ISO NEW ENGLAND PLANNING PROCEDURE NO. 5-6

INTERCONNECTION PLANNING PROCEDURE FOR

GENERATION AND ELECTIVE TRANSMISSION UPGRADES

EFFECTIVE DATE: XXXXXXX

REFERENCES:

ISO New England Transmission, Markets and Services Tariff

* Section I.3.9 Review of Market Participant’s Proposed Plans
* (Schedules 22, 23 and 25 of the Open Access Transmission Tariff)

ISO New England Planning Procedures

* Planning Procedure 3 (PP3): Reliability Standards for the New England Area Pool Transmission Facilities
* Planning Procedure 5-1 (PP5-1): Procedure for Review of Market Participant’s or Transmission Owner’s Proposed Plans
* Planning Procedure 5-3 (PP5-3): Guidelines for Conducting and Evaluating Proposed Plan Application Analyses
* Planning Procedure 9 (PP9): Major Substation Bus Arrangement Requirements and Guidelines
* Planning Procedure 10 (PP10): Planning Procedure to Support the Forward Capacity Market

ISO New England Operating Procedures

* Operating Procedure No. 12 – Voltage and Reactive Control
* Operating Procedure No. 14 – Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources
* Operating Procedure No. 19 – Transmission Operations
* Operating Procedure No. 24 - Protection Outages, Settings and Coordination

ISO New England Transmission Planning Technical Guide

North American Electric Reliability Corporation (NERC) Reliability Standards

* TPL-001, Transmission System Planning Performance Requirements
* TPL-007, Transmission System Planned Performance for Geomagnetic Disturbance Events
* FAC-001, Facility Interconnection Requirements
* FAC-002, Facility Interconnection Studies
* MOD-026, Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions
* MOD-027, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions
* MOD-032, Data for Power System Modeling and Analysis
* PRC-024, Frequency and Voltage Protection Settings for Generating Resources
* PRC-006-NPCC, Automatic Underfrequency Load Shedding

NPCC Directory 1, Design and Operation of the Bulk Power System

NPCC Regional Reliability Reference Criteria A-10, Classification of Bulk Power System Elements

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INTERCONNECTION PROCEDURE FOR

GENERATION AND ELECTIVE TRANSMISSION UPGRADES

# Introduction

The purpose of this procedure is to describe the scope of Interconnection Studies conducted pursuant to Schedule 22 (“Large Generator Interconnection Procedures” or “LGIP”), Schedule 23 (“Small Generator Interconnection Procedures” or “SGIP”) and Schedule 25 (“Elective Transmission Upgrade Interconnection Procedures” or “ETU IP”) of Section II of the ISO New England Transmission, Markets and Services Tariff (the “Tariff”). One objective of this document is to provide guidance that ensures that the Network Capability Interconnection Standard (“NCIS”) and Capacity Capability Interconnection Standard (“CCIS”) are consistently applied in defining the scope and study assumptions for Generating Facility and ETU Interconnection Studies.

Studies conducted in accordance with this procedure are also used to support applications made pursuant to Section I.3.9 (“Review of Market Participant’s Proposed Plans”) of the Tariff,[[1]](#footnote-2) including studies of proposed distributed energy resources (DERs) that are processed under state interconnection procedures.[[2]](#footnote-3)

This document (and the relevant documents referenced herein) describes the interconnection requirements and procedures for coordinated studies of new or materially modified existing Generating Facility and ETU interconnections and their impacts on affected system(s) as required by NERC FAC-001, Facility Interconnection Requirements. Those responsible for the reliability of affected system(s)[[3]](#footnote-4) of new or materially modified existing interconnections are notified in accordance with the “coordination with affected systems” provisions of the interconnection procedures.

The studies conducted in accordance with this procedure also serve to meet the requirements of NERC FAC-002, “Facility Interconnection Studies”, to demonstrate that the proposed Generating Facility or ETU has been comprehensively studied to identify any reliability impact of the new interconnection, or materially modified existing interconnection, on affected system(s). As described in this document, studies shall include steady-state, short-circuit, dynamics and other studies, as necessary, to evaluate system performance under both normal and contingency conditions and to ensure that the proposed implementation will not cause non-compliance with the applicable NERC Standards including TPL-001, “Transmission System Planning Performance Requirements”.

Studies that follow the guidance provided by this document will typically be sufficient to comply with Tariff requirements; however, that does not preclude the possibility that some situations may require additional analyses.

## Interconnection Standards

## NCIS

NCIS describes the minimum requirements to interconnect a proposed new Generating Facility in the New England Control Area, to interconnect an Eligible External ETU[[4]](#footnote-5), to materially change an existing Generating Facility, to materially change an Eligible External ETU, or to increase the capability of an existing Generating Facility or Eligible External ETU for the purpose of providing energy to the Administered Transmission System.

The NCIS is defined in the LGIP, the SGIP and the ETU IP of the Tariff.

The basic principle underlying the study approach to making the determination of no significant adverse impact is that the energy, incrementally injected by Generating Facilities or injected by virtue of the requested objective associated with an ETU, is allowed to be dispatched in an economic, security-constrained manner provided that there is no significant adverse impact on the reliability of the system, and that the ability to reliably and practicably operate the system is not compromised. Thus, when the new Generating Facility or ETU is added to the system models used in the study, energy injections from other Generating Facilities or ETUs generally may be reduced by an amount not more than the net energy injection associated with the new Generating Facility or ETU, adjusted for changes in system losses caused by the redispatch.

## CCIS

CCIS describes the minimum requirements to interconnect a proposed new Generating Facility in the New England Control Area, to interconnect an Eligible External ETU,[[5]](#footnote-6) to materially change an existing Generating Facility, to materially change an Eligible External ETU, or to increase the capability of an existing Generating Facility or Eligible External ETU for the purposes of providing capacity to the Administered Transmission System.

CCIS is defined in the LGIP, SGIP and ETU IP of the Tariff.

The basic principle underlying the CCIS study approach is to ensure that there is no significant adverse impact as a result of the capacity, incrementally injected by Generating Facilities or injected by virtue of the requested objective associated with an ETU, when it is dispatched while other resources are supplying capacity. The study is intended to ensure that there is no significant adverse impact on the reliability of the system, and that the ability to reliably and practicably operate the system is not compromised. Thus, when the new Generating Facility or ETU is added to the system models used in the study, capacity injections from other Generating Facilities, external transactions, other interface transfers or ETUs generally may not be reduced. This means that the proposed Generating Facility or ETU can operate without re-dispatch of other capacity resources. CCIS examines the deliverability of Generating Facilities or ETUs under study to their associated Load Zones.[[6]](#footnote-7)

Generating Facilities and Eligible External ETUs requesting Capacity Network Resource Interconnection Service (CNRIS) or Capacity Network Import Interconnection Service (CNIIS) that have not previously established an appropriate amount of Network Resource Interconnection Service (NRIS) or Network Import Interconnection Service (NIIS) need to be studied according to both the NCIS and CCIS[[7]](#footnote-8).

## Interconnection Studies

The definition and scopes of Interconnection Studies are described in the LGIP, SGIP and ETU IP of the Tariff. A Cluster Study[[8]](#footnote-9), or a Cluster Restudy, shall meet all of the requirements of this procedure.

## Elective Transmission Upgrade Interconnection Requests

The approach used in the study of an Interconnection Request for an ETU will differ depending on the type of ETU.

When addition of a specific technology is identified in an ETU Interconnection Request, the study will take into account the type of the facility and the project’s performance objective.

When a performance objective associated with a specific Generating Facility(s) is identified in an ETU Interconnection Request, the study will take into account both the generation and the objectives.

When a performance objective of increasing transfer capability between points is identified in an ETU Interconnection Request, the study, while meeting the requirements of Section 7 of this procedure, will address what is specified for:

Transfer points (from/to)

Transfer capability increase and direction(s) of flow

# Requirements for Interconnection Studies

## General Requirements

The Interconnection Studies of all Interconnection Requests for Generating Facilities and ETUs, conducted in accordance with this procedure, shall identify the minimum required upgrades to meet all of the following requirements:

The proposed Generating Facility or ETU must satisfy the requirements of ISO New England Planning Procedure 3: “Reliability Standards for the New England Area Pool Transmission Facilities” (the “Reliability Standards”) and NPCC Directory 1, “Design and Operation of the Bulk Power System” on a regional (i.e., New England Control Area) and sub-regional basis, subject to the conditions analyzed; and shall not compromise the ability of the system to meet NERC TPL-001: “Transmission System Planning Performance Requirements”.

The proposed Generating Facility or ETU must not diminish system transfer capability, whether limited by an individual constrained element or a relevant interface, below the level of achievable transfers during reasonably stressed conditions[[9]](#footnote-10) and does not diminish the reliability or operating characteristics of the New England Area bulk power supply system and its component systems.

The proposed Generating Facility or ETU must not diminish system transfer capability, whether limited by an individual constrained element or a relevant interface, below the level of possible imports into an importing area during reasonably stressed conditions and does not diminish the reliability or operating characteristics of the New England Area bulk power supply system and its component systems.

For the NCIS: For a proposed new Generating Facility in an exporting area, or ETU with a terminal in an exporting area, an increase in the transfer capability out of the exporting area is not required to meet this interconnection standard unless the transfer capability needs to be increased to allow the proposed new Generating Facility or ETU to operate at the requested maximum output even after the allowed redispatch described in this procedure.

For the CCIS: The proposed new Generating Facility or ETU is not responsible for increasing the transfer capabilities of interfaces that form the boundaries between existing Load Zones. Where the addition of such a project results in a transfer across an interface that forms the boundary between existing Load Zones that is higher than the interface transfer capability, then other harmer resources with the lowest distribution factor (DFAX)[[10]](#footnote-11) located on the same side of the interface may be reduced to bring the transfer level back to the interface transfer capability.

The addition of the proposed Generating Facility or ETU does not create a significant adverse effect on the ISO’s or local Transmission Owner’s ability to reliably operate and maintain the system. Creation of new constraints when applying planning criteria, particularly due to stability or dynamic voltage performance, may likely be deemed to be unacceptable, as this compromises the ability to operate the system, especially where the number of existing interfaces cannot be increased due to operating complexity. Creation of operating limitations, particularly those caused by short circuit contribution or equipment with limited voltage ratings are also likely be deemed unacceptable.

## System Configuration

Analyses shall be performed with the existing system facilities and topology, with the addition of all Planned transmission projects (those with approved Proposed Plan Applications under Section I.3.9 of the Tariff) and with all relevant Generating Facilities and ETUs with active Interconnection Requests along with their associated upgrades in the Interconnection Queue ahead of the Generating Facilities or ETUs under study in a Cluster.[[11]](#footnote-12) Analyses shall also consider the Generating Facilities and ETUs under study in a Cluster.[[12]](#footnote-13)

For analyses performed to meet the NCIS and CCIS, Generating Facilities and ETUs with a pending retirement date[[13]](#footnote-14) will not be modeled in cases representing system conditions on or after the respective retirement dates. For analyses performed to meet the CCIS, Generating Facilities and ETUs with a pending date on which the facility will be permanently de-listed from the Forward Capacity Market will not be modeled in cases representing system conditions on or after the respective date the facility will be permanently de-listed.

In situations where projects have later in-service dates than the Generating Facility or ETU under study (both for earlier queued Generating Facilities or ETUs and Generating Facilities or ETUs within the same Cluster), the Interconnection Study may need to analyze the topology when the Generating Facility or ETU goes into service and the topology when all of the above projects are planned to be in service. In addition, sensitivity analysis shall be performed as appropriate for proposed transmission facilities that are relevant to the Interconnection Study for the Generating Facility or ETU under study.[[14]](#footnote-15)

Behind the meter (BTM) DERs shall be modeled in steady state and stability analyses.[[15]](#footnote-16)

## Load Levels

The following load levels may be utilized in Interconnection Studies: [[16]](#footnote-17)

Peak load: Load shall be at 100% of the projected (“90/10 forecast”) peak New England Control Area load for the year the Generating Facility or ETU is projected to be in service

Intermediate Load: 18,000 MW New England Control Area load

Light Load: 12,500 MW New England Control Area load

Nighttime Minimum Load: 8,000 MW New England Control Area load

Daytime Minimum Load: 12,000 MW New England Control Area load

Studies performed to meet the CCIS will only examine Peak Load Levels, while studies performed to meet the NCIS may examine any of the listed load levels.

## Resources[[17]](#footnote-18)

The table below lists the maximum Generating Facility output and controllable ETU flow assumptions.

*Table 2.4.1 – Summary of Maximum Generator Output and Controllable ETU Flow Assumptions*

|  |  |  |
| --- | --- | --- |
| **Maximum Generator Output and Controllable ETU Flow Assumptions** | **NCIS** | **CCIS** |
| Generating Facilities: Steady State, Summer Peak Load Level | Summer NRC (50°F) | Summer CNRC |
| Generating Facilities: Stability, Summer Peak Load Level | Summer NRC (50°F) | N/A |
| Generating Facilities: Steady State and Stability, All Load Levels that are not Summer Peak | Winter NRC (0°F) | N/A |
| Controllable ETUs: Steady State, Summer Peak Load Level | Maximum Flow (based on control objective) | Summer CNIC |
| Controllable ETUs: Stability, Summer Peak Load Level | Maximum Flow (based on control objective) | N/A |
| Controllable ETUs: Steady State and Stability, All Load Levels that are not Summer Peak | Maximum Flow (based on control objective) | N/A |

## Second Contingency Testing

Sufficient steady state and stability N-1-1 testing to assess performance relative to NERC, NPCC and ISO New England criteria shall be performed.[[18]](#footnote-19)

## Data Provision

The LGIP, SGIP and ETU IP specify data submittal requirements for the associated stages of each of these procedures. Starting with the Cluster Request Window, and for any updates during the related Cluster Study or Cluster Restudy, resources undergoing the Interconnection Procedures, shall submit all data through the Interconnection Request Tracking Tool (IRTT)[[19]](#footnote-20). NERC Standard MOD-032[[20]](#footnote-21) requires that dynamic models be provided for Generating Facilities, HVDC lines, and other power electronic devices that are a part of the Bulk Electric System. ISO Operating Procedure OP-14 Section II.A.6 also requires dynamics models for Generating Facilities that are 5 MW or greater in size when the ISO determines it to be necessary for it to carry out its responsibility to reliably and efficiently operate the power system.

Appendix B describes the usability and acceptability requirements for PSS/E models for use in Interconnection Studies and in accordance with NERC Standard MOD-026 and MOD-027.

Resources undergoing the ISO Interconnection Procedures shall submit the as-studied data through the Dynamics Data Management System (DDMS) and Short Circuit Data Management System[[21]](#footnote-22) after a Cluster Study is completed.[[22]](#footnote-23)

# Steady-State Analysis

Steady-state thermal and voltage analyses will be considered for studies to meet the NCIS. Only steady state thermal analysis is considered for studies to meet the CCIS.

## Steady-State Criteria

Steady-state analyses shall be performed to demonstrate compliance with applicable voltage and thermal loading criteria and shall identify any system upgrades required to satisfy these criteria.

## Details on Thermal Criteria

Table 3.1.1.1 lists the criteria used to identify violations associated with a proposed Generating Facility or ETU.

*Table 3.1.1.1 – Criteria for Identifying Thermal Violations Associated with a Proposed Generating Facility or ETU*

|  |  |
| --- | --- |
| **NCIS** | **CCIS** |
| For each studied dispatch, when the proposed Generating Facilities or ETUs are delivering their output, the list of those new overloads that result from the addition of the proposed Generating Facilities or ETUs and any existing overloads that are worsened due to the addition of the proposed Generating Facilities or ETUs will be recorded. The list will identify each recorded overload that meets the following threshold:  • An overload greater than or equal to 2% above the applicable thermal rating of the transmission element.  A Proposed Generating Facility or ETU will be associated with recorded overloads that meet any of the above-listed thresholds when, in relation to the New England System and the overloaded transmission element:  • The proposed Generating Facility or ETU increases the flow over the transmission element by 2%; and  • The proposed Generating Facility or ETU has an observed DFAX[[23]](#footnote-24) greater than or equal to 3%. | For each studied dispatch, when the proposed Generating Facilities or ETUs are delivering their output, the list of those new overloads that result from the addition of the proposed Generating Facilities or ETUs and any existing overloads that are worsened due to the addition of the proposed Generating Facilities or ETUs will be recorded. The list will identify each recorded overload that meets at least one of the following thresholds:  • An overload greater than 10 MVA above the applicable thermal rating of the transmission element; or  • An overload greater than or equal to 2% above the applicable thermal rating of the transmission element; or  • A transfer above the interface transfer capability of the modeled intrazonal stability or voltage-limited interface.  A Proposed Generating Facility or ETU will be associated with recorded overloads that meet any of the above-listed thresholds when, in relation to the Load Zone to which they are interconnecting and the overloaded transmission element:  • The proposed Generating Facility or ETU has an observed DFAX[[24]](#footnote-25) greater than or equal to 3%; or  • The proposed Generating Facility or ETU has an observed impact (as measured by DFAX times proposed MW) greater than or equal to 3% of the applicable thermal rating of the transmission element. |

Table 3.1.1.2 lists the applicable thermal ratings used for analyses that meet the NCIS and CCIS.

*Table 3.1.1.2 – Thermal ratings used for Analyses that Meet the NCIS and CCIS*

|  |  |
| --- | --- |
| **System Condition** | **Maximum Allowable Facility Loading** |
| Pre-Contingency | Normal Rating |
| Post Contingency, N-1 | Long Time Emergency Rating[[25]](#footnote-26) |
| Post Contingency, N-1-1 | Long Time Emergency Rating[[26]](#footnote-27) |

## Details on Voltage Criteria

Mitigation of a voltage violation is required when the addition of Generating Facilities or ETUs which, when online in any combination, causes:

a voltage level seen on an Element that is higher or lower than the appropriate rating by more than one percent (1%), and

at least a one percent (1%) change in a voltage experienced by the Element.

If mitigation of a voltage violation is required, then the added Generating Facilities or ETUs with a project impact, according to Section 10.4.5 of this procedure, of one percent (1%) or more will be responsible for the mitigation.

## Steady-State Stresses

Steady-state studies shall be performed with a dispatch of Generating Facilities, with flows on controllable ETUs, and with imports and exports such that it stresses power flows across applicable transmission lines or interfaces. A stressed line or interface shall, to the extent reasonable, be at or near their ratings or transfer limits[[27]](#footnote-28).

A reasonable condition when power flows may not be at or near their transfer limits would exist when the maximum number of fully loaded Generating Facilities and ETUs that may reasonably be expected to be in service does not result in stressed power flows.

## Steady-State Redispatch

The steady-state portion of an Interconnection Study typically includes an analysis of the transmission system with the system configuration described in Section 2.2 of this procedure but without the proposed Generating Facility or ETU that is under study dispatched (pre-project case), and an analysis of the transmission system with the same system configuration but with the proposed Generating Facility or ETU under study dispatched (post-project case). The change to output of Generating Facilities and external controllable ETUs from the values in a pre-project case to the values in the post-project case is commonly referred as redispatch[[28]](#footnote-29).

The N-1 redispatch objective for NCIS and CCIS is a defining difference between these two interconnection standards. The table below summarizes the different redispatch objectives and additional notes for the NCIS and CCIS.

*Table 3.3.1 – NCIS and CCIS Dispatch Objectives and Notes*

|  |  |
| --- | --- |
| N-1 NCIS Redispatch Objective | As a result of the dispatch of the proposed project, the maximum collective change in the output of other generation and changes to the flows of controllable external ETUs (the maximum redispatch) must not exceed the requested maximum net output of the proposed Generating Facility or ETU under study. |
| NCIS Redispatch Notes | The dispatch of an energy storage system project being evaluated in charging mode shall not cause the maximum collective change of other energy storage systems’ charging demand or of other generation and controllable external ETUs generation output to exceed the requested maximum charging demand of the project.  If the request for interconnection involves multiple generating units at a Generating Facility and the applicant for interconnection controls all the existing generating units at that Generating Facility, the applicant for interconnection shall specify the desired maximum output for the Generating Facility in the Interconnection Study Agreement and the design of the interconnection shall be based on this specified maximum output.  No increase in a conditional dependence is allowed. If no existing Generating Facility or ETU is required to be in service to avoid criteria violations for the conditions studied prior to placing the new Generating Facility or ETU in service, no existing Generating Facility or ETU can become required to operate as a condition for acceptable operation of the new Generating Facility or ETU for that study condition. If an existing Generating Facility or ETU is required to be in service to avoid criteria violations for the conditions studied prior to placing the new Generating Facility or ETU in service, the existing Generating Facility or ETU may continue to be modeled as required to avoid criteria violations, but such reliance shall not be increased. Generating Facilities and ETUs that continue to be required to be in service to avoid criteria violations for the conditions studied shall not be reduced, by redispatch in the study, below the level required for system reliability before the addition of the Generating Facility or ETU. Studies must examine relevant stressed existing Generating Facility and ETU outage conditions in addition to outages or reductions that have been considered as part of Generating Facility and ETU redispatch. |
| N-1 CCIS Redispatch Objective | There is no redispatch (i.e. reduction) in the output of other impactful generation with established CNRC or the flows of impactful controllable External ETUs with established CNIIS after the dispatch of the proposed Generating Facility or ETU. |
| CCIS Redispatch Notes | The percent loading on each monitored element is first determined without the proposed Generating Facilities or ETUs under study. This will provide a base reference loading for the monitored element. The base reference loading is developed by completing a transfer from a source of all harmer resources with a DFAX of 3% or greater for the given monitored element to a sink of all other resources. This transfer will be limited when a monitored element (including a modeled intrazonal stability or voltage limited interface) reaches a loading of 100% or when all harmer resources with a distribution factor of 3% or above have been turned on up-to their established CNRC/CNIIS. Next, the percent loading on each monitored element will be calculated by adding the additional flow resulting from the proposed Generating Facilities or ETUs to the base reference loading. The additional loading caused by the proposed Generating Facilities or ETUs is calculated based on a transfer from the proposed Generating Facilities or ETUs to resources that are not included in the list of harmer resources with a DFAX of 3% or greater for the given monitored element. |

In addition, the following restricts the pre-contingency redispatch of Generating Facilities or external ETUs for first contingency (N-1) conditions:

Redispatched Generating Facilities and redispatched ETUs and the new Generating Facility or ETU must be able to be automatically monitored and observed for purposes of system operation and unit commitment (for example a facility monitored and controlled by the System Operator via SCADA and security constrained economic dispatch), and,

Generating Facility and ETU redispatch is not acceptable for limiting system constraints that occur on sub-transmission or lower voltage (less than 100 kV) facilities.

