State Analysis Results

Steady-state analyses were performed to determine the power flow levels on transmission circuits as well as system voltage profiles on the New Hampshire transmission system under base case conditions and following design criteria contingency events. A total of nine (9) base cases for 2017 with varying load levels and stressed interface transfers were established for this study. In addition, two sensitivity cases with the Northern Pass Transmission HVDC facility in-service were studied.

Steady-state N-1 and N-1-1 reliability analyses at the 2017 peak and shoulder load levels examined system performance with the New Hampshire reliability projects in service. The results of the steady state analyses indicate that the New Hampshire reliability projects do not result in transmission facilities exceeding their normal and emergency thermal capabilities or system bus voltages deviating outside the acceptable performance range.

A minimum load level was not analyzed as part of this study.

Stability Analysis Results

Stability analyses were conducted to determine the dynamic performance of electric machines with respect to rotor angle displacement, system voltage stability and system frequency deviations following system fault conditions. Transient stability analyses including Bulk Power System

[2] This PPA was submitted in support of the Pittsfield/Greenfield Project, October 2012.

classification testing were used to evaluate the performance of the transmission system at 2017 light and peak load levels with the New Hampshire reliability project additions and upgrades in-service. Three phase, line-line to ground and single-line to ground faults were simulated under normal and extreme contingency conditions.

BPS testing was performed in accordance with NPCC requirements. The following stations will be classified as BPS subsequent to the New Hampshire reliability projects, as listed below.

New BPS Stations
345-kV Eagle
115-kV Eagle
115-kV Power Street

BPS testing without the NH 10-Yr. upgrades in-service revealed that the Vernon 115-kV Station failed the BPS test. Additional analysis will be performed by VELCO to confirm the need to classify the Vernon 115 kV substation and other substations as BPS before the NH upgrades. The 345-kV Eagle, 115-kV Eagle, and 115-kV Power Street Substations are classified as part of the Bulk Power System due to the proposed projects (Eagle 345/115-kV autotransformer).

The stability light and peak load testing results are summarized below.

345 kV EC testing

- 345-kV extreme contingencies demonstrated acceptable system responses. Two extreme contingencies resulted in a system separation between the Orrington-South and Surowiec-South interfaces. However, the loss of source is within the extreme contingency criteria. The same system response was observed in pre-project cases and the proposed projects did not significantly impact the system responses.

345 kV NC testing

- All 345-kV normal contingencies demonstrated acceptable system responses.

230 kV EC testing

- All 230-kV extreme contingencies demonstrated acceptable system responses.

230 kV NC testing

- All 230-kV normal contingencies demonstrated acceptable system responses.

115 kV EC testing

- All 115-kV extreme contingencies demonstrated acceptable system responses.

115 kV NC testing

- All 115-kV normal contingencies demonstrated acceptable system responses.

Double Circuit Tower Contingency testing

- The 345-kV/115-kV double circuit tower contingencies demonstrated acceptable system responses.

345 kV Line Out Testing for Stability

- The 345-kV design contingency faults tested demonstrated acceptable system responses.

345 kV EC and 115 kV EC Contingency testing with the Northern Pass Transmission Project

- The faults tested demonstrated acceptable system responses. A limited number faults were run on a single case, which included the Northern Pass Transmission Project.

Short Circuit Analysis

Short circuit studies were conducted to determine the short-circuit levels at system locations and the ability of existing or new electrical equipment to safely interrupt such levels. There is a single 115-kV circuit breaker (Merrimack Q171) that exceeded its short circuit momentary rating. This circuit breaker will be replaced. All other circuit breakers are within the applicable short circuit ratings.

Delta-P Analysis

The scope of the New Hampshire reliability projects do not add any new 345-kV transmission circuits in the vicinity of large generating stations connected to the 345-kV network at Seabrook and Newington. On the 115-kV network, a new 115-kV transmission line is being added between the Madbury and Portsmouth Substations. This will strengthen the electrical network in this area. At this time, the proposed New Hampshire reliability projects do not change the capability of regional interfaces or the interconnection of Merrimack and Schiller. Therefore, no delta P analyses will be needed or performed under this study.

2 Revision History

Rev. #	Date	Reason for Revision
a	08-07-2012	Incorporated comments from ISO-NE.
b	10-22-2012	Submitted to TWG/SSG for review and comment. Dynamic modeling updates for the following, provided by ISO-NE: 1. Comerford/Moore generation 2. Kingdom Wind 3. Granite Wind power plant controller 4. Antrim Wind 5. Timbertop Wind 6. Merrimack G2 PSS enabled Updated the stability power flow case with the following: 1. NEEWS project update, 345-kV capacitors at Montville removed Changed assumption for Granite Ridge generation tripping; if steam unit trips, GT's trip also.
c	11-24-2012	The following items were added: Steady-state 1. Delta V analysis for capacitor bank switching 2. Short circuit study results Stability 1. Adjusted ME-NH transfer to ≅ 1960 MW and East-West to ≅ 3500MW 2. Stability summary of results for BPS, design and extreme contingencies
d	11-26-2012	The following items were added: 1. PPA numbers in the Executive Summary 2. PSS/E modeling information
e	11-28-2012	Editorial corrections
f	12-06-2012	The following stability sections were updated: 1. Appendix H- Stability Summary of Results a. Results for DCT contingencies b. Results of a case that included the Northern Pass Transmission Project 2. The impact of reduced clearing times were evaluated for the following: a. Power St. (BPS fault) b. Vernon (BPS fault) c. 230-kV design contingency faults

		3. Stability Analysis Results 4. Executive Summary
g	12-19-2012	The following sections of the report were updated for stability results: 1. Appendix H- Stability Summary of Results a. 230-kV design contingency fault clearing times were confirmed. Simple diagrams have been added to the end of the appendix to document a teleconference held to better understanding the existing and future clearing times in this area. 2. Section 10 Stability Analysis Results a. 345-kV extreme contingency section updated regarding 326 SPS set point. b. 230-kV design contingency section updated to reflect use of updated clearing times. 3. Executive Summary- updated
h	01-06-2013	The following additional testing was performed and the applicable sections of the report were updated: 1. ISO-NE requested that two 345-kV line out scenarios (394 & 397) be tested to ensure no adverse impact on the ISO-NE line out stability guides, due to the proposed projects. a. Section 7.3.1, updated to document the line scenarios . b. Section 10.6, updated to document the results of the simulation. c. Appendix H, updated to document the results of the simulation. d. Appendix P, updated for description of the 326 SPS in the line out stability mode. e. Appendix R, updated with the line out power flow one-line diagrams. f. Appendix T, updated with the detailed line out base case summaries. g. Executive Summary- updated for the line out testing results. 2. Two 345-kV extreme contingencies were rerun as design contingencies. a. Section 10.2.2, updated to reflect the rerunning of the extreme contingencies as design contingencies. b. Appendix H, updated to document the results of the simulation.
i	01-11-2013	The following additional testing was performed and the applicable sections of the report were updated: Steady-State: 1. Sensitivities for the 326 SPS in the thermal mode were run evaluating different load levels and assumed arming of different generation. a. Section 8.5, added to document the steady-state thermal

		testing of the 326 SPS. Stability: 1. Additional BPS test was requested to be performed for the West Methuen 115-kV Substation. a. Section 10.1, updated to include the added BPS testing. b. Appendix H, updated to document the results of the simulation. 2. A 115-kV normal contingency (DC207) was corrected and rerun. a. Appendix H, updated to document the results of the simulation. b. A plot set was added to include the rotor angle for the Bellows Falls generation. 3. Appendix T, case summaries, was updated to include the Granite Wind and Bellows Falls generation output. 4. Appendix L, was updated to update incorrect plots. 5. Section 7.3.1, updated to reflect a dynamic modeling inconsistency.
j	01-25-2013	1. Incorporated editorial comments from ISO-NE. 2. Updated Appendix H, clarifying 230-kV clearing time data for the existing system. 3. Added PPA# NU-13-T02 for Power St. BPS upgrades to the Executive Summary and Table 3-1.

3 Background Information

In 2010, ISO New England's (ISO-NE) New Hampshire/Vermont (NH/VT) Working Group including representatives from National Grid (NGRID), Vermont Electric Power Company (VELCO), Unitil, and Northeast Utilities (NU) performed reliability analyses on the New Hampshire and Vermont transmission systems. These analyses were used to develop a comprehensive NH/VT Needs Assessment report and Solutions Study report that have been vetted through the ISO-NE regional planning process including stakeholder input via the Planning Advisory Committee (PAC).

The NH/VT Needs Assessment report examined the steady-state thermal and voltage performance of the system under various dispatches and transfer scenarios, intended to stress the system at summer peak load conditions. The NH/VT Needs Assessment was the first step in the study process defined in accordance with the Regional Planning Process as outlined in Attachment K to the ISO-NE Open Access Transmission Tariff (OATT or ISO-NE Tariff). The results of the Needs Assessment are presented in the report titled *"Vermont/New Hampshire Transmission System 2011 Needs Assessment"* dated November 2011 and "*Follow-up Analysis to the 2011 New Hampshire/Vermont Needs Assessment*" dated April 2012.

A NH/VT Solutions Study was also conducted to develop and analyze potential transmission solutions and to identify the best solution alternatives for the New Hampshire and Vermont transmission system to address the needs identified in the needs Assessment report. The results of the Solutions Study are presented in the report titled *"New Hampshire/Vermont Transmission Solution"* dated April 2011 and "*Follow-up Analysis to the 2011 New Hampshire/Vermont Solutions Study*" dated April 2012.

This Proposed Plan Application (PPA) study evaluates the reliability performance of the New Hampshire transmission system performed in accordance with national and regional reliability standards. The preferred solutions developed under the NH/VT Solutions Study for the New Hampshire area are the subject of this report. The assumptions, modeling and analyses are performed in accordance with the ISO-NE Tariff and Planning Procedures. The Vermont preferred solutions will be the subject of a separate PPA study performed by VELCO.

The New Hampshire reliability projects are scheduled to be in service by 2017.

3.1 Study Objective

These analyses have evaluated the New Hampshire reliability projects to ensure compliance with the applicable procedures, criteria, and guidelines outlined in Section 5: Study Methodology.

3.2 Project Description

The components that comprise the New Hampshire reliability projects are described in detail in Appendices A through E, containing diagrams of the substations and transmission lines configurations comprising the New Hampshire reliability projects.

Table 3-1 New Hampshire Reliability Project Descriptions

PPA No.	Northern New Hampshire
NU-12-T44	Install a second 230/115-kV autotransformer at the Littleton Substation. Connect the new autotransformer at Littleton to a tap of the C203 line. Install a 230-kV circuit switcher and two (2) 115-kV circuit breakers at the Littleton Substation.
NEP-12-T20	Tap the existing National Grid 230-kV Comerford-Moore C203 line into the Littleton Substation. Build a new 0.2 mile 230-kV transmission line between the tap point and the Littleton Substation.
PPA No.	**Central New Hampshire**
NU-12-T46	Install four (4) 26.6 MVAR 115-kV capacitor banks and two (2) 115-kV circuit breakers at the Webster Substation.
NU-12-T45	Install two (2) 25 MVAR 115-kV dynamic reactive devices and two (2) 115-kV circuit breakers at the Saco Valley Substation.
NU-12-X02	Retire the Saco Valley Under Voltage Load Shedding scheme
NU-12-X03	Retire the Beebe River Under Voltage Load Shedding scheme
PPA No.	**Southern New Hampshire**
NU-12-T47	Tap the 345-kV Scobie Pond – Amherst 380 line and build a new three (3) circuit breaker 345-kV ring bus and install a single 345/115 kV autotransformer at the Eagle Substation in Merrimack, New Hampshire. Install two (2) 115-kV circuit breakers at the Eagle Substation. BPS upgrades for Eagle 115-kV Substation.

	Install four (4) 26.6 MVAR 115-kV capacitor banks and two (2) circuit breakers at the Eagle Substation.
NU-12-T23	Eliminate the conductor clearance limitations on the 18 mile 345-kV Scobie Pond –NH/MA border 326 line (NU).
NEP-12-T19	Rebuild the 12 mile 345-kV NH/MA border - Sandy Pond 326 line (NGRID).
NU-12-T48	Install a new 345-kV series circuit breaker next to the existing 802 circuit breaker at the Scobie Pond Substation.
NU-12-T49	Build a new 6 mile 115-kV transmission line between the Scobie Pond and Huse Road Substations in parallel with the existing I158 line. Install two (2) 115-kV circuit breakers at the Huse Road Substation and one (1) 115-kV circuit breaker at the Scobie Pond Substation.
NU-12-T50	Eliminate terminal equipment and conductor clearance limitations on the 115-kV Garvins-Deerfield G146 line.
NU-12-T51	Eliminate terminal equipment and conductor clearance limitations on the 115-kV Oak Hill-Merrimack P145 line
NU-12-T52	Rebuild the existing 15 mile 115-kV Deerfield-Pine Hill D118 line
NU-12-T53	Rebuild the existing 3 mile 115-kV Merrimack-Garvins H137 line.
NU-12-T54	Eliminate terminal equipment and conductor clearance limitations 115-kV Greggs-Rimmon J114 line.
NU-12-T55	Tap the 115-kV Garvins – Webster V182 line into the Oak Hill Substation and build a new six (6) 115-kV circuit breaker substation in a "breaker & half" configuration.
NU-12-T08[3]	Install a 115-kV circuit breaker in series with each of the BT12 and BT23 circuit breakers at the Merrimack Substation.
NU-12-T56	At the Merrimack Substation relocate the existing (2) 36.7 MVAR 115-kV capacitor banks from Bus 2, installing one bank onto Bus 1 and the other onto Bus 3. Replace the existing Q171 circuit breaker at Merrimack Substation.
NU-12-T57	Rebuild the existing 5 mile 115-kV Eagle - Bridge Street - Power Street K165 line.
NU-13-T02	BPS upgrades for Power Street 115-kV Substation.
PPA No.	**Seacoast New Hampshire**
NU-12-T58	Build a new 13 mile 115-kV transmission line between the Madbury and Portsmouth Substations. Install one (1) 115-kV circuit breaker at both substations.
NU-12-T59	Build a new 6 mile 115-kV transmission line between the Scobie Pond and Chester Substations. Build a new five (5) 115-kV circuit breaker substation in a "breaker & half" configuration at the Chester Substation and install one (1) 115-kV circuit breaker at the Scobie Pond Substation.
NU-12-T60	Install six (6) 13.3 MVAR 115-kV capacitor banks at the Schiller Substation and install a 115-kV circuit breaker in series with the BT10 circuit breaker. Relocate the 115-kV Schiller – Portsmouth Z156 line terminal from bus A to bus B.

[3] These system upgrades were approved May 2012, in support of the generator interconnection for the Groton Wind Project (QP345).

NU-12-T61	Eliminate terminal equipment and conductor clearance limitations on the 115-kV Chester - Great Bay H141 line.
NU-12-T62	Eliminate terminal equipment and conductor clearance limitations on the 115-kV Scobie – Kingston Tap R193 line.
NU-12-T63	Install a new 115-kV circuit breaker in series with the R1690 circuit breaker at the Three Rivers Substation.
PPA No.	**Western New Hampshire**
NU-12-T64	Build a new 2 mile 115-kV line between the Fitzwilliam and Monadnock Substations. Install two (2) 115-kV circuit breakers at the Fitzwilliam Substation and one (1) 115-kV circuit breaker at the Monadnock Substation.
NU-12-T65	Install two (2) 26.6 MVAR 345-kV capacitor banks and one (1) 345-kV circuit breaker at the Amherst Substation.
NU-12-T66	Eliminate terminal equipment and conductor clearance limitations on the 115-kV Keene-Monadnock T198 line.
NU-12-T67	Install two (2) 13.3 MVAR 115-kV capacitor banks and one (1) 115-kV circuit breaker at the Weare Substation.
NU-12-T68	Rebuild the 13 mile 115-kV Chestnut Hill – Westport - Swanzey A152 line.
NU-12-T69	Rebuild the 1 mile 115-kV NH/VT Border - Chestnut Hill N186 line.
NU-12-T41[4]	Eliminate conductor clearance limitations on the 345-kV Line 381, MA/NH border to NH/VT border, 11 miles.

4 Study Area

4.1 New Hampshire Transmission System

Figure 4-1 is a geographical map of the New Hampshire bulk power transmission system.

[4] This PPA was submitted in support of the Pittsfield/Greenfield Project, October 2012.

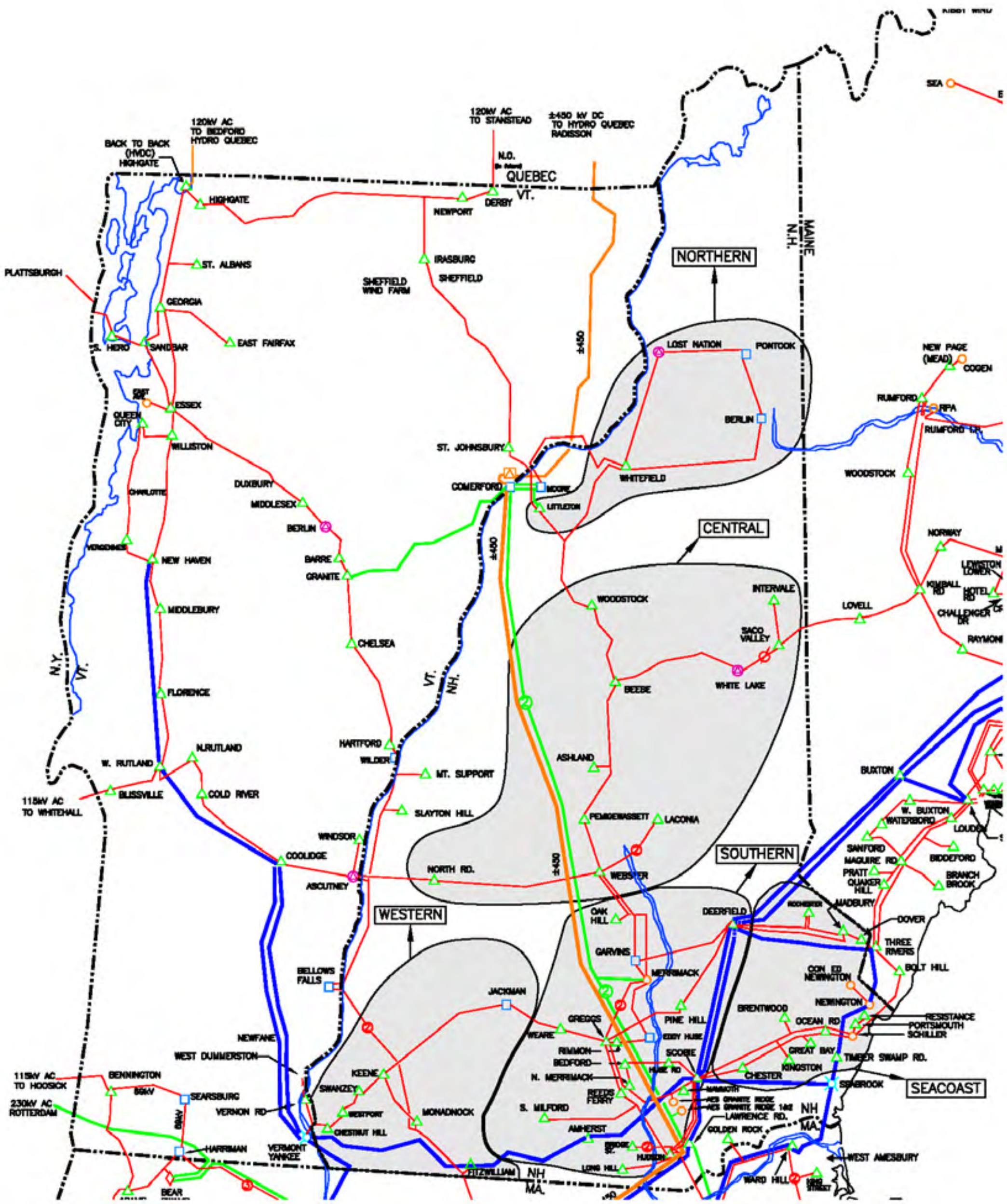


Figure 4-1 New Hampshire Transmission System

4.2 Interface Definitions

The 345-kV transmission network is the key infrastructure that integrates the region's supply resources with load centers. The major northern New England generation resources, as well as the supply provided via ties from New Brunswick, primarily rely on the 345-kV transmission system for delivery of power to the area's load centers. This network provides significant power supply to New Hampshire, Maine and Vermont. The following sections include descriptions of the primary interfaces in the vicinity of the New Hampshire area for the year 2017.

