ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

Background

Northeast Power Coordinating Council Inc. (NPCC)

The Northeast Power Coordinating Council Inc. (NPCC) is one of six Regional Entities (REs) that have executed a Regional Delegation Agreement (RDA) with the North American Electric Reliability Corporation (NERC - the Electric Reliability Organization (ERO)). This RDA, effective as of January 1, 2021, amended and restated August 31, 2021, authorizes NPCC to develop and enforce Reliability Standards applicable to all owners, operators, and users of the Bulk-Power System (BPS), within geographic boundaries[1] and for other purposes, and execute its respective responsibilities in a transparent manner pursuant to Section 215 of the Federal Power Act (FPA) to promote effective and efficient administration of BPS reliability in accordance with the FPA, ERO Regulations, and the NERC Rules of Procedure (ROP) as approved by the Federal Energy Regulatory Commission (FERC; the Commission).

New England Independent System Operator (ISO-NE)

The New England Independent System Operator, ISO New England Inc. (ISO-NE), is the independent not for-profit entity authorized by the FERC, responsible to perform three critical, complex, interconnected roles for the New England region. The three roles encompass:

- reliable operation of New England's bulk power generation and transmission system
- administration of the region's wholesale electricity markets
- management of the comprehensive planning of the regional bulk power system (BPS).

ISO-NE is registered with NERC as a Reliability Coordinator, Balancing Authority, Planning Authority [Note: Planning Authority is currently referred to as Planning Coordinator], Resource Planner, Reserve Sharing Group, Transmission Operator, Transmission Planner and Transmission Service Provider.

[1] Per RDA Attachment A: all or part of the states of Connecticut, Massachusetts, New Hampshire, Rhode Island, Vermont and most of Maine. The geographic boundaries of NPCC are determined by the service areas as documented in the NERC Compliance Registry and in accordance with Memorandums of Understanding (MOUs) and similar agreements.

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

North American Electric Reliability Corporation (NERC)

The North American Electric Reliability Corporation (NERC) is the organization certified by the FERC pursuant to Section 215(c) of the FPA, to establish and enforce Reliability Standards for the BPS.

The NERC Compliance Monitoring and Enforcement Program (CMEP) is the annual operating plan used by NERC in performing CMEP responsibilities and duties. NERC executes CMEP activities in accordance with the NERC Rules of Procedure (ROP) and the respective Regional Delegation Agreement (RDAs). An integral part of the CMEP involves Compliance Audits of NERC Reliability Standards and Requirements that are applicable to the function(s) for which an entity has registered. NERC, in developing the annual CMEP with input from the Regional Entities (REs), stakeholders, and regulators, identifies risk elements used to focus on compliance monitoring and enforcement activities and related NERC Reliability Standards and Requirements. Compliance with all NERC Reliability Standards is required, whether or not they are included in the subset of Reliability Standards and Requirements identified in the annual NERC CMEP Implementation Plan.

NERC relies on the REs to enforce the NERC Reliability Standards with BPS owners, operators, and users through approved RDAs. REs are responsible for monitoring compliance of the registered entities within their regional boundaries, assuring mitigation of all violations of approved Reliability Standards and assessing penalties and sanctions for failure to comply. Depending on regional or registered entity distinctions, the RE may focus compliance monitoring activities. The set of compliance procedures that document how NPCC will meet the obligations described in the ROP and Appendices are posted to the NPCC website.

Purpose of this Document

NPCC, in its role of administering the CMEP, performs periodic audits of Registered Entities that are users, owners, or operators of the Bulk Electric System (BES) within the ISO-NE Reliability Coordinator Area (RCA). In the conduct of such audits, the NPCC auditors and/or audited Registered Entities have frequently requested corroborating evidence, compliance guidance, or other information from ISO-NE, based on ISO-NE's substantial authorities and responsibilities as both a Regional Transmission Organization (RTO) and as defined by its aforementioned registrations with NERC. The corroborating evidence and guidance provided in this document is used by NPCC auditors to determine the applicability of the Requirement(s) of certain NERC Standards to a given Registered Entity and, for applicable Requirements, to assist NPCC auditors in assessing the compliance of that Registered Entity with those Requirements. This assessment takes into account the rules and procedures contained in the ISO New England Inc. Transmission, Markets, and Services Tariff (ISO-NE Tariff), which is accepted by the Federal Energy Regulatory Commission (FERC; the Commission) as just and reasonable. Given the repetitive nature of many of these requests, NPCC and ISO-NE have joined to provide an agreed upon set of "Corroborating Evidence Interpretations and Compliance Guidance" (CEICG) narratives containing corroborating evidence and/or compliance guidance to facilitate

NPCC assessments of compliance with the Requirements of applicable NERC Reliability Standards. The supporting ISO-NE Operating Documents may be provided by the Registered Entity to NPCC, as audit evidence, in accordance with the ISO-NE Information Policy. The information contained in the CEICG document does not preclude other evidence that may be introduced by the Registered Entity and accepted by the NPCC auditing body. In addition, the information contained in the CEICG document may not be construed as modifying or contradicting any part of the ISO-NE Tariff, ISO-NE Filed Documents or any part of any ISO-NE Operating Document. In the event that a Registered Entity believes that any part of the CEICG document conflicts with the ISO-NE Tariff, ISO-NE Filed Documents or ISO-NE Operating Document, ISO-NE urges that Registered Entity to bring the matter to ISO-NE's attention immediately.

Document Revision and Control

The CEICG document will be reviewed on an annual basis, or more often, as necessary. Any updates to the CEICG document will be processed and posted to the ISO-NE public website in accordance with the following:

- For the CEICG document to become effective, both ISO-NE and NPCC must review and approve the document
- Any changes to the CEICG shall be presented to the Master/Local Control Center (M/LCC) Heads

Each revision to the CEICG document shall be assigned a Revision Number and a Revision Date.

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

Index of Standards Addressed by Current CEICG Narratives (Alphabetically by Standard)

NERC STANDARD (Requirement(s))	CEICG TITLE (*CEICG #*) (Ctrl + Click)
BAL-005-1 (R7)	Standard pertaining to Dynamic Transfers does not apply within the ISO-NE **Reliability Coordinator** Area (RCA) at this time (*CEICG-02*)
CIP-002-5.1a (R1 - item iv, Part 1.2 and 1.3, with associated Attachment 1 Impact Rating Criteria 2.3, 2.6, 2.7. 2.9 and 3.4)	ISO-NE notifications to entities regarding its identification of assets within certain categories of facilities identified in the Critical Infrastructure Protection (CIP) Standards as impactive to reliability (*CEICG-30*)
CIP-014-2 (R1)	ISO-NE notifications to entities regarding its identification of assets within certain categories of facilities identified in the Critical Infrastructure Protection (CIP) Standards as impactive to reliability (*CEICG-30*)
COM-001-3 (R3, R4, R5, R7, R8, R10, R11)	Interpersonal Communication capabilities and protocols in New England (*CEICG-29*)
COM-002-4 (R5, R6, R7)	ISO-NE after-the-fact notifications to entities regarding its identification of time periods when an Operating Emergency has existed on the Bulk Electric System (BES) in New England (*CEICG-32*)
EOP-005-3 (R10, R16)	Identification of **Transmission Operators (TOPs)** and **Generator Operators (GOPs)** requested to participate in ISO-NE's system restoration exercises (*CEICG-21*)
FAC-002-4 (R2, R3, R4, R5)	How **Generator Owners (GOs)**, **Transmission Owners (TOs)** and **Distribution Providers (DPs)** can provide evidence of coordination and cooperation with **Transmission Planners (TPs)** and **Planning Authority** / **Planning Coordinator (PA/PC)** on assessments for integration of new facilities (*CEICG-13*)
FAC-003-5 (*All*)	ISO-NE notifies **Transmission Owners (TOs)** if any of their transmission lines operated below 200 kV are identified by ISO-NE as an element of an Interconnection Reliability Operating Limit (IROL) under FAC-014 Requirements (*CEICG-31*)
FAC-008-5 (R8)	Adherence by Market Participants (MPs) and **Transmission Owners (TOs)** to certain ISO-NE requirements (comply with Operating Instructions, provide information to, notify and coordinate with ISO-NE) is evidence of compliance with certain comparable Requirements of NERC Standards (*CEICG-20*)
IRO-001-4 (R2, R3)	Interpersonal Communication capabilities and protocols in New England (*CEICG-29*)
IRO-001-4 (R2, R3) **IRO-010-4** (R3)	Adherence by Market Participants (MPs) and **Transmission Owners (TOs)** to certain ISO-NE requirements (comply with Operating Instructions, provide information to, notify and coordinate with ISO-NE) is evidence of compliance with certain comparable Requirements of NERC Standards (*CEICG-20*)

NERC STANDARD (Requirement(s))	CEICG TITLE (*CEICG #*) (Ctrl + Click)
IRO-017-1 (R2)	
IRO-017-1 (R4)	ISO-NE serves as the **Planning Authority / Planning Coordinator (PA/ PC)** and "Lead" **Transmission Planner (TP)** for the ISO-NE **PC** Area and its outage coordination procedures apply to all BES within the ISO-NE PC Area. ISO-NE Outage Coordination has established procedures which support assessment of the impact of selected known outages for the Near-Term Planning Horizon for the P0 and P1 categories identified in Table 1 with the System Peak or Off-Peak conditions that the System is expected to experience when known outages are planned. (***CEICG-37***)
MOD-025-2 (*All*)	Describes the process for **Generator Owners (GOs)** and **Transmission Owners (TOs)** to submit an outage request to ISO-NE for conducting a verification of real or reactive power capability to meet MOD-025-2 Requirements and to submit the results of such verifications to ISO-NE. ISO-NE serves as the "Lead" **Transmission Planner (TP)** within the ISO-NE **Reliability Coordinator Area (RCA)** (and the sole **TP** to receive such results) (***CEICG-33***)
MOD-026-1 (*All*) **MOD-027-1** (*All*)	ISO-NE serves as the "Lead" **Transmission Planner (TP)** within the ISO-NE **Reliability Coordinator Area (RCA)** and is the sole **TP** within the ISO-NE **RCA** responsible for maintaining models in accordance with MOD-026-1 and MOD-027-1 Standard Requirements. **Generator Owner (GO)** interactions with the **TP** pertaining to these Standards should always take place with ISO-NE. (***CEICG-23***)
MOD-027-1 (R2)	ISO-NE requires governor model validation from any nuclear power station that provides under-frequency response and allows exemptions for those that do not. (***CEICG-35***)
MOD-032-1 (R2, R3)	Adherence by Market Participants (MPs) and **Transmission Owners (TOs)** to certain ISO-NE requirements (comply with Operating Instructions, provide information to, notify and coordinate with ISO-NE) is evidence of compliance with certain comparable Requirements of NERC Standards (***CEICG-20***)
NUC-001-4 (R2)	The nature of Agreements, including NPIRs, pertaining to NUC-001-4 ensure compliance within the ISO-NE **Reliability Coordinator Area. (RCA)** (***CEICG-22***)
NUC-001-4 (R9.3.7)	As Undervoltage Load Shedding (UVLS) programs existing within the ISO-NE **Reliability Coordinator Area (RCA)** are intended to provide local protection only, Standards pertaining to UVLS programs do not apply within the ISO-NE RCA at this time (***CEICG-06***)
PRC-002-4 (R5, R8)	Based on the Dynamic Disturbance Recorder (DDR) capability requirements that ISO-NE has established and specified for the ISO-NE **Reliability Coordinator Area (RCA)**, ISO-NE has notified certain **Transmission Owners (TOs)** that certain of their Bulk Electric System (BES) elements require DDR data. (***CEICG-24***)
PRC-006-5 (R8)	Adherence by Market Participants (MPs) and **Transmission Owners**

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

NERC STANDARD (Requirement(s))	CEICG TITLE (*CEICG #*) (Ctrl + Click)
	(TOs) to certain ISO-NE requirements (comply with Operating Instructions, provide information to, notify and coordinate with ISO-NE) is evidence of compliance with certain comparable Requirements of NERC Standards (***CEICG-20***)
PRC-006-5 (R10)	The ISO-NE Underfrequency Load Shedding (UFLS) program does not require a **Transmission Owner (TO)** to provide automatic switching of its existing capacitor banks, transmission lines, and reactors to control over-voltage in support of UFLS (***CEICG-26***)
PRC-006-NPCC-2 R4, R9, R11, R13 (Part 13.2), R16 (Part 16.3)	Adherence by Market Participants (MPs) and **Transmission Owners (TOs)** to certain ISO-NE requirements (comply with Operating Instructions, provide information to, notify and coordinate with ISO-NE) is evidence of compliance with certain comparable Requirements of NERC Standards (***CEICG-20***)
PRC-010-2 (*All*) **PRC-011-0** (*All*)	As Undervoltage Load Shedding (UVLS) programs existing within the ISO-NE **Reliability Coordinator Area (RCA)** are intended to provide local protection only, Standards pertaining to UVLS programs do not apply within the ISO-NE **RCA** at this time (***CEICG-06***)
PRC-023-6 (R3, R4)	How **Transmission Owners (TOs)**, **Generator Owners (GOs)** and **Distribution Providers (DPs)** within the ISO-NE **Reliability Coordinator Area (RCA)** can comply with the Requirement to obtain agreement of the **Planning Authority / Planning Coordinator (PA/PC)**, **Transmission Operator (TOP)** and **Reliability Coordinator (RC)** regarding the calculated circuit capability in the setting of protective relays, such that they do not limit transmission system loadability and, for entities that use PRC-023-4 R1 criterion 2 as the basis for verifying transmission line relay loadability, how to comply with the Requirement to annually provide an updated list of circuits associated with those transmission line relays to their **PA/PC, TOP and RC** (***CEICG-18***)
PRC-023-6 (R6)	ISO-NE has identified circuits in its **Planning Authority / Planning Coordinator (PA/PC)** area for which **Transmission Owners (TOs)**, **Generator Owners (GOs)**, and **Distribution Providers (DPs)** must comply with PRC-023-6 Requirements R1 through R5 and provides the list of these circuits to the respective owners of those facilities and to NPCC (***CEICG-27***)
PRC-024-3 (R3, R4)	Identifies ISO-NE as the "Lead" **Transmission Planner (TP)** for and instructs **Generator Owners (GOs)** required by PRC-024-3 Requirement R3, Part 3.1 and Requirement R4 to send information to their **TP** to send that information to ISO-NE (and not to other **TPs** in New England) (***CEICG-34***).
PRC-026-2 (R1, R2)	ISO-NE has identified Bulk Electric System (BES) Elements in its **Planning Authority / Planning Coordinator (PA/PC)** area for which **Transmission Owners (TOs)** and **Generator Owners (GOs)** must comply with PRC-026-1 Requirement R2 and provides the list of these Elements to the respective owners of those facilities. (***CEICG-36***)
TOP-001-6 (R5, R6)	Interpersonal Communication capabilities and protocols in New England (***CEICG-29***)

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

NERC STANDARD (Requirement(s))	CEICG TITLE (*CEICG #*) (Ctrl + Click)
TOP-001-6 (R3, R4, R5, R6) **TOP-003-5** (R5)	Adherence by Market Participants (MPs) and **Transmission Owners (TOs)** to certain ISO-NE requirements (comply with Operating Instructions, provide information to, notify and coordinate with ISO-NE) is evidence of compliance with certain comparable Requirements of NERC Standards (***CEICG-20***)
TPL-001-5.1 (R1)	ISO-NE serves as the **Planning Authority / Planning Coordinator (PA/PC)** and "Lead" **Transmission Planner (TP)** for the ISO-NE **PC Are**a and maintains models for all **TPs** within the ISO-NE **PC** Area (***CEICG-28***)
TPL-001-5.1 (R2.1.4, R2.4.4)	ISO-NE serves as the **Planning Authority / Planning Coordinator (PA/ PC)** and "Lead" **Transmission Planner (TP**) for the ISO-NE **PC** Area and its outage coordination procedures apply to all BES within the ISO-NE PC Area. ISO-NE Outage Coordination has established procedures, which support assessment of the impact of selected known outages for the Near-Term Planning Horizon for the P0 and P1 categories identified in Table 1 with the System Peak or Off-Peak conditions that the System expects to experience when known outages are planned. (***CEICG-37***)
TPL-007-4 (R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12, R13)	ISO-NE serves as the **Planning Authority / Planning Coordinator (PA/ PC)** and "Lead" **Transmission Planner (TP**) for the ISO-NE **PC** Area and its geomagnetic disturbance analysis procedures which apply to all BES facilities within the ISO-NE PC Area. ISO-NE has established procedures, which support assessment of the impact of selected benchmark and supplemental geomagnetic disturbances for the Near-Term Planning Horizon. (***CEICG-38***
VAR-001-5 (R6)	ISO-NE operations and planning processes do not result in ISO-NE identifying and requesting changes to Generator Step-Up (GSU) transformer tap settings (***CEICG-16***)
VAR-002-4.1 (R1, R3, R4, R5)	Adherence by Market Participants (MPs) and **Transmission Owners (TOs)** to certain ISO-NE requirements (comply with Operating Instructions, provide information to, notify and coordinate with ISO-NE) is evidence of compliance with certain comparable Requirements of NERC Standards (***CEICG-20***)