Second contingency (N-1-1) testing considers two initiating events that can occur close together in time. Following the first initiating event, system adjustments can be made in preparation for the next initiating event. [[29]](#footnote-30) In the case of pre-second contingency Generating Facility or ETU runback and/or tripping after a first contingency to be secure for N-1-1 conditions:

The runback and/or tripping that can be assumed to be achievable in 30 minutes following the first contingency shall utilize available replacement operating reserves consistent with PP3.

Generating Facilities and ETUs that are assumed to be runback or tripped (which may include the new Generating Facility or ETU) must be able to be automatically monitored and observed for purposes of system operation and unit commitment (for example a facility monitored and controlled by the System Operator via security constrained economic dispatch), and, Generating Facility and ETU runback or tripping is not acceptable for limiting system constraints that occur on sub-transmission or lower voltage (less than 100 kV) facilities, except as follows;

where the first and second contingencies are not contingencies listed in PP3 and where the potential performance violation is for a facility that is not a Pool Transmission Facility, runback or tripping of non-market generation and/or Settlement Only Generators may also be assumed in the assessment. The assessment must confirm that such redispatch is operable[[30]](#footnote-31) and does not introduce any other performance violations.

## Post Contingency Resource Adjustments

No Generating Facility or ETU can be manually tripped or manually ramped down to relieve any first contingency facility loading in excess of the more limiting of either the Short Time Emergency Ratings or any other applicable Transmission Owner-specific emergency ratings.

## Steady-State Load Levels

## NCIS Steady-State Load Levels

For studies performed to meet the NCIS, steady-state analysis shall be performed at the following load levels and in accordance with Table 3.5.1.1 below (not all scenarios will be studied for every project). Scenarios will be selected as part of the project study scoping process:

Analysis shall be performed at Peak Load with the Generating Facility or ETU operating at full capability:

Four scenarios may be analyzed:

An evening peak scenario characterized by high load, low solar, and energy storage available for discharging, while wind and conventional resources are available up to their full capability.

An evening peak scenario characterized by high load, no solar, and energy storage available for discharging, while wind and conventional resources are available up to their full capability[[31]](#footnote-32).

A mid-day peak scenario, characterized by high load, high solar, and energy storage unavailable, while wind and conventional resources are available up to their full capability.

A mid-day peak scenario, characterized by high load, high solar, and energy storage available for charging,[[32]](#footnote-33) while wind and conventional resources are available up to their full capability.

Analysis shall be performed at Intermediate Load with the Generating Facility or ETU operating at full capability in the cases where conditions such as the preservation of transfer capability are a concern:

Two scenarios may be analyzed:

A shoulder load scenario characterized by intermediate load, no solar, and energy storage available for charging, while wind and conventional resources are available up to their full capability.

A shoulder load scenario characterized by intermediate load, no solar, and energy storage available for discharging, while wind and conventional resources are available up to their full capability.

Analysis shall be performed at Light Load as required by the ISO to identify any upgrades that are required to allow the Generating Facility or ETU to operate at the requested output level while no other nearby generating facilities (that would contribute to any identified violations) are operating:

Two scenarios may be analyzed:

A light load scenario characterized by light load, high solar, and energy storage available for charging, while wind and conventional resources are available up to their full capability.

A light load scenario characterized by light load, no solar, and energy storage available for discharging, while wind and conventional resources are available up to their full capability.

Analysis shall be performed at Minimum Load in cases where the Generating Facility or ETU, and its Interconnection Facilities and Network Upgrades, add a significant amount of charging current to the system or in areas where there are significant resources without significant voltage control:

Two scenarios may be analyzed:

A Day-Time minimum load scenario characterized by minimum load, high solar, and energy storage unavailable, while wind and conventional resources are available up to their full capability.

A Night-Time minimum load scenario characterized by minimum load, no solar, and energy storage unavailable, while wind and conventional resources are available up to their full capability[[33]](#footnote-34).

Co-Located or Hybrid facilities may be required to analyze the combination of all scenarios listed under the different resources of which they are comprised

Other Load levels and resource scenarios may be added at the discretion of the ISO where needed.

BTM-DERs and other non-Modeled assets will be modelled as dispatched at the resource availability level as shown in table 3.5.1.1 below

Table 3.5.1.1 – NCIS Steady State Scenarios[[34]](#footnote-35)[[35]](#footnote-36)[[36]](#footnote-37)

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| ***Available Scenarios/For Consideration*** | Solar Availability Across NE (Both Market and BTM) | Batteries/Stored Hydro Availability | Wind Availability | Conventional Resources Availability |
| Peak Load 90/10 (Gross) Low Solar | 26% | 100%  Discharging | 100% | 100% |
| Peak Load 90/10 (Gross) High Solar | 85% | 0%  OFF | 100% | 100% |
| Peak Load 90/10 (Gross) High Solar | 85% | 100%  Charging[[37]](#footnote-38) | 100% | 100% |
| Peak Load 90/10 (NET = Gross) No Solar | 0% | 100%  Discharging | 100% | 100% |
| Shoulder Load 18,000MW (NET = Gross) | 0% | 100%  Charging | 100% | 100% |
| Shoulder Load 18,000MW (NET = Gross) | 0% | 100%  Discharging | 100% | 100% |
| Light Load 12,500 (NET) | 100% | 100%  Charging | 100% | 100% |
| Light Load 12,500 (NET = Gross) | 0% | 100%  Discharging | 100% | 100% |
| N-Minload 8,000MW (NET = Gross) | 0% | 0%  OFF | 100% | 100% |
| D-Minload 12,000MW (Gross) | 100% | 0%  OFF | 100% | 100% |

## CCIS Steady-State Load Level

For studies performed to meet the CCIS, steady-state analysis shall be performed at the following load level and in accordance with Table 3.5.2.1 below:

Analysis shall be performed at Peak Load with the Generating Facility or ETU operating at full capability:

One scenario may be analyzed:

A mid-day peak scenario, characterized by high load and resources providing expected capacity (i.e. resources dispatched up to established summer CNRC).

BTM Solar and Demand Response will be modelled as dispatched at the resource availability level as shown in table 3.5.2.1 below

Table 3.5.2.1 – CCIS Steady State Scenarios[[38]](#footnote-39)[[39]](#footnote-40)

|  |  |  |
| --- | --- | --- |
| ***Available Scenarios/For Consideration*** | BTM Solar Availability Across NE[[40]](#footnote-41) | Demand Capacity Resources |
| Peak Load 90/10 (Gross) | 40%[[41]](#footnote-42) | Qualified Capacity Availability Factor[[42]](#footnote-43) |

# Stability Analysis

Stability analysis is performed for studies to meet the NCIS. Stability analysis is not performed for studies to meet the CCIS.

## Stability Criteria

Stability analyses shall be performed to demonstrate compliance with applicable criteria and shall identify any system upgrades required to satisfy these criteria.

## Stresses in Stability Analysis

For normal contingency testing, power flows across applicable transmission lines or interfaces shall be at the most limiting of the existing stability or thermal (set using winter transmission equipment ratings, with appropriate margin, for light load testing) transfer limits.[[43]](#footnote-44)

## Stability Analysis Scenarios

Stability analysis shall consider reasonable combinations of all relevant Generating Facilities, ETUs and devices that would be expected to have significant interactions[[44]](#footnote-45).

The Generating Facility or ETU under study shall be dispatched at full capability and local and relevant Generating Facilities and ETUs shall be dispatched at the resource availability level as shown in Table 4.4.1. If all Generating Facilities and ETUs cannot be dispatched behind the limiting lines or interface, a reasonable number of combinations may need to be studied.

## Stability Load Levels

Stability analysis shall be performed at the following load levels:

Analysis shall be performed at Light Load with high levels of renewable generation online. Appropriate combinations of relevant Generating Facilities, distributed energy resources and ETUs shall be studied to ensure that stability is maintained for all reasonable conditions.

Two scenarios may be analyzed:

A light load scenario characterized by light load, high solar, and energy storage available for charging, while wind and conventional resources are available up to their full capability.

A light load scenario characterized by light load, no solar, and energy storage available for discharging, while wind and conventional resources are available up to their full capability.

Analysis shall be performed at Peak Load when required by the ISO. The emphasis of the stability analyses performed at this load level is to confirm that the response has not significantly changed with the load level. It may also be used to assess changes in damping if the possibility of an oscillatory response is recognized in the light load analyses.

Two scenarios may be analyzed:

An evening peak scenario characterized by high load, low solar, and energy storage available for discharging, while wind and conventional resources are available up to their full capability.

An evening peak scenario characterized by high load, no solar, and energy storage available for discharging. While wind and conventional resources are available up to their full capability[[45]](#footnote-46)

Analysis shall be performed at Minimum Load in cases where the Generating Facility or ETU, and its Interconnection Facilities and Network Upgrades, add a significant amount of charging current to the system or in areas where there are significant resources without significant voltage control.

Two scenarios may be analyzed:

A Day-Time minimum load scenario characterized by minimum load, high solar, and energy storage unavailable, while wind and conventional resources are available up to their full capability.

A Night-Time minimum load scenario characterized by minimum load, no solar, and energy storage unavailable, while wind and conventional resources are available up to their full capability[[46]](#footnote-47).

Co-Located or Hybrid facilities will be required to analyze the combination of all scenarios listed under the different resources of which they are comprised

Other Load levels and resource scenarios may be added at the discretion of the ISO where needed.

BTM distributed energy resources and other non-Modeled assets will be modelled as dispatched at the resource availability level as shown in the table below

Table 4.4.1 Stability Scenarios[[47]](#footnote-48)[[48]](#footnote-49)

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| ***Available Scenarios/For Consideration*** | Solar Availability Across NE (Both FERC and Non-FERC) | Batteries/Stored Hydro | Wind Availability | Conventional Resources Availability |
| Peak Load 90/10 (Gross) Low Solar | 26% | Discharging | 100% | 100% |
| Peak Load 90/10 No Solar | 0% | Discharging | 100% | 100% |
| Light Load 12,500 (NET) | 100% | Charging | 100% | 100% |
| Light Load 12,500 (NET = Gross) | 0% | Discharging | 100% | 100% |
| N-Minload 8,000MW (NET = Gross) | 0% | OFF | 100% | 100% |
| D-Minload 12,000MW (Gross) | 100% | OFF | 100% | 100% |

# Short Circuit

Short circuit analysis is performed for studies to meet the NCIS. Short circuit analysis is not performed for studies to meet the CCIS. Short circuit analyses[[49]](#footnote-50) shall be conducted to demonstrate that short circuit duties will not exceed equipment capability and shall identify any system upgrades required to satisfy this criterion. The short circuit study base case shall include all generation and transmission projects that are proposed for the New England Transmission System and any Affected System and for which a transmission expansion plan has been submitted and approved by the applicable authority and which, in the sole judgment of the System Operator, may have an impact on the Interconnection Request. The base case shall include all generating facilities and ETUs (and with respect to (iii), any identified upgrades) that, on the date the study is commenced: (i) are directly interconnected to the New England Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the New England Transmission System and may have an impact on the Interconnection Request, and (iv) all proposed Generating Facilities and ETUs within a Cluster undergoing a Cluster Study. A Generating Facility that has notified the ISO that it will retire will not be included in short circuit studies for timeframes beyond its retirement date.

Mitigation of an overdutied Element is required when the addition of Generating Facilities or ETUs which, when online in any combination, causes:

a short circuit stress that is higher than the Element’s interrupting or withstand capability.

If mitigation of an overdutied Element is required, then the added Generating Facilities or ETUs with a positive fault current contribution will be responsible for the mitigation.

# Other Requirements

## Voltage Control and Reactive Power Requirements

Where specified in Schedule 22, 23 or 25, Generating Facilities, ETUs and their associated Interconnection Facilities, that are capable of voltage control, are required to be capable of a composite power delivery at their maximum rated power output (maximum MW) at the Point of Interconnection (or at the high side of the station transformer, or at the Point of Interconnection if there is no station transformer, in the case of a non-synchronous Generating Facility) at both the power factor of 0.95 leading and 0.95 lagging. The Interconnection Study shall verify this capability.

Cluster Study testing shall evaluate the compliance of the voltage control capability with the requirements of OP-14.

While it shall be identified in the Interconnection Study if the voltage control strategy must be designed with the purpose of maintaining a scheduled voltage at the Point of Interconnection (or some other appropriate point), it shall be acceptable for the resource to dynamically control its terminal voltage under transient conditions, unless the Interconnection Study identifies a reliability issue that requires the resource be capable of controlling voltage at another point, such as the Point of Interconnection.

The power factor evaluation shall be conducted with the new Generating Facility or Eligible ETU modeled at unity terminal voltage and maximum rated power output. The maximum leading and lagging reactive power capabilities at maximum rated power output shall be taken from the associated facility “D-Curve” or similar specification. At both the maximum leading reactive output and at the maximum lagging reactive output, the real and reactive power losses in the step-up transformer(s) and other interconnection facilities, station service real and reactive load, as well any additional reactive contribution provided by project auxiliary reactive devices, shall be calculated. The resulting net real and reactive power at the Point of Interconnection (or the high side of the station transformer in the case of a wind generating facility) shall be required to meet the 0.95 leading and 0.95 lagging dynamic reactive power standards. Generating Facilities that operate in a combined mode (such as combined cycle generation) shall be evaluated on an overall combined basis.

Cluster Study testing shall evaluate the compliance of the voltage ride-through capability with the requirements of NERC PRC-024, Generator Frequency and Voltage Protective Relay Settings.

## Governor Control/Frequency Response

Cluster Study testing shall evaluate the frequency response compliance of each new Generating Facility with the droop, deadband and overall response requirements of OP-14. Testing shall include an appropriate frequency changing event such as a large loss of load or generation.

Cluster Study testing shall evaluate the compliance of the frequency ride-through capability with the requirements of NERC PRC-024 and PRC-006-NPCC Generator Frequency and Voltage Protective Relay Settings.

## Shaft Torque (Delta P) Testing

Where there is a likelihood of large angular difference across an open transmission line, or of a large change in power flow when closing a transmission line, an Interconnection Study for a Generating Facility shall include determination of the largest change in power (Delta P) that the Generating Facility, and other Generating Facilities in proximity, including each proposed Generating Facility or ETU within a Cluster Study, could experience as the result of reclosing following an N-1 contingency. The value of Delta P shall be included in the Interconnection Study report. The Generating Facility or ETU shall be required to mitigate any unacceptable consequence of increased Delta P which they cause.

## Subsynchronous Resonance and Subsynchronous Torsional Interaction Screening

An Interconnection Study for an HVDC facility or any project that includes a series-connected capacitor in Interconnection Facilities or Network Upgrades shall include screening for the potential of causing subsynchronous stresses on nearby generation, including for each proposed Generating Facility or ETU within a Cluster Study. This screening shall examine N-1, N-1-1 and other potential contingent or operating conditions specified by the ISO. The results of this screening shall be included in the Interconnection Study report.

## Electromagnetic Transient Testing

Any inverter-based Generating Facility, including DER, an ETU that includes power electronics as part of the facility or a Generating Facility or ETU that includes power electronics as part of Interconnection Facilities or Network Upgrades shall provide a Electromagnetic Transient (EMT) model(s) useable in PSCAD, of that equipment. The EMT study shall examine N-1, N-1-1 and other potential contingent or operating conditions specified by the ISO. Guidance regarding the requirements for PSCAD model submittals and for EMT testing is provided in Appendix C. [[50]](#footnote-51)

These EMT requirements shall not apply to wind or inverter based Generating Facilities that are not connected to the PTF and that are not subject to the requirements of Schedules 22 or 23 of the OATT, unless ISO New England identifies that the EMT requirements are needed to be met by the Generating Facility for reliability reasons.

## Operating Procedure Requirements

An Interconnection Study shall ensure that all Generating Facilities or ETUs within a Cluster Study satisfy the relevant equipment design requirements in Operating Procedures OP-12, OP-14 and OP-19.

## IEEE 2800 Requirements

Non-synchronous resources participating in the first ISO-NE Cluster study, pursuant to FERC Order No. 2023, (and all subsequent clusters) must meet the requirements of Appendix F.

## Geomagnetic Disturbance (GMD) Testing

As required, an Interconnection Study shall evaluate GMD testing pursuant to NERC TPL-007.

# Additional Considerations for Studies of ETUs

The appropriate study of an Interconnection Request for an ETU will differ depending on the type and objective of the ETU.

## Eligible External ETUs

The scope of study of Eligible External ETUs is described in Section 2 of this procedure. The analysis of ETUs that have one or more terminals outside of the New England Control Area shall be coordinated with the other Control Area(s). The analysis at the point of injection to the New England transmission system shall be performed similar to the analysis of a Generating Facility connecting at that terminal. The impact of loss of the ETU when it is operating at full output shall be analyzed.

The analysis of a new Eligible External ETU shall include analysis with relevant existing external interfaces modeled with imports and exports at the maximum levels used in planning studies.

## Internal Controllable ETUs

A controllable ETU could be a HVDC line or an AC line with a phase-angle regulator or other control device.

In a manner consistent with other parts of this procedure, the Interconnection Customer shall identify the generator dispatch or dispatches that will be used to provide the energy and/or capacity transmitted by the ETU at each terminal which is drawing power from the transmission system. The analysis shall identify the system upgrades required to maintain the reliability of the sending area in accordance with New England planning standards. This analysis shall be similar to the analysis that would be conducted if a new load was added at the point of withdrawal from the New England system.

The analysis at the point of injection to the transmission system shall be performed similar to the analysis of a Generating Facility connecting at that terminal. The analysis shall identify the system upgrades required to maintain the reliability of the receiving area.

The impact of loss of the ETU when it is operating at full output shall be analyzed.

## Non-controllable ETUs Involving Specified Equipment Additions without Associated Specified Objectives

The analysis of a non-controllable ETU involving specified equipment additions without specified objectives shall be conducted consistent with the analysis of transmission additions pursuant to PP5-3.

## ETUs Involving Specified Objectives

An ETU Interconnection Request may not always specify the equipment that it wishes to install. For example, a request may have the objective to increase the transfer limit across an interface by a certain amount. When an ETU Interconnection Request specifies an objective without specifying facilities, the study shall identify the solution necessary to satisfy the needs identified in the Interconnection Request and shall identify the transmission upgrades required. Section 3.1 of the Elective Transmission Upgrade Interconnection Procedures states that the ISO, at its sole discretion, determines if a proposed objective is appropriate to propose in a single Interconnection Request.

# Operational Considerations

As appropriate, the analysis shall include an assessment of the operating constraints of the proposed transmission and generation system without identifying the additional upgrades (beyond those identified pursuant to Section 2 of this procedure) necessary to reduce the operating constraints. The analysis shall determine the estimated magnitude of required redispatch of generation under typical and reasonably stressed conditions. If requested by the ISO, limited operating studies may be required to demonstrate viable operability of the proposed Generating Facility or ETU and provide some indication of the system conditions for which the Generating Facilities or ETU’s operation may be restricted. The conditions to be considered in these studies shall be coordinated through the ISO. Examples of studies that may be expected include, but are not limited to:

Examination of the operation of the proposed transmission or generating facilities over expected or suspected constrained conditions with examination of the limiting performance concern (for example thermal, voltage or stability issues). Hour-to-hour operability or performance over longer periods may be considered. Light, intermediate or peak load levels may be considered. Any increased need for operational oversight of the system, such as resource operating restrictions, atypical switching or the creation of additional procedures under outage conditions shall be noted.

Determination if the system adjustments required to reliably serve the area of interest within 30 minutes following the first contingency change significantly, or are no longer effective, given the proposed change.

(Note: Extensive operating studies, separate from the Interconnection Studies, may be necessary prior to actual operation.)

# Additional Considerations for Generating Facilities that include Storage

The study of the discharging (i.e. generating) operating condition of a proposed electrical storage facility shall use the study approaches described in this procedure. The study of the charging (i.e. absorbing) operating condition of a proposed electrical storage project shall use the study approaches described in this procedure except that it will not be studied under any of the Peak Load scenarios listed in section 3.5.

# Cluster Studies

## Cluster Study Overview

A Cluster Study, or Cluster Restudy, is an Interconnection Study that identifies the upgrades needed to interconnect proposed Generating Facilities or ETUs at their requested levels of Interconnection Service, pursuant to the NCIS or CCIS, as applicable. The scope of a Cluster Study, or a Cluster Restudy, is described in the LGIP, SGIP and ETU IP of the Tariff. Cluster Studies shall meet the requirements of this procedure.

All projects in a Cluster Study are considered equally queued:

* As a result, all proposed Generating Facilities and ETUs within a Cluster are included in the base case used to perform the related Cluster Study.
* Generating Facilities and ETUs within an earlier Cluster have a higher priority queue position than Generating Facilities and ETUs within a subsequent Cluster.

A Cluster may contain projects with Interconnection Requests for NRIS/NIIS and projects with Interconnection Requests for CNIS/CIIS:

* Cluster Studies will include analyses that meet the requirements of both the NCIS and CCIS, as applicable.