Maine – New Hampshire Interface

The Maine – New Hampshire transmission interface facilities electrically divide these two states along its common border. The primary interface transmission links are three 345-kV transmission lines. Several underlying 115-kV transmission facilities are also part of the interface.

- [redacted]

Northern New England - Scobie plus 394 Line Interface

The northern New England - Scobie plus 394 line transmission interface facilities electrically cut across the southern New Hampshire 345-kV network. The primary interface transmission links are four 345-kV transmission lines. There are no underlying 115-kV transmission facilities that are part of the interface.

- [redacted]

North – South Interface

The North – South transmission interface facilities electrically divide New Hampshire and Vermont with Massachusetts along their common border. The primary interface transmission links are three 345-kV transmission lines. Several underlying 230-kV and 115-kV transmission facilities are also part of the interface.

- [redacted]

[redacted]

East -West Interface

The East - West transmission interface facilities electrically divide New England roughly in half. Vermont, southwestern New Hampshire, western Massachusetts, and Connecticut are located to the west of this interface; while Maine, eastern New Hampshire, eastern Massachusetts, and Rhode Island are to the east. The primary east-west transmission links are three 345-kV and two 230-kV transmission lines. Several underlying 115-kV transmission facilities are also part of the interface.

Pre-project:

- [redacted]

*Post-project:

The East-West interface definition is modified. [redacted]

West - East Interface

The West - East transmission interface facilities are similar to the East – West transmission interface facilities [redacted].

Pre-project:

- [redacted]

*Post-project:
The West-East interface definition is modified. [redacted]

5 Study Methodology

This PPA study evaluated the New Hampshire reliability projects to ensure that the proposed additions and modifications do not have significant adverse system impact on the reliability, stability and operating characteristics of the interconnected bulk power transmission system. The reliability analyses were performed in accordance with the following national and regional standards and criteria:

- North American Electric Reliability Corporation (NERC) Reliability Standards, per category A, B, C, and D events, *"Transmission Planning Standards, TPL-001, -002, -003,-004"*, dated May 13, 2009.
- NERC Standard NUC-001-2 — Nuclear Plant Interface Coordination, dated April 1, 2010.

- Northeast Power Coordinating Council (NPCC) Regional Reliability Reference Directory #1, *"Design and Operation of the Bulk Power System",* dated December 1, 2009.
- Northeast Power Coordinating Council (NPCC) Document A-10 *"Classification of Bulk Power System Elements"*, dated April 28, 2007.
- ISO New England Planning Procedure No. 3, "*Reliability Standards for the New England Area Bulk Power System*", dated March 5, 2010.
- ISO New England Planning Procedure No. 5-3*, "Guidelines for Conducting and Evaluating Proposed Plan Application Analyses",* dated March 5, 2010.
- ISO New England Planning Procedure No. 7, "*Procedures For Determining and Implementing Transmission Facility Ratings in New England"*, dated April 14, 2006.
- ISO New England Planning Procedure No. 9, "*Major Substation Bus Arrangement Application Guidelines"*, May 12, 2008.
- ISO New England Operating Procedure No. 19 Transmission Operations, dated June 1, 2010.
- "Transmission Planning Guideline for Northeast Utilities", dated May 2008.

5.1 Reliability Analyses

The reliability analysis was performed in accordance with the above referenced documents in Section 5 Study Methodology. All reliability standards require that the Bulk Electric System thermal and voltage limits remain within applicable limits after the events described in Table 5-1 Applicable NERC Reliability Standardscontingency descriptions.

Table 5-1 Applicable NERC Reliability Standards Contingency Descriptions

Category	Initiating Event(s) and Contingency Element(s)
A – No Contingencies	All facilities in service
B – Events resulting in the loss of a single element	Single-line-to-ground (SLG) or 3-phase (3Φ) fault with normal clearing: • Generator • Transmission Circuit • Transformer Loss of an element without a fault
C – Events resulting in the loss of two or more elements	SLG fault with normal clearing: • Bus • Circuit breaker (failure or internal fault)
	SLG or 3Φ fault with normal clearing, manual system adjustments, followed by another SLG or 3Φ fault with normal clearing • Generator • Transmission Circuit • Transformer
	Any two circuits of a multiple circuit tower line
	SLG fault with delayed clearing (stuck breaker or protection system failure): • Generator • Transmission Circuit • Transformer • Bus

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing (stuck breaker or protection system failure)[e]: 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing: 5. Breaker (failure or internal Fault)

Notes:
d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

Steady-state analyses (N-1 and N-1-1) were performed on peak and shoulder load levels to determine the power flow levels on transmission facilities as well as voltage levels under base case conditions and following contingency events. Stability analyses were performed on peak and light load levels to evaluate dynamic system performance in regards to machine rotor angle displacement, voltage stability and frequency deviations on the transmission system following contingency events. A general description of the reliability analyses is as follows:

- **Thermal** – analyses to determine the level of steady-state power flows on transmission facilities under base case conditions and following contingency events. These flows are compared to the applicable facility rating to determine if the equipment will be operated within its capabilities.
- **Voltage** – analyses to determine system voltage levels and performance under base case conditions and following contingency events. These voltages are then compared to applicable voltage criteria.
- **Stability** – analyses to determine the dynamic performance of electric machines with respect to rotor angle displacement, system voltage stability and system frequency deviations following fault conditions.

• **Thermal Transmission Transfer Capability** – analyses to determine the capability of the transmission system from one portion of the system to a specific subarea.

• **Short - circuit** – analyses to determine the short-circuit levels at system locations and the relative impact of each alternative on the required interrupting capability at major substations in the study area.

• **Delta P** – analyses to determine the mechanical stress put on local machines in the area due to line switching associated with system contingency events**.**

5.1.1 Steady-State System Performance Criteria

5.1.1.1 Voltage Performance Criteria

Table 5-2 identifies the voltage criteria that were used for the steady state voltage assessment. Voltages were monitored at all buses with voltages 69 kV and above in the study area. System bus voltages outside of limits identified in Table 5-2 were identified for all normal (pre-contingency) and post-contingency conditions.

Table 5-2 Steady State Voltage Criteria

Facility Owner	Voltage Level	Bus Voltage Limits (Per-Unit)	
		Pre-Contingency	Post-Contingency
Northeast Utilities	230 kV and above	0.95 to 1.05	0.95 to 1.05
	115 kV and below	0.95 to 1.05	0.95 to 1.05
National Grid	230 kV and above	0.98 to 1.05	0.95 to 1.05
	115 kV and below	0.95 to 1.05	0.90 to 1.05*
Millstone / Seabrook[5]	345 kV	1.00 to 1.05	1.00 to 1.05
Vermont Yankee	115 kV	1.00 to 1.05	1.00 to 1.05
Vermont Yankee	345 kV	0.98 to 1.05	0.98 to 1.05

*Limits only apply to certain parts of the NGRID System.

5 This is in compliance with NUC-001-2, *“Nuclear Plant Interface Coordination Reliability Standard,”* adopted August 5, 2009.

5.1.1.2 Thermal Performance Criteria

Power flow loadings on all transmission facilities rated 69 kV and above in the study area were monitored. Table 5-3 below identifies the thermal criteria that were used for the steady state thermal assessment. These criteria apply to all categories of contingencies.

Table 5-3 Steady State Thermal Criteria

SYSTEM CONDITION	MAXIMUM ALLOWABLE FACILITY LOADING
Normal (Pre-Contingency)	Normal Rating
Emergency (Post-Contingency)	Long Time Emergency (LTE) Rating

All Normal (N), Long Time Emergency (LTE), and Short Time Emergency (STE) ratings for this study were updated based on actual operating ratings consistent with ISO-NE Planning Procedure 7, *"Procedures for Determining and Implementing Transmission Facility Ratings in New England"*.

The thermal criteria used for the N-1-1 thermal analysis requires that all power flow loadings must stay below the STE ratings at all times. After the first contingency, the following manual system adjustments were considered to reduce loadings to the extent possible following the subsequent contingency:

- Quick start generation re-dispatch (within 10 minutes)
- Tripping or runback of generation
- Phase-angle regulator adjustment
- HVDC adjustments

5.1.1.3 Steady State Solution Parameters

The steady state analysis was performed with pre-contingency solution parameters that allowed adjustment of load tap-changing transformers (LTCs), static var devices (SVDs including automatically-switched capacitors) and phase angle regulators (PARs). Post-contingency solution parameters only allowed adjustment of LTCs and SVDs. The solution parameters are summarized in Table 5-4.

Table 5-4 Study Solution Parameters

Case	Area Interchange	Transformer LTCs	Phase Angle Regulators	SVDs & Switched Shunts
Base	Tie Lines Regulating	Stepping	Regulating or Manually Set	Regulating
Contingency	Disabled	Stepping	Disabled	Disabled*

*Under certain system conditions, there may be evaluations of contingencies that would assume that the switched shunts are allowed to switch.

5.2 Stability Analysis

Analyses were conducted to determine the dynamic performance with respect to electric machine rotor angle displacement, system voltage stability and system frequency deviations following phase to ground fault conditions. Stability analyses examined power system dynamic performance with the New Hampshire reliability projects additions and upgrades in-service.

5.2.1 Stability Performance Criteria

For the stability assessment, a set of design criteria contingencies and extreme contingencies, were simulated with the following criteria, stated in ISO-NE Planning Procedure #3:

> "The New England bulk power system shall remain stable during and following the most severe of the contingencies stated below with due regard to re-closing and before making any manual system adjustments."

The following criteria define acceptable transmission system performance for design contingencies:

- All generating units must remain transiently stable (Reference ISO-NE OP No. 19).
- Generating units are allowed to be tripped off-line but only as part of the fault clearing.

The criteria for extreme contingencies faults are as follows:

- A loss of generation less than 1,400 MW is acceptable.

- A loss of generation between 1,400 MW and 2,200 MW may be acceptable depending upon the circumstances surrounding the contingency event and likelihood of occurrence.
- A loss of generation above 2,200 MW is not acceptable.

For faults at stations classified as Bulk Power System ("BPS"), stability shall be maintained when the simulation is based on fault clearing initiated by either the "System A" protection group, or the "System B" protection group. This form of delayed clearing was also modeled concurrent with a stuck breaker condition.

An important attribute of a stable system response is the rapid damping of any oscillations that occur after the fault is cleared from the system. The purpose of the damping criterion is to assure small signal stability of the New England bulk power supply system. System damping is characterized by the damping ratio, zeta. The damping ratio provides an indication of the length of time an oscillation will take to dampen. The damping criterion specifies a minimum damping ratio of 0.03, which corresponds to a 1% settling time of one minute or less for all oscillations with a frequency of 0.4 Hz or higher. Conformance with the criterion may be demonstrated with the use of small signal eigenvalue analysis to explicitly identify the damping ratio of all questionable oscillations. Time domain analysis may also be utilized to determine acceptable system damping. Acceptable damping with time domain analysis requires running a transient stability simulation for sufficient time (up to 30 seconds) such that only a single mode of oscillation remains. A 53% reduction in the magnitude of the oscillation must then be observed over four periods of the oscillation, measuring from the point where only a single mode of oscillation remains in the simulation.

Figure 5-1 provides a graphical representation of the stability simulation time domain criteria. As an alternate method, the time domain response of system state quantities such as generator rotor angle, voltage, and interface transfers can be transformed into the frequency domain where the damping ratio can be calculated. A sufficient number of system state quantities including rotor angle, voltage, and interface transfers should be analyzed to ensure that adequate system damping is observed.

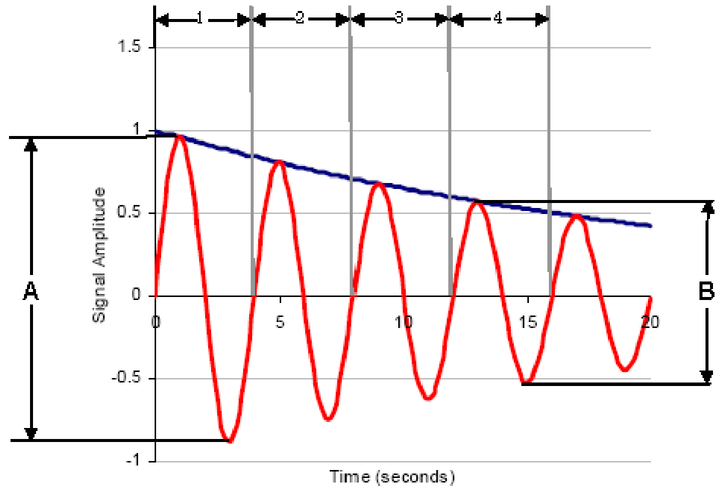


Figure 5-1 Stability Damping Criterion

A system fault event is considered stable if the magnitude of B divided by A is less than 0.53 (B/A < 0.53).

5.2.1 Dynamic Stability Simulation Voltage Sag Guideline

The following is extracted from the voltage sag guideline, "The minimum post-fault positive sequence voltage sag must remain above 70% of nominal voltage and must not exceed 250 milliseconds below 80% of nominal voltage within 10 seconds following a fault". A PSSE user model has been developed to monitor the post-fault voltage based on this voltage sag guideline.

This guideline is used for evaluating an acceptable system response for a design contingency. However, for an extreme contingency, the guideline is used as a gauge for robustness of the system voltages. Severe voltage sags are considered a precursor to line relays operating and resulting in a potential system split.

5.2.2 Seabrook Nuclear Plant Interface Transient Stability Requirements

The below information is extracted from the Nuclear Plant Interface Requirements (NPIR) for the Seabrook Nuclear Power Station and is in accordance with NERC Standard NUC-001, "Nuclear Plant Interface Coordination":

[redacted]

[redacted]

[redacted]

[redacted]

For b) and c) above, a PSSE under voltage load shedding model with transfer trip (LVS3BL) is used to model the resulting impact of relatively low voltages on the Seabrook 13.8-kV plant auxiliary system, due to a transmission system disturbance. Further modeling details are included in Appendix O - Seabrook Auxiliary Plant Load Modeling.

5.2.3 Stability Fault Descriptions

The following normal contingencies, as defined by ISO-NE PP3, were considered for this analysis:

- Permanent 3Ø fault on any generator, transmission circuit, transformer or bus section, with normal fault clearing

- Permanent phase-to-ground fault on any transmission circuit, transformer, or bus section with delayed fault clearing. This delayed fault clearing could be due to circuit breaker, relay system, or signal channel malfunction

The reliability standards also address extreme contingencies; which are considered more severe relative to a normal contingency, but lower in probability of occurrence. The transmission bulk power system performance, in response to an extreme contingency, is intended to be a gauge of the system's robustness or a measure of the extent of the disturbance (unless the loss of generation is greater than 2200 MW, which is unacceptable for an extreme contingency). As defined by ISO-NE PP3, a permanent three-phase fault on a generator, transmission circuit, transformer or bus section, with delayed fault clearing and with due regard to re-closing was modeled. The delayed fault clearing could be due to circuit breaker, relay system or signal channel malfunction.

5.2.4 Stability Assumptions

5.2.4.1 Generator Bus Under/over Frequency Relay Model

An under/over frequency relay model is included at the New England generator buses as part of the transmission system dynamic model. The under frequency set point of the model is 57.0 Hz or -5% of 60 Hz, and the over frequency set point is 62.0 Hz or +3.33% of 60 Hz are assumed. If a generator bus frequency exceeds the set points, the generator is automatically tripped in the simulation.

These set points are assumed based on IEEE Standard C50.13-2005, "IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above". Within the standard, the +3.33/-5% is a frequency range of continuous operation within +/- %5 of the generator terminal voltage; outside of which starts the aggregate degradation of the machine insulation. For the purposes of this study, the +3.33/-5% frequency range is conservatively assumed for transient stability operation.

5.2.4.2 Loss of Granite Ridge Steam Unit

The Granite Ridge generating station is a combined cycle plant. The plant is composed of three units, two combustion turbines and one steam unit. The combustion turbine units connect to the National Grid 230-kV system at the N. Litchfield Switching Station and the steam unit connects to the PSNH 115-V system at the Watts Brook Switching Station.

For simulated system disturbances that cause the steam unit to trip, the combustion units will be assumed to trip off-line.

5.2.4.3 Saco Valley Synchronous Condenser Model

The modeling for the two proposed Saco Valley 25 Mvar (lag) synchronous condensers is based on the Granite synchronous condensers, which are connected to the 13.8 kV tertiary winding of the Granite 230-115 kV transformers in Vermont. The modeling of the step-up transformer will assume typical generator step-up transformer parameters for this size of synchronous machine MVA. Further modeling details are included in Appendix S - Saco Valley Synchronous Condenser Modelling.

5.2.4.4 Seabrook Auxiliary Plant Load Model

The modeling of the Seabrook auxiliary plant load is modified to include the unit auxiliary transformers (UAT-2A and UAT-2B). Each UAT is a three-winding transformer (13.8/24.5/4.16-kV). The single lumped auxiliary load is split into four lumped loads distributed between the two 13.8-kV and two 4.16-kV buses. [redacted] Further modeling details are included in Appendix O - Seabrook Auxiliary Plant Load Modeling.

5.2.4.5 345-kV Line 326 SPS Model

Modeling the Line 326 SPS, in the thermal mode, a PSSE library relay model is used, a 'time inverse overcurrent relay' (TIOCR1). The relay model is set-up to monitor the ampere flow on Line 326 [redacted] Modeling of the Line 326 SPS in the stability mode is simulated by use of a PSSE user model 'C326SP'. Further modeling details are included in Appendix P - Line 326 Special Protection System Modeling

5.2.4.6 115-kV Line Y151 SPS Model

The modeling of the Line Y151 SPS uses the same PSSE library model as described above. However, if the ampere flow on Line Y151 exceeds the set point, for a specified time, then Line Y151 is tripped. Further modeling details are included in Appendix Q - Line Y151 Special Protection System Modeling.

5.2.4.7 Generator Rotor Angle Monitoring

The PSSE function 'GENSCAN' is utilized to monitor machine rotor angles during the simulations. If the machine angle meets or exceeds 250 degrees the machine is tripped off-line in the simulation.