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

ISO-NE CORROBORATING EVIDENCE INTERPRETATIONS AND COMPLIANCE GUIDANCE (CEICG) DOCUMENT INDEX <u>by NERC STANDARD</u> (Revision 14, September 1, 2024) *ISO-NE Public Use*													
			FUNCTIONAL ENTITIES to WHICH REQUIREMENT <u>and</u> CEICG APPLY										
NERC STANDARD	**REQUIREMENT #**	**CEICG #** (Ctrl + Click)	**BA**	**DP**	**GO**	**GOP**	**PA/PC**	**RC**	**RP**	**TO**	**TOP**	**TP**	**TSP**
BAL-005-1	R7	***CEICG-02***	x										
CIP-002-5.1a	R1	***CEICG-30***	x	x	x	x	x	x		x	x		
CIP-014-3	R1	***CEICG-30***					x	x		x		x	
COM-001-3	R3, R4, R5, R7, R8, R10, R11	***CEICG-29***	x	x		x		x			x		
COM-002-4	R5, R6, R7	***CEICG-32***	x	x		x		x			x		
EOP-005-3	R10, R16	***CEICG-21***				x		x			x		
FAC-002-4	R2, R3, R4, R5	***CEICG-13***		x	x					x			
FAC-003-5	*All*	***CEICG-31***			x					x			
FAC-008-5	R8	***CEICG-20***			x		x	x		x	x	x	
IRO-001-4	R2, R3	***CEICG-29***	x	x		x		x			x		
IRO-001-4	R2, R3	***CEICG-20***	x	x		x		x			x		
IRO-010-4	R3	***CEICG-20***	x	x	x	x		x		x	x		
IRO-017-1	R2	***CEICG-20***	x					x			x		
IRO-017-1	R4	***CEICG-37***					x	x				x	
MOD-025-2	*All*	***CEICG-33***			x					x		x	
MOD-026-1	*All*	***CEICG-23***			x							x	
MOD-027-1	*All*	***CEICG-23***			x							x	
MOD-027-1	R2	***CEICG-35***			x							x	
MOD-032-1	R2, R3	***CEICG-20***	x		x		x		x	x		x	x
NUC-001-4	R2	***CEICG-22***				x				x	x	x	
NUC-001-4	R9.3.7	***CEICG-06***				x				x	x		
PRC-002-4	R5, R8	***CEICG-24***			x		x			x			
PRC-006-5	R8	***CEICG-20***		x	x		x			x			
PRC-006-5	R10	***CEICG-26***					x			x			
PRC-006-NPCC-2	R4, R9, R11, R13, R16	***CEICG-20***		x	x		x			x			
PRC-010-2	*All*	***CEICG-06***		x	x	x	x			x	x	x	
PRC-011-0	*All*	***CEICG-06***		x	x	x				x	x		
PRC-023-6	R3, R4	***CEICG-18***		x	x		x	x		x	x		
PRC-023-6	R6	***CEICG-27***		x	x		x	x		x			

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

ISO-NE CORROBORATING EVIDENCE INTERPRETATIONS AND COMPLIANCE GUIDANCE (CEICG) DOCUMENT INDEX by NERC STANDARD
(Revision 14, September 1, 2024)
ISO-NE Public Use

			FUNCTIONAL ENTITIES to WHICH REQUIREMENT and CEICG APPLY										
NERC STANDARD	**REQUIREMENT #**	**CEICG # (Ctrl + Click)**	**BA**	**DP**	**GO**	**GOP**	**PA/PC**	**RC**	**RP**	**TO**	**TOP**	**TP**	**TSP**
PRC-024-3	R3, R4	***CEICG-34***			x		x					x	
PRC-026-2	R1, R2	***CEICG-36***			x		x			x			
TOP-001-6	R5, R6	***CEICG-29***	x	x		x					x		
TOP-001-6	R3, R4, R5, R6	***CEICG-20***	x	x		x					x		
TOP-003-5	R5	***CEICG-20***	x	x	x	x				x	x		
TPL-001-5.1	R1	***CEICG-28***					x					x	
TPL-001-5.1	R2.1.4, R2.4.4	***CEICG-37***					x					x	
TPL-007-4	R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12, R13	***CEICG-38***			x		x			x		x	
VAR-001-5	R6	***CEICG-16***			x						x		
VAR-002-4.1	R1, R3, R4, R5	***CEICG-20***			x	x					x	x	
VAR-002-4.1	R6	***CEICG-16***			x						x		

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

ISO-NE CORROBORATING EVIDENCE INTERPRETATIONS AND COMPLIANCE GUIDANCE (CEICG) DOCUMENT INDEX by CEICG (Revision 14, September 1, 2024) *ISO-NE Public Use*													
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CEICG # (Ctrl + Click)	NERC STANDARD	REQUIREMENT #	BA	DP	GO	GOP	PA/PC	RC	RP	TO	TOP	TP	TSP
CEICG-02	BAL-005-1	R7	x										
CEICG-06	NUC-001-4	R9.3.7				x				x	x		
	PRC-010-2	*All*		x	x	x	x			x	x	x	
	PRC-011-0	*All*		x	x	x				x	x		
CEICG-13	FAC-002-4	R2, R3, R4, R5		x	x		x			x		x	
CEICG-16	VAR-001-5	R6			x						x		
	VAR-002-4.1	R6			x						x		
CEICG-18	PRC-023-6	R3, R4		x	x		x	x		x	x		
CEICG-20	FAC-008-5	R8			x		x	x		x	x	x	
	IRO-001-4	R2, R3	x	x		x		x			x		
	IRO-010-4	R3	x	x	x	x		x		x	x		
	IRO-017-1	R2	x					x			x		
	MOD-032-1	R2, R3	x		x		x		x	x		x	x
	PRC-006-5	R8		x	x		x			x			
	PRC-006-NPCC-2	R4, R9, R11, R13, R16		x	x		x			x			
	TOP-001-6	R3, R4, R5, R6	x	x		x					x		
	TOP-003-5	R5	x	x	x	x				x	x		
	VAR-002-4.1	R1, R3, R4, R5			x	x					x	x	
CEICG-21	EOP-005-3	R10, R16				x		x			x		
CEICG-22	NUC-001-4	R2				x				x	x	x	
CEICG-23	MOD-026-1	*All*			x							x	
	MOD-027-1	*All*			x							x	
CEICG-24	PRC-002-4	R5, R8			x		x			x			
CEICG-26	PRC-006-5	R10					x			x			
CEICG-27	PRC-023-6	R6		x	x		x	x		x			
CEICG-28	TPL-001-5.1	R1					x					x	
CEICG-29	COM-001-3	R3, R4, R5, R7, R8, R10, R11	x	x		x		x			x		
	IRO-001-4	R2, R3	x	x		x		x			x		
	TOP-001-6	R5, R6	x	x		x					x		

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

ISO-NE CORROBORATING EVIDENCE INTERPRETATIONS AND COMPLIANCE GUIDANCE (CEICG) DOCUMENT INDEX by CEICG (Revision 14, September 1, 2024) *ISO-NE Public Use*													
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CEICG # (Ctrl + Click)	**NERC STANDARD**	**REQUIREMENT #**	**BA**	**DP**	**GO**	**GOP**	**PA/PC**	**RC**	**RP**	**TO**	**TOP**	**TP**	**TSP**
CEICG-30	CIP-002-5.1a	R1	x	x	x	x	x	x		x	x	x	
	CIP-014-3	R1					x	x		x		x	
CEICG-31	FAC-003-5	*All*			x					x			
CEICG-32	COM-002-4	R5, R6, R7	x	x		x		x			x		
CEICG-33	MOD-025-2	*All*			x					x		x	
CEICG-34	PRC-024-3	R3, R4			x		x					x	
CEICG-35	MOD-027-1	R2			x							x	
CEICG-36	PRC-026-2	R1, R2			x		x			x			
CEICG-37	IRO-017-1	R4					x	x				x	
	TPL-001-5.1	R2.1.4, R2.4.4					x					x	
CEICG-38	TPL-007-4	R1, R2, R3, R4, R5, R6, R7, R8, R9, R10, R11, R12, R13			x		x			x		x	

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

CEICG Narratives

CEICG-02	***Standard pertaining to Dynamic Transfers does not apply within the ISO-NE Reliability Coordinator Area (RCA) at this time***
NERC Standard	**BAL-005-1** **Balancing Authority Control**
Applicable Requirement(s)	**R7.** Each **Balancing Authority** shall ensure that each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent **Balancing Authority** is equipped with: **…7.1.** a common source to provide information to both **Balancing Authorities** for the scan rate values used in the calculation of Reporting ACE; and, **…7.2.** a time synchronized common source to determine hourly megawatt-hour values agreed-upon to aid in the identification and mitigation of errors.
Applicable Functional Entities	**Balancing Authority**
ISO-NE Disposition: BAL-005-01, R7	<u>Explanation of why this Requirement of this Standard does not apply within the ISO-NE Balancing Authority Area (BAA) at this time</u> BAL-005-1 R7 pertains, in part, to Dynamic Schedules and Pseudo-Ties. ISO-NE currently only dispatches generation within the ISO-NE BAA operational jurisdiction footprint and, therefore, per the NERC definitions, there are no Dynamic Schedules or Pseudo-Ties within the ISO-NE BAA. Therefore, this Requirement is **not** applicable to entities in the ISO-NE BAA. Neither ISO-NE nor any of its neighboring BAs implement Dynamic Interchange at this time. As a general matter, ISO-NE modifies eTags, as appropriate, when schedules are modified via ISO-NE's external transaction scheduling software. ISO-NE also communicates the release of the limit to both the Sink and Source BAs. Any initiating or reloading (i.e., restoring) of a curtailment of an interchange transaction within the ISO-NE BAA would be performed by ISO-NE and implemented through its external transaction scheduling software in an automated fashion and there would be no need for any Market Participant to respond. We note that Docket #ER19-2565-000 Import Transaction Requirement Updates effective October 23, 2019 removed language pertaining to Dynamic Scheduling from the ISO-NE Tariff. As a result, as stated above, at this time there are no Dynamic Schedules or Dynamic Transfers within the ISO-NE BAA. However, should Dynamic Scheduling be instituted within the ISO-NE BAA in the future, ISO-NE will provide advance notice to NPCC's Manager, Compliance Audit Program (NPCCCI@npcc.org).

CEICG-06	***As Undervoltage Load Shedding (UVLS) programs existing within the ISO-NE Reliability Coordinator Area (RCA) are intended to provide local protection only, Standards pertaining to UVLS programs do not apply within the ISO-NE RCA at this time***
NERC Standard	**NUC-001-4** **Nuclear Plant Interface Coordination**
Applicable Requirement(s)	**R9**. The **Nuclear Plant Generator Operator** and the applicable **Transmission Entities** shall include the following elements in aggregate within the Agreement(s) (identified in R2): **…9.3**. Operations and maintenance coordination: **…9.3.7**. Coordination of the NPIRs with transmission system Remedial Action Schemes and any programs that reduce or shed load based on underfrequency **or undervoltage**. ***R2 noted below due to reference in R9*** (**R2** The **Nuclear Plant Generator Operator** and the applicable **Transmission Entities** shall have in effect one or more Agreements[1] that include mutually agreed to NPIRs and document how the **Nuclear Plant Generator Operator** and the applicable **Transmission Entities** shall address and implement these NPIRs.) [1] *Agreements may include mutually agreed upon procedures or protocols in effect between entities or between departments of a vertically integrated system.*
NERC Standard	**PRC-010-2** **Undervoltage Load Shedding**
Applicable Requirement(s)	**CEICG pertains to *all* Requirements of Standard PRC-010-2.** <u>Purpose</u>: To establish an integrated and coordinated approach to the design, evaluation, and reliable operation of Undervoltage Load Shedding Programs (UVLS Programs). [*Applicable to certain entities that develop, assess, own, or operate a UVLS program –* ***Planning Authority / Planning Coordinator*** *(PA/PC),* ***Transmission Planner*** *(TP),* ***Transmission Owner*** *(TO),* ***Distribution Provider*** *(DP)*]
NERC Standard	**PRC-011-0** **Undervoltage Load Shedding System Maintenance and Testing**
Applicable Requirement(s)	**CEICG pertains to *all* Requirements of Standard PRC-011-0.** <u>Purpose</u>: Provide system preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an Undervoltage Load Shedding (UVLS) program. [*Applicable to certain entities that own or operate a UVLS program –* ***Transmission Owner*** *(TO),* ***Distribution Provider*** *(DP)*]
Applicable Functional Entities	Any of the following that own or operate an Undervoltage Load Shedding (UVLS) System or program: **Distribution Provider**, **Generator Owner, Generator Operator**, **Planning Authority / Planning Coordinator, Transmission Operator, Transmission Owner**, **Transmission Planner**, including any "**Transmission Entities"** (as pertains to NUC-001-4)
ISO-NE Disposition: NUC-001-4, R9.3.7	<u>Explanation of why these Standards or identified Requirements do not apply to:</u> • <u>Distribution Providers (DPs)</u> • <u>Generator Owners (GOs)</u> • <u>Generator Operators (GOPs)</u> • <u>Planning Authorities (PAs) / Planning Coordinators (PCs)</u> • <u>Transmission Owners (TOs)</u>

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

CEICG-06	***As Undervoltage Load Shedding (UVLS) programs existing within the ISO-NE Reliability Coordinator Area (RCA) are intended to provide local protection only, Standards pertaining to UVLS programs do not apply within the ISO-NE RCA at this time***
PRC-010-2, ***All*** **PRC-011-0,** ***All***	• Transmission Operators (TOPs) • Transmission Planners (TPs) or • Transmission Entities (TEs – as defined in NUC-001-4) within the ISO-NE Reliability Coordinator Area (RCA) Although there are UVLS programs provided by Market Participants (MPs) operating within the ISO-NE RCA, none are intended to mitigate the risk of voltage collapse or voltage instability of the Bulk Electric System (BES). Those UVLS programs existing within the ISO-NE RCA are intended to provide local protection only. An "NPCC Assessment of Under-Voltage Load Shedding (UVLS)" report was published on November 29, 2005. This report provided conclusions and recommendations based on limited steady-state analysis conducted by the *SS37 Working Group*. The SS-37 report did not recommend general use of, and drew no conclusion about, the practicality of UVLS schemes. The report left it to individual areas to assess the benefits against the costs and risks of deployment of UVLS schemes in specific situations. Further, the SS-37 report concluded that UVLS schemes cannot be universally and unconditionally applied as a means to limit cascading outages, as they can potentially have a counterproductive effect. In addition, the final conclusion of the SS-37 report stated, "If UVLS schemes are found to be potentially beneficial, more detailed steady state and transient stability studies will be required to thoroughly assess if a UVLS scheme should be pursued." On January 31, 2007, the NPCC *Task Force on System Studies* (TFSS) recommended not to pursue further generic studies of UVLS, stating that further action should only be taken if a member system in the Eastern Interconnection proposes a specific UVLS application, which can then be studied in more detail. [1] For NUC-001-4, R9.3.7, the Agreements between the Nuclear Plant Generator Operator (NPGOP) and the Transmission Entity (TE) required by NUC-001-4 R2 do not need to include provisions pertaining to coordination of the Nuclear Plant Interface Requirements (NPIRs) with transmission system UVLS programs (because there are no such programs). [1] *Letter, David Conroy, Chair-TFSS to Guy Zito, Assist. V.P. Standards, Re- UVLS Study Recommendations.*