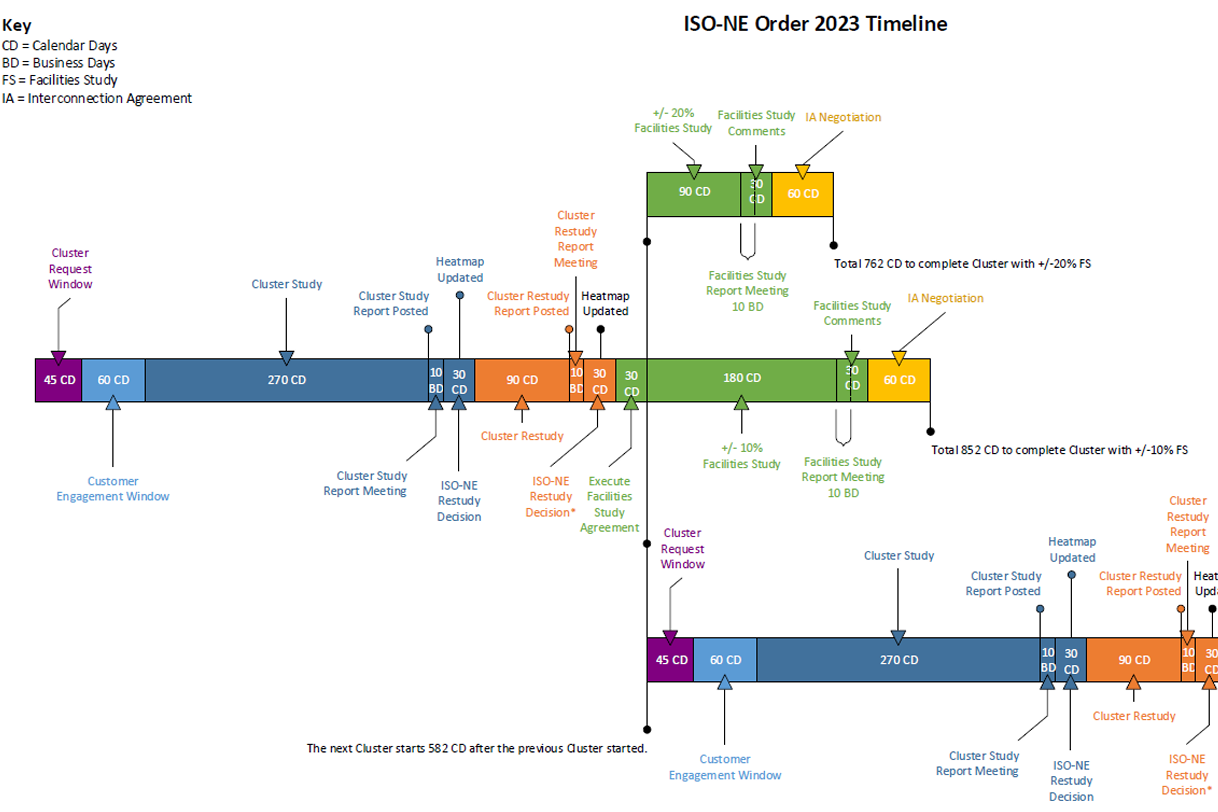
## Cluster Study Milestones and Timeline

The main Cluster Study milestones are:

* + Cluster Request Window: This window lasts 45 Calendar Days. This is the window where the ISO accepts Interconnection Requests for a new Cluster.[[51]](#footnote-52) Interconnection Customers must cure any deficiencies with their Interconnection Requests by the close of the Cluster Request Window.
  + Customer Engagement Window (with Scoping Meeting): This window lasts a maximum of 60 Calendar Days. During this window, the ISO will post an anonymized list of the valid Interconnection Requests associated with the Cluster, provide a non-binding, good faith estimate of the cost and timeframe for completing the Cluster Study, and issue a Cluster Study Agreement to each Interconnection Customer. The Cluster Study Agreement must be executed prior to the close of the Customer Engagement Window. The ISO will also hold a Scoping Meeting during this window which can include discussion on, among other things, alternative interconnection options, posted Cluster Study materials, and information necessary to facilitate the administration of the Interconnection Procedures. Interconnection Customers must select a definitive Point of Interconnection to be studied for their projects no later than the execution of the Cluster Study Agreement.
  + Cluster Study: The ISO completes the Cluster Study within a 270 Calendar Day window.
  + Issuance of draft Cluster Study Report: This is when the ISO issues the draft Cluster Study Report, which is after the completion of the Cluster Study Window.
  + Cluster Study Report Meeting: Within 10 Business Days after the ISO issues the draft Cluster Study Report, the ISO holds a Cluster Study Report meeting to discuss the results of the applicable Cluster Study.
  + ISO Restudy Decision: Within 30 Calendar Days after the Cluster Study Report Meeting, the ISO will determine if a Cluster Restudy is required:
    - If no Cluster Restudy is necessary, the ISO will provide an updated Cluster Study Report within 30 Calendar Days of this Cluster Restudy determination.
    - If a Cluster Restudy is necessary, the ISO will notify Interconnection Customers of this determination within 30 Calendar Days after the Cluster Study Report Meeting.
  + Cluster Restudy (if needed): Cluster Restudies shall be completed within 90 Calendar Days of the ISO informing Interconnection Customers that the Cluster Restudy is needed. The results of the Cluster Restudy will be combined into a single Cluster Study Report. Multiple rounds of Cluster Restudy may be needed before a Cluster Study is finalized.

Figure 10.2.1 below illustrates the milestones and timeline described above, as well as the timing for starting subsequent Cluster Studies. See the LGIP, SGIP and ETU IP of the Tariff for more details on the milestones and timing for performing a Cluster Study, and a re-study thereof.

*Figure 10.2.1 - Cluster Study Milestones and Timelines*



## Cluster Study Process

There are three main phases for performing a Cluster Study:

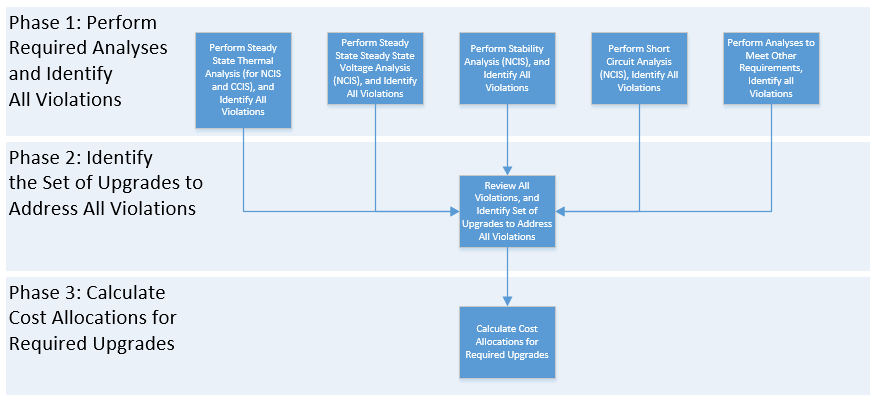
Perform Required Analyses and Identify All Violations

Identify the Set of Upgrades to Address All Violations

Calculate Cost Allocations for Required Upgrades

These phases are illustrated in Figure 10.3.1

*Figure 10.3.1 – Overall Cluster Study Process*



## Phase 1: Perform Required Analyses and Identify All Violations

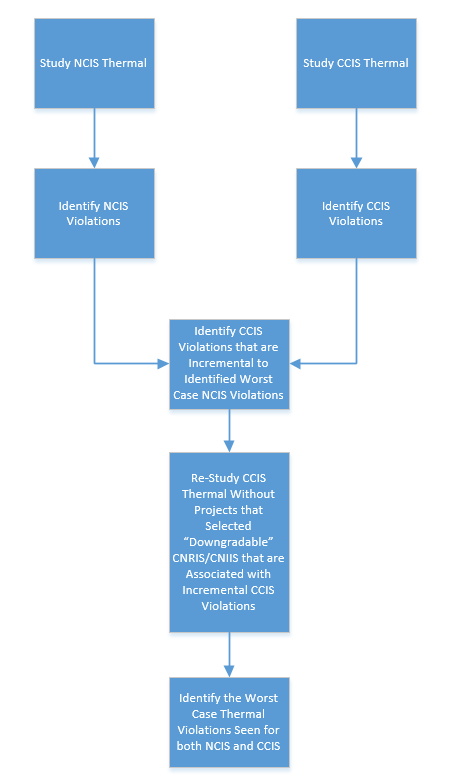
During this phase the ISO performs all required analyses (e.g. steady-state, voltage, stability, short circuit, etc.) to study all projects in a Cluster. The following analyses may be performed as part of a Cluster Study:

* Short circuit [NCIS]
* Steady-state - thermal [NCIS, CCIS]
* Steady-state - voltage [NCIS]
* Stability [NCIS][[52]](#footnote-53)
* EMT Testing [NCIS]
* Other requirements [NCIS]:
  + Voltage control and reactive power requirements
  + Governor control/frequency response
  + Shaft torque (delta P) testing
  + SSR/SSTI screening
  + Operating procedure requirements
  + GMD testing
  + IEEE 2800 requirements[[53]](#footnote-54)

All analyses performed shall meet the requirements of this procedure. The ISO may perform these analyses in parallel to take advantage of study efficiencies in order to meet study deadlines. The output of this phase is the identification of all violations associated with each project in the Cluster.

Pursuant to Schedules 22, 23 and 25 of the Tariff, an Interconnection Custer may request “downgradable” CNRIS/CNIIS, where CNRIS/CNIIS is originally requested, but is automatically downgraded to NRIS/NIIS if violations requiring upgrades are solely seen when evaluating a project according to the CCIS. This requires coordination of the thermal analyses to meet the NCIS and CCIS, as illustrated in Figure 10.3.1.1.

*Figure 10.3.1.1 – Coordination Between CNRIS/CNIIS and NRIS/NIIS Thermal Analysis*



## Phase 2: Identify the Set of Upgrades to Address All Violations

During this phase the ISO reviews all violations from all analyses performed, and identifies the worst case violation for each element. These “worst case for each element” violations are the violations that must be addressed through system upgrades.

The output of this phase is:

* the identification of the set of upgrades to address all the “worst case for each element” violations, based on the best available information during performance of a Cluster Study (or a restudy thereof), and
* the classification of these upgrades as either Interconnection Facilities, Substation Network Upgrades, or System Network Upgrades.

Applicable Transmission Owners must provide information to the ISO, including cost and time to construct estimates, to support the identification of the set of upgrades to address all identified violations.

In some cases, the ISO may identify a set of common upgrades to address multiple “worst case for each element” violations.

## Alternative Transmission Technologies

The ISO will evaluate the use of alternative transmission technologies when determining upgrades to address violations found during a Cluster Study. The Cluster Study Report will include an explanation of the ISO’s evaluation of each of these technologies.

For this evaluation, the ISO will:

1. Review all violations and identify which violations could be addressed with an alternative transmission technology, consistent with Table 10.3.2.1.1 below.
2. Based on feedback from applicable Transmission Owners, Good Utility Practice, Applicable Reliability Standards and Applicable Laws and Regulations, compare the effectiveness and efficiency of the alternative transmission technology upgrade solution to other possible upgrade solutions for addressing the applicable violations.

*Table 10.3.2.1.1 – Evaluation Guidance for Alternative Transmission Technologies*

|  |  |
| --- | --- |
| **Alternative Transmission Technology** | **Violation Types that the Alternative Transmission Technology May Address** |
| Static Synchronous Compensators | * Voltage * Stability * Voltage Control/Reactive Power Requirements |
| Static VAR Compensators | * Voltage * Stability   Voltage Control/Reactive Power Requirements |
| Advanced Power Flow Controllers | * Thermal * Voltage * Stability |
| Transmission Switching | * Thermal * Voltage * Stability |
| Synchronous Condensers | * Voltage * Stability * Voltage Control/Reactive Power Requirements * Weak Grid Issues |
| Voltage Source Converters | * Voltage * Stability * Voltage Control/Reactive Power Requirements |
| Advanced Conductors | * Thermal |
| Tower Lifting | * Thermal |

## Phase 3: Calculate Cost Allocations for Required Upgrades

During this phase, the ISO calculates allocated costs for the identified set of upgrades to address all identified violations in a Cluster Study (or a restudy thereof).

## Upgrade Classifications

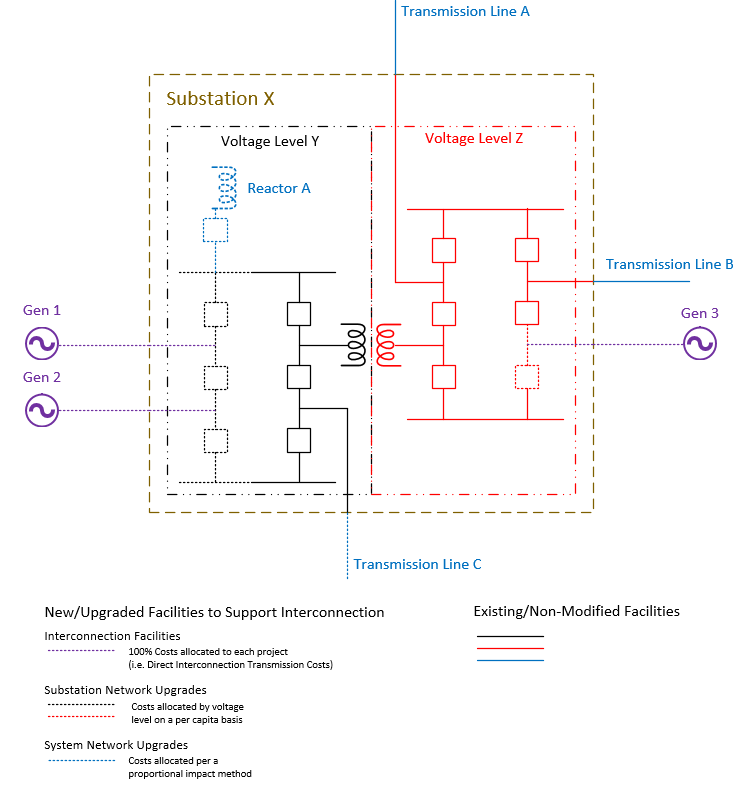
Cost allocation calculations depend on the classification of identified upgrades. There are three classifications for identified upgrades, as illustrated in Figure 10.4.1.1:

Interconnection Facilities: As defined in Schedules 22, 23 and 25 of the Tariff, Interconnection Facilities are sole use facilities for electrically interconnecting a Generating Facility or ETU to the Administered Transmission System. Pursuant to Schedule 11 of the Tariff, 100% of the cost of these Interconnection Facilities are allocated to the Generating Facility or ETU that requires them.

Substation Network Upgrades: As defined in Schedules 22, 23 and 25 of the Tariff, Substation Network Upgrades are substation related equipment required at Generating Facilities’ Points of Interconnection. Pursuant to Schedule 11 of the Tariff, the costs for these upgrades are allocated by voltage level and on a per capita basis to each Generating Facility or ETU interconnecting at the related voltage level.

System Network Upgrade: As defined in Schedules 22, 23 and 25 of the Tariff, System Network Upgrades are upgrades required beyond the substation at the Point of Interconnection. Pursuant to Section 11 of the Tariff, the costs of these upgrades are allocated based on the proportional impact of each individual Generating Facility or ETU in a Cluster on the need for the upgrades.

*Figure 10.4.1.1 – Upgrade Classifications*



Example 1 of Appendix G provides a high level example of how cost allocation is handled for these different system upgrade classifications. The example shows the cost allocation calculation details for Interconnection Facilities and Substation Network Upgrades. Further details on the cost allocation details for System Network Upgrades are provided below and through additional examples in Appendix G.

## Cost Allocation Calculation Details for System Network Upgrades

The cost allocation calculations for System Network Upgrades:

* involve proportional impact based methodologies
* consider a project’s impact on all elements with a violation that require a System Network Upgrade

Cost allocation calculations for System Network Upgrades have three general steps:

* Step 1: Calculate the impacts for each project with the violation that requires the System Network Upgrades. Details on the impacts calculation to address different types of violations are provided below.
* Step 2: Calculate the impact proportionality for each project in Step 1. This calculation is:

*project impact proportionality = project impact/Σ of all project impacts*

* Step 3: Calculate the cost allocation for each project. This calculation is:

*project cost allocation = project impact proportionality x cost of System Network Upgrades*

Projects requesting Regional Network Service (RNS) are included in cost allocation calculations.

## Impact Calculations to Address Short Circuit Violations

The impact calculation for a project on an element for a short circuit violation is:

*project impact = project contribution to fault current seen at the element*

where:

* project contribution to fault current seen at the element is measured in kA

Example 2 of Appendix G illustrates cost allocation calculations for a scenario where a System Network Upgrade is required to mitigate a short circuit violation.

If an identified System Network Upgrade to address non-short circuit related violations introduces a new short circuit violation, then the mitigation of the introduced short circuit violation and resulting costs will be considered part of the identified System Network Upgrade (and costs) that introduced the short circuit violation. The projects that drove the need for the pre-mitigated identified System Network Upgrade will continue to be responsible for the post-mitigated identified System Network Upgrade.

Details on thresholds associated with identification of and responsibility for short circuit violations are contained in Section 5.0 of this procedure.

## Impact Calculations to Address Thermal Violations

The impact calculation for a project on an element for a thermal violation is:

*project impact = project MW x DFAX*

where:

* project MW = requested applicable summer or winter NRC/NIS or CNRC/CNIC for a Generating Facility, or equivalent capability for an ETU, and
* DFAX = the DFAX associated with the highest violation seen on an element resulting from the project (either for meeting the NCIS or CCIS) under post-contingency/pre-upgrade conditions:
  + For meeting the NCIS, the DFAX is calculated by transferring from the project under study to New England load.
  + For meeting the CCIS, the DFAX is calculated by transferring from the project under study to the Load Zone where the project is seeking to interconnect.
  + An equivalent model that allows for the calculation of a DFAX may be used for projects requesting Regional Network Service.

Examples 3 to 6 of Appendix G illustrate cost allocation calculations for various scenarios where one or more System Network Upgrades are required to address elements with thermal violations.

Details on thresholds associated with identification of and responsibility for thermal violations are contained in Section 3.1.1 of this procedure.

## Impact Calculations to Address Steady-State Voltage Violations

The impact calculation for a project on an element for a steady-state voltage violation is:

*project impact = ∆ in per unit voltage*

where:

* The critical bus is the bus with the lowest observed voltage for the worst case voltage violation associated with the project, and
* ∆ in per unit voltage = for the critical bus, the absolute value per unit voltage difference between the observed worst case violation associated with the project and the observed voltage when the project is switched offline. When switching the project offline, the project MW output is replaced by the system swing bus, and all impactful voltage regulating equipment is locked[[54]](#footnote-55).
  + In the case of a severe voltage violation where the powerflow solution is not converged, ∆ in per unit voltage is calculated by creating a case reflecting the post contingency topology but with all the added impactful Generating Facilities or ETUs offline, and then switching online each impactful Generating Facility or ETU one at a time and calculating the absolute value per unit voltage difference between the online and offline states for the bus with the lowest voltage in the online state. All impactful voltage regulating equipment is locked for this analysis.

Example 7A of Appendix G illustrate the project impact calculation for a voltage violation, and examples 7B and 8 of Appendix G illustrate the cost allocation calculations to address elements with voltage violations.

Details on thresholds associated with identification of and responsibility for voltage violations are contained in Section 3.1.2 of this procedure.

## Impact Calculations to Address Stability Violations

The impact calculation for a project associated with a stability violation is:

*project impact = project MW*

where:

* project MW = requested applicable summer or winter NRC/NIS, or equivalent capability for an ETU

Example 9 illustrates cost allocation calculations to address stability violations.

## Impact Calculations to Address Violations Identified Through an Analysis that is not a Short Circuit, Steady-State Thermal, Steady-State Voltage and Stability Analysis

The impact calculation for a project associated with a violation identified through an analysis that is not a short circuit, steady-state thermal, steady-state voltage or stability analysis:

*project impact = project MW*

where:

* project MW = requested applicable summer or winter NRC/NIS, or equivalent capability for an ETU

# State Jurisdictional Affected System Operator (ASO) Studies

## ASO Studies Overview

State-jurisdictional generation interconnection projects (including battery storage projects) undergoing interconnection study for the purposes of supporting I.3.9 applications must meet the requirements of Generating Facilities as listed in this document. Interconnection Studies comprised of state jurisdictional projects undergoing Level III analysis are considered Affected System Operator (ASO) studies. The ISO serves as the affected party to these studies and helps to coordinate these projects’ approval pursuant to section I.3.9 of the Tariff. The Transmission Owner (TO) is responsible for conducting the Interconnection Study on the project developer’s behalf for state jurisdictional projects. ISO’s role in these studies is to provide guidance on study practices and modeling methods, to ensure the study is in compliance with the applicable Tariff and Planning Procedure requirements in pursuit of I.3.9 approval.

The ISO’s participation as the ASO includes, but is not limited to:

* Providing written input to the TO regarding study scopes
* Providing cases and relevant EMT/stability models to the TO for use in the study
* Facilitating PSCAD model sharing between TOs and project developers for relevant projects in the study
* Coordinate feedback and guidance between TO and ISO-NE internal review related to clarification of study scope and results
* Ensuring the study will meet the study and modeling requirements of this Planning Procedure 5-6 to include, but not limited to:
  + Steady state, stability, short circuit, and EMT study methodologies
  + Modeling requirements
  + Studied load levels
  + Study case definitions
  + DER modeling methodology
  + Transmission and generation projects relevant to the study
  + Performance requirements
  + Providing steady state, short circuit, and stability base cases
* Ensuring study is coordinated with relevant ISO Interconnection Studies

## ASO Scope and Study Report Review Timing

ASO study scopes of work[[55]](#footnote-56) and study reports shall be reviewed with the following timelines:

* The ISO shall acknowledge receipt within five (5) Business Days of receiving the ASO study scope or study report
* The ISO shall provide comments within fifteen (15) Business Days of receiving the ASO study scope or study report
* The Transmission Owner shall provide responses to ISO-NE comments within fifteen (15) Business Days of receiving ISO-NE comments.
* The ISO shall issue approval of the finalized ASO study scope or study report no later than five (5) Business Days after receipt of Transmission Owner responses to ISO-NE comments so long as ISO agrees the responses address ISO comments completely.
  + ISO-NE will respond within 5 BD’s should it be identified that TO has not addressed the comments fully.