5.3 Short-Circuit Analysis

Short circuit analyses were conducted to determine the short-circuit levels at all 115-kV, 230-kV and 345-kV substations in New Hampshire. This analysis is to determine if the existing or new electrical equipment can safely interrupt the short-circuit levels at the substation location. Pre-fault voltages were assumed to be 1.05 per unit (p.u.), unless otherwise specified. The performance requirement is that no circuit breaker shall be operated in excess of 100 percent of its fault interrupting duty or momentary capability or substation equipment exceed its current carrying capabilities. For further details refer to Appendix M - Short Circuit Analysis Results

5.4 Delta-P Analysis

Delta-P studies determine the torsional impact on the mechanical equipment at a generating station associated with transmission line switching. Delta-P is usually tested under conditions of maximum power flow through the 345-kV lines terminating at the station under investigation while simulating line reclosing operations of these lines. All lines in conditions and limited line out conditions can be examined.

Delta P simulations are conducted with the PSS/E network solution activity TYSL, designed specifically for switching studies. The activity assumes the internal flux linkages of the generators are unchanged before and after the switching event. The instantaneous change in network voltages is calculated along with the resulting change in generator electrical power output (Delta P). The percent change in electrical power referenced in the sections below is based on the following formula:

For each event, a solved power flow case was created for the pre-switching event (t^{0-}) based on the above described methodology. The change in electrical power on generators was recorded following the switching event (t^{0+}) along with a calculation of percent change (% Change) based on machine MVA as mentioned above. No modifications were made in the generation dispatch during these events. Generator electrical power change greater than 50% is identified and provided to the station owners for review.

The nature and scope of the New Hampshire reliability projects do not add new 345-kV transmission circuits in the vicinity of large generating stations connected to the 345-kV network at Seabrook and Newington. On the 115-kV network, a new 115-kV transmission line is being added between the Madbury and Portsmouth Substations. This will strengthen the electrical network in this area. The New Hampshire reliability projects do not change the capability of regional interfaces or the interconnection of Merrimack and Schiller. Therefore, no delta P analyses will be needed or performed under this study.

5.5 Bulk Power System Analysis

Bulk Power System (BPS) stability testing was conducted for the New Hampshire reliability projects to determine if the outage of a complete substation will have an adverse impact outside the local control area of New England. BPS classification requirements were determined in accordance with NPCC A-10.

5.5.1 BPS Stability Testing Methodology

BPS testing was performed to determine if the New Hampshire reliability projects cause a substation to be classified as part of the New England bulk power system. For BPS contingencies all protection systems for the station being tested are assumed inoperable. Simulations were conducted using existing remote-end clearing times when available otherwise clearing times of 300 cycles were used. Based on the results of these simulations shorter clearing times were evaluated to minimize a particular station's impact on the bulk power system as an alternative to BPS classification. Otherwise, the station was classified as BPS. If a station was classified as part of the BPS, then all stations one bus away were tested in a similar fashion until no other stations needed to be classified as BPS. The stations that were tested are listed in Section 6.3.1.

5.5.2 BPS Acceptance Criteria

The BPS or non-BPS status of a bus was determined based on following criteria:
Acceptable Responses (leading to a non-BPS classification):

- A 53% reduction in the magnitude of system oscillations observed over four periods
- Loss of source up to 1,200 MW

Unacceptable Responses (leading to a BPS classification):

- Transiently unstable, with wide spread system collapse
- Transiently stable, with undamped or sustained power system oscillations
- Loss of source greater than 1,200 MW
- System separation resulting in the isolation of a control area

6 Contingency Descriptions

6.1 Contingency List for Thermal and Voltage Analyses

Each base case was subjected to single contingencies (N-1 testing) such as the loss of a generator, transmission circuit or transformer and also to the loss of multiple elements that might result from a single event such as a stuck (malfunctioning) circuit breaker, bus faults, or loss of any two adjacent circuits on a multiple-circuit tower line. The same contingencies were also applied to each line-out case for N-1-1 testing at the peak load and shoulder load level.

The contingency definitions were developed using the ISO-NE base case database, but modified to reflect changes in breaker arrangements and bus configurations associated with the New Hampshire reliability projects. All categories of contingencies were included with the exception of the “NF” contingencies that model outages of individual segments of multi-terminal transmission lines and individual facilities sharing bus positions at transmission substations.

Appendix G - Steady State Contingency Lists contains listings of the contingency files used for the steady state portion of this study.

Table 6-1 New Contingencies with the New Hampshire Reliability Projects

[redacted]

6.2 Initial Facility Outages for N-1-1 Analysis

N-1-1 contingency analysis was conducted to evaluate the reliability of the transmission system with a critical element out of service. The N-1-1 assessment examined each contingency that was tested for the N-1 analysis as described in Section 6.1, using the same contingency files.

Table 6-2 Initial Transmission Element Outages

LINE NUMBER	kV	DESCRIPTION
326	345	Sandy Pond – Scobie Pond
354	345	Ludlow - Northfield
363	345	Scobie Pond - Seabrook
369	345	Seabrook - Timber Swamp
373	345	Scobie Pond - Deerfield
379	345	Vernon - Fitzwilliam
380E	345	Scobie Pond-Eagle
380W	345	Eagle-Amherst

LINE NUMBER	kV	DESCRIPTION
381	345	Northfield - Vernon
385	345	Deerfield - Buxton
391	345	Scobie Pond - Buxton
394	345	Ward Hill - Seabrook
3022	345	Eliot - Maguire Rd
307	345	Deerfield - Eliot
3176	345	Eliot - Newington
214	115	Saco Valley - Kimball Rd
B172	115	Scobie Pond - Chester
C129	115	Deerfield - Rochester
D118	115	Deerfield - Pine Hill
G146	115	Deerfield - Garvins
I158	115	Scobie Pond - Huse Rd
I135N	115	Fitzwilliam - Monadnock-Bellows
L175	115	Deerfield - Madbury
N186	115	Chestnut Hill l- Vernon Rd
R187	115	Scobie Pond - Mammoth Rd
R193	115	Scobie Pond – Kingston-Brentwood
Fitzwilliam TB34	345/115	Autotransformer at Fitzwilliam Substation
Deerfield TB28	345/115	Autotransformer at Deerfield Substation
Scobie Pond TB120	345/115	Autotransformer at Scobie Pond Substation
Merrimack auto	230/115	Autotransformer at Merrimack Substation
Littleton auto	230/115	Autotransformer at Littleton Substation
Eagle auto	345/115	Autotransformer at Eagle Substation

Table 6-2 Initial Transmission Element Outages lists the system elements that were considered as the initial facility out (N-1) for the assessment of the New Hampshire reliability projects.

6.3 Stability Contingency List

Appendix H - Stability contains the 345-kV and 115-kV normal and extreme contingencies that were simulated in these analyses.

6.3.1 Stability BPS Fault Contingencies

Stability bulk power system testing was performed on the following stations for the post-New Hampshire reliability project system configuration. Table 6-3 contains a listing of the substations that will be BPS tested. Detailed stability BPS fault definitions including clearing times can be found in Appendix H - Stability .

Table 6-3 Substations to be BPS Tested

Substation	kV	Company	Dispatch
1. Eagle	345	NU	D10
2. Comerford	230	NGRID	D11
3. Brentwood	115	NU	D10
4. Chester	115	NU	D10
5. Eagle[6]	115	NU	D10
6. Garvins	115	NU	D10
7. Greggs	115	NU	D10
8. Littleton	115	NU	D11
9. Madbury	115	NU	D10
10. Merrimack	115	NU	D10
11. Monadnock	115	NU	D10
12. Pine Hill	115	NU	D10
13. Power Street	115	NU	D10
14. Eastport (a k.a Rochester)	115	NU	D10
15. Three Rivers	115	NU	D10
16. Vernon	115	VELCO	D10

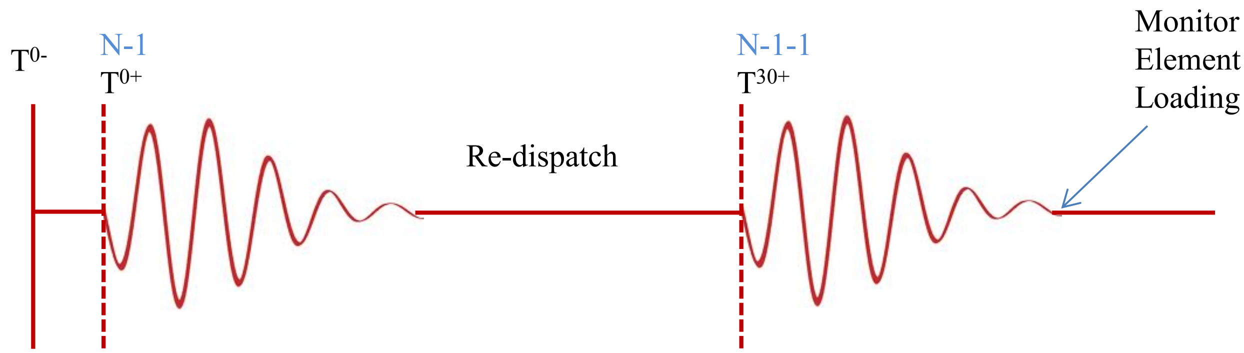
6 [redacted].

Table 6-4 Existing BPS Substation Boundary of the Study Area

[redacted]		[redacted]	[redacted]
	[redacted] [redacted]	[redacted]	[redacted]
	[redacted] [redacted]	[redacted]	[redacted]
	[redacted] [redacted]	[redacted]	[redacted]
	[redacted] [redacted]	[redacted]	[redacted]
	[redacted] [redacted]	[redacted]	[redacted]
	[redacted] [redacted]	[redacted]	[redacted]
	[redacted] [redacted]	[redacted]	[redacted]
	[redacted] [redacted]	[redacted]	[redacted]
	[redacted] [redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]

After the BPS testing is completed, the second part of the analysis will include simulating selected transmission system faults for normal (design) and extreme contingency (robustness test) on the pre-project cases. If the system response to a three phase fault as an extreme contingency is unacceptable, then the contingency is rerun as a normal contingency with a single-line-to-ground fault; and mitigation measures will be investigated.

The third part of the analysis will encompass planned or unplanned transmission element outages, followed by either a normal or extreme contingency (N-1-1). System adjustments are assumed after the first contingency, within a 30 minute timeframe. Examples of system adjustments may include change in MW transfers by re-dispatching generation (limited to a 1200 MW change), phase shifter adjustment, or re-dispatching generation.



The system disturbances with be evaluated with due regard to reclosing, in accordance with the applicable NERC, NPCC and ISO-NE design criteria.

7 Base Case Development

7.1 Base Case Assumptions and Technical Specifications

The base cases used in this study were derived from the ISO-NE Multi-Regional Modeling Working Group (MMWG) 2010 library cases for external outside of New England and the latest ISO-NE Model on Demand case dated December 28, 2011. Appendix F - Generation and Transmission Projects with PPA Approval Included in Study, contains listings of recent generation and transmission projects that were included in the representation. All projects that have received PPA approval by ISO-NE under Section I.3.9 of the ISO-NE Tariff, and have scheduled in-service dates on or before December 31, 2017 are included.

7.1.1 Load Forecast

In accordance with ISO-NE planning practices, transmission planning studies utilize the ISO-NE extreme weather ("90/10") forecast assumptions for modeling summer peak load profiles in New England. The May 2012 ISO-NE Capacity, Energy, Loads and Transmission (CELT) report was the basis for the load levels utilized in this PPA report. Table 7-1 2017 CELT Load Forecast contains the load levels used in these analyses and represent the year 2017 that corresponds to the first full year following completion of the New Hampshire reliability projects. The 2012 CELT report projected that the 2017 summer New England 90/10 peak demand forecast would be 32,255

MW and the 50/50 demand forecast would be approximately 29,895 MW, exclusive of demand resource and future Energy Efficiency forecast corrections.

Table 7-1 2017 CELT Load Forecast

CELT	Peak	Shoulder	Light
Forecast	90/10	50/50	50/50
%	100%	75%	45%
Load Level	32,255 MW	22,421 MW	13,453 MW

A minimum load level was not studied as part of this PPA study. The proposed projects do not add a significant amount of reactive charging to the system, which contributes to system over voltages. The 345-kV Line 326, Sandy Pond- NH/MA Border, is being rebuilt; however the line charging is approximately equal pre and post-project.

7.1.2 Demand Resources

Demand Resource (DR) load reductions for New England were modeled in the peak, shoulder and light load cases (active DR was excluded). Loads in the shoulder and light load cases were reduced to 75% and 45% of the peak passive DR reduction, respectively. All DR values were derived from the Forward Capacity Auction #6 (FCA #6) Summary.

Demand Resource (DR) and Energy Efficiency (EE) load reductions will be modeled in the peak load cases by adding negative load to represent DR and EE. Active DR is not included in the shoulder load levels. All DR values are derived from the FCA # 6 summary. Table 7-2 Passive Demand Resource (PDR) and EE forecast Summary and Table 7-3 Active Demand Resource (ADR) below summarizes the 2017 Demand Resource and Energy Efficiency by zones.

Table 7-2 Passive Demand Resource (PDR) and EE forecast Summary

Load Zone	EE forecast 2012 (8% gross-up included)	EE forecast 2012_DRV	Passive SUM DRV (Source: FCA6)	Total Passive SUM DRV
ME	17.00	15.74	145.82	161.56
NH	20.00	18.52	78.03	96.55
VT	37.00	34.26	114.80	149.06
MA	267.00	247.22	703.74	950.96

RI	51.00	47.22	129.07	176.29
CT	60.00	55.56	388.95	444.51
ISO-NE	451.00	417.59	1560.41	1978.00

Table 7-3 Active Demand Resource (ADR)

Dispatch Zone	ADR zone 30-48	Active DR - SUM_DRV	Active DR - WIN_DRV
Bangor Hydro	30	44.13	46.61
Maine	31	151.25	159.73
Portland	32	100.08	105.69
New Hampshire	33	53.41	52.75
Seacoast	34	7.60	7.50
NW Vermont	35	40.80	45.55
Vermont	36	22.27	24.87
Boston	37	198.08	175.53
North Shore	38	69.81	61.86
Central MA	39	79.81	69.06
Springfield	40	38.89	33.65
Western MA	41	53.60	46.38
Lower SEMA	42	48.42	43.82
SEMA	43	110.13	99.68
Rhode Island	44	84.43	75.00
Eastern CT	45	41.51	37.54
Northern CT	46	55.12	49.85
Norwalk-Stamford	47	63.46	57.39
Western CT	48	194.53	175.93
ISO NE		1457.33	1368.39

7.2 Base Cases for Steady State Analyses

7.2.1 Steady State Base Case Generation Dispatch and Interface Transfers

Nine regional generation dispatch scenarios were developed for the New Hampshire reliability projects steady state analysis at the 2017 summer peak and shoulder load level. Three dispatch scenarios were developed for the West to East biased transfer and six for the East to West biased transfer case. In these cases, the New England East-West and West-East interfaces are stressed to their FERC 715 limit, to the extent possible, constrained by available generation. The dispatch scenarios represented a wide range of unit commitment within the northern New England system. These various generator combinations represented both import and export conditions across major interfaces such as the Maine-New Hampshire, North -South and Boston Import interfaces within the study area. The objective of modeling these various stressed conditions was to examine the ability of the transmission system to reliably serve customer peak demands under a wide range of system operating conditions.

Overviews of the dispatch and transfer conditions are given in Table 7-4 Dispatch Summary and Interface Transfer. Appendix I - Steady-State Analysis Base Case Summaries, contains the detailed case summaries.

Table 7-4 Dispatch Summary and Interface Transfer

[redacted]

The general descriptions and philosophy used to develop these peak load dispatch scenarios are as follows:

Dispatch D1 – The D1 dispatch stresses the northern New England interface as shown in Figure 7-1, with Merrimack 2 and Granite Ridge out of service. With a 1,200 MW export to New York, the east to west flow is high along with the Boston import. These interface transfers represent stressed conditions for the New Hampshire reliability project.

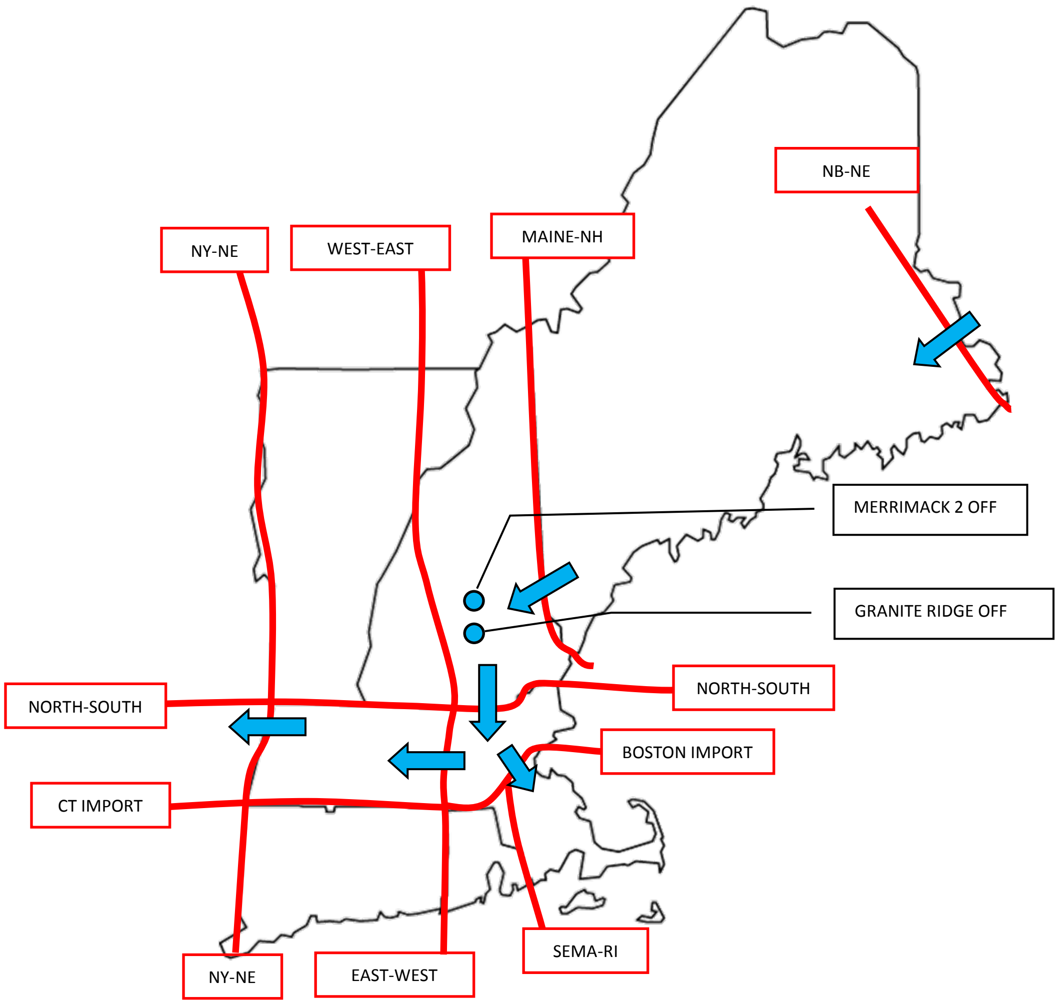


Figure 7-1 Peak Load D1 Dispatch

Dispatch D2 – The D2 dispatch stresses the northern New England interface as shown in Figure 7-2, with Schiller 4 and 6 out of service. With a 1,200 MW export to New York, the east to west flow is high along with the Boston import. These interface transfers represent stressed conditions for the New Hampshire reliability project.