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

CEICG-13	***How Generator Owners (GOs), Transmission Owners (TOs) and Distribution Providers (DP)s can provide evidence of coordination and cooperation with Transmission Planners (TPs) and Planning Authority / Planning Coordinator (PA/PC) on assessments for integration of new facilities***
NERC Standard	**FAC-002-4** **Facility Interconnection Studies**
Applicable Requirement(s)	**R2.** Each **Generator Owner** seeking to interconnect new generation Facilities, or existing interconnections of generation Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, shall coordinate and cooperate on studies with its **Transmission Planner** or **Planning Coordinator**, including but not limited to the provision of data as described in **R1, Parts 1.1-1.4.** **R3.** Each **Transmission Owner** and each **Distribution Provider** seeking to interconnect new transmission Facilities or electricity end-user Facilities, or existing interconnections of transmission Facilities or electricity end-user Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, shall coordinate and cooperate on studies with its **Transmission Planner** or **Planning Coordinator**, including but not limited to the provision of data as described in **R1, Parts 1.1-1.4.** **R4.** Each **Transmission Owner** shall coordinate and cooperate with its **Transmission Planner** or **Planning Coordinator** on studies regarding requested new or existing interconnections seeking to make a qualified change as defined by the **Planning Coordinator** under Requirement R6, to its Facilities, including but not limited to the provision of data as described in **R1, Parts 1.1-1.4.** **R5.** Each applicable **Generator Owner** shall coordinate and cooperate with its **Transmission Planner** or **Planning Coordinator** on studies regarding requested interconnections to its Facilities, including but not limited to the provision of data as described in **R1, Parts 1.1-1.4.** ***R1 noted below due to reference in R2, R3, R4 and R5*** **(R1.** Each Transmission Planner and each Planning Coordinator shall study the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities and (ii) existing interconnections of generation, transmission, or electricity end-user Facilities seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6. The following shall be studied: **1.1.** The reliability impact of the new interconnection, or existing interconnection seeking to make a qualified change as defined by the Planning Coordinator under Requirement R6, on affected system(s); **1.2.** Adherence to applicable NERC Reliability Standards; regional and Transmission Owner planning criteria; and Facility interconnection requirements; **1.3.** Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions;

CEICG-13	***How Generator Owners (GOs), Transmission Owners (TOs) and Distribution Providers (DP)s can provide evidence of coordination and cooperation with Transmission Planners (TPs) and Planning Authority / Planning Coordinator (PA/PC) on assessments for integration of new facilities***
	1.4. Study assumptions, system performance, alternatives considered, and coordinated recommendations. While these studies may be performed independently, the results shall be evaluated and coordinated by the entities involved.)
Applicable Functional Entities	**Distribution Provider, Generator Owner, Planning Coordinator, Transmission Owner, Transmission Planner**
ISO-NE Disposition: FAC-002-4, R2, R3, R4, R5	Explanation of how Generator Owners (GOs), Transmission Owners (TOs) and Distribution Providers (DPs) can provide evidence of coordination and cooperation with the Transmission Planner (TP) and Planning Authority / Planning Coordinator (PA/PC) on assessments for integration of new facilities A GO, TO or DP can provide evidence of its coordination and cooperation with the TP and PA/PC on assessments for integration of new facilities through their participation in the Proposed Plan Application (PPA) process, as established in Section I.3.9 of the ISO New England Inc. Transmission, Markets, and Services Tariff (ISO-NE Tariff). This process, which may involve studies and discussions by ISO-NE and NEPOOL stakeholders, is documented on the ISO-NE public website - PPAs. In accordance with Section I.3.9 General Terms and Conditions - Review of Market Participant's Proposed Plans: "Each Market Participant and Transmission Owner shall submit to the ISO at least (60) days prior to the proposed in service date in such form, manner and detail as the ISO may reasonably prescribe, (i) any new or materially changed plan for additions to or changes to any generating and demand resources or transmission facilities rated 69 kV or above subject to control of such Market Participant or Transmission Owner, and (ii) any new or materially changed plan for any other action to be taken by the Market Participant or Transmission Owner, except for retirements of or reductions in the capacity of a generating resource or a demand resource, which may have a significant effect on the stability, reliability or operating characteristics of the Transmission Owner's transmission facilities, the transmission facilities of another Transmission Owner, or the system of a Market Participant."[1] Schedule 22 Large Generator Interconnection Procedures, Schedule 23 Small Generator Interconnection Procedures and Schedule 25 Elective Transmission Upgrade Interconnection Procedures of Section II Open Access Transmission Tariff (OATT) of the ISO-NE Tariff also contain requirements for coordinating with ISO-NE and submitting data for studies to ISO-NE. [1] Section I.3.9 provides, in full, that: *"In the case of changes to transmission facilities-developed through the Solutions Study process or the competitive solution process, no significant action (other than*

CEICG-13	***How Generator Owners (GOs), Transmission Owners (TOs) and Distribution Providers (DP)s can provide evidence of coordination and cooperation with Transmission Planners (TPs) and Planning Authority / Planning Coordinator (PA/PC) on assessments for integration of new facilities***
	engineering reasonably necessary to support the Solutions Study or competitive solution process) shall be taken. *Unless the ISO notifies the Market Participant or Transmission Owner in writing within sixty (60) days of the submittal (or ninety (90) days if the ISO determines that it requires additional time), that it has determined that implementation of the plan will have a significant adverse effect upon the reliability or operating characteristics of the Transmission Owner's transmission facilities, the transmission facilities of another Transmission Owner, or the system of a Market Participant, the Market Participant or Transmission Owner shall be free to proceed.* *The ISO shall maintain on its website a list of such applications that are currently under review and the status of each such application. The ISO shall provide notice of any action taken with respect to any such applications, including an explanation of its reasons for such action, to each Market Participant or Transmission Owner as soon as reasonably practicable after such action is taken. The time limits provided by this section may be changed with respect to any such submission by agreement between the ISO and the Market Participant or Transmission Owner."*

CEICG-16	***ISO-NE operations and planning processes do not result in ISO-NE identifying and requesting changes to Generator Step-Up (GSU) transformer tap settings***
NERC Standard	**VAR-001-5** **Voltage and Reactive Control**
Applicable Requirement(s)	**R6.** After consultation with the **Generator Owner** regarding necessary step-up transformer tap changes and the implementation schedule, the **Transmission Operator** shall provide documentation to the **Generator Owner** specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.
NERC Standard	**VAR-002-4.1** **Generator Operation for Maintaining Network Voltage Schedules**
Applicable Requirement(s)	**R6**. After consultation with the **Transmission Operator** regarding necessary step-up transformer tap changes, the **Generator Owner** shall ensure that transformer tap positions are changed according to the specifications provided by the **Transmission Operator**, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. **…6.1.** If the **Generator Owner** cannot comply with the **Transmission Operator**'s specifications, the **Generator Owner** shall notify the **Transmission Operator** and shall provide the technical justification.
Applicable Functional Entities	**Generator Owner, Transmission Operator**
ISO-NE Disposition: VAR-001-5, R6 VAR-002-4.1, R6	Explanation of how ISO-NE operations and planning processes do not result in ISO-NE identifying and requesting changes to generator step-up (GSU) transformer tap settings In New England, VAR-001-5 R6 and VAR-002-4.1 R6 do not apply because the Transmission Operators [ISO-NE and the Local Control Centers (LCCs)] do not specify or request changes to GSU transformer tap settings. Generator Owners (GOs) determine GSU transformer tap settings that are appropriate for their Generator Assets and inform ISO-NE of the settings they are proposing to use. Any change to a GSU transformer tap setting could be considered a material change to the system and would be processed through the ISO-NE planning process in accordance with Section I.3.9 of the ISO-NE Tariff. In accordance with ISO-NE Planning Procedure 5-1, "Procedure for Review of Market Participant's or Transmission Owner's Proposed Plans (Section I.3.9 Applications: Requirements, Procedures and Forms)" (Section 2.2 Transmission Changes), "All transmission changes that change the topology or characteristics of the transmission system or that change the thermal capability of a portion of the system by replacement of transmission facilities…require a Proposed Plan Application (PPA)" under Section I.3.9 of the ISO-NE Tariff. This requirement applies to Generator Asset leads and associated equipment, such as GSU transformers. ISO-NE does not specifically review and request GSU transformer tap changes for voltage/reactive control in Real-Time. Generator Assets are required to maintain a specified voltage schedule within a tolerance band. If ISO-NE or an LCC identifies a voltage issue, a study would likely be conducted and the results of such a study could

CEICG-16	***ISO-NE operations and planning processes do not result in ISO-NE identifying and requesting changes to Generator Step-Up (GSU) transformer tap settings***
	lead to a list of potential solutions, which may (or may not) include changes to GSU transformer tap settings. ISO-NE would then inform the Generator Asset Lead Market Participant (Lead MP) of the voltage issue and potential solution(s). The Lead MP may (or may not) choose to address the issue through a modification to a generator tap setting, but that would be their determination (not ISO-NE's or an LCC's). If the Generator Asset Lead MP opts to resolve the voltage issue through a change to a GSU transformer tap setting, it may be processed through the ISO-NE planning process described above or would be accepted by ISO-NE based on the study already conducted by ISO-NE.

CEICG-18	***How Transmission Owners (TOs), Generator Owners (GOs) and Distribution Providers (DPs) within the ISO-NE Reliability Coordinator Area (RCA) can comply with the Requirement to obtain agreement of the Planning Authority / Planning Coordinator (PA/PC), Transmission Operator (TOP) and Reliability Coordinator (RC) regarding the calculated circuit capability in the setting of protective relays, such that they do not limit transmission system loadability and, for entities that use PRC-023-6 R1 criterion 2 as the basis for verifying transmission line relay loadability, how to comply with the Requirement to annually provide an updated list of circuits associated with those transmission line relays to their PA/PC, TOP and RC***
NERC Standard	**PRC-023-6** **Transmission Relay Loadability**
Applicable Requirement(s)	**R3**: Each **Transmission Owner**, **Generator Owner**, and **Distribution Provider** that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the **Planning Coordinator**, **Transmission Operator**, and **Reliability Coordinator** with the calculated circuit capability. ***R1 Criterion 7, 8, 9, 12, or 13 noted below due to reference in R3*** **(R1.** Each **Transmission Owner**, **Generator Owner**, and **Distribution Provider** shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each **Transmission Owner**, **Generator Owner**, and **Distribution Provider** shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. …**7.** Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration. **8.** Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration. **9.** Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration. **12.** When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints: a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer. b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees. c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

CEICG-18	***How Transmission Owners (TOs), Generator Owners (GOs) and Distribution Providers (DPs) within the ISO-NE Reliability Coordinator Area (RCA) can comply with the Requirement to obtain agreement of the Planning Authority / Planning Coordinator (PA/PC), Transmission Operator (TOP) and Reliability Coordinator (RC) regarding the calculated circuit capability in the setting of protective relays, such that they do not limit transmission system loadability and, for entities that use PRC-023-6 R1 criterion 2 as the basis for verifying transmission line relay loadability, how to comply with the Requirement to annually provide an updated list of circuits associated with those transmission line relays to their PA/PC, TOP and RC***
	13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations. **R4**. Each **Transmission Owner**, **Generator Owner**, and **Distribution Provider** that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its **Planning Coordinator**, **Transmission Operator**, and **Reliability Coordinator** with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. ***R1 Criterion 2 noted below due to reference in R4*** **(R1.** Each **Transmission Owner**, **Generator Owner**, and **Distribution Provider** shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each **Transmission Owner**, **Generator Owner**, and **Distribution Provider** shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. **2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).) [1] *When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.*
Applicable Functional Entities	**Distribution Provider, Generator Owner, Planning Authority / Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Owner**
ISO-NE Disposition PRC-023-6, R3, R4	<u>Explanation of how Transmission Owners (TOs), Generator Owners (GOs) and Distribution Providers (DPs) provide information to ISO-NE to comply with PRC-023-6 R3 and R4</u> In accordance with PRC-023-6 R6, ISO-NE determines the circuits in its Planning Coordinator Area (PCA) for which certain Registered Entities must comply with Requirements R1 through R5. ISO-NE CEICG-27 lists the TOs, GOs and DPs that own the applicable terminals of these circuits and that must comply with PRC-023-6 R1 through R5.

CEICG-18	***How Transmission Owners (TOs), Generator Owners (GOs) and Distribution Providers (DPs) within the ISO-NE Reliability Coordinator Area (RCA) can comply with the Requirement to obtain agreement of the Planning Authority / Planning Coordinator (PA/PC), Transmission Operator (TOP) and Reliability Coordinator (RC) regarding the calculated circuit capability in the setting of protective relays, such that they do not limit transmission system loadability and, for entities that use PRC-023-6 R1 criterion 2 as the basis for verifying transmission line relay loadability, how to comply with the Requirement to annually provide an updated list of circuits associated with those transmission line relays to their PA/PC, TOP and RC***
	To meet PRC-023-6 R3 and R4, identified TOs, GOs and DPs must provide information to ISO-NE (and, for R3, must also obtain agreement from ISO-NE). To meet PRC-023-6 R3, each identified TO, GO and DP that owns the applicable terminal of these circuits with transmission relays set according to PRC-023-6 R1, criterion 7, 8, 9, 12, or 13 must use the calculated circuit capability as the Facility Rating of the circuit and obtain agreement from ISO-NE on the resulting Facility Rating. To obtain such agreement from ISO-NE, each identified TO, GO and DP must send the pertinent Facility Rating calculations (e.g., Facility Rating spreadsheets or Facility Rating database) to ISO-NE Operations Support Services group at the following ISO-NE email address: prc_setting@iso-ne.com. ISO-NE's review of, and agreement to, the Facility Ratings submitted in accordance with PRC-023-6 would be limited to the line rating change and the selection of the method used for the calculation of the line rating. ISO-NE will provide an email response indicating whether it agrees or disagrees with the Facility Ratings proposed by a TO, GO or DP. To meet PRC-023-6 R4, each identified TO, GO and DP that owns the applicable terminal of these circuits and that chooses to use PRC-023-6 R1, criterion 2 as the basis for verifying transmission line relay loadability must provide ISO-NE with an updated list of circuits associated with those transmission line relays (if any) at least once each calendar year, with no more than 15 months between provision of updates (the updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list). ISO-NE has established a **target date of April 15th** for all annual transmittals from a TO, GO or DP pertaining to PRC-023-6 R4 Requirements. These annual transmittals should be sent to the ISO-NE Operations Support Services group at the following ISO-NE email address: prc_setting@iso-ne.com. *Note: Each TO, GO and DP maintains its own records of these email transmittals, for audit purposes*.

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

CEICG-20	***Adherence by Market Participants (MPs) and Transmission Owners (TOs) to certain ISO-NE requirements (comply with Operating Instructions, provide information to, notify and coordinate with ISO-NE) is evidence of compliance with certain comparable Requirements of NERC Standards***
NERC Standard	**FAC-008-5** **Facility Ratings**
Applicable Requirement(s)	**R8.** Each **Transmission Owner** (and each **Generator Owner** subject to Requirement **R2**) shall provide requested information as specified below (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated **Reliability Coordinator**(s), **Planning Coordinator**(s), **Transmission Planner**(s), **Transmission Owner**(s) and **Transmission Operator**(s): **8.1.** As scheduled by the requesting entities: **8.1.1.** Facility Ratings **8.1.2.** Identity of the most limiting equipment of the Facilities **8.2.** Within 30 calendar days (or a later date if specified by the requester), for any requested Facility with a Thermal Rating that limits the use of Facilities under the requester's authority by causing any of the following: 1) An Interconnection Reliability Operating Limit, 2) A limitation of Total Transfer Capability, 3) An impediment to generator deliverability, or 4) An impediment to service to a major load center: **8.2.1.** Identity of the existing next most limiting equipment of the Facility **8.2.2.** The Thermal Rating for the next most limiting equipment identified in Requirement R8, Part 8.2.1. ***R2 noted below due to reference in R8*** (**R2.** Each **Generator Owner** shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of interconnection with the **Transmission Owner** that contains all of the following:…)
NERC Standard	**IRO-001-4** **Reliability Coordination - Responsibilities**
Applicable Requirement(s)	**R2**. Each **Transmission Operator**, **Balancing Authority**, **Generator Operator**, and **Distribution Provider** shall comply with its **Reliability Coordinator**'s Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. **R3.** Each **Transmission Operator**, **Balancing Authority**, **Generator Operator**, and **Distribution Provider** shall inform its **Reliability Coordinator** of its inability to perform the Operating Instruction issued by its **Reliability Coordinator** in **Requirement R1**. ***R1 noted below due to reference in R3***

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

CEICG-20	***Adherence by Market Participants (MPs) and Transmission Owners (TOs) to certain ISO-NE requirements (comply with Operating Instructions, provide information to, notify and coordinate with ISO-NE) is evidence of compliance with certain comparable Requirements of NERC Standards***
	(**R1:** Each **Reliability Coordinator** shall act to address the reliability of its **Reliability Coordinator** Area via direct actions or by issuing Operating Instructions).
NERC Standard	**IRO-010-4** **Reliability Coordinator Data Specification and Collection**
Applicable Requirement(s)	**R3**. Each **Reliability Coordinator**, **Balancing Authority**, **Generator Owner**, **Generator Operator**, **Transmission Operator**, **Transmission Owner**, and **Distribution Provider** receiving a data specification in **Requirement R2** shall satisfy the obligations of the documented specifications using: 3.1 A mutually agreeable format 3.2 A mutually agreeable process for resolving data conflicts 3.3 A mutually agreeable security protocol ***R2 noted below due to reference in R3*** (**R2:** The **Reliability Coordinator** shall distribute its data specification to entities that have data required by the **Reliability Coordinator**'s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.)
NERC Standard	**IRO-017-1** **Outage Coordination**
Applicable Requirement(s)	**R2**. Each **Transmission Operator** and **Balancing Authority** shall perform the functions specified in its **Reliability Coordinator**'s outage coordination process.
NERC Standard	**MOD-032-1** **Data for Power System Modeling and Analysis**
Applicable Requirement(s)	**R2**. Each **Balancing Authority**, **Generator Owner**, Load Serving Entity, **Resource Planner**, **Transmission Owner**, and **Transmission Service Provider** shall provide steady-state, dynamics, and short circuit modeling data to its **Transmission Planner**(s) and **Planning Coordinator**(s) according to the data requirements and reporting procedures developed by its **Planning Coordinator** and **Transmission Planner** in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. **R3.** Upon receipt of written notification from its **Planning Coordinator** or **Transmission Planner** regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified **Balancing Authority**, **Generator Owner**, Load Serving Entity, **Resource Planner**, **Transmission Owner**, or **Transmission Service Provider** shall respond to the notifying **Planning Coordinator** or **Transmission Planner** as follows: **3.1.** Provide either updated data or an explanation with a technical basis for maintaining the current data; **3.2.** Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying **Planning Coordinator** or **Transmission Planner**.