## Coordination of ASO Studies with ISO Interconnection Studies

ASO studies taking place in a part of the system that are not relevant[[56]](#footnote-57) to any ongoing ISO Interconnection Studies will be able to complete their studies without respecting those ongoing ISO Interconnection Studies as necessary.

ASO studies taking place in a part of the system that are relevant will need to respect and coordinate with those relevant ongoing ISO Interconnection Studies. Coordination includes but is not limited to:

* Using base cases that represents the study year(s) of the relevant ISO Interconnection Studies[[57]](#footnote-58)
* Modeling all relevant ISO Interconnection Requests, and any associated upgrades in the ASO study base cases, and keeping them current
* Updating ASO study scopes to reflect latest information as learned in ISO studies

## Coordination of ASO Studies with ISO Interconnection Studies – Post Order No. 2023

FERC Order No. 2023 establishes a Cluster Study process that requires fixed targeted timeframes for the initiation and completion of ISO Interconnection Requests. These fixed timeframes necessitate alignment of ASO study initiation and completion.

ISO shall continue to perform Level 0 and Level III determinations, in accordance with Appendix I of this Planning Procedure, through the beginning date of the Transitional Cluster Study, 2024. Thereafter, the next opportunity to submit requests for Level 0 and Level III determinations will be during the next state project submission window as described in section 11.5

ASO studies that are relevant to the ISO Cluster Study will continue to coordinate with the study as described in section 11.3.

ASO studies taking place in a part of the system that are not relevant to the ISO Cluster Study will be able to complete their studies without respecting the ISO Cluster Study.

## Coordination of ASO Studies with the Transition Cluster Study

## ASO Studies Completing Before the Beginning of the Transitional Cluster Study (TCS)

Prior to the start of the TCS, determinations will be made on whether the state jurisdictional projects within an ongoing ASO study, that are relevant to the TCS, will be able to be included in the base cases of the TCS. The minimum criteria for the TCS to include these state jurisdictional projects undergoing an Interconnection Study, is as follows:

* The projects within the ASO study being ready to receive Reliability Committee approval within 90 days of the start of the TCS. This is defined as:
  + The ASO study having completed preliminary EMT analyses
  + Identification and design of any upgrades needed to address violations has been completed
  + Models used for both the projects under study, and any associated upgrades have been finalized
* Submitting finalized models from the ASO study, to the ISO prior to the start date of the TCS

State jurisdictional projects that do not meet these thresholds will not be able to be included in the TCS base cases, and shall meet the requirements of Section 11.4.1.2.

## Coordination of ASO Studies with the Transitional Cluster Study (TCS)

Those ASO studies that do not meet the thresholds listed in section 11.4.1.1, that the ISO has determined are relevant to the TCS shall respect the TCS, and coordinate with the TCS. Coordination includes:

* Using the TCS study cases as the base case[[58]](#footnote-59)
* Modeling all relevant ISO Interconnection Requests within the TCS
* Modeling all relevant upgrades from the TCS
* Updating study scopes to reflect latest information as learned from the TCS

## Coordination of ASO Studies with the Transitional Cluster Study (TCS) – Timing

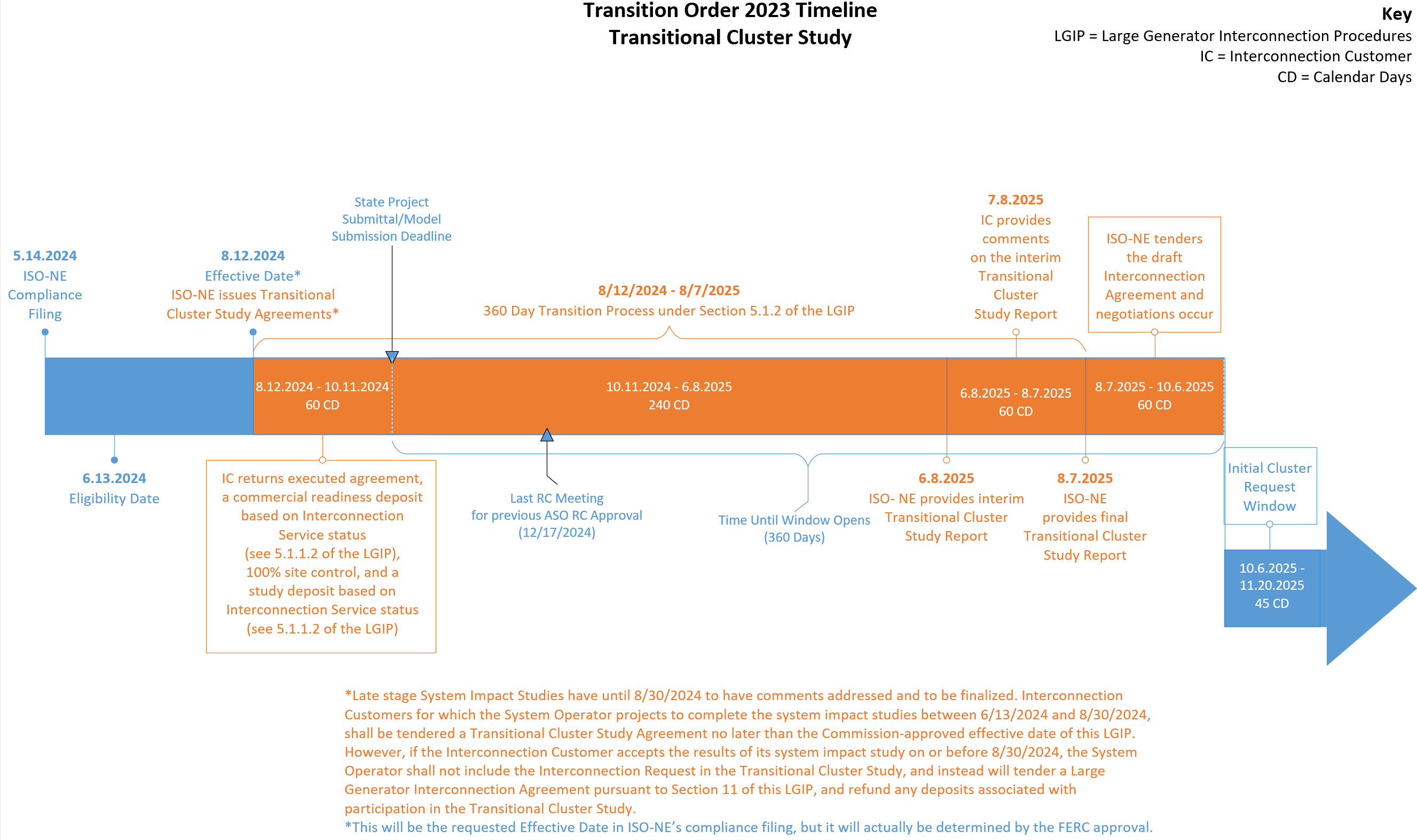
Those ASO studies as identified in section 11.4.1.2 shall provide a scope of work for ISO review. The approval of the scope of work shall apply for the remainder of the TCS with the exception of additional sensitivities being added for unforeseen issues that may arise within the TCS.

The ISO will continue to coordinate any other information from the TCS to the relevant TO’s as needed for the duration of the TCS. This includes:

* Setting up coordination calls on a time frame agreed upon by both the TO and the ISO
* Making timelines and project specifics available
* Forwarding updated modeling files should they be needed
* Forwarding results
* Forwarding upgrade files

ASO studies that have been identified as needing to respect the TCS will need to wait until the TCS[[59]](#footnote-60) is sufficiently completed before completing their analyses to ensure the TCS finalized upgrades are respected.

*Figure 11.4.1.3.1 – Transition Cluster and ASO Coordination*



## ASO Study Coordination After Transition

After the completion of the Transitional Cluster Study, ASO studies will continue to be coordinated with ISO Cluster Studies in a similar manner to that of the TCS.

## ASO Studies Completing Before the Beginning of the ISO Cluster Study

Prior to the start of the ISO Cluster Study, determinations will be made on whether the state jurisdictional projects within on-going ASO studies, that are relevant to the ISO Cluster Study, will be able to be included in the base cases of the ISO Cluster Study. The minimum criteria for the ISO Cluster Study to include these state jurisdictional projects undergoing an interconnection study, is as follows:

* The projects within the ASO study being ready to receive Reliability Committee approval within 90 days of the start of the ISO Cluster Study. This is defined as:
  + The ASO study having completed preliminary EMT analyses
  + Identification and design of any upgrades needed to address violations has been completed
  + Models used for both the projects under study, and any associated upgrades have been finalized
* Submitting finalized models from the ASO study, to the ISO prior to the start date of the ISO Cluster Study

State jurisdictional projects that do not meet these thresholds will not be able to be included in the ISO Cluster Study base cases, and shall meet the requirements of Section 11.4.2.2.

## 11.4.2.2 Coordination of ASO Studies with the ISO Cluster Study

Those ASO studies that do not meet the thresholds listed in Section 11.4.2.1, that the ISO has determined are relevant to the ISO Cluster Study shall respect the ISO Cluster Study, and coordinate with the ISO Cluster study. Coordination includes:

* Setting up coordination calls on a timeframe agreed upon by both the TO and the ISO
* Using the ISO Cluster Study cases as the base case[[60]](#footnote-61)
* Modeling all relevant projects within the ISO Cluster Study
* Modeling all relevant upgrades from the ISO Cluster Study
* Updating study scopes to reflect latest information as learned from the ISO Cluster Study

## 11.4.2.3 Coordination of ASO Studies with the ISO Cluster Study – Timing

TOs shall provide a scope of work for those ASO studies identified in section 11.4.2.2. The approval of the scope of work shall apply for the remainder of the ISO Cluster Study with the exception of additional sensitivities being added for unforeseen issues that may arise within the ISO Cluster Study.

ISO will continue to coordinate any other information from the ISO Cluster Study to the relevant TO’s as needed for the duration of the ISO Cluster Study. This includes:

* Making timelines and project specifics available
* Forwarding updated modeling files should they be needed
* Forwarding results
* Forwarding modeling files for any upgrades as they become available

## 11.4.2.4 Coordination of ASO Studies with the ISO Cluster Restudy

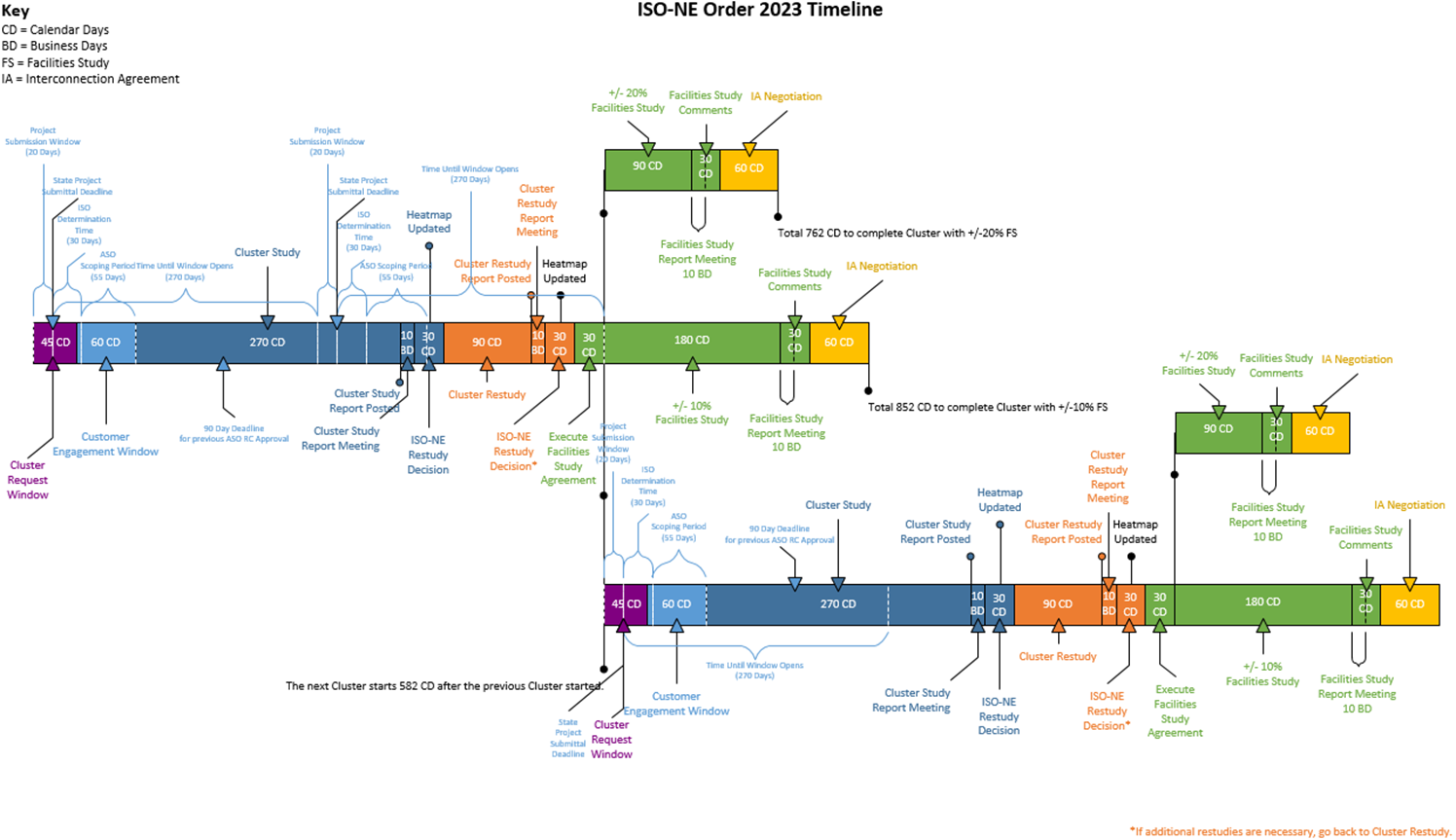
Prior to the start of the ISO Cluster Restudy (if one is needed) the ISO will make determinations on which state jurisdictional projects are relevant to the restudy work.

* Projects from the ongoing ASO study, that are relevant to the ISO Cluster Restudy, will need to undergo further analysis to respect the restudy, and will be coordinated in the same manner as the ISO Cluster Study coordination
* New projects that were determined to require Level III analysis during the previous ISO Determination Window, and are relevant to the ISO Cluster Restudy, shall either be included in the current ASO Study and coordinate with the ISO Cluster Restudy, or start their own separate ASO study that respects the ISO Cluster Restudy and the current ASO Study
* Projects from the ongoing ASO study, that are not relevant to the ISO Cluster Restudy, will not be required to respect the ISO Cluster Restudy

## State Jurisdictional Project Clustering Milestones

* State project submission window: This window starts at the same time as the ISO Cluster Request Window and lasts for 20 CDs. During this time the ISO will accept all requests for Level 0 and Level III determinations. These can be submitted in the form as described in Appendix I of this document, or in the form of Generator Notification Forms or Proposed Plans Applications
* ISO determinations window: This window starts at the end of the state project submission window and lasts 30 CDs. During this time ISO will provide determinations in accordance with Appendix I of this document for all projects submitted within the state project submission window
* ASO scoping period: This window starts at the end of the ISO determinations window and concurrently, 5 CDs after the end of the ISO Cluster Request Window. This window lasts for 55 days during which ISO will coordinate with the relevant TOs to develop scopes of work for the ASO studies that are being started to support the I.3.9 applications for the state jurisdictional projects that were determined to be Level III during the ISO determinations window.
* Cluster study window: The ASO study will start at the same time as the ISO Cluster Study, and have until the start of the next ISO Cluster Study to satisfy the requirements of section 11.4.2.2
* Interim state project submission window: This window opens 270 CD after the close of the previous state project submission window. During this time, ISO will accept requests for Level 0 and Level III determinations. These can be submitted in the form as described in Appendix I of this document, or in the form of Generator Notification Forms or Proposed Plans Applications
* Interim ISO determinations window: This window starts at the end of the interim state project submission window and lasts 30 days. During this time the ISO will provide determinations in accordance with Appendix I of this document for all projects submitted within the interim state project submission window
* Interim ASO scoping period: This window starts at the end of the interim ISO determinations window. This window lasts for 55 days during which the ISO will coordinate with the relevant TO’s to develop scopes of work for the ASO studies that are being started to support the I.3.9 applications for the state jurisdictional projects that were determined to be Level III during the interim ISO determinations window
* ISO-NE restudy decision: The timeline for the next opening of the state project submission window is dependent on whether or not there is an ISO Cluster Restudy:
  + If there is an ISO Cluster Restudy the next state project submission window will open 270 days after the close of the interim state project submission window
  + If there is no ISO Cluster Restudy the next state project submission window will open approximately 145 Days after the close of the interim state project submission window

*Figure 11.5.1*



**Document History[[61]](#footnote-62)**

|  |  |  |
| --- | --- | --- |
| **Rev. No.** | **Date** | **Reason** |
| Rev 0 | RTPC – 4/13/99 |  |
| Rev 1 | RC – 2/13/01; PC 3/2/01 |  |
| Rev 2 | Effective 2/1/05 | Addition of overlapping impact language to PP to conform with recently approved updates to the ISO Tariff |
| Rev 3 | RC 5/19/09; NPC 6/5/09; ISO-NE 7/7/09 |  |
| Rev 4 | RC 7/19/10; NPC 8/6/10; ISO-NE 8/10/10 | Administrative document changes to conform to Tariff terminology and to add back miscellaneous footnotes that were lost in prior versions. |
| Rev 5 | RC 8/12/14; NPC 9/12/14; ISO-NE 9/15/14 | Additions made to describe load level modeling. |
| Rev 6 | RC 07/14/2015  NPC 08/07/2015 | Additions made to address Elective Transmission Upgrades and add clarifications. Format updated to be consistent with Operating Procedures |
| Rev 7 | RC 06/09/16  NPC 06/21/16 | Additions made to conform with Interconnection Process Improvements filing (February 18, 2016) |
| Rev 8 | RC 02/13/2018  NPC 03/02/2018 | Additions to: (i) clarify alignment with other planning procedures, (ii) clarify certain provisions, (iii) clarify compliance with NERC standards, and (iv) clarify certain requirements for inverter-based generators. |
| Rev 9 | RC 12/18/2020  NPC 02/06/2020 | Correcting the title of PP5-1 in the References section. |
| Rev 10 | RC 03/17/2020  NPC 04/02/2020 | Update to loss-of-source interconnection design requirement in Appendix A. |
| Rev 11 | RC 04/27/2022  NPC 05/05/2022 | Additional guidance for Distributed Energy Resources |
| Rev 12 | RC 02/22/2023  NPC 04/06/2023 | Aligning generator outputs for steady-state and stability analyses |
| Rev 13 | RC 12/19/2023  NPC 02/01/2024 | Update to study scenarios  Addition of new appendix for IEEE 2800 adoption  Updated EMT model requirements |
| Rev 14 | RC XX/XX/XXXX  NPC XX/XX/XXXX | Update to conform with Orders Nos. 2023/2023-A  Modifications to Appendix C to support new Appendix C-2 on model acceptance testing, and include Affected System Operator study coordination and determination practices. |

# Appendix A – General Transmission System Design Requirements for the Interconnection of New Generating Facilities and ETUs to the Administered Transmission System

All electrical facilities must be designed, built and operated in accordance with applicable NERC, NPCC, ISO New England (including Planning Procedure 9) and the Interconnecting Transmission Owners’ standards, guidelines, criteria, or the equivalent. This document describes only the general transmission system design requirements for new Generating Facilities and ETUs to interconnect to the Pool Transmission Facilities (PTF). Additional technical and design requirements related to resource interconnection and operation may also apply.

**Point of Interconnection**

The following shall be applied to the design of a new Generating Facility (resource) or ETU interconnection:

1. All new Generating Facilities or ETUs shall be connected to the system at a new or existing station on the existing Administered Transmission System.

2. The station shall be designed to provide independent switching of each Generating Facility or ETU interconnection to the system and each transmission line terminating in the station. The intent is to design the interconnection in a manner that does not adversely affect the ability to maintain major components of the transmission system.

3. A ring bus or breaker-and-a-half connection shall be used at the point of Generating Facility or ETU interconnection with the transmission system. Transmission system needs and use may require a breaker-and-a-half arrangement. Alternative interconnection designs to Non-PTF facilities shall be considered where appropriate. Additionally, two circuit breakers placed in series may be required to mitigate the consequences of a stuck breaker that would otherwise result in an unacceptable system performance.

4. Transmission system circuit breakers shall not be used for synchronization of new Generating Facilities.

**Interconnection Design – Loss-of-Source**

The interconnection shall be designed such that, with all lines initially in service, there is no normal design contingency or common mode transmission system, station, or internal plant failure which could result in a net loss of more than 1,200 MW of resources, except in the case of an increase of no more than 2% above the maximum capability, in place at the time of the original incorporation of this provision into PP5-6 in June 2016, of an existing facility that already corresponded to a loss of more than 1,200 MW of resource for a normal design contingency.

**Out of Step Protection**

Each PTF connected synchronous generating resource shall be required to have out-of-step protection installed. This protection shall detect an out-of-step condition and trip the Generating Facility to protect the transmission system against adverse impact associated with the Generating Facility losing synchronism with the system. Additionally, the Transmission Owner and/or the ISO may require that supplementary supervisory detection be used in conjunction with the out-of-step protection when necessary to prevent unnecessary and undesirable out-of-step protection operation.

**Transmission Circuit Breakers**

All new 345 kV and, where identified as necessary, 230 kV and 115 kV, circuit breakers must meet the requirements of Planning Procedure 9.