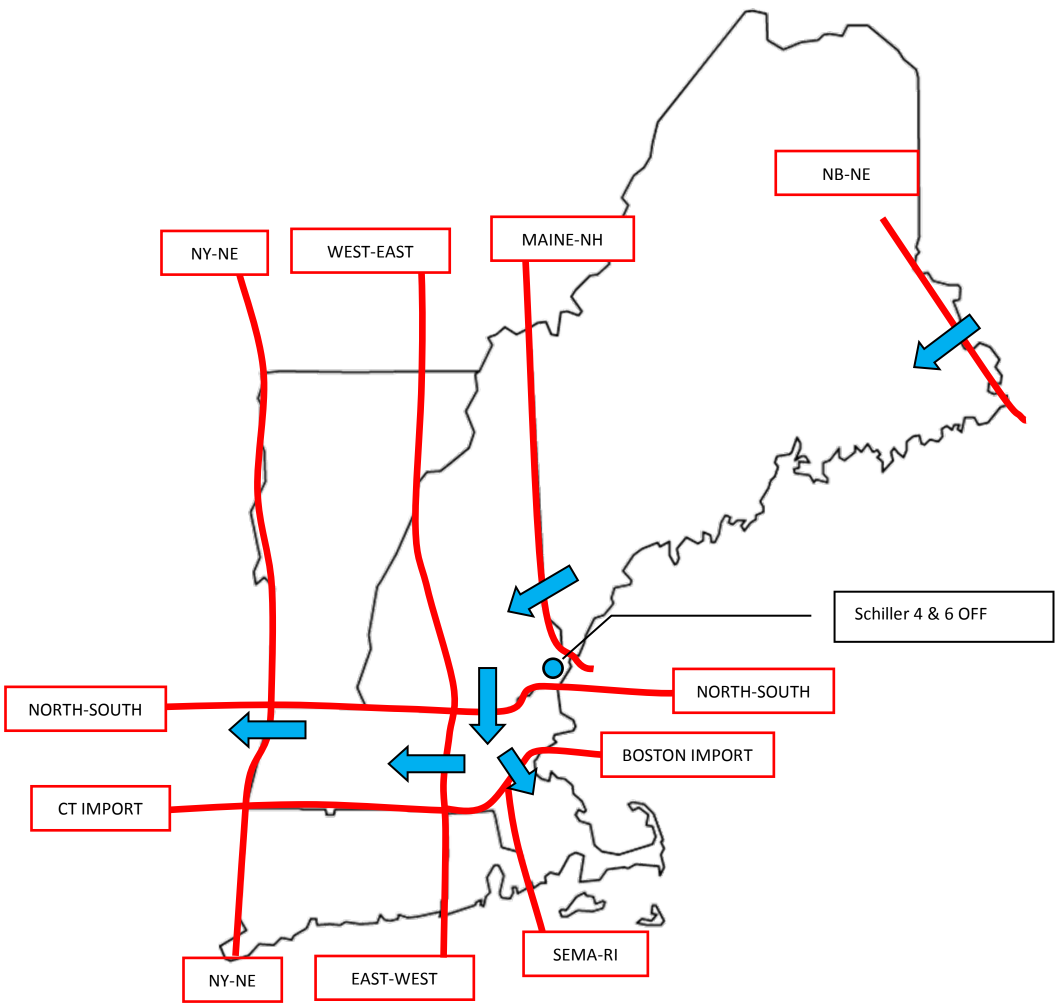


Figure 7-2 Peak Load D2 Dispatch

Dispatch D3 – The D3 dispatch stresses the northern New England interface as shown in Figure 7-3, with Merrimack 2 and Granite Ridge out of service. With a 1,200 MW import from New York, the west to east flow is high along with the Boston import. These interface transfers represent stressed conditions for the New Hampshire reliability project configurations.

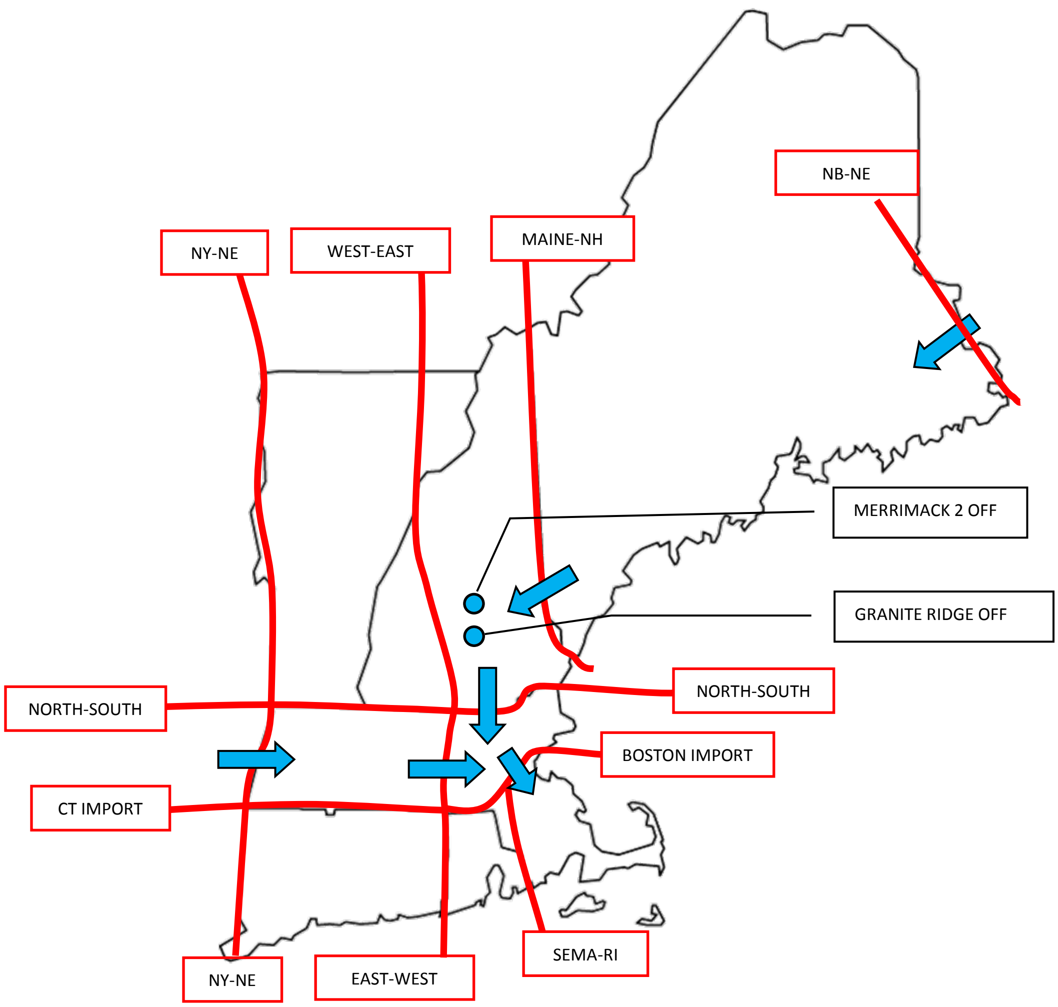


Figure 7-3 Peak Load D3 Dispatch

Dispatch D4 – The D4 dispatch stresses the northern New England interface as shown in Figure 7-4, with Merrimack 1 and 2 and Schiller 4 and 6 out of service. With a 1,200 MW export to New York, the east to west flow is high along with the Boston import. These interface transfers represent stressed conditions for the New Hampshire reliability project.

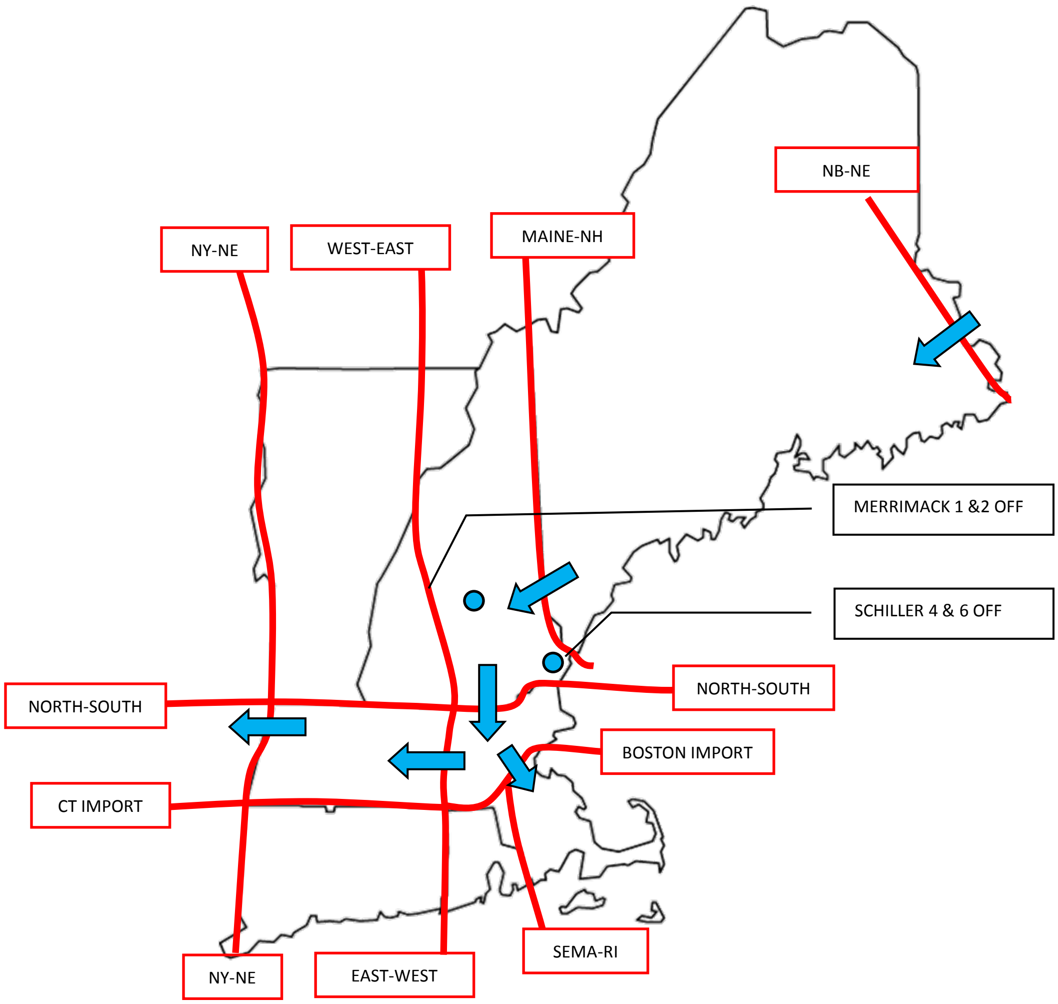


Figure 7-4 Peak Load D4 Dispatch

Dispatch D5 – The D5 dispatch stresses the northern New England interface as shown in Figure 7-5, with Merrimack 2 and Vermont Yankee out of service. With a 1,200 MW export to New York, the east to west flow is high along with the Boston import. These interface transfers represent stressed conditions for the New Hampshire reliability project configurations.

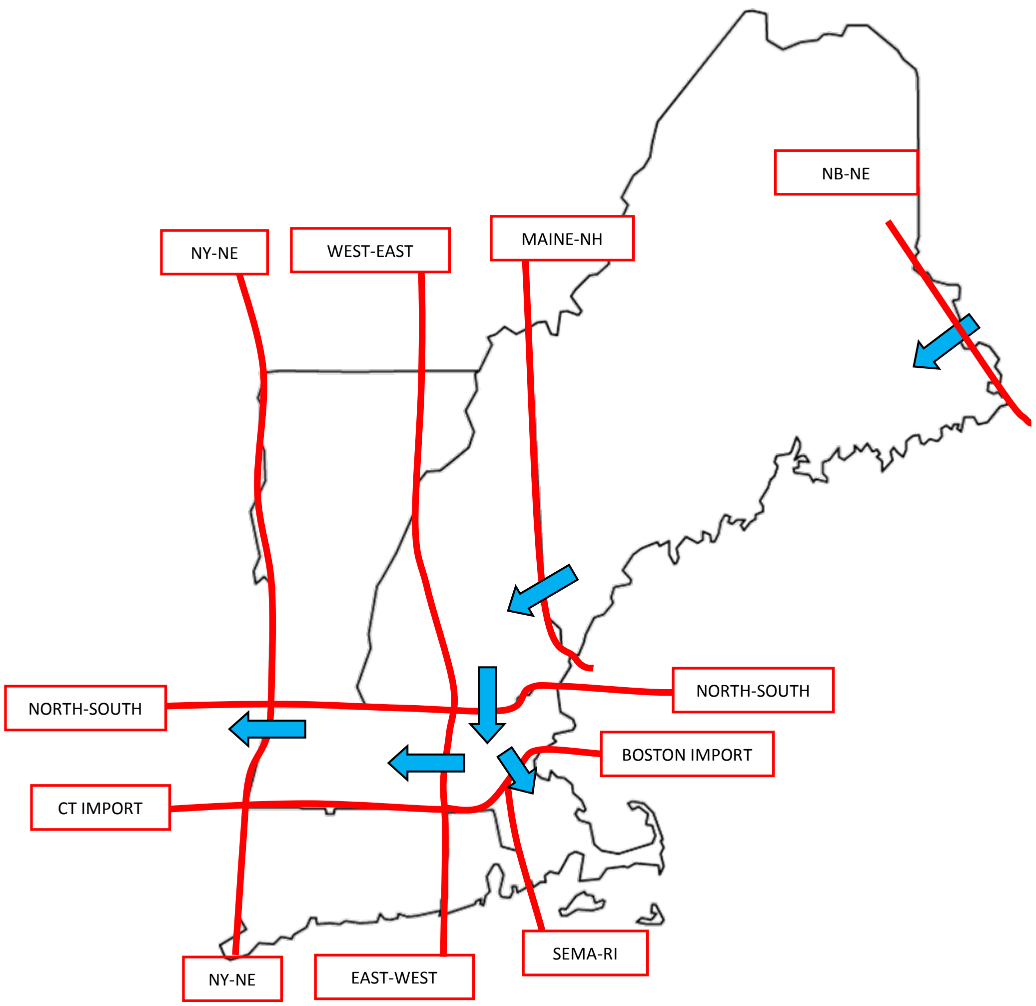


Figure 7-5 Shoulder Load D5 Dispatch

Dispatch D6 – The D6 dispatch stresses the northern New England interface as shown in Figure 7-6, with Merrimack 2 and Granite Ridge out of service. With a 1,200 MW import from New York, the west to east flow is high along with the Boston import. These interface transfers represent stressed conditions for the New Hampshire reliability project.

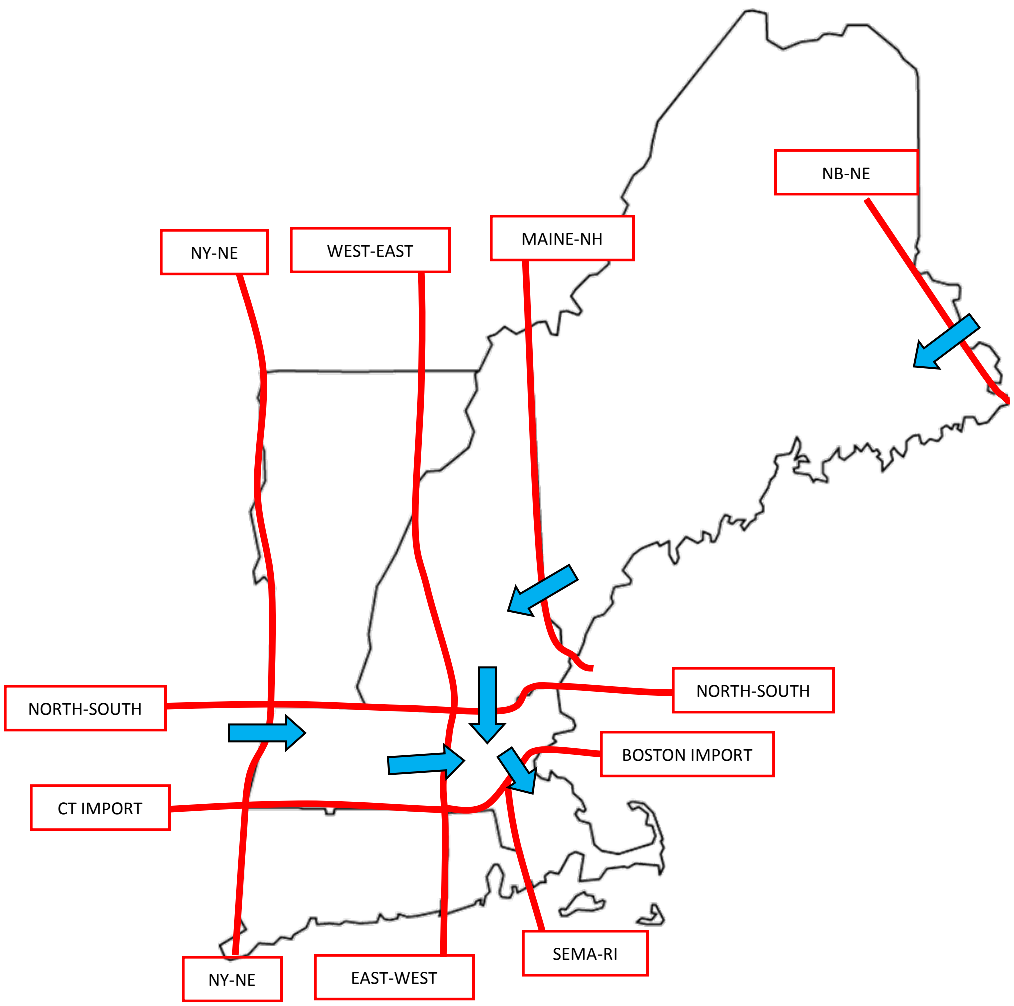


Figure 7-6 Shoulder Load D6 Dispatch

Steady state thermal and voltage analysis will be conducted for peak load conditions to verify the project does not have an adverse impact on the current regional interface transfer levels. The focus of the analysis is to show the effect of the Project on the Maine - New Hampshire interface and on the New England West - East transfers. Table 7-5 below provides a summary of dispatch scenarios and target interface flows

Maine- New Hampshire transfer

Two regional transfer scenarios (D7 and D8) were developed starting with ME-NH at 1960 MW and all of New Hampshire generators online. ACCC was run on the pre-project case to check for thermal and voltage violations in northern New England. If violations occurred, generation in New Hampshire was reduced by some amount (e.g. 50MW) and rerun until the thermal and voltage violations are just at their limit. The same process was applied to D8 however generation in Maine was reduced. [redacted]

West-East Transfer

One West-East transfer scenario was developed. This D9 scenario started with West-East transfer at 2200 MW. ACCC was run on the pre-project case to check for thermal and voltage violations in northern New England. If violations occurred, West-East transfer was reduced by some amount (e.g. 50MW) until the thermal and voltage violations are just at their limit.