CEICG-20	***Adherence by Market Participants (MPs) and Transmission Owners (TOs) to certain ISO-NE requirements (comply with Operating Instructions, provide information to, notify and coordinate with ISO-NE) is evidence of compliance with certain comparable Requirements of NERC Standards***
	R1 noted below due to reference in R2 (**R1.** Each **Planning Coordinator** and each of its **Transmission Planners** shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the **Planning Coordinator**'s planning area that include: **1.1.** The data listed in Attachment 1. **1.2.** Specifications of the following items consistent with procedures for building the Interconnection-wide case(s): **1.2.1.** Data format; **1.2.2.** Level of detail to which equipment shall be modeled; **1.2.3.** Case types or scenarios to be modeled; and **1.2.4.** A schedule for submission of data at least once every 13 calendar months. **1.3.** Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.)
NERC Standard	**PRC-006-5** **Automatic Underfrequency Load Shedding**
Applicable Requirement(s)	**R8.** Each **UFLS entity** [*in New England, could include **TOs**, **GOs** and **DPs***] shall provide data to its **Planning Coordinator**(s) according to the format and schedule specified by the **Planning Coordinator**(s) to support maintenance of each **Planning Coordinator**'s UFLS database.
NERC Standard	**PRC-006-NPCC-2** **Automatic Underfrequency Load Shedding**
Applicable Requirement(s)	**R4.** Each **Distribution Provider** or **Transmission Owner** in the Eastern Interconnection portion of NPCC that does not meet the UFLS program parameters specified in Attachment C, Table 1-3, and each **Distribution Provider** or **Transmission Owner** in the Quebec Interconnection that does not meet the UFLS program parameters specified by its **Planning Coordinator** shall: • Within 30 calendar days of determining that it does not meet the specified parameters, notify its **Planning Coordinator** that it does not meet the UFLS program parameters; and • Within the following 180 calendar days from notification of the **Planning Coordinator**, (1) develop a Corrective Action Plan and a schedule for implementation that is mutually agreed upon with its **Planning Coordinator** or (2) provide its **Planning Coordinator** with a technical study that demonstrates that the deviations from the program parameters will not result in failure of UFLS performance criteria being met for any island. The technical study must be acceptable to the **Planning Coordinator** prior to implementing deviations from program parameters and shall demonstrate coordination with UFLS programs of all entities residing within the same island(s) identified by the **Planning Coordinator** in Requirement R2. The technical study shall also demonstrate coordination with other UFLS programs of adjoining **Planning**

CEICG-20	*Adherence by Market Participants (MPs) and Transmission Owners (TOs) to certain ISO-NE requirements (comply with Operating Instructions, provide information to, notify and coordinate with ISO-NE) is evidence of compliance with certain comparable Requirements of NERC Standards*
	Coordinators, or (3) provide its **Planning Coordinator** with an analysis demonstrating that no alternative load shedding solution is available that would allow the **Distribution Provider** or **Transmission Owner** to comply with UFLS Attachment C Table 2 or Attachment C Table 3. ***R2 noted below due to reference in R4*** (**R2**. Each **Planning Coordinator** shall provide UFLS island boundaries, as identified per the NERC continent-wide PRC-006 Standard on UFLS, to **Distribution Providers**, **Generator Owners**, and **Transmission Owners** within 30 calendar days of receipt of a request.) **R9.** Each **Transmission Owner** and **Distribution Provider** shall annually provide documentation, with no more than 15 calendar months between updates, to its **Planning Coordinator** of the actual net Load that would have been shed by the UFLS relays at each UFLS stage. The actual net Load shall be coincident with the entity's integrated hourly peak net Load during the previous year, as determined by measuring or calculating Load through the switches that would disconnect load if triggered by the UFLS relays. If measured data is unavailable then calculated data may be used. **R11**. Each **Generator Owner** shall transmit the generator underfrequency trip setting and time delay within 45 days of the **Planning Coordinator**'s request. **R13.** For existing non-nuclear units in service prior to July 1, 2015, that have underfrequency protections set to trip above the appropriate curve in Figure 2: (See Standard Figure 2 – Underfrequency Load Shedding Program – Thresholds for Setting Underfrequency Trip Protection for Generators): … **13.2** Each **Generator Owner** shall transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the **Planning Coordinator.** **R16**. Each **Generator Owner** of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 2 (See Standard Figure 2 – Underfrequency Load Shedding Program – Thresholds for Setting Underfrequency Trip Protection for Generators) based on their licensing design, shall: …**16.3** Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the **Planning Coordinator**.
NERC Standard	**TOP-001-6** **Transmission Operations**
Applicable Requirement(s)	**R3**. Each **Balancing Authority**, **Generator Operator**, and **Distribution Provider** shall comply with each Operating Instruction issued by its **Transmission Operator**(s), unless

CEICG-20	***Adherence by Market Participants (MPs) and Transmission Owners (TOs) to certain ISO-NE requirements (comply with Operating Instructions, provide information to, notify and coordinate with ISO-NE) is evidence of compliance with certain comparable Requirements of NERC Standards***
	such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **R4.** Each **Balancing Authority**, **Generator Operator**, and **Distribution Provider** shall inform its **Transmission Operator** of its inability to comply with an Operating Instruction issued by its **Transmission Operator**. **R5.** Each **Transmission Operator**, **Generator Operator**, and **Distribution Provider** shall comply with each Operating Instruction issued by its **Balancing Authority**, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **R6.** Each **Transmission Operator**, **Generator Operator**, and **Distribution Provider** shall inform its **Balancing Authority** of its inability to comply with an Operating Instruction issued by its **Balancing Authority**.
NERC Standard	**TOP-003-5** **Operational Reliability Data**
Applicable Requirement(s)	**R5**. Each **Transmission Operator**, **Balancing Authority**, **Generator Owner**, **Generator Operator**, **Transmission Owner**, and **Distribution Provider** receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications using: **5.1.** A mutually agreeable format **5.2.** A mutually agreeable process for resolving data conflicts **5.3.** A mutually agreeable security protocol ***R3 noted below due to reference in R5*** (R3. Each **Transmission Operator** shall distribute its data specification to entities that have data required by the **Transmission Operator**'s Operational Planning Analyses, Real-time monitoring, and Real-time Assessment.) ***R4 noted below due to reference in R5*** (R4. Each **Balancing Authority** shall distribute its data specification to entities that have data required by the **Balancing Authority**'s analysis functions and Real-time monitoring.)
NERC Standard	**VAR-002-4.1** **Generator Operation for Maintaining Network Voltage Schedules**
Applicable Requirement(s)	**R1.** The **Generator Operator** shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the **Transmission Operator** unless: 1) the generator is exempted by the **Transmission Operator**, or

CEICG-20	*Adherence by Market Participants (MPs) and Transmission Owners (TOs) to certain ISO-NE requirements (comply with Operating Instructions, provide information to, notify and coordinate with ISO-NE) is evidence of compliance with certain comparable Requirements of NERC Standards*
	2) the **Generator Operator** has notified the **Transmission Operator** of one of the following: • That the generator is being operated in start-up[1], shutdown[2], or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the **Transmission Operator**; or • That the generator is not being operated in automatic voltage control mode or in the control mode that was instructed by the **Transmission Operator** for a reason other than start-up, shutdown, or testing. 1. Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation. 2. Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline. **R3.** Each **Generator Operator** shall notify its associated **Transmission Operator** of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. If the status has been restored within 30 minutes of such change, then the **Generator Operator** is not required to notify the **Transmission Operator** of the status change. **R4.** Each **Generator Operator** shall notify its associated **Transmission Operator** within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the **Generator Operator** becoming aware of such change, then the **Generator Operator** is not required to notify the **Transmission Operator** of the change in reactive capability. • Reporting of status or capability changes as stated in Requirement R4 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition. **R5**. The **Generator Owner** shall provide the following to its associated **Transmission Operator** and **Transmission Planner** within 30 calendar days of a request. **5.1**. For generator step-up and auxiliary transformers[5] with primary voltages equal to or greater than the generator terminal voltage: **5.1.1**. Tap settings. **5.1.2**. Available fixed tap ranges. **5.1.3**. Impedance data. [5] *For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.*

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

CEICG-20	***Adherence by Market Participants (MPs) and Transmission Owners (TOs) to certain ISO-NE requirements (comply with Operating Instructions, provide information to, notify and coordinate with ISO-NE) is evidence of compliance with certain comparable Requirements of NERC Standards***
Applicable Functional Entities	**Balancing Authority, Distribution Provider, Generator Operator, Generator Owner, Planning Authority (Planning Coordinator), Reliability Coordinator, Resource Planner, Transmission Operator, Transmission Owner, Transmission Planner, Transmission Service Provider**
ISO-NE Disposition: **FAC-008-5, R8** **IRO-001-4, R2, R3** **IRO-010-4, R3** **IRO-017-1, R2** **MOD-032-1 R2, R3** **PRC-006-5 R8** **PRC-006-NPCC-2, R5 (parts 5.2 & 5.4),**	Explanation of how adherence by Market Participants (MPs) and Transmission Owners (TOs) to certain ISO-NE requirements (comply with Operating Instructions, provide information to, notify and coordinate with ISO-NE) is evidence of compliance with certain comparable Requirements of NERC Standards. ISO-NE performs reliability functions for the New England Area [including Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), Planning Authority / Planning Coordinator (PA/PC), and Transmission Planner (TP), as defined by NERC]. ISO-NE relies on compliance with its issued Operating Instructions and Resource performance that is consistent with submitted operational characteristics, to perform its RC, BA and TOP functions. Accurate and complete data is critical to the creation of the database models used by ISO-NE in Real-Time reliability operations, Market operations, operations planning and long-term planning, and to the computer applications that operate on those models. ISO-NE therefore relies on Resource owners' submitting accurate operating characteristics in order to issue Operating Instructions in response to Real-Time system events, and to assess the long-term needs of the New England system, to fulfill its various reliability functions (RC, BA, TOP, PA/PC and TP). Under various system conditions, issuing an Operating Instruction based on inaccurate operating characteristics may contribute to ISO-NE violating obligations under NERC Standards Requirements, and, in extreme cases, may lead to instability, cascading, or uncontrolled separation. Per the ISO-NE documents (such documents include, but may not be limited to, the ISO-NE Tariff, the Market Participant Service Agreement (MPSA), Transmission Operating Agreement (TOA), and ISO-NE Operating Documents), generally, all Market Participants (MPs) and Transmission Owners (TOs) must comply with Operating Instructions from ISO-NE. For the Generator Asset Resources within the ISO-NE Reliability Coordinator Area (RCA), operational characteristics are submitted to ISO-NE through various means: • Market System (unit offer data such as maximum output, etc. ramp rate, response rate), • NX-12 and NX-12 D data (Resource capability, blackstart ability, voltage/reactive capability, etc.) • ISO-NE Outage Scheduling software • Redeclarations (Real-Time changes in capability)

CEICG-20	***Adherence by Market Participants (MPs) and Transmission Owners (TOs) to certain ISO-NE requirements (comply with Operating Instructions, provide information to, notify and coordinate with ISO-NE) is evidence of compliance with certain comparable Requirements of NERC Standards***
	For the Transmission Resources within the ISO-NE RCA, operational characteristics are submitted to ISO-NE through: • NX-9 transmission system data application for submittal of physical characteristics, ratings, and operational data of transmission system equipment • ISO-NE Outage Scheduling software For long-term planning purposes, ISO-NE has provided a comprehensive guide to the types of data required, and how they are submitted, in Compliance Bulletin – MOD-032 and ISO New England's Model Data Requirements and Reporting Procedures (Compliance Bulletin – MOD-032). ISO-NE may research incidents of failures to provide Generator Asset or transmission data and evaluate such failures with respect to compliance with the applicable Standards, ISO-NE Tariff and/or relevant ISO-NE Operating Procedures if an MP or TO fails to: • respond to an ISO-NE request for data, • coordinate with ISO-NE, • perform the applicable functions of ISO-NE's outage coordination process, or • fails to notify ISO-NE of changes in equipment capabilities and characteristics within the requirements and timeframes described in ISO-NE Operating Procedures. NPCC has requested that ISO-NE corroborate evidence of compliance with NERC Standards provided to NPCC by MPs and TOs regarding compliance with Operating Instructions issued by ISO-NE, provision of data to ISO-NE, notifications to ISO-NE or coordination with ISO-NE, as such actions are required by the NERC Standards listed in CEICG-20 and by related requirements in the ISO-NE Tariff and Operating Procedures. ISO-NE and NPCC have agreed that such corroborating evidence provided by ISO-NE will be by exception, as necessary and appropriate.

CEICG-21	***Identification of Transmission Operators (TOPs) and Generator Operators (GOPs) requested to participate in ISO-NE's system restoration exercises***
NERC Standard	**EOP-005-3** **System Restoration from Blackstart Resources**
Applicable Requirement(s)	**R10**. Each **Transmission Operator** shall participate in its **Reliability Coordinator**'s restoration drills, exercises, or simulations as requested by its **Reliability Coordinator**. **R16**. Each **Generator Operator** shall participate in its **Reliability Coordinator**'s restoration drills, exercises, or simulations as requested by its **Reliability Coordinator**.
Applicable Functional Entities	**Generator Operator, Reliability Coordinator, Transmission Operator**
ISO-NE Disposition: EOP-005-3, R10, R16	<u>Explanation of the determination of Generator Operator (GOP) and Transmission Operator (TOP) applicability for the Requirements to participate in system restoration exercises of the Reliability Coordinator (RC)</u> Applicability and compliance determinations by NPCC regarding EOP-005-3, R10 (applicable to TOPs) and EOP-005-3, R16 (applicable to GOPs), both of which pertain to participation in the RC's restoration drills, exercises, or simulations, depend, in part, on the specifics of the requests for participation in ISO-NE's Cycle 1 New England System Restoration Plan (Plan) Training exercises (Cycle 1 Training) sent to the TOPs and GOPs. As the RC, ISO-NE conducts Cycle 1 Training and requests TOPs and GOPs to participate, in accordance with **EOP-006-3, R8 and R8.1:** **R8.** Each Reliability Coordinator shall conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. **…R8.1.** Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every two calendar years. ISO-NE provides specifics (such as what type(s) of individuals and how many individuals from each entity's organization) that the System Restoration Working Group (SRWG) would like to see participating in Cycle 1 Training, included in the text of the ISO-NE requests that are sent to TOPs and GOPs identified in the Plan. ISO-NE includes NPCC as a "cc" on the emailed invitations (sending them to email address NPCCCI@npcc.org) and maintains records of such requests. NPCC uses this information to determine applicability of EOP-005-3, R10 and EOP-005-3, R16 to TOPs and GOPs, respectively, and to assess the compliance of TOPs and GOPs with these Requirements.