# Appendix B – Requirements of PSS/E Models

All power flow and dynamic models must be made available for use in the version of PSS/E that is in use by ISO New England and must accurately model all of the relevant control modes and characteristics of the equipment, such as:

* All available voltage/reactive power control modes
* Frequency/governor response control modes (which may be provided by a park controller)
* Low voltage ride through characteristics, if applicable
* Low frequency ride-through characteristics, if applicable
* Park controller or group supervisory functionality (e.g. for a wind farm)
* Appropriate aggregate modeling capability (e.g. for a wind farm)
* Charging or pumping mode, if applicable (e.g., for a battery energy storage device or pumped storage hydro Generating Facility)

**Standard Dynamics Models**

For all Interconnection Studies all models must be standard library models in PSS/E or applicable applications. Where applicable, the most up-to-date revision of the models must be used. User-written models will not be accepted.

**User-Written Dynamics Models**

A user written model is any model that is not a standard Siemens PSS/E library model. For all Interconnection Studies commencing before January 1, 2017, when no compatible PSS/E standard dynamics model(s) can be used to represent the dynamics of a device, accurate and appropriate user written models can be used, if accepted by ISO New England after testing.

User-written models for the dynamic equipment and associated data can be in either dynamic model source code (.lib) or dynamic model object code (.obj) or dynamic linked library (dll):

* User-written source code, object code, and parameters shall be updated for the latest PSS/E version in use and specified by ISO New England:
  1. Dynamics models related to individual units shall be editable in the PSS/E graphic user interface. All model parameters (CONS, ICONS, and VARS) shall be accessible and shall match the description in the model’s accompanying documentation. Certain CONEC or CONET models may be acceptable.
  2. Dynamics models shall have all their data reportable in the “DOCU” listing of dynamics model data, including the range of CONS, ICONS, and VARS numbers. Models that apply to multiple elements (e.g., park controllers) shall also be fully formatted and reportable in DOCU.
  3. Dynamics models shall be capable of correctly initializing and run through the simulation throughout the range of expected steady state starting conditions without additional manual adjustments.
  4. Dynamics models shall be capable of allowing its accompanying element or elements to be switched out-of-service (including when the bus is disconnected) in the steady-state network without additional steps and without errors. Documentation of any special requirements for this condition shall be clearly defined in the model documentation.
  5. Dynamics models shall be capable of allowing all documented (in the model documentation) modes of operation without error.
  6. A park controller model to control more than one generator (e.g., in a wind farm or photovoltaic park) shall be able to accurately control multiple equivalent generators. The relative reactive output of each generator shall be correctly representative of its representation of number of units and impedance data. The park controller shall be able to regulate a minimum of eight equivalent generator units.
  7. Dynamic models shall be coded in such way that any internal changes of model variables or parameters incurred in one simulation run shall not be automatically passed on to the same models in subsequent simulation runs given both load-flow file and snapshot file are restored in the same PSS/E application.
* Models requiring allocation of bus numbers shall be compatible with the New England bus numbering system, and shall allow the user to determine the allocation of the bus numbers.
* Models shall initialize correctly and be capable of successful “flat start” and “ring down” testing using the following guideline (models shall be capable of meeting these requirements when operating at full rated (nameplate) power, and also at partial power within the physical operating range of the equipment, across a range of feasible reactive power output conditions and terminal voltages):
  1. 20 Second No-Fault Simulation (a/k/a “flat start”): This test consists of a 20 second simulation with no disturbance applied. The test will be considered to be passed if the following criteria are met:
     1. No generator MW change of 0.1 MW or more
     2. No generation MVAR change of 0.1 MVAR or more
     3. No line flow changes of 0.3 MW or more
     4. No line flow changes of 0.3 MVAR or more
     5. No voltage change of 0.0001 p.u. or more
  2. 60 Second Disturbance Simulation (a/k/a “ring down”): This test consists of the application of a 3-phase fault for a few cycles at a key transmission bus, followed by removal of the fault without any lines being tripped. The simulation is run for 60 seconds to allow the dynamics to settle and will be considered to be passed if the following criteria are met:
     1. No generator MW change of 1 MW or more from pre-fault to steady-state post-fault conditions
     2. No generator MVAR change of 1 MVAR or more, except for exciters with dead band control (typically IEEE Type 4) from pre-fault to steady-state post-fault conditions
     3. No voltage change of 0.0001 p.u. or more, except in vicinity of exciters with dead band control from pre-fault to steady-state post-fault conditions
     4. No undamped oscillations related to the addition of the new user-written model

User-written model(s) shall be accompanied by the following documentation:

* A user’s guide for each model
* Appropriate procedures and considerations for using the model in dynamic simulations
* Technical description of characteristics of the model
* Block diagram for the model, including overall modular structure and block diagrams of any sub-modules
* Values, names and detailed explanation for all model parameters
* Text form of the model parameter values (PSSE dyr file format)
* List of all state variables, including expected ranges of values for each variable

# Appendix C – Requirements of Electromagnetic Transient (EMT) Models

1. **EMT model requirement**

As the penetration of inverter-based resources (IBR) and distributed energy resources (DER) continues to grow, EMT models are required to support current and future study efforts which are required to maintain a reliable power system. Models are required for one or more of the following reasons. Other specialty studies may also be performed from time to time.

Integration of IBR into low system strength networks

Sub-synchronous control interactions (plant-to-grid)

IBR controls interactions (plant-to-plant and within the plant)

IBR controls stability (large and small disturbance)

IBR frequency and voltage ride-through capability and performance

IBR short-circuit current analysis

Power quality studies (e.g., harmonics, rapid voltage change)

Black start and system restoration studies

Benchmarking and verifying RMS positive sequence dynamic models

1. **EMT Model Requirements**

As mentioned above, specific model requirements for an EMT study depend on the type of study being done. A study with a scope covering weak system interconnection, ride-through, voltage control and event response, and islanding performance (for example) would require a model which must meet the requirements stated in [Appendix C-1](https://www.iso-ne.com/participate/rules-procedures/planning-procedures) attached to this planning procedure, and unless specified otherwise, this type of model is what is required.

1. **Model Submission Report Requirements**

Studies utilizing electromagnetic transient tools such as PSCAD rely heavily on model accuracy and quality to be conducted in a timely manner. Failures in model quality control or insufficient care in preparing site specific models can (and often does) result in long study delays.

In order to allow ISO New England planning studies which may involve electromagnetic transient analysis to be conducted efficiently and accurately, a benchmarking analyses must be conducted to evaluate the accuracy, consistency, and dynamic performance of the provided models. Additionally, a benchmarking report will be required to compare the performance of the PSCAD model against the PSSE model using the same set of tests. The specific details of the tests, expected outcomes and benchmarking report are outlined in [Appendix C-2](https://www.iso-ne.com/participate/rules-procedures/planning-procedures) attached to this planning procedure.

**Important Note**

It is important to note the model acceptance tests are required to provide a basic understanding of the plant’s dynamic performance. More detailed studies are required to analyze the phenomena listed above in Section 1.0 of this Appendix, and the results of these studies may indicate problems which are not evident in these model acceptance tests. For example, interactions with nearby devices will be impossible to ascertain in a simple model without detailed models of the nearby devices available. Other issues may be found as more detailed system models and network conditions are tested.

# Appendix D – Detailed Considerations for the Study of an Inverter Based Generating Facility

**Typical Order of Study for an Inverter Based Generating Facility**

Short Circuit Ratio calculation

Review of PSS/E-PSCAD benchmarking

PSCAD analysis of performance if Short Circuit Ratio is low

Review of performance of PSS/E model

Collector system/GSU tap setting/voltage control strategy calculation

Steady state reactive margin analysis

Initial dynamic fault testing

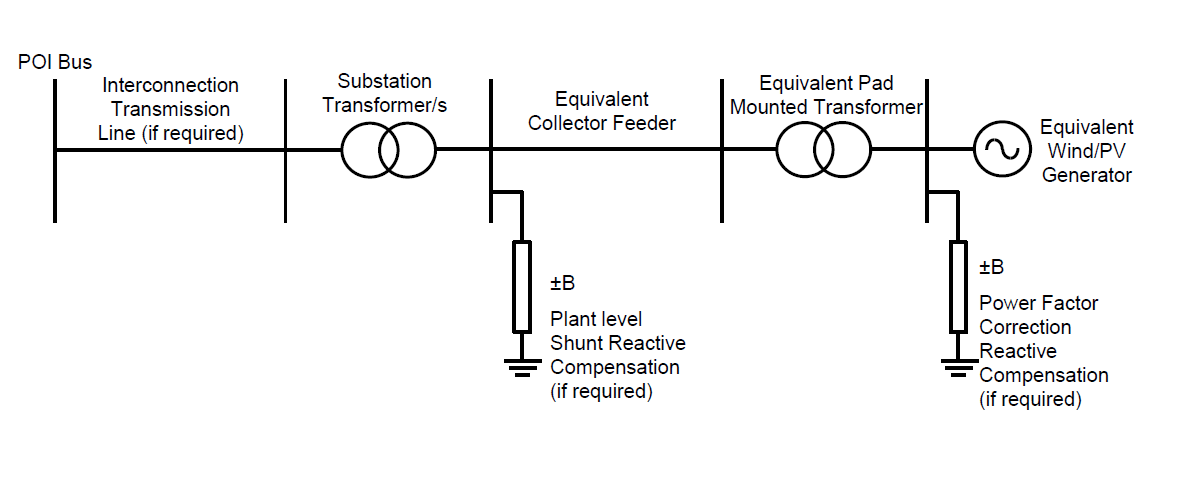
Full steady state testing to meet the requirements of this Planning Procedure

Full dynamic testing to meet the requirements of this Planning Procedure

**Use of Aggregate Models for Collector-Based Generating Facilities**

For the steady-state portion of the Interconnection Study, including the detailed collector system analysis described below, a fully explicit model of the collector system, including all branch connections and step-up transformers shall be used.

For the stability portion of the Interconnection Study, an equivalent model shall be used for each major feeder branch of the Generating Facility. The following figure provides a representation of the appropriate equivalent to be used.



**Collector system/GSU tap setting/voltage control strategy calculation**

A detailed evaluation using a fully explicitly modeled collector-based Generating Facility allows for analysis of voltage control strategies by showing the real and reactive power flow and losses across every element of the facility. Being able to monitor the terminal voltage at each individual generating unit makes it possible to ensure each unit remains within a reasonable voltage range to avoid tripping. All collector branches, junctions, individual high and low voltage busses (including the GSUs and generating units) shall be modeled using the configuration, network impedances, generating unit reactive capabilities and facility ratings for the project.

The following voltage regulation modes should be reviewed as appropriate:

Generating units regulating voltage at a remote bus

Generating units regulating voltage at a Park transformer high side bus

Generating units regulating voltage at a Park transformer low side bus

Generating units regulating voltage at a fixed power factor

**Step 1 – Reactive Power Capability**

This step investigates the reactive power range of the overall Generation Facility and seeks to determine if the collector system design allows full reactive power capability. It also tries to determine what unit and station transformer taps allow for the largest reactive power injection range of the generating units.

The POI may be modeled as a swing bus for this analysis. A fictitious machine may be placed at the swing bus to consume the Project output and to allow for adjustment of transmission system voltages.

Testing is performed to determine if the generating units would violate any voltage trip settings given the full leading and lagging reactive power range of the generating units.

The reactive power output of the generating units is ramped to the maximum leading negative MVAR and to the maximum lagging capability positive MVAR for various system voltages and transformer tap settings.

If any bus voltage within the Project or collector system is outside of the specified range, the generating unit reactive power output for the wind park should be recorded along with the first bus that showed a voltage outside of the range. This information is used to determine which transformer tap settings result in the greatest usable reactive power range of the generating units as a way to pre-screen the testing required for Step 2.

**Step 2 – Collector System Voltage Range**

The goal of this testing is to develop a strategy to maintain sufficient margin to the generating unit trip settings and if possible maintain a preferred Generation Facility terminal voltage range (typically 0.95 to 1.05pu) for any transmission system voltage (typically 0.9 pu to 1.1 pu).

Testing is performed at different plant output levels 0% to 100% output in 10% intervals with equal loading across all individual generating units.

For each of the applicable control strategies described above, and optimum tap settings from Step 1, a voltage profile is created and the minimum and maximum voltages within the facility is recorded.

**Step 3 – VAR impact to the System and Voltage Schedule Margin**

The goal of this testing is to identify a strategy that will minimize the reactive power demand from the system under normal conditions, but also provide VAR support under low voltage conditions and consume MVAR under high voltage conditions.

To ensure there is proper margin with the scheduled voltage (as determined by ISO during the study), +/-2% from scheduled voltage is evaluated.

# Appendix E – Procedures for Material Modification Determinations

This Appendix E provides implementation guidance in the application of the modification review procedures contained in Schedules 22, 23 & 25 of the OATT.

Different thresholds for determining whether a proposed modification constitutes a Material Modification of a Generating Facility or ETU depend on the stage of the project:

After the ISO receives an Interconnection Request but before the submission of an executed Cluster Study Agreement[[62]](#footnote-63) to the ISO[[63]](#footnote-64).

After the submission of an executed Cluster Study Agreement to the ISO:

This includes evaluation of “as purchased data,” “as built/as tested data” and changes to existing facilities (e.g., equipment upgrade, replacement of failed equipment). Note:

“As purchased data” is required to be submitted no later than 180 Calendar Days prior to the Initial Synchronization Date and shall be reviewed prior to the project being allowed to be synchronized to the New England system.

“As built/as tested” is required to be submitted prior to the Commercial Operation Date and shall be reviewed prior to the project being allowed to become Commercial.

In all cases and at any time, a new Interconnection Request is required for:

Any increase to the energy capability or capacity capability output of a Generating Facility or ETU above that specified in an Interconnection Request or existing Interconnection Agreement (whether executed or filed in unexecuted form with the Commission).

A change from Network Resource (NR) Interconnection Service to Capacity Network Resource (CNR) Interconnection Service.

An extension of three or more cumulative years in the Commercial Operation Date, In-Service Date or Initial Synchronization Date of the Large Generating Facility or ETU unless provisions of Section 4.4.6 of the Schedules 22 or 25 are satisfied.

After the ISO receives an Interconnection Request and before submission of an executed Cluster Study Agreement[[64]](#footnote-65) to the ISO, the following will not be deemed material:

Extensions of less than three (3) cumulative years in the Commercial Operation Date, In-Service Date or Initial Synchronization Date of the Large Generating Facility or ETU to which the Interconnection Request relates provided that the extension(s) does not exceed seven (7) years from the date the Interconnection Request was received by the System Operator.

A decrease of up to 60 percent of electrical output (MW) of the proposed project.

Modification of the technical parameters associated with the Large Generating Facility or ETU technology.

Modification of the Large Generating Facility or ETU step-up transformer impedance characteristics.

Modification of the interconnection configuration.

Modification of the Point of Interconnection (POI).

After the submission of an executed Cluster Study Agreement[[65]](#footnote-66) to the ISO:

A proposed project, or an existing Generating Facility or ETU can request that a proposed change be evaluated to determine if the change is a Material Modification. If this happens, the proposed change will be evaluated using technical screening criteria. However, there may be proposed changes that have not been contemplated and might require additional analysis beyond the normal screening criteria.

In addition to the previously listed items that, in all cases and at any time, would require a new interconnection Request, the following will be deemed material and require a new Interconnection Request:

Where the change(s) would either require significant additional study of the same Interconnection Request and could substantially change the interconnection design, or have a material impact (i.e., an evaluation of the proposed modification cannot be completed in less than ten (10) Business Days) on the cost or timing of any Interconnection Studies or upgrades associated with an Interconnection Request with an equal or later Queue Position.

A decrease of the electrical output (MW) of the proposed project where the decrease would result in the transfer of an upgrade obligation to one or more projects in the same or a later Cluster

Modification of the POI and/or interconnection configuration that is not based on unanticipated study results

The following may be deemed material and require a new Interconnection Request:

A decrease of the electrical output (MW) of the proposed project where the decrease would not result in the transfer of an upgrade obligation to one or more projects in the same or a later Cluster

Modification of the technical parameters associated with the Large Generating Facility or ETU technology

Modification of the Large Generating Facility or ETU step-up transformer impedance characteristics

The addition to the Interconnection Request of a Generating Facility with the same Point of Interconnection indicated in the initial Interconnection Request, if the addition of the Generating Facility does not increase the requested Interconnection Service level. The ISO must evaluate such requested additions prior to deeming them a Material Modification, but only if the Interconnection Customer submits them prior to the return of the executed Interconnection Facilities Study to the ISO. Interconnection Customers requesting that such requested additions be evaluated must demonstrate the required Site Control at the time such requests are made.

The following will not be deemed material and will not require a new Interconnection Request

Extensions of less than three (3) cumulative years in the Commercial Operation Date, In-Service Date or Initial Synchronization Date of the Large Generating Facility or ETU to which the Interconnection Request relates provided that the extension(s) does not exceed seven (7) years from the date the Interconnection Request was received by the System Operator

Modification of the POI and/or the interconnection configuration based on study results that were not anticipated and are agreed to by the System Operator and the Interconnecting Transmission Owner.

After the completion of a Cluster Study, and if the ISO determines that a Cluster Restudy is required and at the request of an Interconnection Customer, a one-time decrease of the electrical output (MW) of the proposed project where the project is not responsible for any shared Network Upgrades with another Generating Facility or ETU proposed in a separate Interconnection Request included in the Cluster.

Upon achieving Commercial Operation, a decrease of the electrical output (MW) of the proposed project, but where all Interconnection Facilities, Substation Network Upgrades and System Network Upgrades the project is responsible for, as identified in its Interconnection Studies, have been built.

Screening Criteria

1. Screening Criteria for Changes in Dynamic Models or Voltage Control Schemes:

The following will not be deemed material and will not require a new Interconnection Request:

There is no voltage or dynamic stability problem that may be adversely affected by the change to the project that is found in any base cases for the most severe N-1 and N-1-1 contingencies.

The new models provide similar or better dynamic voltage and stability performance based on dynamic simulation of a few severe faults.

2. Screening Criteria for Short Circuit Impacts of Changes in Generation or ETU or Interconnection Facility Impedances:

The following will not be deemed material and will not require a new Interconnection Request:

The total impedance is greater than that of the previously submitted unit(s) and X/R ratio is less than or equal to that of the previously submitted unit(s).

A short circuit study at only the interconnecting bus confirms that short circuit duty is less than or equal to that of the previously submitted unit(s).

3. Screening Criteria for Stability Impacts of Changes in Generation or ETU or Interconnection Facility Impedances:

The following will not be deemed material and will not require a new Interconnection Request:

The new models provide similar or better dynamic performance (better damping, smaller angular swing) based on dynamic simulation of a few severe faults.

4. Screening Criteria for Voltage Impacts of Changes in Generation or ETU or Interconnection Facility Impedances:

The following will be deemed material and require a new Interconnection Request:

A change that will result in the Generating Facility or ETU not meeting the Tariff's power factor requirement

The following will not be deemed material and will not require a new Interconnection Request:

The change of impedance is small (less than 10% of the impedance used in the SIS), the power factor requirement is satisfied, and there is no pre-existing voltage problem

5. Screening Criteria for PSCAD Changes to Generating Facilities or ETUs that Required a PSCAD model:

The following will not be deemed material and will not require a new Interconnection Request

The new models provide similar or better performance for the most severe N-1 and N-1-1 contingencies.

# Appendix F – IEEE 2800 Requirements

This Appendix E provides implementation guidance in the application of the material modification procedures contained in Schedules 22, 23 & 25 of the OATT.

* For the purposes of this appendix, figures 1,2 and 3 of clause 1.4 shall be adhered to
* This appendix defers to clause 3 of IEEE 2800-2022 for definitions, acronyms, and abbreviations
* Shall be compliant with clause 4 of IEEE 2800-2022
  + Shall be compliant with clause 4.1
  + Shall be compliant with clause 4.2
  + Shall be compliant with clause 4.3
  + Shall be compliant with clause 4.4
  + Shall be compliant with clause 4.7 items d-g
  + Shall be compliant with clause 4.9
* Shall be compliant with clause 5 of IEEE 2800-2022
  + Shall be compliant with clause 5.1
    - Default RPA shall be the POM
    - ICR and ICAR shall be defined as the Rated Active Power Output Rated Active Power Absorption as listed in the IBRs interconnection agreement.
    - Table 4 RPA Voltage Ranges will be defined based on the interconnection TOs requirements.
  + Shall be compliant with clause 5.2
    - Resources shall be enabled in voltage control mode by default
    - Response times under table 5 are adopted as the default
    - Proposed maximum step response timing will be subject to review during SIS to ensure no adverse impact during low system strength conditions
* Shall be compliant with clause 6 of IEEE 2800-2022
  + The default RPA for clause 6 is as written as the default in 6.1.1
  + Shall be compliant with 6.1.1
    - Both under and over frequency response shall be enabled to the fullest extent
    - Default parameters under table 7 are adopted
  + Shall be compliant with 6.1.2
    - Default parameters under table 8 are adopted
* Shall be compliant with clause 7 of IEEE 2800-2022
  + The Default RPA for clause 7 is as written for each sub clause within the standard
  + Shall be compliant with 7.1
  + Shall be compliant with 7.2.1
  + Shall be compliant with 7.2.2.1
    - For resources that will cease to inject current in the permissive operation region, a notification to the ISO must be made.
  + Shall be compliant with 7.2.2.2
    - IBRs shall by default be configured in reactive power priority mode
  + Shall be compliant with 7.2.2.3.1
  + Shall be compliant with 7.2.2.3.2
  + Shall be compliant with 7.2.2.3.3
  + Shall be compliant with 7.2.2.3.4
    - IBRs shall by default be configured in reactive current priority mode
  + Shall be compliant with 7.2.2.3.5
    - Timing will be subject to review during SIS to ensure no adverse impact during low system strength conditions
  + Shall be compliant with
    - Inverter-based resources are expected to ride through a post-fault dynamic voltage oscillation with the following envelope characteristics:
      * Upper and lower limits of 1.15 and 0.8 p.u. settling to between 1.05 and 0.90 p.u.
      * A frequency of oscillation between 0.25 Hz and 2 Hz in a synchronous reference frame
      * A damping ratio of 3% or better
  + Shall be compliant with 7.2.2.5
  + Shall be compliant with 7.2.2.6
    - Active power recovery time will by default be 1s. This will be confirmed and reviewed during the SIS to ensure no adverse impact during low system strength conditions
  + Shall be compliant with 7.2.3
  + Shall be compliant with 7.3
    - Fnom is 60, default values from table 15 shall be adopted

Exceptions:

* 4.5 is not adopted at this time
* 4.6 is not adopted at this time
* 4.7 items a-c are not adopted at this time
* 4.10 is not adopted at this time
* 4.11 is not adopted at this time
* 4.12 is not adopted at this time
* Capability to provide reactive power support when the primary energy source is not available as described in clause 5.1 is not adopted at this time
* 6.2 is not adopted at this time
* 7.4 is not adopted. Generators return to service after trip shall be coordinated with ISO-NE Control Room.
* Clauses 8, 9, 10, 11, and 12 are not adopted at this time

Clarifications:

* The measurement accuracy requirements of clause 4.4 are subject to coordination with all applicable ISO-NE Operating Procedures and NERC standards and the aforementioned will take precedence over compliance with this clause
* The default RPA is the POM as detailed in clause 4.2.1 unless otherwise specified within this Appendix F of PP5-6
* IBR’s are not required to pre-curtail output in order to reserve under frequency response availability
* Resources tripping offline, going into blocking modes, or reducing power output outside of allowable ranges within clause 7 of this standard during SIS review will be treated as significant adverse impact, and mitigations will be required.
* Voltage disturbance oscillations and voltage excursions are defined differently under 7.2.2.4. Voltage excursions are separate events as where oscillations are not.
* Clause 5.1 shall be treated as a minimum reactive capability requirement for non-synchronous generation
* Interconnection Study testing shall evaluate the compliance of the minimum reactive capability with the requirements of clause 5.1 of IEEE 2800.
* Interconnection Study testing shall evaluate the compliance of the voltage and reactive power control with the requirements of clause 5.2 of IEEE 2800.
* Interconnection Study testing shall evaluate the compliance of the active power and frequency response with the requirements of clause 6 of IEEE 2800.
* Interconnection Study testing shall evaluate the compliance of the ride through capability with the requirements of clause 7 of IEEE 2800.