Table 7-5 General Summary for Summer Peak Load Base Case Transfers

[redacted]

Dispatch D7 – The D7 dispatch stresses the northern New England interfaces, particularly ME-NH (approximately 2,000 MW) as shown in Figure 7-7. This peak load case stresses power flow from northern New England to the south coupled with high generation exports from SEMA toward western New England (East to West 3,500 MW) and New York (1200 MW export). These interface transfers represent stressed conditions for the New Hampshire reliability project.

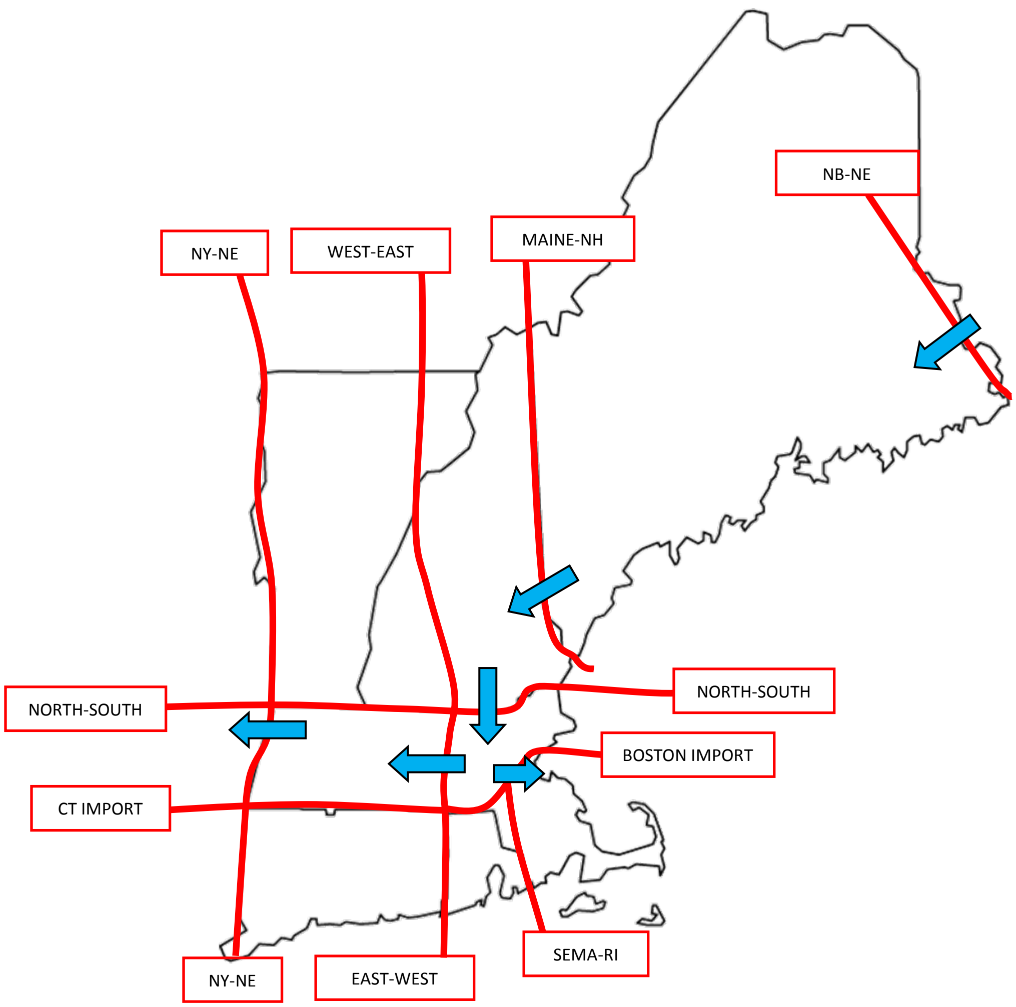


Figure 7-7 Peak Load D7 Dispatch

Dispatch D8 – The D8 dispatch stresses the New England interfaces as shown in Figure 7-8. This peak load case stresses power flow across the north – south interface coupled with high generation imports into Boston and power flows toward western New England (East to West 3,500 MW) and New York (1200 MW export). These interface transfers represent stressed conditions for the New Hampshire reliability project.

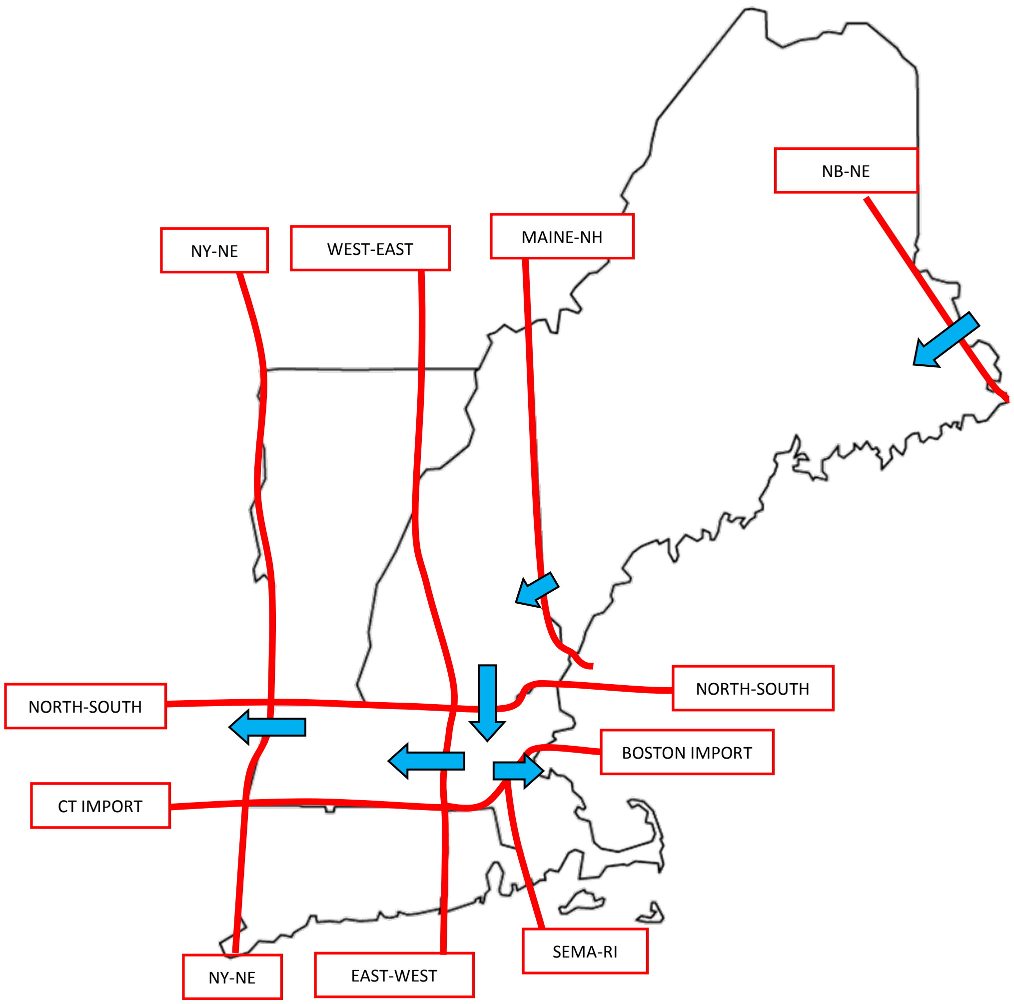


Figure 7-8 Peak Load D8 Dispatch

Dispatch D9 – The D9 dispatch stresses the northern New England interface as shown in Figure 7-9. This peak load case stresses power flow from southern to northern New England coupled with high generation imports to Boston and power flows from toward eastern New England (West to East 663MW) and New York (1200 MW import). These interface transfers represent stressed conditions for the New Hampshire reliability project.

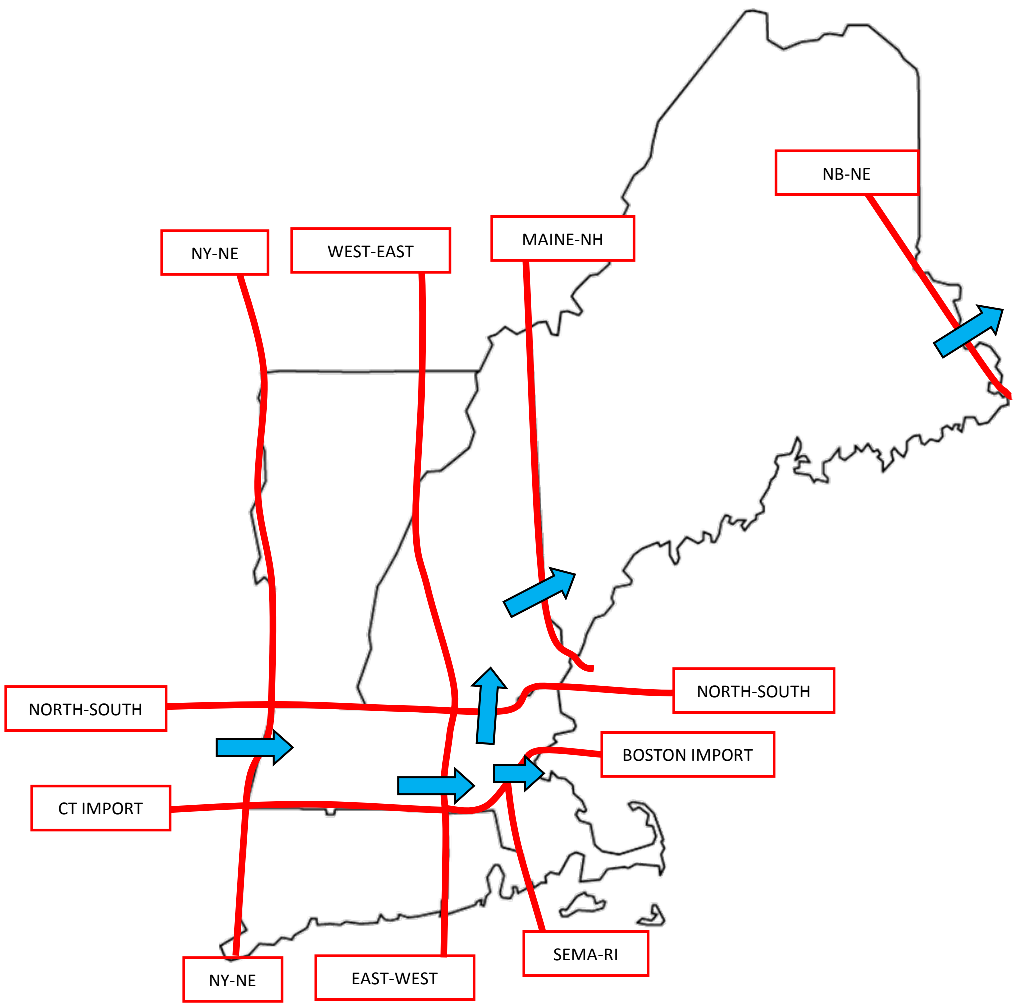


Figure 7-9 Peak Load D9 Dispatch

7.2.2 Sensitivity Cases for Steady-State Analyses

Sensitivity cases will be prepared to include the Northern Pass Transmission (NPT) Project and its' ancillary transmission system upgrades. Two stressed generation dispatch scenarios were selected from the NPT steady state analysis. Table 7-6 NPT Steady-State Sensitivity Transfers below provides a summary of interface flows and dispatch scenarios. Appendix I - Steady-State Analysis Base Case Summaries contains the detailed case summaries.

Table 7-6 NPT Steady-State Sensitivity Transfers

[redacted]

7.2.3 N-1-1 Steady State cases

Dispatch D1, D3 and D8 will be used for 345-kV line out testing.

7.3 Base Cases for Stability Analyses

7.3.1 Stability Base Case Origin, Year and Load Level

Base cases for the stability analyses originated from the MMWG 2010 library cases for the external system and the latest internal ISO-NE model as of April 2011 to represent 2017 forecasted summer peak and light load conditions. The two stability cases are to be set up to model light and peak load conditions based on the 2012 CELT Report. The active demand response (DR) is assumed zero in the cases. The passive DR is based off of the results of the ISO-NE Forward Capacity Auction (FCA) #6 and forecasted energy efficiency for the year 2017 peak load.

A light load level of approximately 13,450 MW is modeled, which is 45% of the summer peak reference load for 2017 (50/50 forecast, 50% probability of being exceeded). The passive DR is assumed to be 45% of the peak passive DR for the light load stability cases. The light load power flow cases and dynamic data for this stability analysis were obtained from the ISO-NE case library on August 15, 2011.

A peak load level of approximately 32,250 MW is modeled, which is an extreme summer peak load for 2017 (90/10 forecast, 10% probability of being exceeded). The passive DR is assumed to be at 100% for the peak load stability cases. The peak load power flow cases and dynamic data for this stability analysis were obtained from the ISO-NE case library on August 1, 2011.

The above power flow cases are updated with the following projects that are relevant to the transmission system in the greater New Hampshire area:

1. Transmission Reliability Projects
   i) The Pittsfield/Greenfield Area Upgrades are added to each of the cases; PPA approval pending.

2. Generator Interconnections-
   ii) Q345, Groton Wind, POI 115-kV Line E115 (Beebe- Ashland tap), 48 MW with an 8 Mvar DVAR; PPA approved.

   iii) Q166, Granite Reliable Wind, POI 115-kV Line W179 (Lost Nation- Berlin), 99 MW wind farm, 4 Mvar DVAR, 20 Mvar of fixed shunt 34.5-kV capacitor banks. Modification of the reactive controls of the wind farm equipment using a power plant controller (PPC); PPA approval pending.

   iv) Q311, Kingdom Wind, POI 115-kV Line K41 (Highgate-Irasburg), 65 MW wind farm, 25 Mvar SVC, 10.8 Mvar of fixed shunt 46-kV capacitor banks.

   v) Q368, Timbertop Wind, POI 34.5-kV line out of the Monadnock 115/34.5-kV Substation, 16 MW wind farm.

   vi) Q371, Antrim Wind, POI 115-kV Line L163 (Jackman-Keene), 33 MW wind farm.

In the peak load case, the Groton Wind DVAR was modeled as 4 Mvar. It should have been model as 8 Mvar. However, the fault simulations run with the peak load case resulted in Groton remaining stable.

The dynamic model for Kingdom Wind (Q311), displayed erratic behavior for remote 345-kV faults; as a result of this the generator was turned 'off'.

For Timbertop Wind (Q368), there was an error when attempting to link the dynamic model. Due to the size (16 MW) and connection POI (34.5-kV), this generator was netted with the load.

The Merrimack Unit 2 power system stabilizer was enabled.

7.3.2 Stability Base Case Generation Dispatches and Interface Transfers

Five regional generation dispatch scenarios were developed for the New Hampshire reliability project's stability analyses; four light load cases and one peak load case. At the summer peak load level the case has a north to south and east to west interface transfers. For the light load cases, three of the cases are stressed north to south and east to west directions. The fourth case is stressed south to north and west to east directions. Interface transfers were adjusted to correspond to the light load and generation conditions. These dispatches are summarized in Table 7-7 and Appendix T - Detailed Stability Base Case Summary contains the detailed dispatch summaries for each dispatch scenario.

Dispatch D10, which has a N-S, E-W bias with NH 115kV southern and seacoast area generation on-line; is compared against Dispatches D11, D12, and D13 for the machine status changes between the dispatches.
Comparison of machine status between Dispatch D10 (working case) and Dispatch D11; D11 has a N-S, E-W bias with NH 230 and 115kV northern generation on-line.

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 105451 [SCHILLER_G5 13.800] 5   -2     1      -2     0
 105452 [SCHILLER_G6 13.800] 6    2     1      -2     0
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 106043 [COMERFORD G413.800] 4   -2     0       2     1
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 106046 [MOORE G3    13.800] 3   -2     0       2     1
 106047 [MOORE G4    13.800] 4   -2     0       2     1
 106056 [GRANITE RDG116.000] C1  -2     0       2     1
 106057 [GRANITE RDG216.000] C2  -2     0       2     1
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 108899 [SHEFLD CLR-S0.6900] 1   -2     0      -2     1
 114857 [BRAYTN PT 1 18.000] 1B  -2     1      -2     0
 116579 [CABOT HYDRO 13.800] 4    2     1      -2     0
 116579 [CABOT HYDRO 13.800] 5    2     1      -2     0
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Comparison of machine status between Dispatch D10 and Dispatch D12; D12 has a N-S, E-W bias with NH 345kV seacoast area generation on-line.:

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 111096 [ANP BLKSTN 221.000] 2   -2     0       2     1
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Comparison of machine status between Dispatch D10 and Dispatch D13; D13 has a S-N, W-E bias with NH 115kV southern and seacoast area generation on-line.