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

<table>
<tr><td>CEICG-22</td><td>The nature of Agreements, including NPIRs, pertaining to NUC-001-4 ensure compliance within the ISO-NE Reliability Coordinator Area (RCA).</td></tr>
<tr><td>NERC Standard</td><td>NUC-001-4
Nuclear Plant Interface Coordination</td></tr>
<tr><td>Applicable Requirement(s)</td><td>R2. The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements[1] that include mutually agreed to NPIRs and document how the Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs.

[1] Agreements may include mutually agreed upon procedures or protocols in effect between entities or between departments of a vertically integrated system.</td></tr>
<tr><td>Applicable Functional Entities</td><td>Each New England Nuclear Plant Generator Operator (NPGOP) has agreed upon certain Nuclear Plant Interface Requirements (NPIRs) with certain “Transmission Entities” (TEs) (as per NUC-001-4). In New England, these TEs include certain Transmission Operators (TOPs), Transmission Planner (TP) and Transmission Owners (TOs). As a result, these NPGOPs and TEs are therefore subject to NUC-001-4 Requirements.</td></tr>
<tr><td>ISO-NE Disposition:

NUC-001-4, R2</td><td><u>Explanation of the nature of the Agreements between NPGOPs and TEs pertaining to NPIRs and how the NPIRs are addressed and implemented, as well as a description of the process by which these NPIRs are agreed upon</u> <u>Scope:</u>

This document pertains to the NPIRs that have been agreed upon by New England NPGOPs and TEs, in accordance with NERC Standard NUC-001-4, R2.
This narrative includes the following:

Table listing of the NPGOPs and TEs to which one or more NPIRs apply
Description of the nature of the Agreements between the NPGOPs and TEs that contain the NPIRs and that describe how NPIRs are addressed and implemented
A description of the process by which the NPIRs are agreed upon

<table>
<tr><th>Nuclear Power Station:</th><th>Millstone</th><th>Seabrook</th></tr>
<tr><td>Name of Registered Entity</td><td>Dominion Energy Nuclear Connecticut, Inc.
[NCR07065]</td><td>NextEra Energy Resources, LLC
[NCR10019]</td></tr>
<tr><td>↓</td><td>(NP)GOP</td><td>(NP)GOP</td></tr>
<tr><td>ISO-NE [NCR07124]</td><td>TOP, TP</td><td>TOP, TP</td></tr>
<tr><td>Eversource Energy Service Company [NCR07176]
LCC/TOP for Millstone-CONVEX
LCC/TOP for Seabrook-New Hampshire</td><td>TOP</td><td>TOP</td></tr>
</table></td></tr>
</table>

CEICG-22	***The nature of Agreements, including NPIRs, pertaining to NUC-001-4 ensure compliance within the ISO-NE Reliability Coordinator Area (RCA).***
	(see nested table and text below)

Eversource Energy Service Company [NCR07176]	TO	TO
New Hampshire Transmission, LLC [NH Transmission] [NCR07091]		TO

Agreements (procedures) that contain the NPIRs:

Master/Local Control Center Procedure No. 1 (M/LCC 1) - Nuclear Plant Transmission Operations contains

- M/LCC 1 - Nuclear Plant Transmission Operations, Attachment C - Millstone Nuclear Power Station
- M/LCC 1 - Nuclear Plant Transmission Operations, Attachment D - Seabrook Nuclear Power Station

The M/LCC 1 Attachments for the nuclear power stations with applicable NPIRs each contain a table that lists all NPIRs pertinent to that nuclear power station applicable to the NPGOP and to the TEs that perform the TOP, TP or TO functions (in Table 1 List of Nuclear Plant Interface Requirements (NPIRs), Section 10 List of NPIRs).

NOTE: The M/LCC 1 and Attachment documents are operating procedures that pertain to the operation of the Bulk Electric System (BES). For this reason, NPIRs that apply to the DP function (if any) **are not** contained in M/LCC 1 Attachments. Any NPIR applicable to the DP function would be contained and addressed in other document(s) that have been mutually-agreed-upon between the NPGOP and DP through a process that is separate and distinct from the M/LCC 1 approval process described herein.

Structure and Content of the Table 1 List of NPIRs in the M/LCC 1 Attachments:

The first column of the NPIR Table 1 in each of the M/LCC 1 Attachments C and D contains the text of the NPIR. Each of the other columns of the NPIR table contains information regarding the TEs that have agreed to one or more of these NPIRs, including:

- Name of the TE (as registered with NPCC, with associated NCR #)
- Name of the TE (as referenced in the M/LCC 1 Attachment)
- Reliability function type(s) that pertain to how NPIR is met (GOP, TOP, TP, TO)

Agreements (procedures) that describe how the NPGOP and applicable TEs address and implement these NPIRs and NUC-001-4 Requirements:

In accordance with NUC-001-4, Agreements for meeting Requirement 2 can include mutually-agreed-upon procedures in effect between the NPGOP and TE. In New England,

CEICG-22	***The nature of Agreements, including NPIRs, pertaining to NUC-001-4 ensure compliance within the ISO-NE Reliability Coordinator Area (RCA).***
	such documents can include any mutually-agreed-upon procedure or any procedure/document which both the NPGOP and TE are obligated to follow. Such procedures/documents include those vetted through the NEPOOL stakeholder process (such as the ISO-NE Tariff and ISO-NE Operating Procedures and Planning Procedures, etc.) and any other mutually-agreed-upon procedure/document. NPGOPs and TEs adhere to NPIRs through their respective implementation of and adherence to, various mutually-agreed upon operating and planning procedures. Documents that contain provisions pertaining to how the NPGOP and applicable TEs address and implement the NPIRs agreed to through the M/LCC 1 approval process are posted to the ISO-NE website and include, but are not limited to: • **M/LCC 1** – Master/Local Control Center Procedure No. 1 - Nuclear Plant Transmission Operations (and Attachments, some of which are confidential and contain Critical Energy Infrastructure Information (CEII)) • **OP-1A** – ISO New England Operating Procedure No. 1 - Central Dispatch Operating Responsibilities and Authority - Appendix A - Assignment of Responsibilities • **PP3** – ISO New England Planning Procedure No. 3 - Reliability Standards for the New England Area Pool Transmission Facilities • **PP5-3** – ISO New England Planning Procedure 5-3 - Guidelines for Conducting and Evaluating Proposed Plan Application Analyses • **ISO-NE Tariff** – ISO New England Inc. Transmission, Markets, and Services Tariff NUC-001-4 R9 requires the NPGOP and TEs to include a variety of elements within the Agreement(s) (procedures) identified by the NPGOPs and TEs in accordance with R2 that show how the NPIRs are addressed and implemented. Such elements pertain to • Technical requirements and analysis, • Operations and maintenance coordination, • Communications and training Administrative elements. There is at least one mutually-agreed upon procedure (and often there are more) that includes each element specified in R9. However, not every element called for in R9 is contained in every mutually-agreed upon procedure identified by the NPGOPs and TEs as one that demonstrates how NPIRs are addressed and implemented. Each TE and NPGOP maintains an internal "mapping" document that summarizes how each Requirement of NUC-001-4 is met (referencing applicable agreed-upon procedures, etc.). Finally, in accordance with agreed-upon procedures, NPGOPs and TEs take appropriate actions to meet NPIRs. If system conditions or other factors impact the ability to meet the

CEICG-22	*The nature of Agreements, including NPIRs, pertaining to NUC-001-4 ensure compliance within the ISO-NE Reliability Coordinator Area (RCA).*
	NPIRs, the NPGOPs and TEs have procedures that can be implemented for communications to be made and corrective actions to be taken to address the inability to meet the NPIRs. **Agreements (procedures) that document how NPIRs are reviewed and approved:** The NPIRs in Section 10, Table 1 of M/LCC 1 Attachments C and D are those that have been agreed-upon between NPGOPs and TOPs, TOs or TPs through a review and approval process described in M/LCC 1 (See especially Section 4 – Periodic Review, Update and Approval of M/LCC 1 and Attachments) . The highlights of this process are as follows: • For any modification to M/LCC 1 or an M/LCC 1 Attachment to become effective, it shall be reviewed and approved by the applicable M/LCC1 Parties (as listed in Table A of M/LCC 1 Nuclear Plant Transmission Operations) in accordance with Section 4 of M/LCC1. Approval of M/LCC 1, Attachment C – Millstone Nuclear Power Station (Att. C) or Attachment D – Seabrook Nuclear Power Station (Att. D) constitutes Agreement by the applicable M/LCC 1 Parties to the applicable NPIRs in Section 10, Table 1 of such Attachment. Documentation of such approval is through: • Internal review of the M/LCC 1 document revision by ISO, as well as the review and approval of the revision by the M/LCC Heads, in accordance with ISO SOP-RTMKTS.0210.0010 - Develop, Revise & Control SOP, OP, M/LCC Documents. • Final review and approval of the M/LCC 1 document revision by the M/LCC 1 Parties (e-mail process – M/LCC 1 Section 4 Periodic Review, Update and Approval of M/LCC 1 and Attachments) • Document finalization and posting process in accordance with ISO-NE SOP-RTMKTS.0210.0010 – Develop, Revise & Control SOP, OP, M/LCC Documents • Revision History section of the respective M/LCC 1 Attachments C and D documents. • Development and retention of documentation of the approval of the M/LCC 1 document by completing Table A of M/LCC 1 and storing it, along with the associated document final approval emails from M/LCC 1 Parties • Notification to M/LCC 1 Parties by email that the revised M/LCC 1 document has been approved by the M/LCC 1 Parties and has been posted • Notification to ISO-NE System Planning that the M/LCC 1 document has been revised and posted • Transmittal by the ISO-NE Outage Coordination staff to the ISO-NE Reliability and Operations Compliance (ROC) Analyst for archiving as RSAW evidence in the Corporate Compliance Program (CCP) SharePoint

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

CEICG-23	***ISO-NE serves as the "Lead" Transmission Planner (TP) within the ISO-NE Reliability Coordinator Area (RCA) and is the sole TP within the ISO-NE RCA responsible for maintaining models in accordance with MOD-026-1 and MOD-027-1 Standard Requirements. Generator Owner (GO) interactions with the TP pertaining to these Standards should always take place with ISO-NE.***
NERC Standard	**MOD-026-1** **Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions**
Applicable Requirement(s)	**CEICG pertains to *all* Requirements of Standard MOD-026-1** Purpose: To verify that the generator excitation control system or plant volt/var control function model (including the power system stabilizer model and the impedance compensator model) and the model parameters used in dynamic simulations accurately represent the generator excitation control system or plant volt/var control function behavior when assessing Bulk Electric System (BES) reliability.
NERC Standard	**MOD-027-1** **Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions**
Applicable Requirement(s)	**CEICG pertains to all Requirements of Standard MOD-027-1** Purpose: To verify that the turbine/governor and load control or active power/frequency control model and the model parameters, used in dynamic simulations that assess Bulk Electric System (BES) reliability, accurately represent generator unit real power response to system frequency variations.
Applicable Functional Entities	**Generator Owner, Transmission Planner**
ISO-NE Disposition: MOD-026-1, *All* MOD-027-1, *All*	Explanation of how ISO-NE is the T**ransmission Planner (TP)** within the ISO-NE Planning Coordinator Area (PCA) with which Generator Owners (GOs) should interact While ISO-NE and seven other entities within the ISO-NE PCA are each registered as a TP, ISO-NE serves as the "Lead" TP for New England and maintains models in accordance with MOD-026 and MOD-027. ISO-NE is the sole TP in New England responsible for meeting all TP Requirements of MOD-026-1, including maintaining models to assess New England Bulk Electric System (BES) reliability and providing information to GOs. For matters pertaining to MOD-026-1 and MOD-027-1 requiring interaction with a TP, GOs should contact ISO-NE and/or provide information to ISO-NE. GOs can contact ISO-NE Participant Support & Solutions by emailing: AskISO@iso-ne.com for instructions on how to obtain and/or provide model information. ISO-NE Participant Support & Solutions contact information is also posted to the ISO-NE public website.

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

<table>
<tr><td>CEICG-24</td><td>Based on the Dynamic Disturbance Recorder (DDR) capability requirements that ISO-NE has established and specified for the ISO-NE Reliability Coordinator Area (RCA), ISO-NE has notified certain Transmission Owners (TOs) that certain of their Bulk Electric System (BES) elements require DDR data.</td></tr>
<tr><td>NERC Standard</td><td>PRC-002-4
Disturbance Monitoring and Reporting Requirements</td></tr>
<tr><td rowspan="2">Applicable Requirement(s)</td><td>R5. Each Reliability Coordinator shall:
5.1 Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:
5.1.1 Generating resource(s) with:
5.1.1.1 Gross individual nameplate rating greater than or equal to 500 MVA.
5.1.1.2 Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.
5.1.2 Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).
5.1.3 Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.
5.1.4 One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).
5.1.5 Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.
5.2 Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:
5.2.1 One BES Element; and
5.2.2 One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand.
5.3 Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data.
5.4 Re-evaluate all BES Elements under its purview at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3.</td></tr>
<tr><td>R8. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, triggered records must meet the following:
8.1 Triggered record lengths of at least three minutes.
8.2 At least one of the following three triggers:

• Off nominal frequency trigger set at:
<table>
<tr><td></td><td>Low</td><td>High</td></tr>
<tr><td>Eastern Interconnection</td><td><59.75 Hz</td><td>>61.0 Hz</td></tr>
<tr><td>Western Interconnection</td><td><59.55 Hz</td><td>>61.0 Hz</td></tr>
<tr><td>ERCOT Interconnection</td><td><59.35 Hz</td><td>>61.0 Hz</td></tr>
<tr><td>Hydro-Quebec Interconnection</td><td><58.55 Hz</td><td>>61.5 Hz</td></tr>
</table></td></tr>
</table>

CEICG-24	***Based on the Dynamic Disturbance Recorder (DDR) capability requirements that ISO-NE has established and specified for the ISO-NE Reliability Coordinator Area (RCA), ISO-NE has notified certain Transmission Owners (TOs) that certain of their Bulk Electric System (BES) elements require DDR data.***
	• Rate of change of frequency trigger set at: | | Low | High | Eastern Interconnection: < -0.03125 Hz/sec; > 0.125 Hz/sec Western Interconnection: < -0.05625 Hz/sec; > 0.125 Hz/sec ERCOT Interconnection: < -0.08125 Hz/sec; > 0.125 Hz/sec Hydro-Quebec Interconnection: < -0.18125 Hz/sec; > 0.1875 Hz/sec • Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.
Applicable Functional Entities	**Reliability Coordinator, Generator Owner, Transmission Owner**
ISO-NE Disposition: PRC-002-4, R5, R8	**<u>Identification of the entities that ISO-NE has requested to install</u> Dynamic Disturbance Recorder <u>(DDR) equipment.</u>** ISO-NE, as the Planning Coordinator (PC)/(Planning Authority (PA)) in New England, has identified Bulk Electric System (BES) elements for which Dynamic Disturbance Recording (DDR) data are required, in accordance with PRC-002-4 R5. The entities for which ISO-NE has specified DDR capability requirements are all Transmission Owners (TOs). ISO-NE's DDR capability requirements do not include any Generator Owners (GOs) or other registered entities. ISO-NE has notified applicable TOs of identified BES elements, of which BES elements require DDR data. **Note:** in accordance with the "Rationale" for PRC-002-4 R5, for an interconnection between a TO and a GO, ISO-NE has determined that the TOs will provide the data. The following is the list of TOs for which ISO-NE has specified DDR capability requirements and that have been notified: • AVANGRID o Central Maine Power Company o United Illuminating Company • Eversource Energy • National Grid USA (NGRID) • New Hampshire Transmission, LLC (NHT) • Town of Wallingford Department of Utilities • Vermont Transco LLC (VELCO) • Versant Power (EMERA-ME) • Rhode Island Energy (RIE a PPL subsidiary)

CEICG-24	***Based on the Dynamic Disturbance Recorder (DDR) capability requirements that ISO-NE has established and specified for the ISO-NE Reliability Coordinator Area (RCA), ISO-NE has notified certain Transmission Owners (TOs) that certain of their Bulk Electric System (BES) elements require DDR data.***
	These TOs are the only entities within the ISO-NE Planning Coordinator Area (PCA) for which ISO-NE has specified DDR capability requirements and they are the only entities within the ISO-NE Reliability Coordinator Area (RCA) that must comply with PRC-002-4 R8 and other applicable PRC-002-4 Requirements. If there are any changes to ISO-NE’s DDR capability requirements, ISO-NE would notify the applicable entities and update this list, as necessary.