# Appendix G – Cost Allocation Methodology Examples

*Example 1 (Cost Allocation Breakdown by Upgrade Classification)*

This example illustrates how cost allocation is calculated differently for each system upgrade classification.

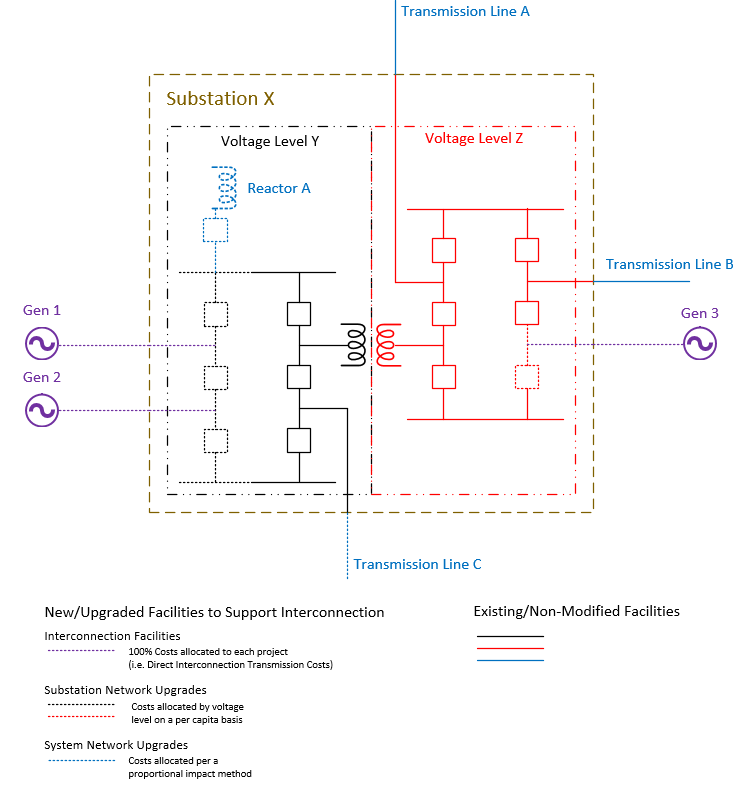
In this example, three generators are seeking to interconnect at the same substation (Substation X):

Generator 1 (Gen 1) and Generator 2 (Gen 2) are seeking to interconnect at Voltage Level Y of Substation X.

Generator 3 (Gen 3) is seeking to interconnect at Voltage Level Z of Substation X.

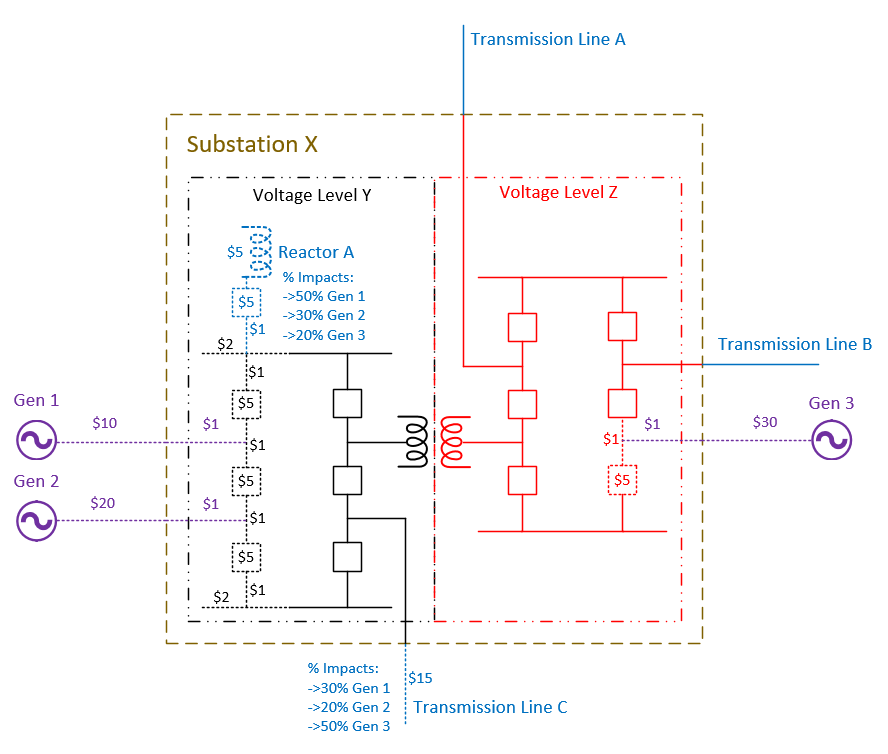
Figure G.1.1 illustrates this scenario, shows the upgrades identified to interconnect these three generators, and distinguishes the different upgrade classifications for each identified upgrade.

*Figure G.1.1*



The dollar amount for each upgrade associated with this example is shown in Figure G.1.2 below.

*Figure G.1.2*



The cost allocation calculations for the Interconnection Facilities are:

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Project** | **Interconnection Facilities** | | | | |
| **Gen 1** | **Upgrade** | **A) Number of Applicable Upgrades** | **B) Cost per Upgrade** | **C) Number of Applicable Projects** | **D) Total Costs per Upgrade =(AxB)/C** |
| Generator Leads (Outside of Substation) | 1 | $10.00 | 1 | $10.00 |
| Generator Leads (Inside of Substation | 1 | $1.00 | 1 | $1.00 |
| **Total Interconnection Facilities Cost (sum of column D): $11.00** | | | | |
| **Gen 2** | **Upgrade** | **A) Number of Applicable Upgrades** | **B) Cost per Upgrade** | **C) Number of Applicable Projects** | **D) Total Costs per Upgrade =(AxB)/C** |
| Generator Leads (Outside of Substation) | 1 | $20.00 | 1 | $20.00 |
| Generator Leads (Inside of Substation | 1 | $1.00 | 1 | $1.00 |
| **Total Interconnection Facilities Cost (sum of column D): $21.00** | | | | |
| **Gen 3** | **Upgrade** | **A) Number of Applicable Upgrades** | **B) Cost per Upgrade** | **C) Number of Applicable Projects** | **D) Total Costs per Upgrade =(AxB)/C** |
| Generator Leads (Outside of Substation) | 1 | $30.00 | 1 | $30.00 |
| Generator Leads (Inside of Substation | 1 | $1.00 | 1 | $1.00 |
| **Total Interconnection Facilities Cost (sum of column D): $31.00** | | | | |

The cost allocation calculations for the Substation Network Upgrades are:

For Voltage Level Y

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Project** | **Substation Network Upgrades @ Y kV** | | | | |
| **Gen 1** | **Upgrade** | **A) Number of Applicable Upgrades** | **B) Cost per Upgrade** | **C) Number of Applicable Projects** | **D) Total Costs per Upgrade =(AxB)/C** |
| Breakers | 3 | $5.00 | 2 | $7.50 |
| Inter-Breaker Bus Segments | 4 | $1.00 | 2 | $2.00 |
| Main Bus Segments | 2 | $2.00 | 2 | $2.00 |
| **Total Substation Network Upgrades @ Y kV Cost (sum of column D): $11.50** | | | | |
| **Gen 2** | **Upgrade** | **A) Number of Applicable Upgrades** | **B) Cost per Upgrade** | **C) Number of Applicable Projects** | **D) Total Costs per Upgrade =(AxB)/C** |
| Breakers | 3 | $5.00 | 2 | $7.50 |
| Inter-Breaker Bus Segments | 4 | $1.00 | 2 | $2.00 |
| Main Bus Segments | 2 | $2.00 | 2 | $2.00 |
| **Total Substation Network Upgrades @ Y kV Cost (sum of column D): $11.50** | | | | |

For Voltage Level Z

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Project** | **Substation Network Upgrades @ Z kV** | | | | |
| **Gen 3** | **Upgrade** | **A) Number of Applicable Upgrades** | **B) Cost per Upgrade** | **C) Number of Applicable Projects** | **D) Total Costs per Upgrade =(AxB)/C** |
| Breakers | 1 | $5.00 | 1 | $5.00 |
| Inter-Breaker Bus Segments | 1 | $1.00 | 1 | $1.00 |
| **Total Substation Network Upgrades @ Z kV Cost (sum of column D): $6.00** | | | | |

The cost allocation calculations for the System Network Upgrades:

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Project** | **System Network Upgrades** | | | |
| **Gen 1** | **Component** | **A) Project Impact Proportionality** | **B) Cost per Component** | **C) Total Costs per Component =(AxB)** |
| Reactor A | 50% | $11.00  (i.e. $5+$5+$1) | $5.50 |
| Transmission Line C | 30% | $15.00 | $4.50 |
| **Total System Network Upgrades Cost (sum of column C): $10.00** | | | |
| **Gen 2** | **Component** | **A) Project Impact Proportionality** | **B) Cost per Component** | **C) Total Costs per Component =(AxB)** |
| Reactor A | 30% | $11.00  (i.e. $5+$5+$1) | $3.30 |
| Transmission Line C | 20% | $15.00 | $3.00 |
| **Total System Network Upgrades Cost (sum of column C): $6.30** | | | |
| **Gen 3** | **Component** | **A) Project Impact Proportionality** | **B) Cost per Component** | **C) Total Costs per Component =(AxB)** |
| Reactor A | 20% | $11.00  (i.e. $5+$5+$1) | $2.20 |
| Transmission Line C | 50% | $15.00 | $7.50 |
| **Total System Network Upgrades Cost (sum of column C): $9.70** | | | |

The final allocated costs for each Generating Facility are:

|  |  |  |  |
| --- | --- | --- | --- |
| **Cost Category** | **Gen 1** | **Gen 2** | **Gen 3** |
| Interconnection Facilities Costs | $11.00 | $21.00 | $31.00 |
| Substation Network Upgrades @ Y kV Costs | $11.50 | $11.50 | $0.00 |
| Substation Network Upgrades @ Z kV Costs | $0.00 | $0.00 | $6.00 |
| System Network Upgrades Costs | $10.00 | $6.30 | $9.70 |
| **Total Costs for Upgrades** | **$32.50** | **$38.80** | **$46.70** |

*Example 2 (Cost Allocation for a System Network Upgrade to Address a Short Circuit Violation)*

This example illustrates the proportional impact based cost allocation calculation basics for a System Network Upgrade to address short circuit violations.

In this example, two generators are seeking to interconnect at different points on the system:

Facilities seeking to interconnect:

Generator 1 (Gen 1).

Generator 2 (Gen 2).

Scenario: The short circuit contributions from Gen 1 and Gen 2 result in an overdutied breaker (Breaker 1, rated at 100 kA):

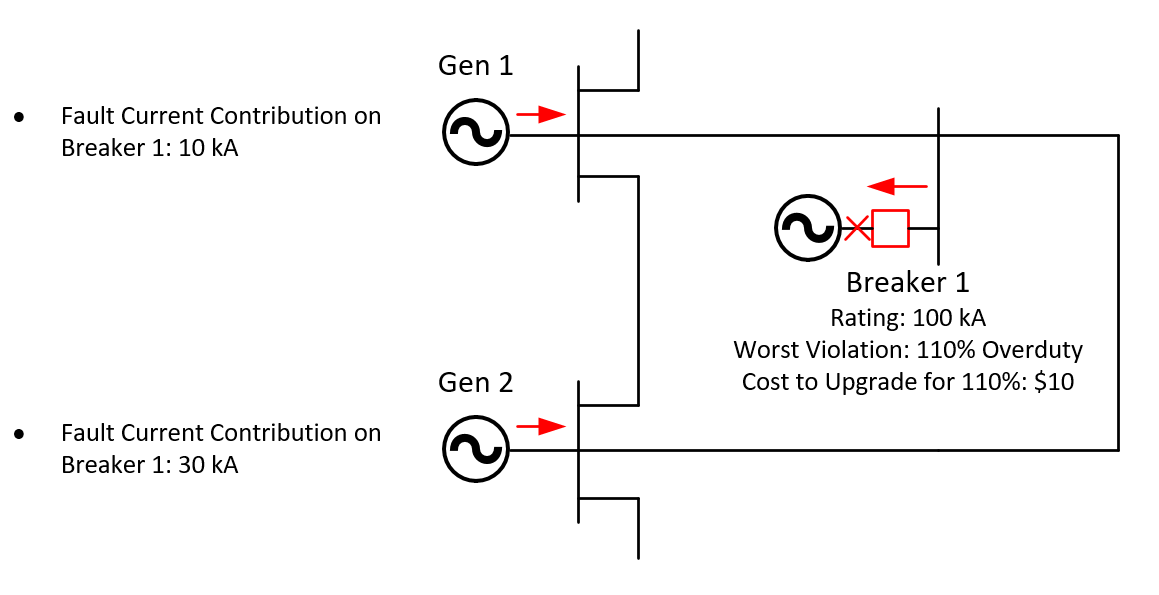
Gen 1 contributes 10 kA to the fault current seen on Breaker 1.

Gen 2 contributes 30 kA to the fault current seen on Breaker 1.

Upgrades Needed: The upgrade to address the overdutied Breaker 1 (which is overdutied to 110%) is to upgrade the breaker with a higher kA rating, and this upgrade costs $10.

Figure G.2.1 illustrates these details.

*Figure G-2.1*



Cost Allocation Calculation: The cost allocation calculations considers the impact each project has on each element with a violation.

|  |  |  |  |
| --- | --- | --- | --- |
| **Project** | **Project Impact (fault current contribution)** | **Project Impact/Σ of All Project Impacts** | **Project Cost Allocation** |
| Gen 1 | 10 kA | 10/(10+30) = 25.00% | 0.2500\*$10 = $2.50 |
| Gen 2 | 30 kA | 30/(10+30) = 75.00% | 0.7500\*$10 = $7.50 |

*Example 3 (Two Projects, One Element with Thermal Violations from NCIS only)*

This example illustrates the proportional impact based cost allocation calculation basics for a System Network Upgrade to address thermal violations.

In this example, two generators are seeking to interconnect at different points on the system:

Facilities seeking to interconnect:

Generator 1 (Gen 1) is a 100 MW generator.

Generator 2 (Gen 2) is a 400 MW generator.

Scenario: Gen 1 and Gen 2 show an overload on the same transmission line (Transmission Line 1, rated at 100 MVA):

When studying Gen 1, the highest violation on Transmission Line 1 is 105% for Stress A and Contingency X with a 20% DFAX on the overloaded element for the post contingency condition.

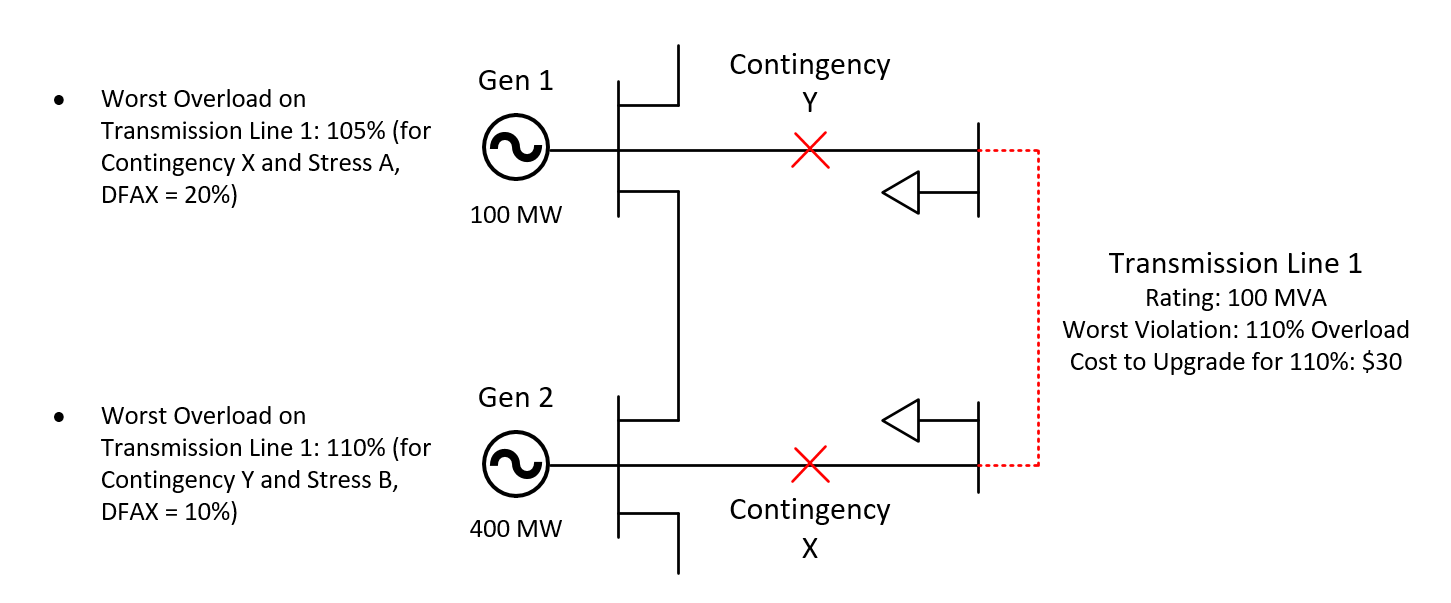
When studying Gen 2, the highest violation on Transmission Line 1 is 110% for Stress B and Contingency Y with a 10% DFAX on the overloaded element for the post contingency condition.

Any violations were identified solely through steady state thermal analyses that met the NCIS (*i.e.* there were no violations identified through steady state thermal analyses that met the CCIS, or through short circuit, voltage or stability analyses).

Upgrades Needed: The upgrade to address all seen violations is upgrading Transmission Line 1 to a thermal rating that equals the highest overload observed under study conditions (110%), and this upgrade costs $30.

Figure G.3.1 illustrates these details.

*Figure G.3.1*



Cost Allocation Calculation: The cost allocation calculations considers the highest impact each project has on each element with a violation.

|  |  |  |  |
| --- | --- | --- | --- |
| **Project** | **Project Impact (DFAX\*MW Rating)** | **Project Impact/Σ of All Project Impacts** | **Project Cost Allocation** |
| Gen 1 | 0.20\*100 = 20 MW | 20/(20+40) = 33.33% | 0.3333\*$30 = $10.00 |
| Gen 2 | 0.10\*400 = 40 MW | 40/(20+40) = 66.67% | 0.6667\*$30 = $20.00 |

*Example 4 (Two Projects, One Element with Thermal Violations from NCIS and CCIS)*

This example illustrates the proportional impact based cost allocation calculation basics for a System Network Upgrade to address thermal violations. This example is similar to Example 2, with the difference that this example involves violations identified through steady state thermal analyses to meet both NCIS and CCIS.

In this example, two generators are seeking to interconnect at different points on the system:

Facilities seeking to interconnect:

Generator 1 (Gen 1) is a 100 MW generator.

Generator 2 (Gen 2) is a 400 MW generator.

Scenario: Gen 1 and Gen 2 show an overload on the same transmission line (Transmission Line 1, rated at 100 MVA):

When studying Gen 1:

For CCIS, the highest violation on Transmission Line 1 is 105% for Stress A and Contingency X with a 20% DFAX on the overloaded element for the post contingency condition.

There were no overloads seen for Gen 1 when studying NCIS.

When studying Gen 2:

For CCIS, the highest violation on Transmission Line 1 is 110% for Stress B and Contingency Y with a 10% DFAX on the overloaded element for the post contingency condition.

For NCIS, the highest violation on Transmission Line 1 is 108% for Stress C and Contingency Y with an 8% DFAX on the overloaded element for the post contingency condition.