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 100388 [WESTBROOK ST18.000] S1   2     1      -2     0
 100389 [BUCKSPORT G418.000] 4    2     1      -2     0
 100418 [SAPPI WBRK 913.800] 9   -2     1      -2     0
 100422 [SAPPI SMSTG113.800] 1    2     1      -2     0
 100423 [SAPPI SMSTG213.800] 2    2     1      -2     0
```

100425	[NEWPAGE COGN13.800]	4	-2	1	-2	0
100465	[CAPE GT 4 13.200]	4	-2	1	-2	0
103062	[MIS ST 18.000]	S1	-2	0	2	1
103069	[WEST ENFIELD13.200]	1	-2	0	-2	1
103072	[RED SHLD ENV13.800]	1	-2	0	-2	1
103074	[LINCOLIN P&T13.200]	1	-2	0	2	1
103125	[MILL2 STEAM 13.800]	3	-2	0	-2	1
105464	[NEWINGTON_G124.000]	1	-2	0	2	1
105477	[NEWINGTON_C218.000]	C2	-2	0	2	1
105478	[NEWINGTON_S118.000]	S1	-2	0	2	1
105633	[GRANITE R ST16.000]	S1	-2	0	2	1
106040	[COMERFORD G113.800]	1	2	1	-2	0
106056	[GRANITE RDG116.000]	C1	-2	0	2	1
106057	[GRANITE RDG216.000]	C2	-2	0	2	1
111009	[MBTA 14.400]	J	-2	1	-2	0
111067	[MYSTIC GT 8A16.000]	8A	2	1	-2	0
111068	[MYSTIC 8ST 18.000]	8C	2	1	-2	0
111069	[MYSTIC GT 9A16.000]	9A	2	1	-2	0
111070	[MYSTIC 9ST 18.000]	9C	2	1	-2	0
111071	[MYSTIC GT 8B16.000]	8B	2	1	-2	0
111072	[MYSTIC GT 9B16.000]	9B	2	1	-2	0
111122	[KENDALL ST A13.800]	2	-2	1	-2	0
111123	[KENDALL ST B13.800]	3	-2	1	-2	0
111125	[PUTNAM 2 13.800]	1	-2	1	-2	0
111125	[PUTNAM 2 13.800]	M	-2	1	-2	0
111126	[KENDALL CT 18.000]	4	-2	1	-2	0
111251	[CANAL G1 18.000]	1	2	1	-2	0
111252	[CANAL G2 18.000]	2	2	1	-2	0
114069	[WHLABRATR NA13.800]	1	2	1	-2	0
114070	[OGDEN-MARTIN13.800]	1	2	1	-2	0
114470	[GE RIVER R&T13.800]	R	2	1	-2	0
114470	[GE RIVER R&T13.800]	T	2	1	-2	0
114474	[GE RIVER S&U13.800]	S	2	1	-2	0
114474	[GE RIVER S&U13.800]	U	2	1	-2	0
114856	[BRAYTN PT 4 18.000]	4	2	1	-2	0
114857	[BRAYTN PT 1 18.000]	1B	-2	1	-2	0
114861	[ANP BLLNGHM121.000]	1	2	1	-2	0
115496	[BROCKTON_ST 15.750]	S1	-2	0	-2	1
115497	[BROCKTON_GT 16.500]	C1	-2	0	2	1
116505	[BERKSHRE_G1 21.000]	1	-2	0	2	1
116579	[CABOT HYDRO 13.800]	1	2	0	2	1
116579	[CABOT HYDRO 13.800]	2	2	0	2	1
116579	[CABOT HYDRO 13.800]	3	2	0	2	1
117029	[OCEAN ST GT113.800]	C1	2	1	-2	0
117031	[OCEAN ST ST113.800]	S1	2	1	-2	0
117034	[OCEAN ST ST213.800]	S2	-2	0	2	1
117426	[MANCHSTR 09A13.800]	9	-2	0	-2	1
121513	[LAKE ROAD_C121.000]	1	-2	0	2	1
121514	[LAKE ROAD_C221.000]	2	-2	0	2	1
122030	[KLEEN_C1 18.000]	C1	-2	0	2	1
122031	[KLEEN_C2 18.000]	C2	-2	0	2	1
122032	[KLEEN_S1 20.000]	S1	-2	0	2	1
122041	[MIDDLETWN_G213.800]	2	-2	0	2	1
122043	[MIDDLETWN_G422.000]	4	-2	0	2	1
122044	[MIDDLETWN_1013.200]	10	-2	0	2	1
122046	[MIDDLETWN_1213.800]	12	-2	0	2	1
122047	[MIDDLETWN_1313.800]	13	-2	0	2	1
122048	[MIDDLETWN_1413.800]	14	-2	0	2	1
122049	[MIDDLETWN_1513.800]	15	-2	0	2	1
122449	[WALLINGFRDG213.800]	2	-2	0	2	1
122450	[WALLINGFRDG313.800]	3	-2	0	2	1
122451	[WALLINGFRDG413.800]	4	-2	0	2	1
122452	[WALLINGFRDG513.800]	5	-2	0	2	1
122470	[DEVON #11 13.800]	11	-2	0	2	1
122471	[DEVON #12 13.800]	12	-2	0	2	1
122472	[DEVON #13 13.800]	13	-2	0	2	1
122473	[DEVON #14 13.800]	14	-2	0	2	1
122476	[DEVON #15-1613.800]	15	-2	0	2	1
122476	[DEVON #15-1613.800]	16	-2	0	2	1
122477	[DEVON #17-1813.800]	17	-2	0	2	1
122477	[DEVON #17-1813.800]	18	-2	0	2	1
122586	[TOWANTIC_CT118.000]	C1	-2	0	2	1
122587	[TOWANTIC_CT218.000]	C2	-2	0	2	1
122588	[TOWANTIC_ST 18.000]	S1	-2	0	2	1
122844	[NORHRBR #1 18.000]	1	-2	0	-2	1
125192	[ROSE GN2 24.000]	2	-2	0	-2	1
126658	[RAV 2 20.000]	1	-2	0	2	1
126658	[RAV 2 20.000]	2	-2	0	2	1
126692	[SCS18-G4 18.000]	1	-2	0	2	1
126710	[SCS18-G5 18.000]	1	-2	0	2	1
126711	[SCS18-G6 18.000]	1	-2	0	2	1
190453	[MACTG4 13.800]	1	2	1	-2	0
190454	[MACTG5 13.800]	1	2	1	-2	0
190458	[C.CVG2 19.000]	1	2	1	-2	0
190459	[C.CVG3 19.000]	1	2	1	-2	0