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

CEICG-26	***The ISO-NE Underfrequency Load Shedding (UFLS) program does not require a Transmission Owner (TO) to provide automatic switching of its existing capacitor banks, transmission lines, and reactors to control over-voltage in support of UFLS.***
NERC Standard	**PRC-006-5** **Automatic Underfrequency Load Shedding**
Applicable Requirement(s)	**R10**. Each **Transmission Owner** shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the **Planning Coordinator**(s) in each **Planning Coordinator** area in which the **Transmission Owner** owns transmission.
Applicable Functional Entities	**Planning Authority / Planning Coordinator, Transmission Owner**
ISO-NE Disposition: PRC-006-5, R10	<u>Explanation of how ISO-NE's UFLS program does not require Transmission Owners (TOs) to provide automatic switching of any of its equipment.</u> As the Planning Authority (PA) / Planning Coordinator (PC) in New England, ISO-NE has developed an underfrequency load shedding (UFLS) program in accordance with the Requirements of PRC-006-5 and NPCC Regional Reliability Reference Directory #12 - Underfrequency Load Shedding Program Requirements. The ISO-NE UFLS program is described in ISO New England Operating Procedure No. 13, Standards for Voltage Reduction and Load Shedding Capability (OP-13) and OP-13 Appendices. As part of ISO-NE's UFLS program, ISO-NE provides notification of and a schedule for the implementation by UFLS entities within its area in the following documents: • ISO New England Operating Procedure No. 13 - Standards for Voltage Reduction and Load Shedding Capability • OP-13 Appendix B - Underfrequency Load Shedding Program Requirements (OP-13B) As explained in OP-13B, the ISO-NE UFLS program does not require any TOs to provide automatic switching of their existing capacitor banks, transmission lines, and reactors to control over-voltage as a result of underfrequency load shedding. Therefore, TOs within the ISO-NE Reliability Coordinator Area (RCA) do not need to provide automatic switching for such equipment.

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

CEICG-27	***ISO-NE has identified circuits in its Planning Authority / Planning Coordinator (PA/PC) area for which Transmission Owners (TOs), Generator Owners (GOs), and Distribution Providers (DPs) must comply with PRC-023-6 Requirements R1 through R5 and provides the list of these circuits to the respective owners of those facilities and to NPCC.***
NERC Standard	**PRC-023-6** **Transmission Relay Loadability**
Applicable Requirement(s)	**R6**. Each **Planning Coordinator** shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-6, Attachment B (Circuits to Evaluate / Criteria) to determine the circuits in its **Planning Coordinator** area for which **Transmission Owner**s, **Generator Owner**s, and **Distribution Provider**s must comply with Requirements R1 through R5. The **Planning Coordinator** shall: **6.1**. Maintain a list of circuits subject to PRC-023-6 per application of Attachment B (Circuits to Evaluate / Criteria), including identification of the first calendar year in which any criterion in PRC-023-6, Attachment B (Circuits to Evaluate / Criteria) applies. **6.2**. Provide the list of circuits to all Regional Entities, **Reliability Coordinators**, **Transmission Owners**, **Generator Owners**, and **Distribution Providers** within its **Planning Coordinator** area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list. ***Refer to PRC-023-6 Reliability Standard for Requirements R1-R5 stated above.***
Applicable Functional Entities	**Distribution Provider, Generator Owner, Planning Authority / Planning Coordinator, Reliability Coordinator, Transmission Owner**
ISO-NE Disposition: PRC-023-6, R6	Explanation of how ISO-NE has identified circuits in its Planning Coordinator (PC) area for which Transmission Owners (TOs), Generator Owners (GOs), and Distribution Providers (DPs) must comply with PRC-023-6 Requirements R1 through R5 and provides the list of these circuits to the respective owners of those facilities and to NPCC. As required by PRC-023-6 R6, ISO-NE conducts an annual assessment to determine the circuits in its Planning Coordinator Area (PCA) for which TOs, GOs and DPs must comply with PRC-023-6 R1 through R5. The annual assessment is conducted with respect to circuit terminals to prevent phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System (BES) for all fault conditions. As required by PRC-023-6 R6, Part 6.1, ISO-NE maintains a list of these identified circuits. An assigned ISO-NE *Reliability & Operations Compliance* Analyst provides this list of circuits to NPCC (NPCCCI@npcc.org) and to the respective TOs, GOs and DPs that own circuits on that list, in accordance with PRC-023-6 R6, Part 6.2. The latest list of circuits developed by ISO-NE and sent to TOs, GOs, DPs and NPCC includes the following TOs, GOs and DPs that own the applicable terminals of these circuits and that must comply with PRC-023-6 R1 through R5:

TOs, GOs and DPs that Received Notifications from ISO-NE and that Must Comply with PRC-023-6 R1-R5	Date of Most Recent ISO-NE Notification to Owner

<table>
<tr><td>CEICG-27</td><td>ISO-NE has identified circuits in its Planning Authority / Planning Coordinator (PA/PC) area for which Transmission Owners (TOs), Generator Owners (GOs), and Distribution Providers (DPs) must comply with PRC-023-6 Requirements R1 through R5 and provides the list of these circuits to the respective owners of those facilities and to NPCC.</td></tr>
<tr><td></td><td>
<table>
<tr><td>AVANGRID, Inc. (Avangrid) (TO)
• Central Maine Power Company (CMP),
• United Illuminating Company (UI)</td><td>8/8/23</td></tr>
<tr><td>Eversource Energy Services Company (Eversource) (TO)</td><td>8/8/23</td></tr>
<tr><td>Fitchburg Gas and Electric Light Company, Inc. (FG&E) (DP)</td><td>8/8/23</td></tr>
<tr><td>National Grid USA (NGRID) (TO)</td><td>8/8/23</td></tr>
<tr><td>Reading Municipal Light Department (Reading) (DP)</td><td>8/8/23</td></tr>
<tr><td>Vermont Electric Power Company, Inc. (VELCO) (TO)</td><td>8/8/23</td></tr>
<tr><td>Versant Power (TO)</td><td>8/8/23</td></tr>
<tr><td>Wallingford Electric Division (Wallingford) (DP)</td><td>8/8/23</td></tr>
<tr><td>Rhode Island Energy (RIE a PPL subsidiary)</td><td>8/8/23</td></tr>
</table>

If and when this list changes, ISO-NE would notify NPCC and the applicable TOs, GOs or DPs within 30 days and would reflect these changes in the next revision of this CEICG.</td></tr>
</table>

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

CEICG-28	***ISO-NE serves as the Planning Authority / Planning Coordinator (PA/ PC) and "Lead" Transmission Planner (TP) for the ISO-NE PC Area and maintains models for all TPs within the ISO-NE PC Area***
NERC Standard	**TPL-001-5.1** **Transmission System Planning Performance Requirements**
Applicable Requirement(s)	**R1.** Each **Transmission Planner** and **Planning Coordinator** shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1 (Steady State & Stability Performance Planning Events) **1.1.** System models shall represent: **1.1.1.** Existing Facilities **1.1.2.** New planned Facilities and changes to existing Facilities **1.1.3.** Real and reactive Load forecasts **1.1.4.** Known commitments for Firm Transmission Service and Interchange **1.1.5.** Resources (supply or demand side) required for Load
Applicable Functional Entities	**Planning Authority / Planning Coordinator, Transmission Planner**
ISO-NE Disposition: TPL-001-5.1, R1	<u>Explanation of how ISO-NE maintains the System models used by all Transmission Planners (TPs) within the ISO-NE Planning Coordinator Area (PCA) to conduct Planning Assessments</u> ISO-NE serves as the Planning Coordinator (PC) and "Lead" TP for the ISO-NE PCA. As the "Lead" TP, ISO-NE maintains the System models for the ISO-NE transmission system, in accordance with <u>TPL-001-5.1 R1</u>. ISO-NE and all other TPs within the ISO-NE PCA use these System models for performing the studies needed to complete their respective Planning Assessments.

CEICG-29	***Interpersonal Communication capabilities and protocols in New England***
NERC Standard	**COM-001-3** **Communications**
Applicable Requirement(s)	**R3.** Each **Transmission Operator** shall have Interpersonal Communication capability with the following entities (unless the **Transmission Operator** detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): …**3.3.** Each **Distribution Provider** within its **Transmission Operator** Area. **3.4.** Each **Generator Operator** within its **Transmission Operator** Area. **3.5.** Each adjacent **Transmission Operator** synchronously connected. **R4.** Each **Transmission Operator** shall designate an Alternative Interpersonal Communication capability with the following entities: …**4.3.** Each adjacent **Transmission Operator** synchronously connected. **R5.** Each **Balancing Authority** shall have Interpersonal Communication capability with the following entities (unless the **Balancing Authority** detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): …**5.3.** Each **Distribution Provider** within its **Balancing Authority** Area. **R7.** Each **Distribution Provider** shall have Interpersonal Communication capability with the following entities (unless the **Distribution Provider** detects a failure of its Interpersonal Communication capability in which case Requirement R11 shall apply): **7.1.** Its **Balancing Authority**. **7.2.** Its **Transmission Operator**. **R8.** Each **Generator Operator** shall have Interpersonal Communication capability with the following entities (unless the **Generator Operator** detects a failure of its Interpersonal Communication capability in which case Requirement R11 shall apply): …**8.2.** Its **Transmission Operator**. **R10.** Each **Reliability Coordinator**, **Transmission Operator**, and **Balancing Authority** shall notify entities as identified in Requirements R1, R3, and R5, respectively within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasts 30 minutes or longer. ***R1 noted below due to reference in R10*** (**R1**. Each **Reliability Coordinator** shall have Interpersonal Communication capability with the following entities (unless the **Reliability Coordinator** detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): **1.1**. All **Transmission Operators** and **Balancing Authorities** within its **Reliability Coordinator** Area. **1.2.** Each adjacent **Reliability Coordinator** within the same Interconnection.) **R11.** Each **Distribution Provider** and **Generator Operator** that detects a failure of its Interpersonal Communication capability shall consult each entity affected by the failure,

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

CEICG-29	*Interpersonal Communication capabilities and protocols in New England*
	as identified in Requirement R7 for a **Distribution Provider** or Requirement R8 for a **Generator Operator**, to determine a mutually agreeable action for the restoration of its Interpersonal Communication capability.
NERC Standard	**IRO-001-4** **Reliability Coordination - Responsibilities**
Applicable Requirement(s)	**R2**. Each **Transmission Operator**, **Balancing Authority**, **Generator Operator**, and **Distribution Provider** shall comply with its **Reliability Coordinator**'s Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. **R3.** Each **Transmission Operator**, **Balancing Authority**, **Generator Operator,** and **Distribution Provider** shall inform its **Reliability Coordinator** of its inability to perform the Operating Instruction issued by its **Reliability Coordinator** in Requirement R1. ***R1 noted below due to reference in R3*** (**R1**: Each **Reliability Coordinator** shall act to address the reliability of its **Reliability Coordinator** Area via direct actions or by issuing Operating Instructions.)
NERC Standard	**TOP-001-6** **Transmission Operations**
Applicable Requirement(s)	**R5.** Each **Transmission Operator**, **Generator Operator**, and **Distribution Provider** shall comply with each Operating Instruction issued by its **Balancing Authority**, unless such action cannot be physically implemented or it would violate safety, equipment, regulatory, or statutory requirements. **R6.** Each **Transmission Operator**, **Generator Operator**, and **Distribution Provider** shall inform its **Balancing Authority** of its inability to comply with an Operating Instruction issued by its **Balancing Authority**.
Applicable Functional Entities	**Balancing Authority, Distribution Provider, Generator Operator, Reliability Coordinator, Transmission Operator**
ISO-NE COM-001-3, R3, R4, R5, R7, R8, R10, R11 Disposition:	<u>Explanation of Interpersonal Communication capabilities and protocols in New England</u> COM-001-3 requires the establishment of Interpersonal Communication capabilities to interact, consult, or exchange information, as necessary, to maintain reliability. In New England, ISO-NE and the Local Control Centers (LCCs) comply with applicable NERC Standards in accordance with established, FERC approved documents, such as the Transmission Operating Agreement (TOA) (See Sections 3.05 The ISO's Responsibilities and 3.06 Each PTO's (Participating Transmission Owners) Responsibilities) and ISO-NE Operating Procedures. In accordance with such documents, Operating Instructions or directives may be issued:

<table>
<tr><th>CEICG-29</th><th>Interpersonal Communication capabilities and protocols in New England</th></tr>
<tr><td></td><td>

- To a Generator Operator (GOP) by <u>either</u> ISO-NE (which is the typical situation) or, in some cases, by an LCC (Local Control Center / Transmission Operator (TOP))
- To a Distribution Provider (DP) by an LCC (**not** by ISO-NE).

The following table clarifies and summarizes how certain Requirements of COM-001-3 are met with respect to Interpersonal Communications Capabilities (ICC) in New England.

<table>
<tr><th>Req.</th><th>Part(s)</th><th>ICC</th><th>ISO-NE</th><th>LCC</th><th>Notes</th></tr>
<tr><td>R3
R7
R10
R11</td><td>3.3
7.2</td><td>TOP-DP</td><td>No</td><td>Yes</td><td>DPs communicate with their LCC (not with ISO-NE)</td></tr>
<tr><td>R3
R8
R10
R11</td><td>3.4
8.2</td><td>TOP-GOP</td><td>Yes</td><td>Yes</td><td>GOPs communicate with <u>both</u> ISO-NE and their LCC</td></tr>
<tr><td>R3
R4
R10</td><td>3.5 & 3.6
4.3 & 4.4</td><td>TOP-adjacent TOP</td><td>Yes</td><td>Yes</td><td>ISO-NE and each LCC communicate with all of their respective adjacent TOPs, with <u>one exception</u>: ISO-NE only communicates with TOPs in adjacent areas that are also RCs/BAs (e.g., ISO-NE does not communicate with National Grid Niagara Mohawk (NIMO), a registered TOP in NY)</td></tr>
<tr><td>R5
R7
R10
R11</td><td>5.3
7.1</td><td>RC/BA-DP</td><td>No</td><td>No</td><td>In New England, there are no communications between ISO-NE (as the BA or as any other function for which ISO-NE has registered) and a DP. Communications with a DP, which are pertinent to the TOP function, are always between the DP and that DP’s LCC (see TOP-DP ICC described above).</td></tr>
</table>

Also, certain aspects of other NERC Standard Requirements, which pertain to issuance of Operating Instructions by ISO-NE to DPs, do not apply within the ISO- NE RCA because

</td></tr>
</table>

CEICG-29	*Interpersonal Communication capabilities and protocols in New England*
	LCCs (not ISO-NE) communicate with DPs, so there would never be an Operating Instruction issued by ISO-NE to a DP [IRO-001-4 R2, R3 and TOP-001-6, R5 and R6].