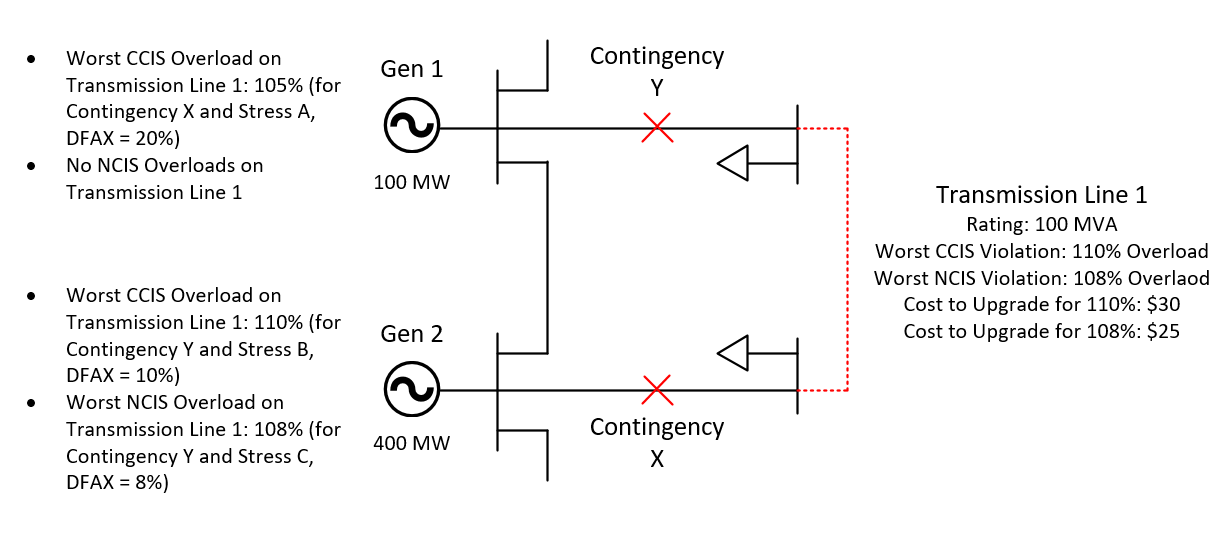
Some violations were identified through steady state thermal analyses that met the NCIS, and some violations were identified through steady state thermal analyses that met the CCIS. There were no violations identified through other analyses (*i.e.* short circuit, voltage or stability analyses).

Gen 1 and/or Gen 2 may have elected “downgradable” CNRIS for its Interconnection (*i.e.* the option where the project would initially be studied for CNRIS, but would automatically revert to NRIS if any violations requiring upgrades were identified for the project to receive CNRIS).

Upgrades Needed: The upgrade to address all observed violations is upgrading Transmission Line 1 to a thermal rating that equals the highest overload observed (either 110% or 108%), and this upgrade costs $30 for 110% of its current rating, and $25 for 108% of its current rating.

Figure G.4.1 illustrates these details.

*Figure G.4.1*



Cost Allocation Calculation: The cost allocation calculation considers the highest impact each project has on each element with a violation.

Case 1 – No projects chose “downgradable CNRIS”

|  |  |  |  |
| --- | --- | --- | --- |
| **Project** | **Project Impact (DFAX\*MW Rating)** | **Project Impact/Σ of All Project Impacts** | **Project Cost Allocation** |
| Gen 1 | 0.20\*100 = 20 MW | 20/(20+40) = 33.33% | 0.3333\*$30 = $10 |
| Gen 2 | 0.10\*400 = 40 MW | 40/(20+40) = 66.67% | 0.6667\*$30 = $20 |

Case 2 – Gen 1 chose “downgradable CNRIS”, but Gen 2 did not.

|  |  |  |  |
| --- | --- | --- | --- |
| **Project** | **Project Impact (DFAX\*MW Rating)** | **Project Impact/Σ of All Project Impacts** | **Project Cost Allocation** |
| Gen 1 | N/A | N/A | N/A |
| Gen 2 | 0.10\*400 = 40 MW | 40/(40) = 100.00% | 1.00\*$30 = $30 |

Case 3 – Gen 2 chose “downgradable CNRIS”, but Gen 1 did not.

|  |  |  |  |
| --- | --- | --- | --- |
| **Project** | **Project Impact (DFAX\*MW Rating)** | **Project Impact/Σ of All Project Impacts** | **Project Cost Allocation** |
| Gen 1 | 0.20\*100 = 20 MW | 20/(20+32) = 38.46% | 0.3846\*$25 = $9.62 |
| Gen 2 | 0.08\*400 = 32 MW | 32/(20+32) = 61.54% | 0.6154\*$25 = $15.38 |

Case 4 – Gen 1 and Gen 2 chose “downgradable CNRIS”

|  |  |  |  |
| --- | --- | --- | --- |
| **Project** | **Project Impact (DFAX\*MW Rating)** | **Project Impact/Σ of All Project Impacts** | **Project Cost Allocation** |
| Gen 1 | N/A | N/A | N/A |
| Gen 2 | 0.08\*400 = 32 MW | 32/(32) = 100.00% | 1.00\*$25 = $25.00 |

*Example 5 (Three Projects, Two Elements with Non-Overlapping Thermal Violations from NCIS, Common Upgrade)*

This example illustrates the proportional impact based cost allocation calculation for a System Network Upgrade to address thermal violations on different elements, where there is no overlap between the violations and the projects causing them, and where a common upgrade is identified to address all the violations.

In this example, three generators are seeking to interconnect at different points on the system:

Facilities seeking to interconnect:

Generator 1 (Gen 1) is a 100 MW generator.

Generator 2 (Gen 2) is a 400 MW generator.

Generator 3 (Gen 3) is a 200 MW generator.

Scenario: Gen 1 shows an overload on one element (Transmission Line 1, 75 MVA), and Gen 2 and Gen 3 show an overload on another transmission line (Transmission Line 2, rated at 100 MVA):

When studying Gen 1, the highest violation on Transmission Line 1 is 120% for Stress A and Contingency X with a 20% DFAX on the overloaded element for the post contingency condition.

When studying Gen 2, the highest violation on Transmission Line 2 is 110% for Stress B and Contingency Y with a 10% DFAX on the overloaded element for the post contingency condition.

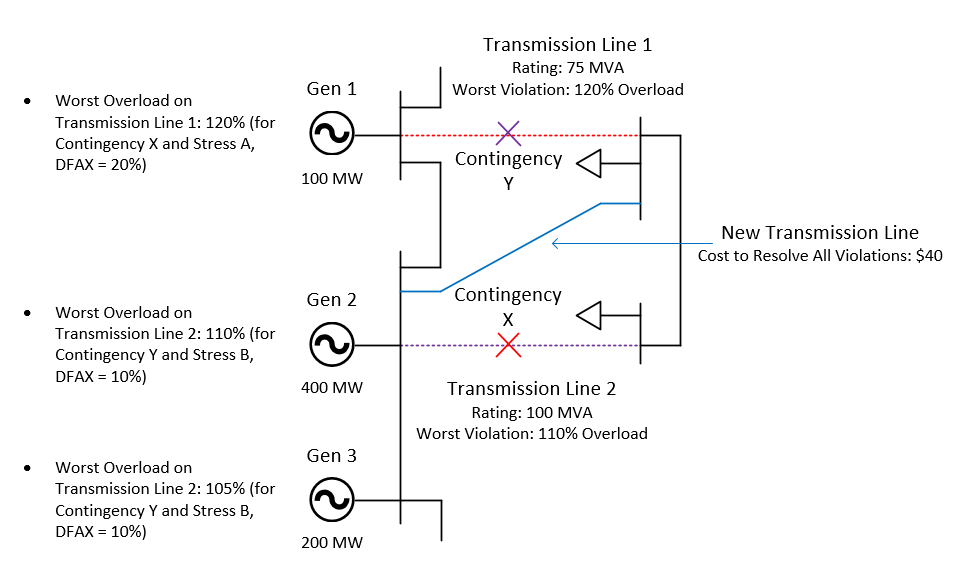
When studying Gen 3, the highest violation on Transmission Line 2 is 105% for Stress B and Contingency Y with a 10% DFAX on the overloaded element for the post contingency condition.

Any violations were identified solely through steady state thermal analyses that met the NCIS (i.e. there were no violations identified through steady state thermal analyses that met the CCIS, or through short circuit, voltage or stability analyses).

Upgrades Needed: The upgrade to address all observed violations is building a new transmission line (New Transmission Line), and this upgrade costs $40.

Figure G.5.1 illustrates these details.

*Figure G.5.1*



Cost Allocation Calculation: The cost allocation calculations consider the highest impact each project has on each element with a violation.

|  |  |  |  |
| --- | --- | --- | --- |
| **Project** | **Project Impact (DFAX\*MW Rating)** | **Project Impact/Σ of All Project Impacts** | **Project Cost Allocation** |
| Gen 1 | 0.20\*100 = 20 MW | 20/(20+40+20) = 25.00% | 0.25\*$40 = $10.00 |
| Gen 2 | 0.10\*400 = 40 MW | 40/(20+40+20) = 50.00% | 0.50\*$40 = $20.00 |
| Gen 3 | 0.10\*200 = 20 MW | 20/(20+40+20) = 25.00% | 0.25\*$40 = $10.00 |

*Example 6 (Two Projects, Two Elements with Overlapping Thermal Violations from NCIS, Common Upgrade)*

This example illustrates the proportional impact based cost allocation calculation for a System Network Upgrade to address thermal violations on different elements, where there is overlap between the violations and the projects causing them, and where a common upgrade is identified to address all the violations.

In this example, two generators are seeking to interconnect at different points on the system:

Facilities seeking to interconnect:

Generator 1 (Gen 1) is a 100 MW generator.

Generator 2 (Gen 2) is a 400 MW generator.

Scenario: Gen 1 and Gen 2 both show an overload on two different elements (Transmission Line 1, 40 MVA, and Transmission Line 2, 100 MVA):

When studying Gen 1:

The highest violation on Transmission Line 1 is 110% for Stress A and Contingency X with a 20% DFAX on the overloaded element for the post contingency condition.

The highest violation on Transmission Line 2 is 105% for Stress A and Contingency Y with a 10% DFAX on the overloaded element for the post contingency condition.

When studying Gen 2:

The highest violation on Transmission Line 1 is 105% for Stress B and Contingency X with a 5% DFAX on the overloaded element for the post contingency condition.

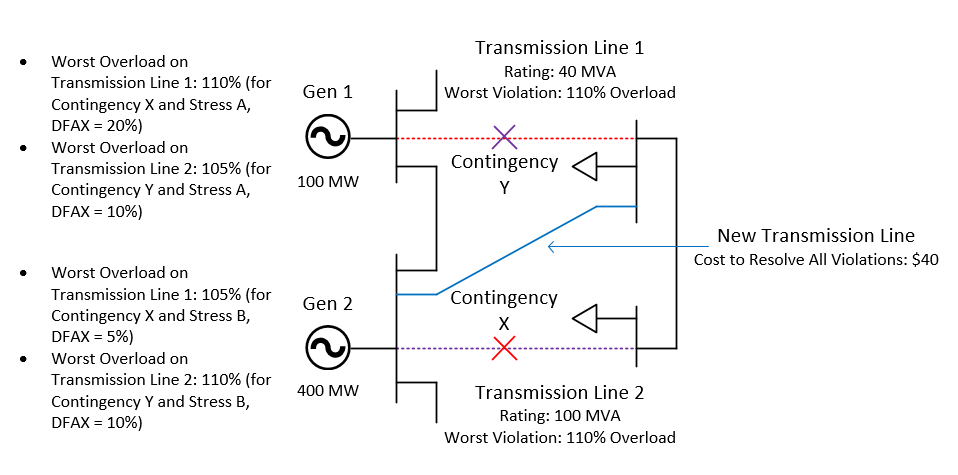
The highest violation on Transmission Line 2 is 110% for Stress B and Contingency Y with a 10% DFAX on the overloaded element for the post contingency condition.

Any violations were identified solely through steady state thermal analyses that met the NCIS (i.e. there were no violations identified through steady state thermal analyses that met the CCIS, or through short circuit, voltage or stability analyses).

Upgrades Needed: The upgrade to address all observed violations is building a new transmission line (New Transmission Line), and this upgrade costs $40.

Figure G.6.1 illustrates these details.

*Figure G.6.1*



Cost Allocation Calculation: The cost allocation calculation considers the highest impact each project has on each element with a violation.

|  |  |  |  |
| --- | --- | --- | --- |
| **Project** | **Project Impact (DFAX\*MW Rating)** | **Project Impact/Σ of All Project Impacts** | **Project Cost Allocation** |
| Gen 1, for Transmission Line 1 Need | 0.20\*100 = 20 MW | 30/(30+60) = 33.33% | 0.3333\*$40 = $13.33 |
| Gen 1, for Transmission Line 2 Need | 0.10\*100 = 10 MW |
| Total Impact Gen 1 | 20+10 = 30 MW |
| Gen 2, for Transmission Line 1 Need | 0.05\*400 = 20 MW | 60/(30+60) = 66.67% | 0.6667\*$40 = $26.67 |
| Gen 2, for Transmission Line 2 Need | 0.10\*400 = 40 MW |
| Total Impact Gen 2 | 20+40 = 60 MW |

*Example 7A (Two Projects, Voltage Violations for the Same Contingency and Critical Bus, Project Impact Calculation)*

This example illustrates the project impact calculation basics for a steady-state voltage violation.

In this example, two generators are seeking to interconnect at different points on the system:

Facilities seeking to interconnect:

Generator 1 (Gen 1) is a 100 MW generator.

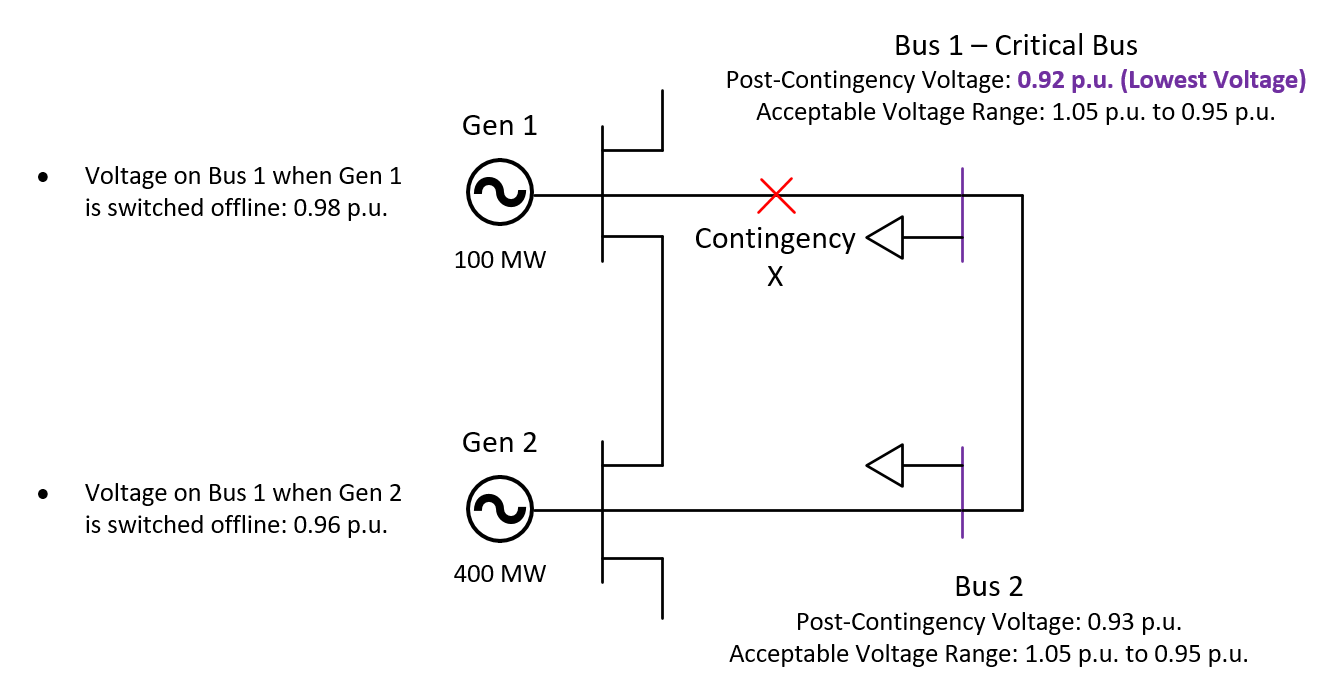
Generator 2 (Gen 2) is a 400 MW generator.

Scenario: Gen 1 and Gen 2 online together show low voltage violations:

The post contingency voltage is lowest at Bus 1, making it the critical bus.

Figure G.7A.1 illustrates these details.

*Figure G.7A.1*



Project Impact Calculation: The project impact calculations considers the highest impact each project has on the critical bus.

|  |  |  |  |
| --- | --- | --- | --- |
| **Project** | **A) Post Contingency Voltage at Critical Bus** | **B) Voltage at Critical Bus when Project Switched Off** | **C) Project Impact (i.e. ∆ in per unit voltage) =|A-B|** |
| Gen 1 | 0.92 p.u. | 0.98 p.u. | |0.92 – 0.98| = 0.06 p.u. |
| Gen 2 | 0.92 p.u. | 0.96 p.u. | |0.92 – 0.96| = 0.04 p.u. |

*Example 7B (Two Projects, Voltage Violations for the Same Contingency and Critical Bus, Cost Allocation Example)*

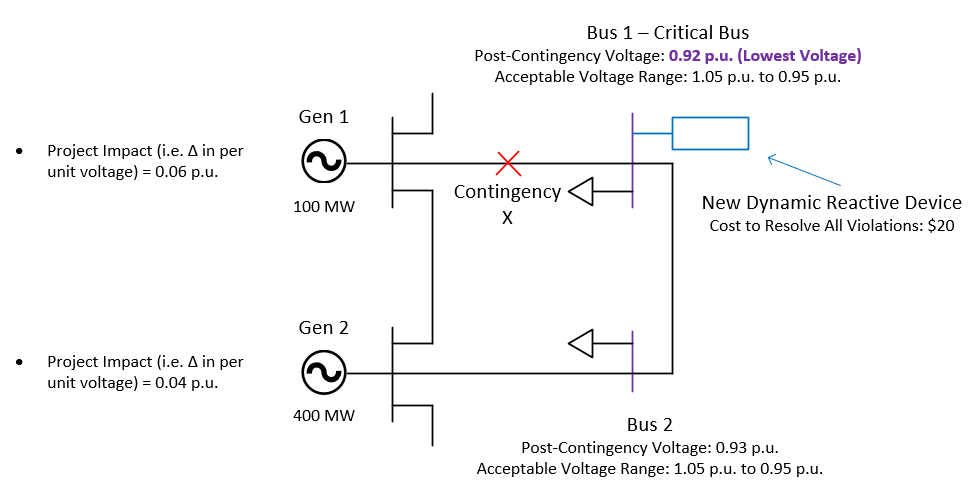
This example illustrates the proportional impact based cost allocation calculation basics for a System Network Upgrade to address voltage violations.

This example carries on from Example 7A:

Upgrades Needed: The upgrade to address all seen violations is adding a dynamic reactive device to Bus 1, and this upgrade costs $20.

Figure G.7B.1 illustrates these details.

*Figure G.7B.1*



Cost Allocation Calculation: The cost allocation calculations considers the highest impact each project has on the critical bus.

|  |  |  |  |
| --- | --- | --- | --- |
| **Project** | **Project Impact (∆ in per unit voltage)** | **Project Impact/Σ of All Project Impacts** | **Project Cost Allocation** |
| Gen 1 | 0.06 p.u. | 0.06/(0.06+0.04) = 60.00% | 0.6000\*$20 = $12.00 |
| Gen 2 | 0.04 p.u. | 0.04/(0.06+0.04) = 40.00% | 0.4000\*$20 = $8.00 |

*Example 8 (Two Projects, Overlapping Voltage Violations with Different Critical Buses for Different Contingencies, Common Upgrade)*

This example illustrates the proportional impact based cost allocation calculation for a System Network Upgrade to address voltage violations on different critical buses for different contingencies, where there is overlap between the violations and the projects causing them, and where a common upgrade is identified to address all violations.

In this example, two generators are seeking to interconnect at different points on the system:

Facilities seeking to interconnect:

Generator 1 (Gen 1) is a 100 MW generator.

Generator 2 (Gen 2) is a 400 MW generator.

Scenario: Gen 1 and Gen 2 both show voltage violations on two different critical buses for different contingencies (Bus 1 for Contingency X, and Bus 2 for Contingency Y):

For Gen 1:

The project impact (*i.e.* ∆ in per unit voltage) on Bus 1 for Contingency X is 0.06 p.u..

The project impact (*i.e.* ∆ in per unit voltage) on Bus 2 for Contingency Y is 0.03 p.u..