```
190461 [DALHG2      19.000] 1    2     1      -2     0
190473 [BAYSIDE6    19.000] 1    2     1      -2     0
190996 [MARHILLSWIND0.6000] 1    2     1      -2     0
```

Table 7-7 Stability Base Case Transfers

[redacted]

The stability cases are set-up to stress the system by turning 'on' generation within the area of interest.

Table 7-8 Stability Case Bias Summary

Dispatch	2017 Load Level	Power Flow Bias	Stressed NH Generation Pocket
D10	Light	N-S, E-W	NH 115 kV, south & seacoast areas
D11	Light	N-S, E-W	NH 230 kV, 115 kV north
D12	Light	N-S, E-W	NH 345 kV, seacoast area
D13	Light	W-E, S-N	NH 115 kV, south & seacoast areas
D14	Peak	N-S, E-W	NH 115 kV, south & seacoast areas

Table 7-9 General Base Case Summary

Case name	D10 (Light) (MW)	D11 (Light) (MW)	D12 (Light) (MW)	D13 (Light) (MW)	D14 (Peak) (MW)
Area 101 load	13454	13454	13454	13454	30802
Area 101 losses	513	542	532	310	924
Area 101 load+losses	13967	13996	13986	13764	31727
Area 101 generation	14074	14104	14094	13775	29846
Area 101 interchange	91	92	92	-3	-1895

7.3.1 Sensitivity Cases for Stability Analyses

A sensitivity case is prepared to include the Northern Pass Transmission (NPT) Project and its' ancillary transmission system upgrades. Stability Dispatch D10 is re-dispatched to include NPT and N-1 contingency analysis performed. The base case summary for this case can be found in Appendix T - Detailed Stability Base Case Summaries.

Two sensitivity cases are prepared to evaluate 345-kV line out scenarios with the 326 SPS assumed in the stability mode, with PSNH Newington armed to trip if 345-kV Line 326 opens (Scobie Pond-Lawrence Road-Sandy Pond). Starting with dispatch D12, one case is re-dispatched to stress the ME-NH interface and another case is re-dispatched to stress the NNE-Scobie+394 interface; for each case two scenarios will be evaluated. The first scenario assumes that 345-kV Line 394 is out-of-service (Seabrook-W. Amesbury-Ward Hill). The second scenario assumes that 345-kV Line 397 is out-of-service (Ward Hill-Tewksbury).

For the cases with the ME-NH interface stressed to the limit identified in the ISO-NE Line Out Stability Guides for Lines 394 and 397, 345-kV generation was required to be backed down.

The base case summaries for these cases can be found in Appendix T - Detailed Stability Base Case Summaries.

The general descriptions and philosophy used to develop these dispatch scenarios for the stability analysis are on the following pages:

Dispatch D10 – The D10 dispatch stresses the northern New England interface as shown in Figure 7-10. This light load case stresses power flow from northern New England to the south coupled with high generation exports from the east toward western New England (East to West 3,500 MW) and New York (1200 MW export). Along with 115-kV generation in the southern and seacoast areas turned 'on', these interface transfers represent stressed conditions for the New Hampshire reliability project.

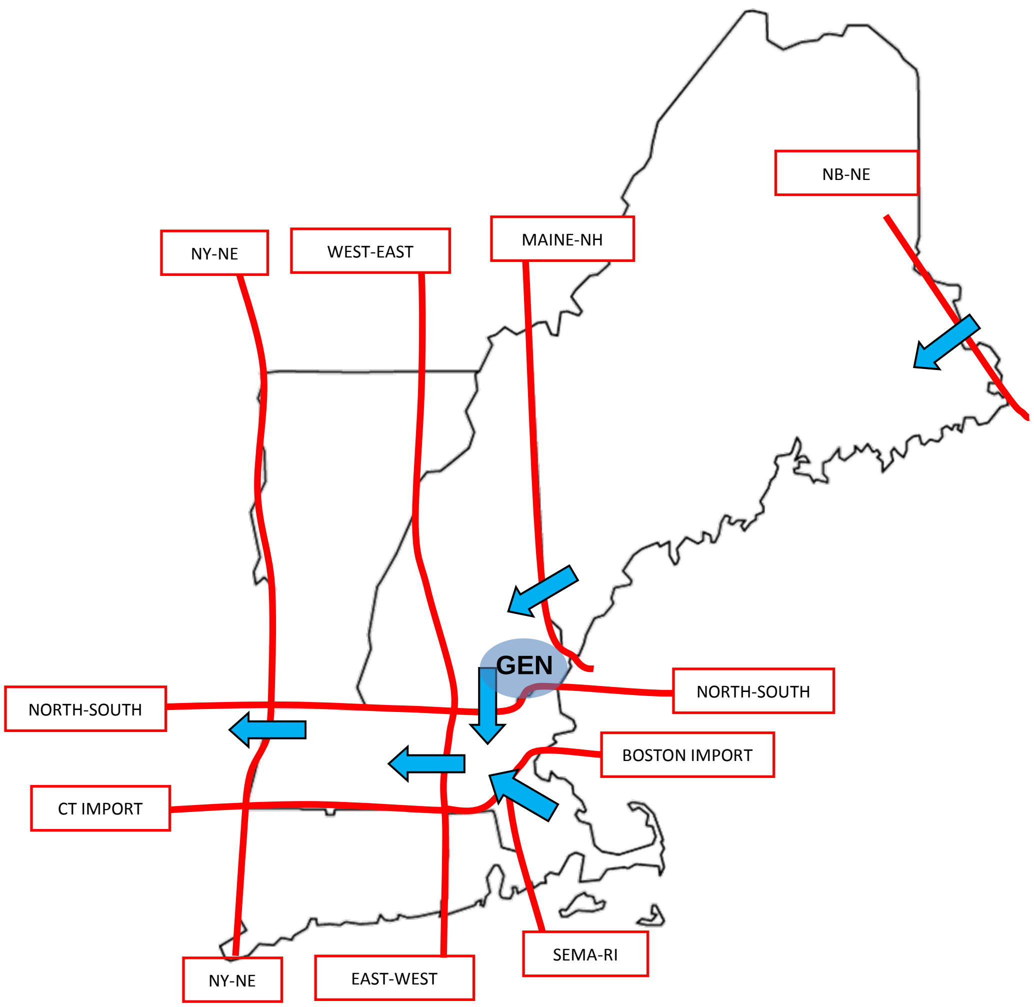

Figure 7-10 Light Load D10 Dispatch

Dispatch D11 – The D11 dispatch stresses the northern New England interface as shown in Figure 7-11. This light load case stresses power flow from northern New England to the south and toward western New England (East to West 3,500 MW) and New York (1200 MW export). Along with 230-kV and 115-kV generation in the northern area turned ‘on’, these interface transfers represent stressed conditions for the New Hampshire reliability project.

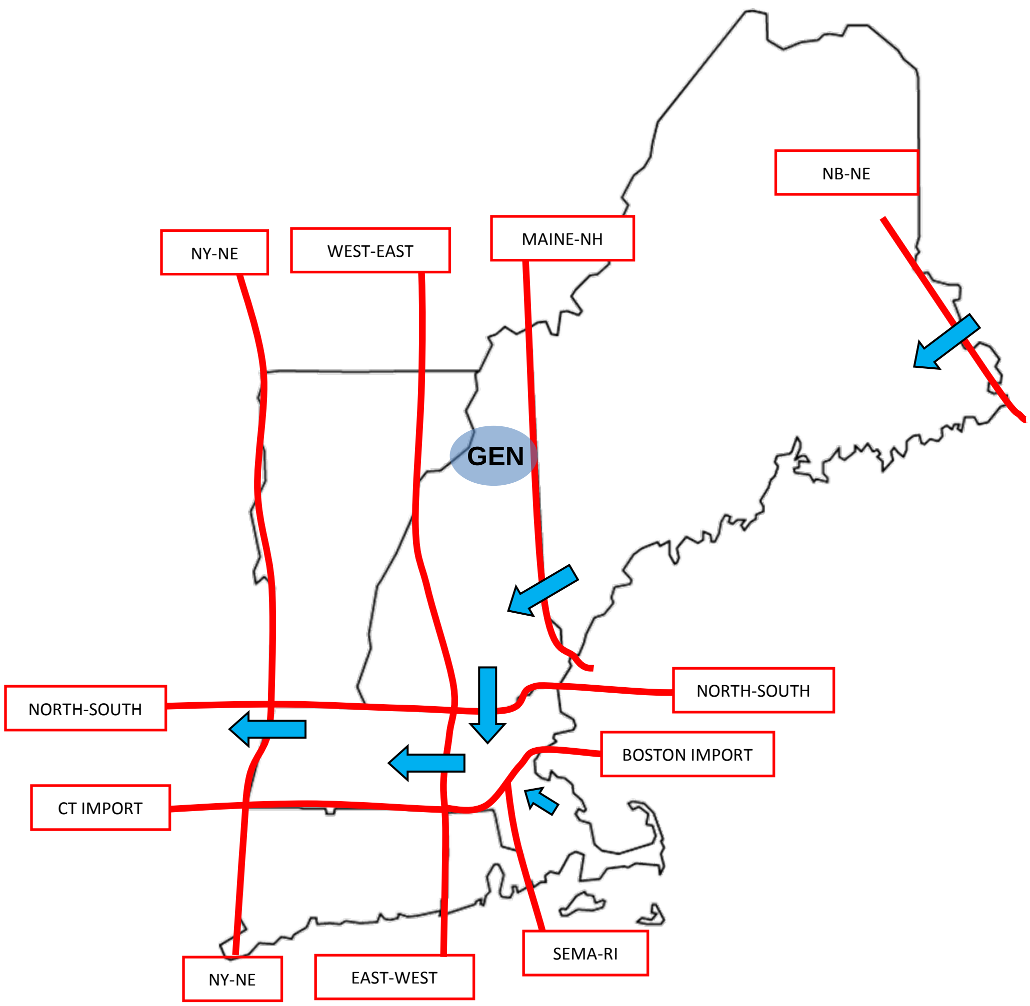

Figure 7-11 Light Load D11 Dispatch

Dispatch D12 – The D12 dispatch stresses the northern New England interface as shown in Figure 7-12. This light load case stresses power flow from northern New England to the south and toward western New England (East to West 3,500 MW) and New York (1200 MW export). Along with 345-kV generation in the seacoast area turned 'on', these interface transfers represent stressed conditions for the New Hampshire reliability project.

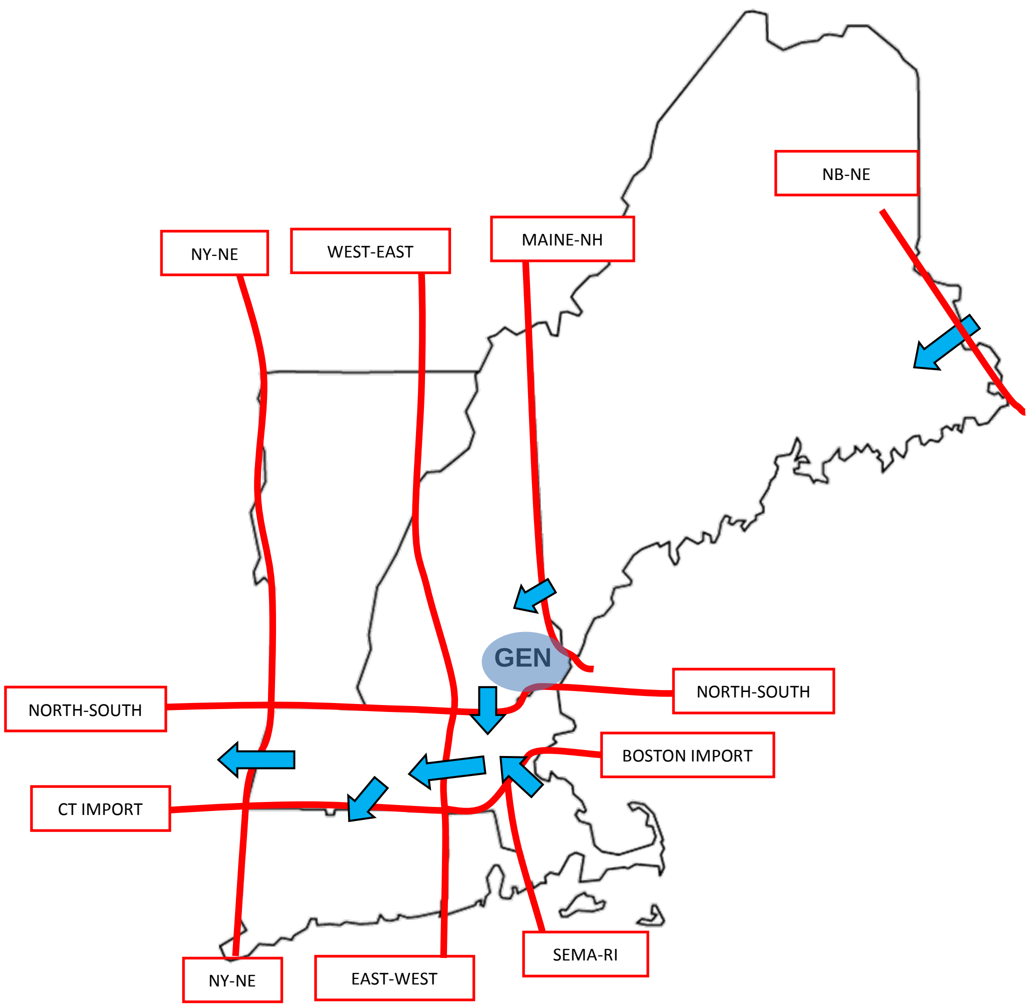

Figure 7-12 Light Load D12 Dispatch

Dispatch D13 – The D13 dispatch reduces power flows from northern New England and stresses power flows from western New England and New York as shown in Figure 7-13. This light load case stresses power flow from western New England toward eastern New England (West to East 500MW) while importing 1200 MW from New York. Along with 115-kV generation in the southern and seacoast areas turned 'on', these interface transfers represent stressed conditions for the New Hampshire reliability project.

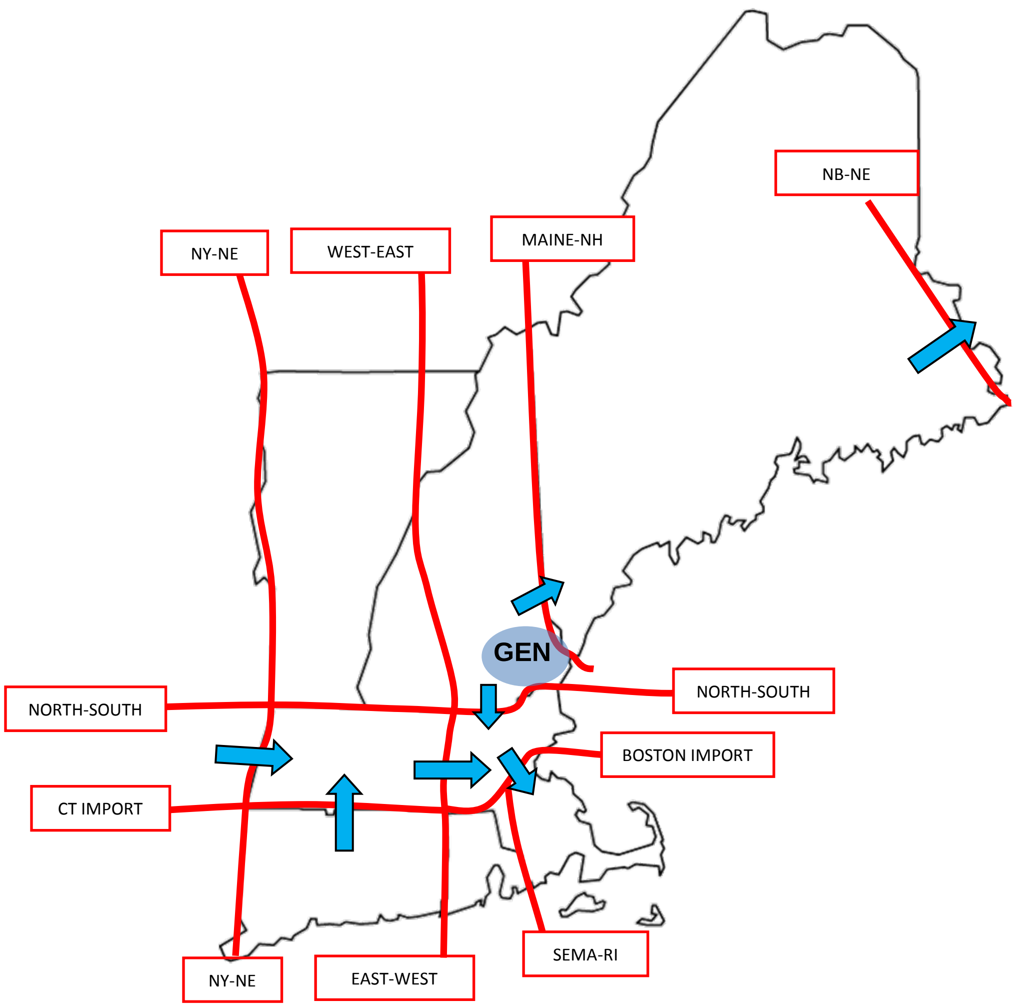

Figure 7-13 Light Load D13 Dispatch

Dispatch D14 – The D14 dispatch stresses the northern New England interface as shown in Figure 7-14. This peak load case stresses power flow from northern New England to the south coupled with high generation exports from SEMA toward western New England (East to West 3,500 MW) and New York (1200 MW export). Along with 115-kV generation in the southern and seacoast areas turned 'on', these interface transfers represent stressed conditions for the New Hampshire reliability project.

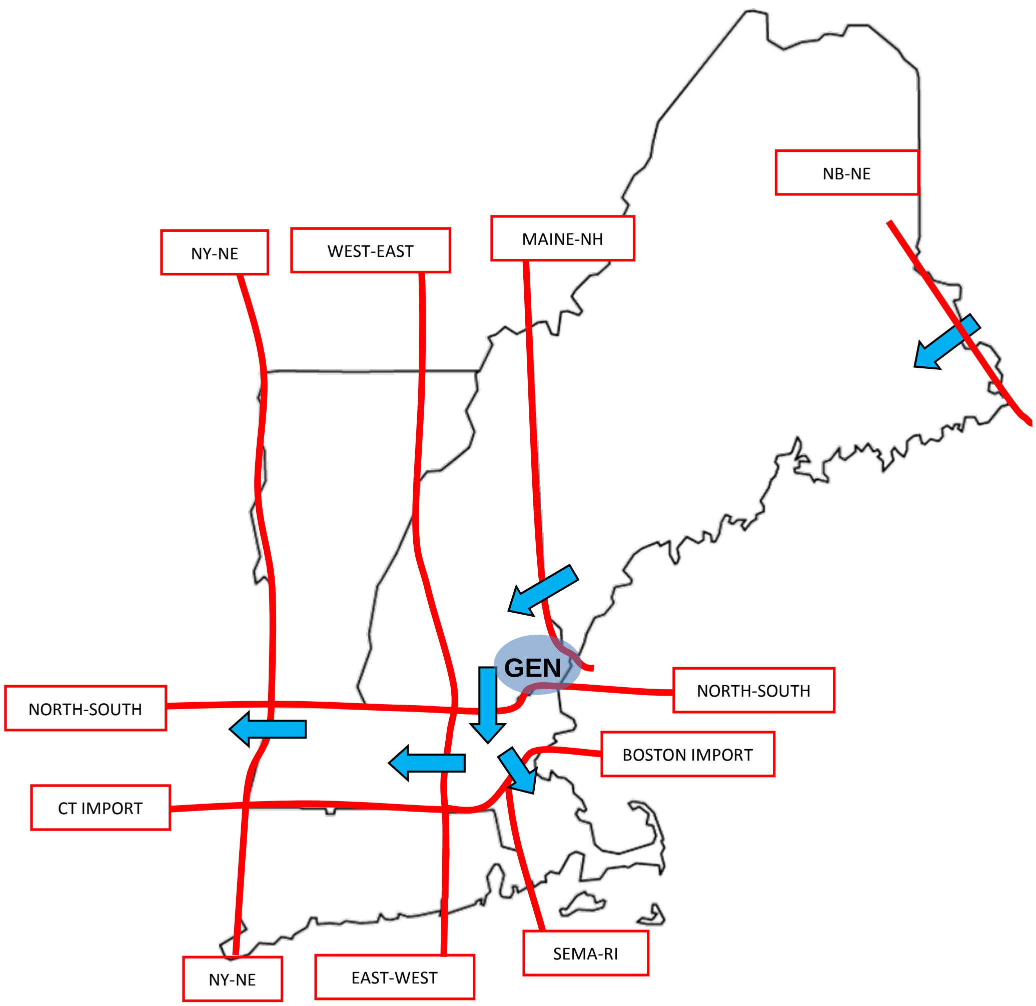

Figure 7-14 Peak Load D14 Dispatch

8 Steady-State Analysis Results

8.1 Steady-State Analyses Under Post-Project Configuration

The steady-state base cases were analyzed for thermal and voltage violations with no contingencies represented (all lines in condition). The detailed results of this analysis are shown in Appendix K - Steady-State Analysis Results.

8.1.1 Base Case Thermal Analysis

Element loadings in the base cases were compared to the normal element rating for all-in thermal violation analysis. With all transmission elements in-service, there were no elements loaded above its Normal rating.

8.1.2 Base Case Voltage Analysis

Bus voltages in the base cases were compared to the applicable Transmission Owner's voltage limit for all elements in-service voltage violation analysis. With all transmission elements in-service, there were no bus/system voltage levels outside of the applicable limits.

8.2 Post-Project Configuration N-1 Contingency Analysis

8.2.1 Post-Project Configuration N-1 Thermal Analysis

8.2.1.1 Post-Project Configuration N-1 Thermal Analysis for 2017 Peak Load Cases

In the seven peak load cases studied, there were no contingencies which resulted in transmission elements being loaded above their LTE rating [redacted].

8.2.1.2 Post-Project Configuration N-1 Thermal Analysis for 2017 Shoulder Load Cases

In the two shoulder load cases studied, there were no contingencies which resulted in transmission element overload increases of more than 1% of the respective LTE rating. [redacted]

8.2.1.3 Post-Project Configuration N-1 Thermal Analysis for NPT Sensitivity Cases

In the two NPT sensitivity cases studied, there were no contingencies which resulted in transmission element overload increases of more than 1% of the respective LTE rating. [redacted]

8.2.2 Post-Project Configuration N-1 Voltage Analysis

8.2.2.1 Post-Project Configuration N-1 Voltage Analysis for 2017 Peak Load Cases

In the seven peak load cases studied, there were only three buses with voltages above steady-state limits until an operator could perform system adjustments, but no contingencies resulted in transmission bus overvoltage increases of more than 0.5% (see "Appendix K - Steady-State Analysis Results").

8.2.2.2 Post-Project Configuration N-1 Voltage Analysis for 2017 Shoulder Cases

In the two shoulder load cases studied, there were only two buses with voltages above steady-state limits until an operator could perform system adjustments, but no contingencies resulted in transmission bus overvoltage increases of more than 0.5% (see "Appendix K - Steady-State Analysis Results").

8.2.2.3 Post-Project Configuration N-1 Voltage Analysis for NPT Sensitivity Cases

In the two NPT sensitivity cases studied, there were five buses with voltages above steady-state limits until an operator could perform system adjustments, but no contingencies resulted in transmission bus overvoltage increases of more than 0.5% (see "Appendix K - Steady-State Analysis Results").

8.2.3 N-1 Y-151 Circuit Overloads

[redacted]

8.3 Post-Project Configuration N-1-1 Contingency Analysis

8.3.1 Post-Project Configuration N-1-1 Thermal Analysis for 2017 Peak Load Cases

In the three peak load cases studied, there were 13 transmission elements loaded above their LTE rating following the second contingency [redacted]. [redacted] The loading of the 13 overloaded transmission elements never exceeded the STE rating and could be reduced by generation redispatch of less than 1200-MW.

8.3.2 Post-Project Configuration N-1-1 Thermal Analysis for 2017 Peak Load Cases

In the two NPT sensitivity cases studied, there was 1 transmission element loaded above its LTE rating following the second contingency [redacted]. The loading of the overloaded transmission element never exceeded the STE rating and could be reduced by generation redispatch of less than 1200-MW.

8.3.3 N-1-1 Y-151 Circuit Overloads

[redacted]

8.3.4 Post-Project Configuration N-1-1 Voltage Analysis for 2017 Peak Load Cases

In the three peak load cases studied, there were three buses with voltages above steady-state limits until an operator could perform system adjustments, but no contingencies resulted in transmission bus overvoltage increases of more than 0.5% (see “Appendix K - Steady-State Analysis Results”).

8.3.5 Post-Project Configuration N-1-1 Voltage Analysis for the NPT Sensitivity Cases

In the two NPT sensitivity cases studied, there were five buses with voltages above steady-state limits until an operator could perform system adjustments, but no contingencies resulted in transmission bus overvoltage increases of more than 0.5% (see “Appendix K - Steady-State Analysis Results”).

8.4 Steady State BPS Analysis

Thermal BPS testing of substations in NH showed that no new substations needed to be designated BPS substations following the Project.

8.5 326 SPS Thermal Mode Testing

The thermal operating mode of the 326 SPS was tested on both pre- and post-NH upgrade cases to evaluate the impact of the New Hampshire Reliability Project. The 326 SPS actions are simulated by generation rejection in northern New England and/or New Brunswick which is designed to relieve an overload on the 326 line following the loss of a parallel major 345 kV line.

One peak case, dispatch D7, was re-dispatched to increase the NNE-Scobie+394 interface to 3,100 MW and the North-South Interface to 3,400 MW. The ME-NH interface was maintained at 1,960 MW. [redacted] The 326 SPS actions eliminated the overload. There were no thermal violations post 326 SPS actuation [redacted]. In the post-project case, the same simulation was performed and there were no thermal violations after 326 SPS actuation, using the present set points.

One Shoulder case, dispatch D5, was modified to increase the NNE-Scobie+394 interface to 3,100MW and North-South interface to 3,800MW. The Vermont Yankee unit was turned on. [redacted] The 326 SPS actions eliminated the overload. There were no thermal violations post 326 SPS actuation [redacted]. In the post-project case, the same simulation was performed and there were no thermal violations after 326 SPS actuation, using the present set points.

A subsequent study will analyze the updating of the set points of the 326 SPS to match the upgraded rating of the 326 transmission line.

8.6 Delta-V Analysis

Delta-V analysis was conducted to determine the impact of the new capacitor banks. NU criteria requires that capacitor banks change the voltage by no more than 2.5% of nominal when all lines are in-service and by no more than 6% of nominal when one line is out-of-service.

Five substations will have new capacitor banks sized between 13.3-MVAr and 26.6-MVAr. The results are shown in Table 8-1.

Table 8-1 Delta-V Results as a Result of Project Capacitor Banks

		All Lines In-Service			One Line Out-of-Service		
Location	**Capacitor Bank Size (MVAr)**	**T0- Voltage (pu)**	**T0+ Voltage (pu)**	**Delta-V (%)**	**T0- Voltage (pu)**	**T0+ Voltage (pu)**	**Delta-V (%)**
Webster	26.6	0.9973	1.0141	1.68	0.9792	1.0020	2.28
Eagle	26.6	1.0197	1.0313	1.16	0.9918	1.0223	3.05
Amherst	26.6	1.0224	1.0257	0.33	1.0305	1.0420	1.15
Schiller	13.3	1.0348	1.0402	0.54	1.0348	1.0409	0.61
Weare	13.3	1.0197	1.0263	0.66	1.0358	1.0795	4.37

9 Short Circuit Analysis Results

9.1 Analysis of Circuit Breakers

Short-circuit analyses were performed on all New Hampshire substations. A flat source voltage of 1.05 per unit was assumed. Table 9-1 provides a summary of all existing 115 and 345-kV circuit breakers that could experience fault duties in excess of 90% of their interrupting or momentary ratings. Only the Merrimack Q171 circuit breaker is overdutied and will be replaced as part of these New Hampshire reliability projects. Refer to Appendix M - Short Circuit Analysis Results for further details.

Table 9-1 Circuit Breaker Analysis Summary - Existing Breakers

Station	Breaker	Post NPT, Pre-NHRP		Post NPT, Post-NHRP	
		Fault Duty (%)	Momentary Duty (%)	Fault Duty (%)	Momentary Duty (%)
Merrimack	Q171	**81.2**	100 5	**82.2**	101 7
	C196	**80.7**	94 9	**81.7**	96 1
	H137	**87.5**	69 7	**91.1**	72 7

10 Stability Analysis Results

The Stability plots are contained in Appendix L - Stability Analysis Plots as a separate electronic file due to the file size.

10.1 Stability BPS Testing Results

Stability bulk power system testing was performed to determine if the New Hampshire reliability projects cause a switching station or substation to be classified as part of the New England bulk power system. The stations that were tested are listed in Section 6.3.1, Table 6-3 Substations to be BPS Tested.

Table 10-1 contains the results of the BPS testing. A "Fail" result means the station did not meet the acceptability criteria and a "Pass" result means the station did meet the acceptability criteria. A failure for any of the dispatches requires BPS classification for the tested station.

Table 10-1 BPS Stability Testing Results

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]					
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

7 [redacted]

BPS faults that resulted in a loss of source of 1200 MW or greater fail the BPS test and are classified as BPS.

Table 10-2 provides a summary of the stations that will be classified as BPS subsequent to each New Hampshire reliability project component.

Table 10-2 New BPS Stations

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Table 10-3 Results for New BPS Stations

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

U≡ undetermined

[redacted]

[redacted]

Since the Power St. 115-kV Substation failed its BPS test, a further BPS fault test was run at the West Methuen 115-kV Substation. The BPS test for the West Methuen Substation resulted in a BPS negative result (non-BPS).

[redacted]

The loss of source for the Littleton 115-kV BPS test was 280 MW, however the simulation failed to converged due to low voltages, identified with the PSSE generic relay scanning enabled. This flagged local area low voltages, which indicates the potential of a local area voltage collapse and therefore a local issue. Based on this reasoning, the Littleton 115-kV Substation is classified as non-BPS.

10.2 345-kV Fault Simulations

10.2.1 345-kV Extreme Contingencies

345-kV extreme contingency faults were simulated for the New Hampshire reliability projects. Complete 345-kV contingency definitions and clearing times can be found in Appendix H - Stability .

For dispatches D10, D11, and D12, light load, post-project, 345-kV three phase faults accompanied with a 345-kV breaker failure at the West Medway Substation, EC321; results in the simulations failing to converge. Other 345-kV extreme contingencies were observed as not meeting the voltage sag guideline and are shown below for information. All other 345-kV extreme contingency results were acceptable based on the stability reliability criteria.

For dispatch D13, light load, post-project (west to east and south to north bias) all of the simulations converged and all of the 345-kV extreme contingency results were acceptable based on the stability reliability criteria.

For dispatch D14, peak load, post-project(east to west and north to south bias), 345-kV three phase faults accompanied with a 345-kV breaker failure at the Sandy Pond Substation, EC320, result in the simulation failing to converge. All other 345-kV extreme contingency results were acceptable based on the stability reliability criteria.

Table 10-4 Results for Light Load 345-kV EC

Dispatch	Contingency	Substation	Loss of Source (MW)	Voltage Sag Guideline Limits Exceeded	App. Z into zone relay of Line 388	App. Z into zone relay of Line 392	Comments
D10	EC300	Scobie Pond	0	Yes	No	No	---
D10	EC320	Sandy Pond	40	Yes	No	No	---
D10	EC321	W. Medway	U	U	U	U	Simulation aborts
D10	EC323	Wachussett	0	Yes	No	No	---
D11	EC300	Scobie Pond	0	Yes	No	No	---
D11	EC320	Sandy Pond	U	U	U	U	Simulation aborts
D11	EC321	W. Medway	U	Yes	No	No	---
D11	EC322	Mystic	0	Yes	No	No	---
D11	EC323	Wachussett	47	Yes	No	No	---
D12	EC300	Scobie Pond	0	Yes	No	No	---
D12	EC318	Seabrook	0	Yes	No	No	---
D12	EC320	Sandy Pond	U	U	U	U	Simulation aborts
D12	EC321	W. Medway	U	U	U	U	Simulation aborts
D12	EC322	Mystic	0	Yes	No	No	---
D12	EC323	Wachussett	0	Yes	No	No	---

U≡ undetermined

Extreme contingency mitigation options for contingencies EC320 and EC321 that have been simulated with Dispatch D12, are shown in Table 10-5 Summary of Mitigation for Dispatch D12. Dispatch D12 was used since both contingencies failed to converge for this dispatch. These case adjustments were made to dispatch D12 attempting to achieve a convergent simulation for both EC320 and EC321, however this was not achieved, but is documented for information. This is considered a pre-existing system condition, not impacted by the proposed projects.

Table 10-5 Summary of Mitigation for Dispatch D12

Option	Simulation Change	EC320 Sandy 2643 BF LOS (MW)	EC321 W.Medway 105 BF LOS (MW)	Comments
Base	None.	U	U	EC320 aborts at about 3 seconds. EC321 aborts at about 3 seconds. Out of step conditions observed between the Orrington-South and Surowiec-South interfaces, lines tripped.
a	increase Boston-Import by turning off Mystic 8 and turning 'on' Bellingham and Edgar units in SEMA	U	1024	EC320 aborts at about 3 seconds, out of step conditions observed between the Orrington-South and Surowiec-South interfaces. EC321 converges with no out of step conditions.
b	Same as 'a', with out of step scanning trip enabled	U	1045	EC320 aborts at about 3 seconds, with out of step conditions observed and lines tripped between the Orrington-South and Surowiec-South interfaces. EC321 converges with no out of step conditions.
c	'a' and 'b', with breaker failure clearing times reduced to 9 cycle	0	U	EC320 converges with no out of step conditions. EC321 simulation aborts with out of step conditions observed and lines tripped between the Orrington-South and Surowiec-South interfaces.
d	Original D12 dispatch, with breaker failure clearing times reduced to 9 cycle, with out of step scanning trip enabled	0	U	Same as 'c', with out of step lines tripping in Maine.
e	Original D12 dispatch, with out of step scanning trip enabled	U	U	EC320 aborts at about 3 seconds. EC321 aborts at about 3 seconds. Out of step conditions observed and lines tripped between the Orrington-South and Surowiec-South interfaces.
f	Original D12 dispatch, decrease North-South by turning off Newington Energy and turning 'on' Bellingham and Edgar units in SEMA	0	U	EC320 converges with no units tripping and no out of step conditions. EC321 abort at about 3 seconds, with out of step conditions observed between the Orrington-South and Surowiec-South interfaces.
g	Combination of a. and f.	U	U	EC320 aborts at about 3 seconds. EC321 aborts at about 4 seconds. Out of step conditions observed between the Orrington-South and Surowiec-South interfaces, lines tripped.