<table>
<tr><td>CEICG-30</td><td>ISO-NE notifications to entities regarding its identification of assets within certain categories of facilities identified in the Critical Infrastructure Protection (CIP) Standards as impactive to reliability</td></tr>
<tr><td>NERC Standard</td><td>CIP-002-5.1a
Cyber Security — BES Cyber System Categorization</td></tr>
<tr><td>Applicable Requirement(s)</td><td>R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:
i. Control Centers and backup Control Centers;
ii. Transmission stations and substations;
iii. Generation resources;
iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and
vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
…1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

CIP-002-5.1a - Attachment 1 - Impact Rating Criteria
… 2. Medium Impact Rating (M)
Each BES Cyber System, not included in Section 1 above (High Impact Rating (H)), associated with any of the following:
… 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.
… 2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
… 2.9. Each Special Protection System (SPS), Remedial Action Scheme (RAS), or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable. … 3. Low Impact Rating (L)

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:
… 3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.</td></tr>
</table>

CEICG-30	***ISO-NE notifications to entities regarding its identification of assets within certain categories of facilities identified in the Critical Infrastructure Protection (CIP) Standards as impactive to reliability***
NERC Standard	**CIP-014-3** **Physical Security**
Applicable Requirement(s)	**R1.** Each **Transmission Owner** shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. **1.1.** Subsequent risk assessments shall be performed: • At least once every 30 calendar months for a **Transmission Owner** that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection; or • At least once every 60 calendar months for a **Transmission Owner** that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection. **1.2.** The **Transmission Owner** shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.
Applicable Functional Entities	**For CIP-002-5.1a,** **Various Functional Entities, as specified in the Section 4. “Applicability” of the Standard** **For CIP-014-3, Applicability** **4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.**
ISO-NE Disposition: CIP-002-5.1a, R1	<u>Explanation of how ISO-NE identifies assets within certain categories of facilities identified in the CIP Standards as impactive to reliability and notifies entities of the assets identified.</u> Entities need certain information in order to identify and categorize BES Cyber Systems and their associated BES Cyber Assets in accordance with CIP-002-5.1a R1. ISO-NE identifies assets within certain categories of facilities identified in CIP-002-5.1a - Attachment 1 - Impact Rating Criteria as impactive to reliability and notifies entities of the assets identified. The following information is provided below:

CEICG-30	***ISO-NE notifications to entities regarding its identification of assets within certain categories of facilities identified in the Critical Infrastructure Protection (CIP) Standards as impactive to reliability***
	- Identification of the types of facilities and systems that ISO-NE has identified that meet certain criteria in CIP-002-5.1a - Attachment 1 - Impact Rating Criteria - Descriptions of how ISO-NE identifies assets that meet these criteria - Lists of the names of the Lead Market Participants (for generation) or owners (for transmission) that are responsible for the assets and that received notifications from ISO-NE of which asset(s) ISO-NE identified as meeting one or more of the criteria in CIP-002-5.1a - Attachment 1 - Impact Rating Criteria. **Criterion 2.3** – Each generation Facility that its **Planning Coordinator** or **Transmission Planner** designates, and informs the **Generator Owner** or **Generator Operator**, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year. (Facilities necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more) **Criterion 2.6** – Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its **Reliability Coordinator**, **Planning Coordinator**, or **Transmission Planner** as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies. (BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-3, Establish and Communicate System Operating Limits, R5.1.1 and R5.1.3.) **Criterion 2.9** – Each Special Protection System (SPS), Remedial Action Scheme (RAS), or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable. (BES Cyber Systems for those Special Protection Systems (SPS), Remedial Action Schemes (RAS), Automatic Control Schemes (ACS) or automated switching systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed.) The term Remedial Action Scheme (RAS) and its definition has been adopted by NPCC in place of the term Special Protection System (SPS). For existing documentation, the terms Remedial Action Scheme (RAS) or Special Protection System (SPS) may be used until such time as the terminology is changed by the **Transmission Owner** on equipment and schematics used in operations and in the field. However, a subset of SPSs were not recognized as RAS and instead became Automatic Control Schemes (ACS) The Guidelines and Technical Basis for CIP-014-3 – Physical Security links CIP-002-5.1a and CIP-014-3 by stating:

CEICG-30	***ISO-NE notifications to entities regarding its identification of assets within certain categories of facilities identified in the Critical Infrastructure Protection (CIP) Standards as impactive to reliability***
	The Standard Drafting Team (SDT) considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security (i.e., those that could cause instability, uncontrolled separation, or Cascading within an Interconnection). The SDT determined that using the **criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1(a)** would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in **Requirement R1 of CIP-014(-3)**. Additionally, the SDT concluded that using the **CIP-002-5.1(a) Medium Impact criteria** was appropriate because it has been approved by stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which **Transmission Owners** should conduct the risk assessment. As described in **CIP-002-5.1(a)**, the failure of a Transmission station or Transmission substation that meets the **Medium Impact criteria** could have the capability to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). The SDT understands that using this bright line criteria to determine applicability may require some **Transmission Owners** to perform risk assessments under **Requirement R1** that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for **Medium Impact Facilities** can be found in the **Guidelines and Technical Basis section of CIP-002-5.1(a)**. ISO-NE identifies IROLs, in accordance with applicable NERC Standards. As part of this effort, ISO-NE identifies which facilities or systems are considered critical to the derivation of IROLs and their associated contingencies. ISO-NE has developed a methodology and criteria for identifying IROLs in accordance with FAC-010-3 — System Operating Limits Methodology for the Planning Horizon and FAC-011-4 — System Operating Limits Methodology for the Operations Horizon. As part of this effort, ISO-NE designated the facilities or systems that were considered critical to

CEICG-30	***ISO-NE notifications to entities regarding its identification of assets within certain categories of facilities identified in the Critical Infrastructure Protection (CIP) Standards as impactive to reliability***
	the derivation of IROLs and their associated contingencies. CIP-002-5.1a includes Attachment 1, Impact Rating Criteria. The Medium Impact Rating Criteria includes the two criteria that were part of the basis for ISO-NE's list of facilities: • Applying Criterion 2.6 led to the inclusion of not only the IROL transmission elements themselves, but also the limiting contingencies that ISO-NE monitors in Real-Time for thermal or voltage (or as otherwise noted in ISO-NEs Transmission Operating Guides). • Applying Criterion 2.9 led to the inclusion of a small number of substations based upon Type 1 SRAS/ACS in New England included on the NPCC RAS/ACS list. Once each calendar year, ISO-NE notifies the owners (for transmission) or Lead Market Participants (for generation) of facilities or systems that meet one or more of the criteria 2.3, 2.6 and 2.9 to inform them of which facilities or systems meet one or more of the criteria. If ISO-NE determines that a facility that once met the criteria no longer meets the criteria, ISO-NE notifies that entity within 30 days of that determination and reflects the revised list of entities below in the next update of this CEICG document, as necessary. An entity listed below would be expected to provide notification(s) received from ISO-NE as evidence supporting their compliance with CIP Standards during an NPCC audit. The following is a list of entities that have received notifications from ISO-NE that one or more of their facilities or systems meets one or more of the criteria 2.3, 2.9: **Transmission facilities (2023 notification):** • ANP Bellingham • AVANGRID [Central Maine Power Company, • United Illuminating Company] • Connecticut Transmission Municipal Electric Energy Cooperative • Cross-Sound Cable Company, LLC • Eversource Energy [The Connecticut Light and Power Company, • NSTAR, Public Service Company of New Hampshire] • National Grid USA (NGRID) • New Hampshire Transmission, LLC • Rhode Island Energy • Vermont Transco LLC • Versant Power **Generation facilities (2023 notification):**

GEN_ID	GEN_NAME
47390	BUCKSPORT
365	CANAL 1

CEICG-30	***ISO-NE notifications to entities regarding its identification of assets within certain categories of facilities identified in the Critical Infrastructure Protection (CIP) Standards as impactive to reliability***

366	CANAL2
38310	CANAL 3
1649	EP NEWINGTON ENERGY, LLC
359	J. COCKWELL 1
360	J. COCKWELL 2
14614	KLEEN ENERGY
40338	MAINE INDEPENDENCE STATION 1
40339	MAINE INDEPENDENCE STATION 2
12505	MIDDLETOWN 12
37366	MIDDLETOWN 13
37367	MIDDLETOWN 14
37368	MIDDLETOWN 15
482	MIDDLETOWN 4
484	MILLSTONE POINT 2
485	MILLSTONE POINT 3
513	NEW HAVEN HARBOR
15477	NEW HAVEN HARBOR UNIT 2
40052	NEW HAVEN HARBOR UNIT 3
40053	NEW HAVEN HARBOR UNIT 4
508	NEWINGTON 1
14217	NORTHFIELD MOUNTAIN 1
14218	NORTHFIELD MOUNTAIN 2
14219	NORTHFIELD MOUNTAIN 3
14220	NORTHFIELD MOUNTAIN 4
555	SEABROOK
14177	WESTBROOK ENERGY CENTER G1
14178	WESTBROOK ENERGY CENTER G2
642	YARMOUTH 4

Criterion 2.7 – Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements

The Transmission Facilities essential to meeting Nuclear Plant Interface

CEICG-30	***ISO-NE notifications to entities regarding its identification of assets within certain categories of facilities identified in the Critical Infrastructure Protection (CIP) Standards as impactive to reliability***
	Requirements (NPIRs) in New England are the transmission lines serving the offsite AC power sources to the nuclear power stations in New England. These transmission lines serving the off-site ac power sources are identified in the following confidential documents: • Master/LCC Procedure No. 1 - Nuclear Plant Transmission Operations, Attachment C - Millstone Nuclear Power Station • Master/LCC Procedure No. 1 - Nuclear Plant Transmission Operations, Attachment D - Seabrook Nuclear Power Station The following entities own one or more transmission lines serving the off-site ac power sources to the nuclear power stations in New England: • Eversource Energy Service Company (The Connecticut Light and Power Company (CL&P)) • New Hampshire Transmission, LLC (NH Transmission) • Eversource Energy Service Company (New Hampshire; Eversource/Public Service Company of New Hampshire (PSNH)) These entities review and approve the M/LCC 1 documents listed above that contain the NPIRs applicable to them and that list the transmission lines serving the off-site ac power sources. These entities are expected to provide the applicable M/LCC 1 Attachment listed above as evidence supporting their compliance with CIP Standards during an NPCC audit. **Criterion 3.4** – Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements. (Facilities critical to system restoration) Lead Market Participants (Lead MPs) or owners of facilities identified in the New England System Restoration Plan (the Plan) may use information provided by ISO-NE to identify and categorize BES Cyber Systems and their associated BES Cyber Assets. ISO-NE, in collaboration with the Local Control Centers (LCCs), has developed the Plan in accordance with EOP-005 — System Restoration from Blackstart Resources and EOP-006 — System Restoration Coordination. As part of the development of the Plan (and in accordance with M/LCC 11 - Maintenance and Verification of New England System Restoration Plan), ISO-NE develops and maintains a list of facilities in the Plan: M/LCC11-Attachment D New England System Restoration Plan Resources List (M/LCC11D). In accordance with EOP-005 R2, ISO-NE provides the Lead MPs or owners of Plan facilities with a description of any changes to their roles and specific tasks. These notifications include a list of their facilities identified in the Plan and the classifications of the facilities (such as Designated Blackstart Resource (DBR), Initial Cranking Path Facility (ICPF), etc.). Entities will use this information to make the appropriate designations of "critical" facilities for their CIP evaluations. The most recent notifications to all entities in the Plan occurred in the 4th quarter of 2016. All future notifications are by exception, as

CEICG-30	***ISO-NE notifications to entities regarding its identification of assets within certain categories of facilities identified in the Critical Infrastructure Protection (CIP) Standards as impactive to reliability***
	needed, when there are changes to the Plan and are documented in M/LCC11D. Whenever ISO-NE updates its list of restoration plan facilities, ISO-NE submits an M/LCC11D document to NPCC (to email address NPCCCI@npcc.org). [Note: the information in this CEICG is current as of 07/01/2024. ISO-NE annually reviews the lists of facilities and systems that meet the CIP-002-5.1a criteria described in this CEICG, and updates these lists, as necessary. Soon after this annual review and update of these lists is completed, ISO-NE notifies entities affected by changes to each list and updates this CEICG, as necessary.]

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

CEICG-31	***ISO-NE notifies Transmission Owners (TOs) if any of their transmission lines operated below 200 kV are identified by ISO-NE as an element of an Interconnection Reliability Operating Limit (IROL) under FAC-014 Requirements.***
NERC Standard	**FAC-003-5** **Transmission Vegetation Management**
Applicable Requirement(s)	**CEICG pertains to *all* Requirements of Standard FAC-003-5.** Purpose: To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.
Applicable Functional Entities	**Transmission Owner** Note: Applicability of FAC-003-5 includes: **4.2 Transmission Facilities:** Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities: **4.2.2** Each overhead transmission line operated below 200 kV, identified by the **Planning Coordinator** or **Transmission Planner**, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event. [1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."* **Generator Owner** Note: Applicability of FAC-003-4 includes: **4.3. Generation Facilities:** Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[2], state, provincial, public, private, or tribal entities: **4.3.1.** Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a **Transmission Owner**'s Facility or (2) do not have a clear line of sight[3] from the generating station switchyard fence to the point of interconnection with a **Transmission Owner**'s Facility and are: **4.3.1.2** Operated below 200 kV identified as an element of an IROL under NERC Standard FAC-014 by the **Planning Coordinator** [2] *Id.* [3] "Clear line of sight" means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.
ISO-NE Disposition: FAC-003-5,	Explanation of ISO-NE's process of identifying generation facilities and transmission lines operated below 200 kV that are an element of an IROL under FAC-014 "Establish

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

CEICG-31	***ISO-NE notifies Transmission Owners (TOs) if any of their transmission lines operated below 200 kV are identified by ISO-NE as an element of an Interconnection Reliability Operating Limit (IROL) under FAC-014 Requirements.***
All	and Communicate System Operating Limits" and notifications to the Transmission Owners (TOs) - owners of such facilities. ISO-NE establishes IROLs in accordance with FAC-014-3, ISO-NE Planning Procedure 3 "Reliability Standards for the New England Area Pool Transmission Facilities" and the ISO New England Available Transfer Capability Implementation Document (ATCID) posted to the Open Access Same-Time Information System (OASIS) under Available Transfer Capability (ATC) Information. The list of facilities developed by ISO-NE for purposes of FAC-003-5 applicability includes all 115 kV, 230 kV and 345 kV elements for all of the New England IROL interfaces monitored by ISO-NE. The FAC-003-4 Standard does not speak to any other type of element to consider (for example, limiting contingencies), and as a consequence, ISO-NE did not include any other facilities (which explains why this list of facilities differs from the list of facilities developed for CIP-002-5.1a and why the associated list of Transmission Owners (TOs) listed in this CEICG-31 differs from the list of TOs listed in CEICG-29). If any transmission line or generation facility operated below 200 kV is identified by ISO-NE as an element of an IROL (based on FAC-003-4 criteria), ISO-NE notifies the owner (for transmission) or Lead Market Participant (for generation) of the facility by email. • ISO-NE has not identified any generation facilities operated below 200 kV that are an element of an IROL • ISO-NE has identified certain transmission lines operated below 200 kV that are an element of an IROL and has notified the following TOs of this: ○ AVANGRID [ME-Central Maine Power Company (CMP), CT-United Illuminating Company (UI)] o Eversource Energy Transmission Ventures, Inc. [The Connecticut Light and Power Company (CL&P), NSTAR Electric Company, Public Service Company of New Hampshire (PSNH)] o National Grid USA o Vermont Transco LLC ○ Versant Power [Note: this list is current as of 07/01/2024 but is subject to change. If additional entities are notified that one or more of their facilities or systems are either being added to or removed from this list, this list will be updated at the next opportunity (typically this document is updated at least annually). An entity listed above would be expected to provide the notification received from ISO-NE as evidence supporting their compliance with FAC-003-5 during an NPCC audit. If entities have questions about this list, they may contact AskISO@iso-ne.com.]

CEICG-32	***ISO-NE after-the-fact notifications to entities regarding its identification of time periods when an Operating Emergency has existed on the Bulk Electric System (BES) in New England***
NERC Standard	**COM-002-4** **Operating Personnel Communications Protocols**
Applicable Requirement(s)	**R5.** Each **Balancing Authority**, **Reliability Coordinator**, and **Transmission Operator** that issues an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: • Confirm the receiver's response if the repeated information is correct (in accordance with Requirement R6). • Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver, or • Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver. **R6.** Each **Balancing Authority**, **Distribution Provider**, **Generator Operator**, and **Transmission Operator** that receives an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: • Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or • Request that the issuer reissue the Operating Instruction. **R7.** Each **Balancing Authority**, **Reliability Coordinator**, and **Transmission Operator** that issues a written or oral single-party to multiple-party burst Operating Instruction during an Emergency shall confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction.
Applicable Functional Entities	**Balancing Authority, Distribution Provider, Generator Operator, Reliability Coordinator, Transmission Operator**
ISO-NE Disposition: COM-002-4, R5, R6, R7	<u>Explanation of ISO-NE identification of periods when an Operating Emergency has existed on the New England Bulk Electric System (BES) and how, after the Operating Emergency has ended, ISO-NE notifies any entity that received an Operating Instruction to mitigate the Operating Emergency, to confirm that the Operating Instruction was issued while an Operating Emergency existed on the New England BES.</u> To reduce the possibility of miscommunication that could lead to action or inaction harmful to BES reliability, COM-002-4 requires that entities follow specified communications protocols when Operating Instructions are issued or received during an Operating Emergency. In New England, an Operating Instruction may be issued by: • ISO-NE to a Transmission Operator (TOP), which in New England, would be one of the Local Control Center (LCC) TOPs, • ISO-NE (the typical situation) or an LCC (much less typical) to a Generator Operator (GOP)

CEICG-32	***ISO-NE after-the-fact notifications to entities regarding its identification of time periods when an Operating Emergency has existed on the Bulk Electric System (BES) in New England***
	• LCC to a Distribution Provider (DP) **ISO-NE after-the-fact notifications to entities that received an Operating Instruction during an Operating Emergency:** As soon as possible after an Operating Emergency has ended and the event has been reviewed, ISO-NE will notify (via email) the Compliance Contact of each entity that received a verbal Operating Instruction issued for the purpose of mitigating the Operating Emergency during the period while the Operating Emergency existed, informing them of the date(s) and time(s) that the Operating Instruction(s) was (were) issued. NPCC will be copied on each of these notifications (NPCCCI@npcc.org). Exceptions: • ISO-NE will **not** make such notifications regarding Operating Instructions for load shedding, as it should be readily apparent to entities that receive a load shed Operating Instruction that it is being issued during an Operating Emergency. • ISO-NE considers an "Operating Instruction issued during an Emergency" (as referenced in COM-002-4) to be limited to an Operating Instruction issued expressly to mitigate an Operating Emergency. • Other operating instructions that may be issued during the period when an Operating Emergency exists that are not related to or issued to address the Operating Emergency are not pertinent to COM-002-4 Requirements R5, R6 or R7, therefore ISO-NE does **not** make notifications regarding such operating instructions. **ISO-NE's criteria for conditions that define an Operating Emergency:** In Master/Local Control Center Procedure No. 13, ISO and LCC Communication Practices (M/LCC 13), ISO-NE and the LCCs have established criteria identifying when an Operating Emergency is considered to exist on the New England BES. These criteria are in alignment with the definition of "Emergency or BES Emergency" in the Glossary of Terms Used in NERC Reliability Standards: "Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System." The following table from M/LCC 13 Section 4.5 ISO and LCC Communications During Operating Emergencies summarizes these criteria:

<table>
<tr><th>CEICG-32</th><th>ISO-NE after-the-fact notifications to entities regarding its identification of time periods when an Operating Emergency has existed on the Bulk Electric System (BES) in New England</th></tr>
<tr><td></td><td>

Point at which Operating Emergency Begins	Point at which Operating Emergency Ends
Any Real-Time exceedance of a thermal or voltage Short Time Emergency IROL	Real-Time IROL exceedance ended
An IROL exceedance [Real Time Contingency Analysis (RTCA) or interface] for period greater than 20 minutes (must resolve in 30 min.)	IROL exceedance ended
OP-4 Action 6 or greater implemented*	The last of implemented OP-4 Actions 6 or greater are cancelled
Load shed Operating Instruction issued	Load shed has mitigated the Operating Emergency.