For Gen 2:

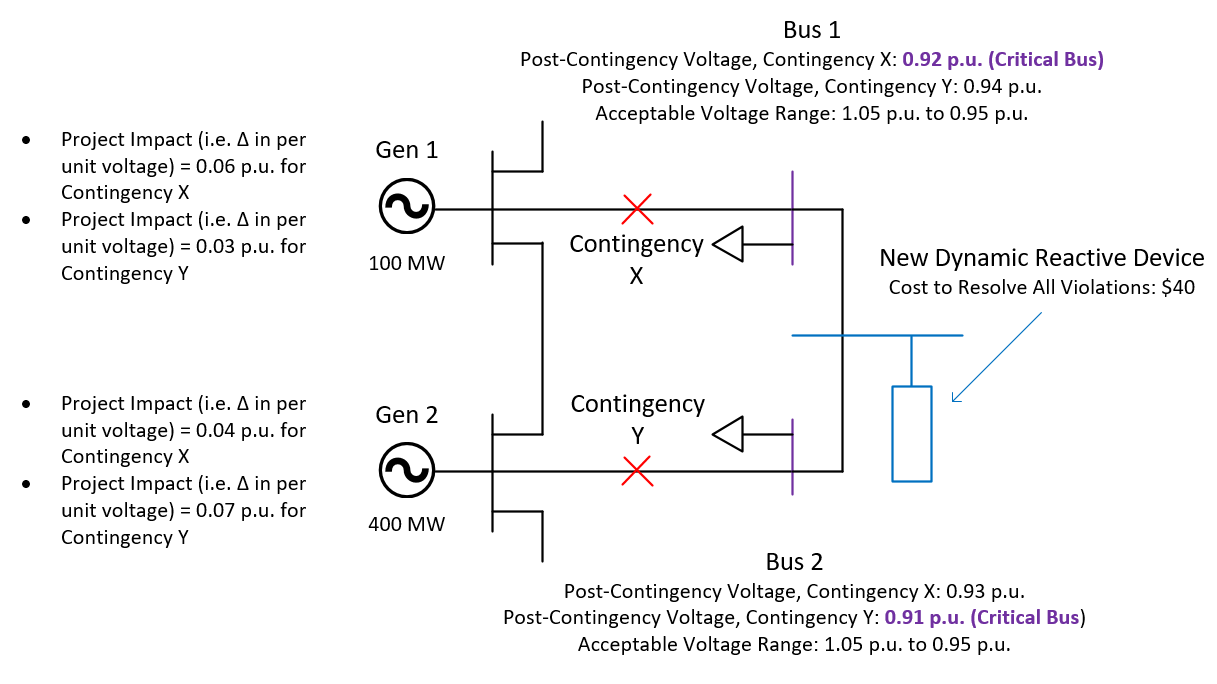
The project impact (*i.e.* ∆ in per unit voltage) on Bus 1 for Contingency X is 0.04 p.u..

The project impact (*i.e.* ∆ in per unit voltage) on Bus 2 for Contingency Y is 0.07 p.u..

Upgrades Needed: The upgrade to address all observed violations is adding a dynamic reactive device to a new Bus on the transmission line between Bus 1 and Bus 2, and this upgrade costs $40.

Figure G.8.1 illustrates these details.

*Figure G.8.1*



Cost Allocation Calculation: The cost allocation calculation considers the highest impact each project has on each element with a violation.

|  |  |  |  |
| --- | --- | --- | --- |
| **Project** | **Project Impact (∆ in per unit voltage)** | **Project Impact/Σ of All Project Impacts** | **Project Cost Allocation** |
| Gen 1, for Bus 1 Contingency X | 0.06 p.u. | 0.09/(0.09+0.11) = 45.00% | 0.4500\*$40 = $18 |
| Gen 1, for Bus 2 Contingency Y | 0.03 p.u. |
| Total Impact Gen 1 | 0.06 + 0.03 = 0.09 p.u. |
| Gen 2, for Bus 1 Contingency X | 0.04 p.u. | 0.11/(0.09+0.11) = 55.00% | 0.5500\*$40 = $22 |
| Gen 2, for Bus 2 Contingency Y | 0.07 p.u. |
| Total Impact Gen 2 | 0.04 + 0.07 = 0.11 p.u. |

*Example 9 (Two Projects, Stability Violations)*

This example illustrates the proportional impact based cost allocation calculation basics for a System Network Upgrade to address stability violations.

In this example, two generators are seeking to interconnect at different points on the system:

Facilities seeking to interconnect:

Generator 1 (Gen 1) is a 100 MW generator.

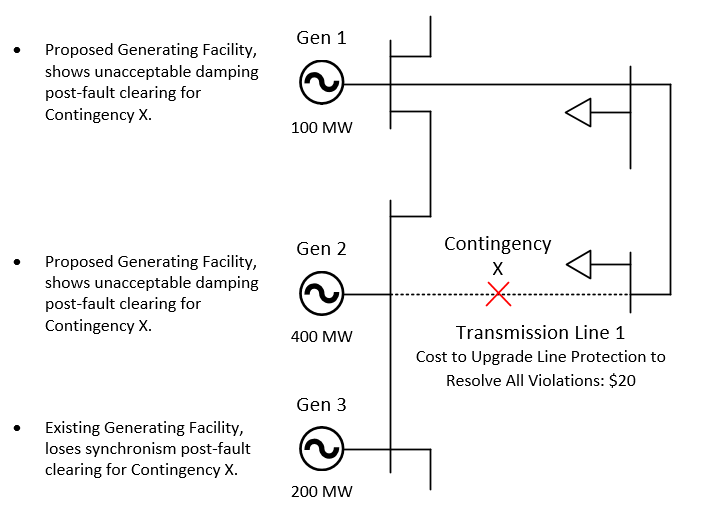
Generator 2 (Gen 2) is a 400 MW generator.

Scenario: When dispatched together with the existing Generator 3 (Gen 3), a fault on and trip of Transmission Line 1 (Contingency X) results in unacceptable damping for Gen 1 and Gen 2, and loss of synchronism for Gen 3.

Upgrades Needed: The upgrade to address all seen violations is upgrading the Transmission Line 1 protection, and this upgrade costs $20.

Figure G.9.1 illustrates these details.

*Figure G.9.1*



Cost Allocation Calculation: The cost allocation calculations considers the highest impact each project has on each element with a violation.

|  |  |  |  |
| --- | --- | --- | --- |
| **Project** | **Project Impact (MW Rating)** | **Project Impact/Σ of All Project Impacts** | **Project Cost Allocation** |
| Gen 1 | 100 MW | 100/(100+400) = 20.00% | 0.2000\*$20 = $4.00 |
| Gen 2 | 400 MW | 400/(100+400) = 80.00% | 0.8000\*$20 = $16.00 |

# Appendix H – Acreage Requirements

Interconnection Customers are prohibited from submitting evidence of Site Control that uses the same land (or in the case of offshore wind, lease area) for multiple Interconnection Requests, unless the site is large enough to host all facilities associated with the Interconnection Requests, and the division of the site is clearly delineated per the Interconnection Customer. The Interconnection Customer is required to meet the acreage requirement listed in this appendix at the time it submits its Interconnection Request.

*Acreage Requirement*

*Table H.1 – Minimum Expected Acreage Requirements[[66]](#footnote-67)*

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Photovoltaic (PV) | Electrical Energy Storage | Onshore Wind | Offshore Wind | Conventional |
| 4 Acres/MW | 1 Acres/100 MWh | 15 Acres/MW | 35 Acres/MW | Attestation |

The minimum expected acreage requirement for Interconnection Requests representing a proposed co-located Generating Facility are calculated by summing the minimum expected acreage requirement for each technology component. For example, an Interconnection Request for a 20 MW co-located Generating Facility, where 15 MW is based on PV and 5 MW is based on electric energy storage, the expected minimum acreage requirement calculations are:

Step 1: Minimum expected acreage requirement for the PV = 15 MW x 5 acres/MW = 75 acres

Step 2: Minimum expected acreage requirement for the electrical energy storage = 5 MW x 0.1 acres/MW = 0.5 acres

Step 3: Minimum expected acreage requirement for the total co-located Generating Facility = PV minimum expected acreage requirement + electrical energy storage minimum expected acreage requirement = 75 acres + 0.5 acres = 75.5 acres.

If the acreage associated with an Interconnection Request’s Site Control is below the minimum expected acreage requirements listed in Table H.1, or if the Interconnection Request uses a technology not listed in Table H.1, then the Interconnection Customer must provide documentation with the Interconnection Request’s Site Control explaining why the Interconnection Request has sufficient acreage. If provision of such documentation is required, the ISO will review any such documentation and determine if the documentation is complete and if the acreage associated with the Interconnection Request’s Site Control is appropriate.

# Appendix I – Determination Procedure for New or Increased Generation >1MW and <5 MW

ISO shall respond to requests for determinations within 10 business days of receiving the request with the determination of whether the project will need to submit a Generator Notification Form, or Proposed Plans Application. The ISO will also respond with the determination of what level of analysis is required to support the application. Determinations will be valid until the start of the next ISO Cluster Request Window.

In these cases, where insufficient analysis is provided to support the proposal, the applications may need to be withdrawn and re-submitted at a later time with sufficient analysis.

**TO Actions:**

Step 0: TO submits determination request(s) to the ISO with at least the following information from the proposed project(s):

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Unique Project Identifier | Transmission Substation | Distribution Substation | Feeder | MW Output | Fuel Type | Technology Type | Bus Number |

**OR:**

TO or MP submits Generator Notification Form(s)/Proposed Plans Application(s) to the Proposed Plans Inbox

**ISO Actions:**

Step 0: Identify if any project is 5MW or greater

If a project is 5MW or greater, notify TO that Level III analysis is required before that project can receive approval

If a project is less than 5MW, move to Step 1

Step 1: Identify the transmission/BES/PTF station(s) that the project(s) normally feed up to. (which ever station is electrically closest for those with multiple paths)

Step 2: Aggregate all inverter based projects submitted for determinations at each station identified in Step 1

Step 3: Determine if aggregate(s) from step 2 exceeds threshold

If aggregate is 20MW or greater, notify TO that Level III analysis is required before any new proposals can be approved

If aggregate is less then 20MW, move to step 4

Step 4: Run 3 phase fault at station identified in step 1 for 6 cycles

Step 5: Create list of all transmission/BES/PTF stations that are at .3pu voltage or less

Step 6: Reset simulation

Step 7: Run steps 4 - 6 for each station within the documented list of stations from step 5

Step 8: Aggregate all inverter based projects submitted for determinations, between all stations documented in step 5

Step 9: Notify TO of determinations

If Aggregate(s) in step 8 is 20MW or greater, then notification will indicate Level III analysis is required before any new proposals can be approved.

If Aggregate(s) in step 8 is less than 20MW then notification will indicate Level 0 analysis is required (no analysis needed, submitted as Generator Notification Form)

1. Additional information on the relevant planning procedures is found in Planning Procedures PP5-1 and PP5-3. [↑](#footnote-ref-2)
2. Studies of proposed DERs are sometimes referred to as “affected system operator” or “ASO” studies. [↑](#footnote-ref-3)
3. This includes Affected Systems and Internal Affected Systems as defined in the ISO Interconnection Procedures. [↑](#footnote-ref-4)
4. External ETUs eligible for Network Import Interconnection Service (“NIIS") are controllable Merchant Transmission (MTF) or Other Transmission Facility (OTF). In this Planning Procedure, these External ETUs are referred to as “Eligible External ETUs.” While not all ETUs are eligible for NIIS, all are interconnected in a manner that, at a minimum, meets the requirements of the NCIS. [↑](#footnote-ref-5)
5. External ETUs eligible for CIIS are controllable MTF or OTF. In this Planning Procedure, these External ETUs are referred to as “Eligible External ETUs.” [↑](#footnote-ref-6)
6. A Generating Facility or ETUs seeking CNIIS will be determined to be in a single Load Zone if it can serve incremental load in that Load Zone, while satisfying the deterministic criteria of PP3, NPCC Directory 1 and NERC TPL-001. [↑](#footnote-ref-7)
7. Pursuant to the LGIP, SGIP and ETU IP of the Tariff, an Interconnection Customer that meets the requirements to obtain CNRIS or CNIIS shall obtain NRIS or NIIS up to the Network Resource (NR) Capability upon completion of all requirements for NRIS or NIIS, including all necessary upgrades. [↑](#footnote-ref-8)
8. Also applicable to the Transitional Cluster Study. [↑](#footnote-ref-9)
9. Reasonably stressed conditions are defined in PP5-3 as “those severe load and generation system conditions which have a reasonable probability of actually occurring.” Reference PP5-3 for additional information [↑](#footnote-ref-10)
10. The DAFX is a measure of the change in electrical loading on a monitored element due to a change in output from the study generator, expressed as a percent of the change in generation output. A generator with a positive DFAX is referred to as a “harmer” resource because increasing its output results in more flow on the monitored element for the specified contingency. [↑](#footnote-ref-11)
11. Reference Section 2.1 of the ISO New England Technical Planning Guide for additional information [↑](#footnote-ref-12)
12. This includes the configurations associated with the proposed Points of Interconnection for all projects included in a Cluster under study. [↑](#footnote-ref-13)
13. The retirement date of the Asset associated with a Generating Capacity Resource or Import Capacity Resource. The retirement date may be the first day of the Capacity Commitment Period associated with a cleared Retirement Delist Bid related to the facility (or a Permanent Delist Bid for CCIS), or the date the facility actually retires if it meets all requirements to retire early pursuant to Section III.13.2.5.2.5.3(a)(ii) of the Tariff, or the date that a facility is deemed retired due to not operating commercially for a period of three calendar years pursuant to Section III.13.2.5.2.5.3(d) of the Tariff. [↑](#footnote-ref-14)
14. Reference Sections 2.1.3, 2.1.4 and 2.1.5 of the ISO New England Technical Planning Guide for additional information [↑](#footnote-ref-15)
15. Reference Appendix K of the ISO New England Technical Planning Guide for additional information [↑](#footnote-ref-16)
16. Reference Section 2.2 of the ISO New England Technical Planning Guide for additional information [↑](#footnote-ref-17)
17. Reference Section 2.3.1 of the ISO New England Technical Planning Guide for additional information on NRC and Section 2.3 for additional information on treatment of different types of resources [↑](#footnote-ref-18)
18. Reference Section 3.4 of the ISO New England Transmission Planning Technical Planning Guide for additional information [↑](#footnote-ref-19)
19. The IRTT system can be accessed from the ISO New England website at: http://www.iso-ne.com/system-planning/transmission-planning/interconnection-request-queue [↑](#footnote-ref-20)
20. Refer to ISO New England Compliance Bulletin - MOD-032 – Model Data Requirements and Reporting Procedures for additional information on generator characteristics located at:

    http://www.iso-ne.com/participate/rules-procedures/nerc-npcc [↑](#footnote-ref-21)
21. The DDMS and SDMS systems can be accessed via the SSO/SMD home page by selecting the Dynamic Data Management System application or Short Circuit Data Management System application. Instructions will be provided to Interconnection Customers during the interconnection process. [↑](#footnote-ref-22)
22. The same requirement may apply after completion of a related Cluster Restudy. [↑](#footnote-ref-23)
23. For NCIS, DFAXs are calculated by transferring from the Generating Facility or ETU to New England load. [↑](#footnote-ref-24)
24. For CCIS, DFAXs are calculated by transferring from the Generating Facility or ETU to the associated Load Zone. [↑](#footnote-ref-25)
25. Element loadings up to the Short Time Emergency (STE) ratings may be used following a contingency for up to fifteen minutes. STE ratings may only be used in limited situations such as in export areas where the Element loading can be reduced below the LTE ratings within fifteen minutes by operator or automatic corrective action. [↑](#footnote-ref-26)
26. Element loadings up to the Short Time Emergency (STE) ratings may be used following the final contingency for up to fifteen minutes. STE ratings may only be used in limited situations such as in export areas where the Element loading can be reduced below the LTE ratings within fifteen minutes by operator or automatic corrective action. [↑](#footnote-ref-27)
27. For CCIS, in order to determine the base dispatch within the Load Zone under study, the generators will be dispatched, up to their CNRC, in a manner that reasonably stresses the system. Internal transfers will be modeled to reflect various conditions ranging from 0 MW transfer up-to their transfer limits. Imports from External Control Areas will be modeled to reflect various conditions changing from 0 MW transfer up-to the associated capacity import limit. Internal transfers that are constrained by the system’s voltage or stability performance will be monitored through the use of internal proxy interfaces. [↑](#footnote-ref-28)
28. For a Cluster Study (including the Transitional Cluster Study), all Generating Facilities and ETUs in the cluster can be considered as available for stressing the pre-project case and for redispatch (in addition to all existing and earlier queued Generating Facilities and ETUs). [↑](#footnote-ref-29)
29. Reference Section 3.4 of the ISO New England Technical Planning Guide for additional information [↑](#footnote-ref-30)
30. For example, the constraints and generation output levels may need to be fully observable to, and controllable by, the operator and the implementation must be scalable and manageable in the context of reliable operating practice. [↑](#footnote-ref-31)
31. The evening peak with no solar scenario may be required if there are topology changes associated with the project [↑](#footnote-ref-32)
32. Not applicable to an electrical energy storage facility under study, pursuant to Section 9 of this Planning Procedure. [↑](#footnote-ref-33)
33. The night time minimum load scenario may be required if there are topology changes associated with the project. [↑](#footnote-ref-34)
34. Availability is interpreted as projects under their respective fuel types are able to be dispatched anywhere between a projects minimum power (PMIN) and the level listed multiplied by the projects maximum power (PMAX). [↑](#footnote-ref-35)
35. Intermittent resources that are dispatched at a lower level than their max availability will not be assumed to be available for re-dispatching post N-1 [↑](#footnote-ref-36)
36. Gross is interpreted as prior to the addition of the DER, netting down of the load. As where Net is interpreted as the load post addition of the DER. For example, the daytime minimum load scenario lists 12000MW (Gross), if 5000MW of DER is added, the net load is then 7000MW. For the light load scenario with high solar, 12,500 (NET) is listed, if 5000MW of DER is added, the net load would be 7,500MW, so the scalable load would need to be scaled up commensurate to the DER added, to meet the required 12,500MW NET level. In the cases where NET=Gross is listed, this means there is no netting of the load due to the DER because there is no DER assumed. [↑](#footnote-ref-37)
37. Not applicable to an electrical energy storage facility under study, pursuant to Section 9 of this Planning Procedure. [↑](#footnote-ref-38)
38. Availability is interpreted as projects under their respective fuel types are able to be dispatched anywhere between a project’s minimum power (PMIN) and the level listed multiplied by the project’s maximum power (PMAX). [↑](#footnote-ref-39)
39. Intermittent resources that are dispatched at a lower level than their max availability will not be assumed to be available for re-dispatching post N-1. [↑](#footnote-ref-40)
40. May also include small solar Generating Facilities that are not BTM solar and are not explicitly tied to a Generating capacity Resource [↑](#footnote-ref-41)
41. This value is based on a review of expected solar generation output for solar based Generating Capacity Resources over the Summer Intermittent Reliability Hours as defined by Section III.13.1.2.2.2.1(c) of the Tariff. [↑](#footnote-ref-42)
42. The Availability Factor is a de-rate factor applied based on expected performance of Demand Capacity Resources. Information on these availability factors can be found in the ICR assumptions presented at the Power Supply Planning Committee. [↑](#footnote-ref-43)
43. Note: All units modeled as in service for a particular stability case shall be modeled at their full available output, consistent with Table 4.4.1, which may result in total transfers greater than the existing thermal transfer limit. More detail on modeling is available in PP5-3. [↑](#footnote-ref-44)
44. For a Cluster Study, this includes all proposed Generating Facilities and ETUs in the Cluster. [↑](#footnote-ref-45)
45. The evening peak with no solar scenario may be required if there are topology changes associated with the project. [↑](#footnote-ref-46)
46. The night time minimum load scenario may be required if there are topology changes associated with the project. [↑](#footnote-ref-47)
47. Availability is interpreted as projects under their respective fuel types are able to be dispatched anywhere between a projects minimum power (PMIN) and the level listed multiplied by the projects maximum power (PMAX). [↑](#footnote-ref-48)
48. Intermittent resources that are dispatched at a lower level than their max availability will not be assumed to be available for re-dispatching post N-1. [↑](#footnote-ref-49)
49. Reference Section 4.3 of the ISO New England Technical Planning Guide for additional information [↑](#footnote-ref-50)
50. Only state jurisdictional projects that are part of studies that will start after the initiation of the Transition Cluster Study pursuant to FERC Order No. 2023 will be required to meet Section 6.5 [↑](#footnote-ref-51)
51. See the LGIA, SGIA and ETU IP of the Tariff for the full Interconnection Request requirements. [↑](#footnote-ref-52)
52. Includes Bulk Power System testing pursuant to NPCC Regional Reference Criteria A-10. [↑](#footnote-ref-53)
53. Not applicable to the Transitional Cluster Study. [↑](#footnote-ref-54)
54. This includes the switching of fixed and switched shunt devices, transformer taps, and the output of dynamic reactive devices. [↑](#footnote-ref-55)
55. ASO study scopes of work shall be submitted in a similar format to study reports [↑](#footnote-ref-56)
56. The determination of relevance is based upon a review of electrical proximity, the likelihood of causing common violations, and whether identified upgrades may impact the performance of the proposed projects. [↑](#footnote-ref-57)
57. Depending on the in-service date of the projects, the ASO study may need to run both pre- and post-FERC project cases. [↑](#footnote-ref-58)
58. Depending on the in-service date of the projects, the ASO study may need to run both pre- and post-FERC project cases. [↑](#footnote-ref-59)
59. Completion of the TCS refers to the TCS Report being posted. [↑](#footnote-ref-60)
60. Depending on the in-service date of the projects, the ASO study may need to run both pre- and post-FERC project cases. [↑](#footnote-ref-61)
61. This Document History documents action taken on the equivalent NEPOOL Procedure prior to the RTO Operations Date as well as revisions to the ISO New England Procedure subsequent to the RTO Operations Date. [↑](#footnote-ref-62)
62. This includes Transitional Cluster Study Agreements. [↑](#footnote-ref-63)
63. For a Cluster Study, Interconnection Customers must execute a Cluster Study Agreement prior to the close of the Customer Engagement Window. For a Transitional Cluster Study, Interconnection Customers must execute a Transmission Cluster Study Agreement by the deadline specified in Section 5.1.1.2 of the LGIP, SGIP and ETU IP. [↑](#footnote-ref-64)
64. Also applies to Transitional Cluster Study Agreements and the deadline to submit Transitional Cluster Study Agreements. [↑](#footnote-ref-65)
65. Also applies to Transitional Cluster Study Agreements and the deadline to submit Transitional Cluster Study Agreements. [↑](#footnote-ref-66)
66. All MW or MWh values shown in table H.1 are AC at the POI, and reflect the maximum nameplate rating. [↑](#footnote-ref-67)