h	decrease Surowiec-South by turning gen. of north of the interface. Turned 'on' Westbrooks to increase ME-NH, turned off coned Newington to reduce N-S. balanced swing with turning 'on' Edgar units in SEMA	0	U	EC320 converges with no units tripping and no out of step conditions. EC321 abort at about 3 seconds, with out of step conditions observed between the Orrington-South and Surowiec-South interfaces.

U≡ undetermined

[redacted]

Extreme contingencies EC320 and EC321 were rerun on a pre-project case and the same results were observed.

[redacted] Again, both the pre and post-project results were similar. The below Figure 10-1- EC318 Pre & Post Project, shows 345-kV bus voltages at certain parts of the system.

Figure 10-1- EC318 Pre & Post Project

[redacted]

[redacted] This was the only fault which resulted in actuating the 326 SPS and the fault resulted in acceptable system responses.

[redacted] Rerunning this fault resulted in acceptable system responses. The below figures illustrate the per unit current flow on Line 326 for the fault EC318, post and pre-326 uprate.

Figure 10-2- EC318 LT 326 SPS Set Point Post-326 Uprate

[redacted]

Referring to Figure 10-2- EC318 LT 326 SPS Set Point Post-326 Uprate, for light load Dispatches D10 and D12 the rerun for EC318 with the post-project 326 SPS set point of 1906 MVA exceeds the 326 SPS post-project set point, however the duration is not long enough (2.0 seconds or greater) to trigger the 326 SPS. For light load Dispatches D11 and D13 the current flow on Line 326 is less than the SPS set point. The pre-project SPS set point of 1430 MVA is shown on the figure for reference.

Figure 10-3- EC318 PK 326 SPS Set Point Post-326 Uprate

[redacted]

Referring to Figure 10-3- EC318 PK 326 SPS Set Point Post-326 Uprate, for the peak load Dispatch D4 the rerun for EC318 with the post-project 326 SPS set point of 1906 MVA exceeds the 326 SPS post-project set point, however the duration is not long enough (2.0 seconds or greater) to trigger the 326 SPS. The pre-project SPS set point of 1430 MVA is shown on the figure for reference.

Figure 10-4- EC318 LT 326 SPS Set Point Pre-326 Uprate

[redacted]

Referring to Figure 10-4- EC318 LT 326 SPS Set Point Pre-326 Uprate and Figure 10-5- EC318 PK 326 SPS Set Point Pre-326 Uprate, the faults run with the SPS modeling a set point of 1430 MVA are shown. [redacted] The actuating of the 326 SPS dynamic model resulted in an acceptable system response. For light load Dispatches D11 and D13 the SPS set point was exceeded temporarily, but the flow was not above the set point for more than 2.0 second time delay; therefore did not actuate the SPS.

Figure 10-5- EC318 PK 326 SPS Set Point Pre-326 Uprate

[redacted]

With Dispatch D10 a three phase to ground 345-kV fault on Line 357, at W. Medway with breaker 105 failure (EC321), light load, pre and post-NH 10-Yr. Projects. Both simulations aborted at approximately 3 seconds. The below figures show generator rotor angles, 345-kV bus voltages, and machine electric power at certain parts of the system.

Figure 10-6- EC321 Pre & Post Project (rotor angle)

[redacted]

Figure 10-7 EC321 Pre & Post Project (345-kV bus voltage)

[redacted]

Figure 10-8 EC321 Pre & Post Project (Pe)

[redacted]

[redacted] These faults were rerun as a design contingency involving the same elements but using 1LG fault with a breaker failure. These faults are designated as DC319 (EC320) and DC320 (EC321).

10.2.2 345-kV Normal Contingencies

345-kV three-phase normal contingency faults with loss of a single element were simulated. For light load and dispatches D10, D11, D12, D13, and peak load dispatch D14; all 345-kV normal contingency simulations demonstrated acceptable system responses. Single-line-to-ground faults with delayed clearing were only run if the 345-kV three-phase-to-ground delayed cleared faults resulted in loss of source.

Two extreme contingencies (EC320; dispatch D14 and EC321; dispatches D10, D11, D12) were rerun as the normal or design contingency version. These two modified contingencies (DC319 and DC320) were rerun and demonstrated acceptable system responses. The stability plots can be found in Appendix L - Stability Analysis Plots

10.3 230-kV Fault Simulations

10.3.1 230-kV Extreme Contingencies

230-kV extreme contingency faults were simulated for the New Hampshire reliability projects. Complete 230-kV contingency definitions and clearing times can be found in Appendix H - Stability Contingency List. The stability plots can be found in Appendix L - Stability Analysis Plots

230-kV three-phase extreme contingency faults were simulated. For light load and dispatches D10, D11, D12, D13, and peak load dispatch D14; the 230-kV extreme contingency simulations demonstrated acceptable system responses.

10.3.2 230-kV Normal Contingencies

230-kV three-phase normal contingency faults with loss of a single element, and 230-kV normal contingency, single-phase faults with stuck breakers were simulated. The stability plots can be found in Appendix L - Stability Analysis Plots.

230-kV three-phase normal contingency faults were simulated. For light load and dispatches D10, D11, D12, D13, and peak load dispatch D14; the 230-kV normal contingency simulations demonstrated acceptable system responses.

There is documentation of a teleconference regarding the protection and controls design, present and near term future, for the 230-kV Lines D204 and C203 in Appendix H - Stability Summary of Results.

10.4 115-kV Fault Simulations

10.4.1 115-kV Extreme Contingencies

115-kV three-phase extreme contingency faults were simulated for light load and dispatches D10, D11, D12, D13, and peak load dispatch D14. The K-Street extreme contingency (EC113) was used as bench marking fault for the pre and post fault simulations. All other 115-kV extreme contingency results were acceptable based on the stability reliability criteria. The stability plots can be found in Appendix L - Stability Analysis Plots.

[redacted] below figure shows 345-kV bus voltages at certain parts of the system.

Figure 10-9 EC113 Pre & Post Project (345-kV)

[redacted]

115-kV extreme contingencies that are acceptable, but had source loss, are rerun as a design contingency, if there is not an existing version of a design contingency. This is usually done by changing the fault from a three-line-to-ground to a single-line-to-ground fault, and still assuming a delayed clearing.

10.4.2 115-kV Normal Contingencies

115-kV three-phase normal contingency faults with loss of a single element, and 115-kV normal contingency, single-phase faults with stuck breakers were simulated. For light load and dispatches D10, D11, D12, D13, and peak load dispatch D14 ; the 115-kV normal contingency simulations demonstrated acceptable system responses, Appendix L - Stability Analysis Plots.

10.5 Double Circuit Tower Contingencies

Contingencies simulating simultaneous faults on 345/115-kV double-circuit towers were tested. All double circuit tower (DCT) contingency simulations demonstrated an acceptable system response, see Appendix L - Stability Analysis Plots. Table 10-6 identifies the lines involved in the DCT testing and the location of the concurrent faults which were applied.

To simulate the DCT contingency, a single line to ground fault is applied on each of the circuits, 345-kV and 115-kV at the fault locations.

Table 10-6 DCT Simulations

Lines Tested	Fault Locations
307 Line, N133 Line	Piscataqua River Lower Crossing
381 Line, N186 Line	Connecticut River Crossing
307 Line, R169 Line	Piscataqua River Upper Crossing

10.6 Stability Line-out Testing

The 345-kV line out simulations for the post-project demonstrated an acceptable system responses, see Appendix L - Stability Analysis Plots. Pre-project cases were run and also found to have acceptable system responses. Table 10-7 345-kV Line Out Scenarios identifies the 345-kV lines assumed out-of-service. Contingencies simulating a system fault with a 345-kV line assumed out-of-service were tested. This testing was performed to ensure that the proposed projects do not adversely impact the ISO-NE Line Out stability guides for 345-kV Lines 394 and 397.

Table 10-7 345-kV Line Out Scenarios

Line Out-of-Service	Stressed Interface
Line 394 (Seabrook-W. Amesbury-Ward Hill)	ME-NH (temporary_LT_D12_post_394oos_MHa.sav) NNE-Scobie+394 (temporary_LT_D12_post_394oos_NNE.sav)
Line 397 (Ward Hill-Tewksbury)	ME-NH (temporary_LT_D12_post_397oos_MHa.sav) NNE-Scobie+394 (temporary_LT_D12_post_397oos_NNE.sav)

Two sensitivity cases are prepared to evaluate 345-kV line out scenarios with the 326 SPS assumed in the stability mode, with Yarmouth #4 and/or PSNH Newington armed in New England, and New Brunswick generation armed to trip if 345-kV Line 326 opens (Scobie Pond-Lawrence Road-Sandy Pond).

One case stresses the ME-NH interface, which has Yarmouth #4 on-line and armed to trip upon loss of Line 326. The second case stresses the NNE-Scobie+394 interface, which has Yarmouth #4 and PSNH Newington on-line and armed to trip upon loss of Line 326.

The first scenario assumes that 345-kV Line 394 is out-of-service (Seabrook-W. Amesbury-Ward Hill). The second scenario assumes that 345-kV Line 397 is out-of-service (Ward Hill-Tewksbury).

Two 345-kV design contingency faults on Line 326, close in to Scobie Pond, are evaluated with the 345-kV line out conditions. A single-line-to-ground fault on 345-kV Line 326, with a 345-kV breaker failure at Scobie Pond and a three phase-to-ground fault, normally cleared. [redacted] The simulation results are in Appendix H - Stability Summary of Results and the simulation plots in Appendix L - Stability Analysis Plots

10.7 Stability Case with Northern Pass Transmission

For light load dispatch D10; a limited number of 345-kV and 115-kV extreme contingencies, and a 345-kV normal contingency were simulated and demonstrated acceptable system responses. The contingencies were selected based on removing the lines with greatest MVA flow. The stability plots can be found in Appendix L - Stability Analysis Plots

11 Delta-P Analysis Results

Delta-P testing was not conducted in this analysis.

Appendices A through U are CEII: redacted.

Stephen J. Rourke
Vice President, System Planning

March 7, 2013

Ms. Farah Simplace
Northeast Utilities Service Company
107 Selden Street
Berlin, CT 06037-1651

Mr. Jingyuan Dong
New England Power Company
40 Sylvan Road
Waltham, MA 02451

Subject: New Hampshire Transmission Upgrades Project Proposed Plan Applications (PPAs) NU-12-T23, NU-12-T44 through NU-12-T69, NU-13-T02, NU-12-X02, NU-12-X03, NEP-12-T19, NEP-12-T20

Dear Ms. Simplace and Mr. Dong:

This letter is to inform you that pursuant to review under Section I.3.9 of the ISO Tariff, no significant adverse effect has been identified with regard to the following PPAs:

NU-12-T23 – Transmission Notification from Northeast Utilities Service Company (NU) to eliminate the conductor clearance limitations on the 18-mile 345 kV overhead line from Scobie Pond to Lawrence Road NH/MA border. Proposed in-service date of the project is December 2016.

NU-12-T44 – Transmission Notification from NU to install a 2nd 230/115 kV autotransformer at the Littleton Substation. Tap the existing National Grid 230 kV Comerford - Moore C203 line into the Littleton Substation. Build a new 1/2-mile 230 kV transmission line between the C203 tap point and the Littleton Substation and connect it to the new 230/115 kV autotransformer. Install a 230 kV circuit switcher and two 115 kV circuit breakers at Littleton Substation. Proposed in-service date of the project is December 2016.

NU-12-T45 – Transmission Notification from NU to install two +25/-12.5 MVAR 115 kV dynamic devices and two 115 kV circuit breakers at the Saco Valley Substation. Two 115/13.8 kV transformers will also be installed to accommodate the dynamic devices. Proposed in-service date of the project is December 2016.

NU-12-T46 – Transmission Notification from NU to install four 26.6 MVAR 115 kV capacitor banks and two 115 kV circuit breakers at the Webster Substation. Proposed in-service date of the project is December 2016.

ISO New England Inc.
One Sullivan Road, Holyoke, MA 01040-2841
www.iso-ne.com T 413 535-4306 F 413 540-4203

NU-12-T47 – Transmission Notification from NU to tap the existing 345 kV Scobie Pond to Amherst 380 line and build a new three-circuit breaker 345 kV ring bus. Install a single 345/115 kV autotransformer at the Eagle Substation. Install four 115 kV circuit breakers and four 26.6 MVAR capacitor banks at the Eagle Substation. Proposed in-service date of the project is December 2016.

NU-12-T48 – Transmission Notification from NU to install a new 345 kV series circuit breaker next to the existing 802 circuit breaker for the 380E line at the Scobie Pond Substation. Proposed in-service date of the project is December 2016.

NU-12-T49 – Transmission Notification from NU to build a new 6-mile 115 kV transmission line between the Scobie Pond and Huse Road Substations in parallel to the existing I158 line. Install two 115 kV circuit breakers at the Huse Road Substation and one circuit breaker at the Scobie Pond Substation. Proposed in-service date of the project is December 2016.

NU-12-T50 – Transmission Notification from NU to eliminate terminal equipment and conductor clearance limitations on the 18-mile 115 kV Deerfield to Garvins G146 line. Proposed in-service date of the project is December 2016.

NU-12-T51 – Transmission Notification from NU to eliminate terminal equipment and conductor clearance limitations on the 12-mile 115 kV Merrimack to Oak Hill P145 line. Proposed in-service date of the project is December 2016.

NU-12-T52 – Transmission Notification from NU to rebuild the existing 15-mile 115 kV Deerfield to Pine Hill D118 line. Proposed in-service date of the project is December 2016.

NU-12-T53 – Transmission Notification from NU to rebuild the existing 3-mile 115 kV Merrimack to Garvins H137 line. Proposed in-service date of the project is December 2016.

NU-12-T54 – Transmission Notification from NU to eliminate terminal equipment and conductor clearance limitations on the existing 115 kV Greggs-Rimmon-Eddy J114 line. Proposed in-service date of the project is December 2016.

NU-12-T55 – Transmission Notification from NU to tap the existing 115 kV Garvins-Webster V182 line into the Oak Hill Substation and build six 115 kV circuit breakers at the new substation in a "breaker & half" configuration. Proposed in-service date of the project is December 2016.

NU-12-T56 – Transmission Notification from NU to relocate the existing two 36.7 MVAR 115 kV capacitor banks from Bus 2, installing one bank on Bus 1 and the other bank on Bus 3 at the Merrimack Substation. Replace the existing Q171 circuit breaker at the Merrimack Substation. Proposed in-service date of the project is December 2016.

NU-12-T57 – Transmission Notification from NU to rebuild the existing 5-mile 115 kV Eagle – Bridge Street – Power Street K165 line. Proposed in-service date of the project is December 2016.

NU-12-T58 – Transmission Notification from NU to build a new 13-mile 115 kV transmission line between the Madbury and Portsmouth Substations. Install one 115 kV circuit breaker at both the Madbury and Portsmouth Substations. Proposed in-service date of the project is December 2016.

NU-12-T59 – Transmission Notification from NU to build a new 6-mile 115 kV transmission line between the Scobie Pond and Chester Substations. Build a new five 115 kV circuit breaker substation in a "breaker & half" configuration at the Chester Substation and install one 115 kV circuit breaker at the Scobie Pond Substation. Proposed in-service date of the project is December 2016.

NU-12-T60 – Transmission Notification from NU to install six 13.3 MVAR capacitor banks and two 115 kV circuit breakers at the Schiller Substation. Install a new 115 kV circuit breaker in series with the existing BT10 circuit breaker. Relocate the existing 115 kV Schiller – Portsmouth Z156 line from Bus A to Bus B. Proposed in-service date of the project is December 2016.

NU-12-T61 – Transmission Notification from NU to eliminate terminal equipment and conductor clearance limitations on the 19-mile 115 kV Chester to Great Bay H141 line. Proposed in-service date of the project is December 2016.

NU-12-T62 – Transmission Notification from NU to eliminate terminal equipment and conductor clearance limitations on the 11-mile portion of the 115 kV Scobie Pond to Kingston Tap R193 line. Proposed in-service date of the project is December 2016.

NU-12-T63 – Transmission Notification from NU to install a new 115 kV circuit breaker in series with the R1690 circuit breaker at the Three Rivers Switching Station. Proposed in-service date of the project is December 2016.

NU-12-T64 – Transmission Notification from NU to build a new 2-mile 115 kV transmission line between the Fitzwilliam and Monadnock Substations. Install two 115 kV circuit breakers at the Fitzwilliam Substation and one 115 kV circuit breaker at the Monadnock Substation. Proposed in-service date of the project is December 2016.

NU-12-T65 – Transmission Notification from NU to install two 345 kV 26.6 MVAR capacitor banks and one 345 kV circuit breaker at the Amherst Substation. Proposed in-service date of the project is December 2016.

NU-12-T66 – Transmission Notification from NU to eliminate terminal equipment and conductor clearance limitations on the 11-mile 115 kV Keene to Monadnock T198 line. Proposed in-service date of the project is December 2016.

NU-12-T67 – Transmission Notification from NU to install two 115 kV 13.3 MVAR capacitor banks and one 115 kV circuit breaker at the Weare Substation. Proposed in-service date of the project is December 2016.

NU-12-T68 – Transmission Notification from NU to rebuild the existing 13-mile 115 kV Chestnut Hill to Westport to Swanzey A152 line. Proposed in-service date of the project is December 2016.

NU-12-T69 – Transmission Notification from NU to rebuild the existing 1-mile 115 kV Chestnut Hill to NH/VT border N186 line. Proposed in-service date of the project is December 2016.

NU-12-X02 – Transmission Notification from NU to retire the Saco Valley Under Voltage Load Shedding (UVLS) scheme. Proposed in-service date of the project is December 2016.

NU-12-X03 – Transmission Notification from NU to retire the Beebe River UVLS scheme. Proposed in-service date of the project is December 2016.

NU-13-T02 – Transmission Notification from NU to upgrade the Power Street Substation in Hudson, NH to NPCC BPS standards. Proposed in-service date of the project is December 2016.

NEP-12-T19 – Transmission Notification from New England Power Company (NEP) to reconductor the 345 kV 326 line section between Sandy Pond in Ayer, MA and MA/NH state border with 2-1113 ACSR. Replace five 345 kV 2000A disconnects with 3000A disconnects at the Sandy Pond Substation. Proposed in-service date of the project is June 15, 2017.

NEP-12-T20 – Transmission Notification from NEP to build a new 0.2-mile 230 kV C-203 tap line into the Littleton Substation (NU). Proposed in-service date of the project is June 15, 2016.

The Reliability Committee (RC) reviewed the materials presented in support of the proposed project and did not identify a significant adverse effect on the reliability or operating characteristics of the transmission facilities of NU, NEP, the transmission facilities of another Transmission Owner or the system of any other Market Participant.

Having given due consideration to the RC review, ISO New England has determined that implementation of the plan will 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.

A determination under Section I.3.9 of the ISO Tariff is limited to a review of the reliability impacts of a proposed project as submitted by Participants and does not constitute an approval of a proposed project under any other provisions of the ISO Tariff.

Sincerely,

Stephen J. Rourke
Vice President, System Planning

cc: Proposed Plan Applications