* If Action 10 or 11 is implemented at a time prior to an actual capacity deficiency or transmission reliability issue or extended beyond an actual capacity deficiency or transmission reliability issue (e.g., extended heatwave), ISO or the applicable LCC is **not** considered to be in an Operating Emergency until the time that the actual capacity deficiency or transmission reliability issue occurs (which will be the point at which the Operating Emergency begins) and will remain in the Operating Emergency until implemented OP-4 Actions 6 or greater are cancelled (which will be the point at which the Operating Emergency ends).
</td></tr>
</table>

CEICG-33	***Describes the process for Generator Owners (GOs) and Transmission Owners (TOs) to submit an outage request to ISO-NE for conducting a verification of real or reactive power capability to meet MOD-025-2 Requirements and to submit the results of such verifications to ISO-NE. ISO-NE serves as the "Lead" Transmission Planner (TP) within the ISO-NE Reliability Coordinator Area (RCA) (and the sole TP to receive such results). (CEICG-33).***
NERC Standard	**MOD-025-2** **Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability**
Applicable Requirement(s)	**R1.** Each **Generator Owner** shall provide its **Transmission Planner** with verification of the Real Power capability of its applicable Facilities as follows: **1.1.** Verify the Real Power capability of its generating units in accordance with Attachment 1. (See Standard MOD-025 Attachment 1 – Verification of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability). **1.2.** Submit a completed Attachment 2 (see Standard MOD-025 Attachment 2 – One-line Diagram, Table, and Summary for Verification Information Reporting) (or a form containing the same information as identified in Attachment 2) to its **Transmission Planner** within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.
	R2. Each **Generator Owner** shall provide its **Transmission Planner** with verification of the Reactive Power capability of its applicable Facilities as follows: **2.1.** Verify, in accordance with Attachment 1 (see Standard MOD-025 Attachment 1 – Verification of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability), (i) the Reactive Power capability of its generating units and (ii) the Reactive Power capability of its synchronous condenser units. **2.2.** Submit a completed Attachment 2 (see Standard MOD-025 Attachment 2 – One-line Diagram, Table, and Summary for Verification Information Reporting) (or a form containing the same information as identified in Attachment 2) to its **Transmission Planner** within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.
	R3. Each **Transmission Owner** shall provide its **Transmission Planner** with verification of the Reactive Power capability of its applicable Facilities as follows: **3.1.** Verify, in accordance with Attachment 1 (see Standard MOD-025 Attachment 1 – Verification of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability), the Reactive Power capability of its synchronous condenser units. **3.2.** Submit a completed Attachment 2 (see Standard MOD-025 Attachment 2 – One-line Diagram, Table, and Summary for Verification Information Reporting) (or a form containing the same information as identified in Attachment 2) to its **Transmission Planner** within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.

CEICG-33	***Describes the process for Generator Owners (GOs) and Transmission Owners (TOs) to submit an outage request to ISO-NE for conducting a verification of real or reactive power capability to meet MOD-025-2 Requirements and to submit the results of such verifications to ISO-NE. ISO-NE serves as the "Lead" Transmission Planner (TP) within the ISO-NE Reliability Coordinator Area (RCA) (and the sole TP to receive such results). (CEICG-33).***
Functional Entities to which Requirement(s) and CEICG Apply	**Generator Owner, Transmission Owner, Transmission Planner**
ISO-NE Disposition: MOD-025-2, *All* R1, R2, R3	Explanation of how **Generator Owners (GOs)** and **Transmission Owners (TOs)** submit an outage request to ISO-NE for conducting a verification of real or reactive power capability to meet MOD-025-2 Requirements and submit the results of such verifications to ISO-NE. ISO-NE serves as the "Lead" **Transmission Planner (TP)** within the ISO-NE **Planning Coordinator** Area (PCA) (and the sole **TP** to receive such results). NERC Standard MOD-025-2 requires GOs and TOs to verify generator real and reactive power capability and synchronous condenser reactive power capability and to report results of such verifications to its TP. While ISO-NE and seven other entities within the ISO-NE PCA are each registered as a TP, ISO-NE serves as the "Lead" TP for New England. Accordingly, all GOs and TOs in the New England PCA submit the results of their MOD-025-2 verifications of generator real and reactive power capability and synchronous condenser reactive power capability, as applicable, to ISO-NE. ISO-NE has forms and procedures for scheduling outages to conduct these verifications and for reporting the results to ISO-NE that can serve to facilitate GO and TO compliance with MOD-025-2 Requirements. GOs and TOs should note that the information contained in this CEICG pertains solely to compliance with MOD-025-2 Requirements and does **not** pertain to the separate ISO-NE requirements for verification of real and reactive power capability contained in ISO New England Operating Procedure No. 23 - Resource Auditing. While information provided in this CEICG is intended to facilitate GO or TO compliance with MOD-025-2, ultimately, the responsibility for meeting and documenting compliance with the MOD-025-2 Standard lies with the GO or applicable TO. ***Scheduling outages to conduct verifications to meet MOD-025-2 Requirements:*** GOs or TOs that want their facility to operate at a predefined schedule for purposes of verifying real or reactive power capability must submit an outage request to ISO-NE in accordance with one of the following procedures, as applicable: • *For Generator Assets:* ISO New England Operating Procedure No. 5 - Resource Maintenance and Outage Scheduling (see "Owner Test Request") • *For synchronous condensers:* ISO New England Operating Procedure No. 3 - Transmission Outage Scheduling For reactive capability verifications, a GO or TO must also complete the ISO New England Operating Procedure No. 23 - Resource Auditing - Appendix H - Reactive Capability Audit

CEICG-33	***Describes the process for Generator Owners (GOs) and Transmission Owners (TOs) to submit an outage request to ISO-NE for conducting a verification of real or reactive power capability to meet MOD-025-2 Requirements and to submit the results of such verifications to ISO-NE. ISO-NE serves as the "Lead" Transmission Planner (TP) within the ISO-NE Reliability Coordinator Area (RCA) (and the sole TP to receive such results). (CEICG-33).***
	Request Form posted on the ISO-NE public website, under ISO Operating Procedures. This form must then be attached to an outage request in the outage scheduling software at least five (5) business days prior to the date of the verification. ***Submitting results of verifications to meet MOD-025-2 Requirements to ISO-NE:*** MOD-025-2 Attachment 2 One-line Diagram, Table, and Summary for Verification Information Reporting is a form listing the verification information required to be documented and submitted. Verification information may be submitted using the Attachment 2 form or other form containing equivalent information. The MOD-025-2 Standard requires submittal of verification information within 90 calendar days of the date when the verification was performed. All MOD-025-2 verification information must be emailed to ISO-NE at the following address: MOD25@iso-ne.com.

CEICG-34	***Identifies ISO-NE as the "Lead" Transmission Planner (TP) for and instructs Generator Owners (GOs) required by PRC-024-3 Requirement R3, Part 3.1 and Requirement R4 to send information to their TP to send that information to ISO-NE (and not to other TPs in New England) (CEICG-34).***
NERC Standard	**PRC-024-3** **Frequency and Voltage Protection Settings for Generating Resources**
Applicable Requirement(s)	**R3.** Each **Generator Owner** shall document each known regulatory or equipment limitation[1] that prevents an applicable generating resource(s) with frequency or voltage protection from meeting the protection setting criteria in Requirements R1 or R2, including (but not limited to) study results, experience from an actual event, or manufacturer's advice. **3.1.** The **Generator Owner** shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its **Planning Coordinator** and **Transmission Planner** within 30 calendar days of any of the following: • Identification of a regulatory or equipment limitation. • Repair of the equipment causing the limitation that removes the limitation. • Replacement of the equipment causing the limitation with equipment that removes the limitation. • Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance. [1] Excludes limitations caused by the setting capability of the frequency, voltage, and volts per hertz protective relays for the generating resource(s). This does not exclude limitations originating in the equipment protected by the relay. This also does not exclude limitations of frequency, voltage, and volts per hertz protection embedded in control systems.
	R4. Each **Generator Owner** shall provide its applicable protection settings associated with Requirements R1 and R2 to the **Planning Coordinator** or **Transmission Planner** that models the associated generating resource(s) within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested settings unless directed by the requesting **Planning Coordinator** or **Transmission Planner** that the reporting of protection setting changes is not required. ***Refer to PRC-024-3 Reliability Standard for Requirements R1-R2 stated above.***
Applicable Functional Entities	**Generator Owner, Planning Authority / Planning Coordinator, Transmission Planner**
ISO-NE Disposition: PRC-024-2, R3, Part 3.1	<u>Explanation of how Generator Owners (GOs) required by PRC-024-3 Requirement R3, Part 3.1 and Requirement R4 to send information to their Transmission Planner (TP) should send that information to ISO-NE only.</u> PRC-024-3 requires that GOs send certain information pertaining to generator protection settings to their TP according to certain criteria and within specific timeframes specified in the Standard. This includes information pertaining to:

CEICG-34	***Identifies ISO-NE as the "Lead" Transmission Planner (TP) for and instructs Generator Owners (GOs) required by PRC-024-3 Requirement R3, Part 3.1 and Requirement R4 to send information to their TP to send that information to ISO-NE (and not to other TPs in New England) (CEICG-34).***
R4	• Limitations that prevent a generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria [as per R3, Part 3.1] • Generator protection trip settings [as per R4] Such information should be sent to ISO-NE (and only to ISO-NE) at email address prc_setting@iso-ne.com. While ISO-NE and seven other entities within the ISO-NE Planning Coordinator Area (PCA) are each registered as a TP, ISO-NE serves as the "Lead" TP for the New England PCA, so all such information should be sent only to ISO-NE.

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

<table>
<tr><td>CEICG-35</td><td>ISO-NE requires governor model validation from any nuclear power station that provides under-frequency response and allows exemptions for those that do not.</td></tr>
<tr><td>NERC Standard</td><td>MOD-027-1
Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions</td></tr>
<tr><td>Applicable Requirement(s)</td><td>R2. Each Generator Owner shall provide, for each applicable unit, a verified turbine/governor and load control or active power/frequency control model, including documentation and data (as specified in Part 2.1) to its Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1 (Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity).
2.1 Each applicable unit's model shall be verified by the Generator Owner using one or more models acceptable to the Transmission Planner. Verification for individual units rated less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s) or both. Each verification shall include the following:
2.1.1 Documentation comparing the applicable unit's MW model response to the recorded MW response for either:
• A frequency excursion from a system disturbance that meets MOD-027 Attachment 1 (Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity) Note 1 with the applicable unit on-line,
• A speed governor reference change with the applicable unit on-line, or
• A partial load rejection test[1],

[1] Differences between the control mode tested and the final simulation model must be identified, particularly when analyzing load rejection data. Most controls change gains or have a set point runback which takes effect when the breaker opens. Load or set point controls will also not be in effect once the breaker opens. Some method of accounting for these differences must be presented if the final model is not validated from on-line data under the normal operating conditions under which the model is expected to apply.

2.1.2 Type of governor and load control or active power control/frequency control[2] equipment,

[2] Turbine/governor and load control or active power/frequency control:
a. Turbine/governor and load control applies to conventional synchronous generation.
b. Active power/frequency control applies to inverter connected generators (often found at variable energy plants).

2.1.3 A description of the turbine (e.g. for hydro turbine – Kaplan, Francis, or Pelton; for steam turbine – boiler type, normal fuel type, and turbine type; for gas turbine – the type and manufacturer; for various energy plane – type and manufacturer).</td></tr>
</table>

CEICG-35	***ISO-NE requires governor model validation from any nuclear power station that provides under-frequency response and allows exemptions for those that do not.***
	2.1.4 Model structure and data for turbine/governor and load control or active power/frequency control, and **2.1.5** Representation of the real power response effects of outer loop controls (such as operator set point controls, and load control but excluding AGC control) that would override the governor response (including blocked or nonfunctioning governors or modes of operation that limit Frequency Response), if applicable.
Applicable Functional Entities	**Generator Owner, Transmission Planner**
ISO-NE Disposition: MOD-027-1, R2	<u>Explanation of why ISO-NE requires governor model validation from any nuclear power station that provides under-frequency response and allows exemptions for those that do not.</u> In New England, ISO-NE has determined that the reliability need regarding Generator Asset real power response to system frequency variations pertains only to under-frequency excursion events (and not over-frequency excursion events). Accordingly, ISO-NE allows Generator Assets that are only capable of responding to over-frequency (and not capable of responding to under-frequency) to obtain the same exemption from the MOD-027-1 R2 model verification Requirements that the Standard allows for Generator Assets that are not responsive to *both* over- and under-frequency excursion events. According to MOD-027 Attachment 1, Row Number 7, Verification Condition: “Applicable unit is not responsive to both over and under frequency excursion events (The applicable unit does not operate in a frequency control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.); OR Applicable unit either does not have an installed frequency control system or has a disabled frequency control system.” Then, according to MOD-027 Attachment 1, Row 7, Required Action: “Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner.” As mentioned above, ISO-NE has no reliability need for governor model validation from nuclear power stations that do not provide under-frequency response (even if they do provide over-frequency response). Therefore, In New England, nuclear power stations may meet Requirement R2 by providing a written statement to ISO-NE, as applicable, stating that the nuclear power station is either: • not responsive to both over- and under-frequency excursion events; or • not responsive to under-frequency excursion events. Nuclear power stations that are responsive to under-frequency excursion events must meet MOD-027-1 R2 model verification Requirements, as must all other types of Generator Assets.

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

CEICG-36	***ISO-NE has identified Bulk Electric System (BES) Elements in its Planning Authority / Planning Coordinator (PA/PC) area for which Transmission Owners (TOs) and Generator Owners (GOs) must comply with PRC-026-1 Requirement R2 and provides the list of these Elements to the respective Lead Market Participants of those facilities (CEICG-36).***
NERC Standard	**PRC-026-2** **Relay Performance During Stable Power Swings**
Applicable Requirement(s)	**R1.** Each **Planning Coordinator** shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective **Generator Owner** and **Transmission Owner**: Criteria: 1. Generator(s) where an angular stability constraint, identified in Planning Assessments of the Near-Term Transmission Planning Horizon for a planning event that is addressed by limiting the output of a generator or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). 2. Elements associated with angular instability identified in Planning Assessments of the Near-Term Transmission Planning Horizon for a planning event. 3. An Element that forms the boundary of an island in the most recent underfrequency load shedding (UFLS) design assessment based on application of the **Planning Coordinator**'s criteria for identifying islands, only if the island is formed by tripping the Element due to angular instability. 4. An Element identified in the most recent annual Planning Assessment of the Near-Term Transmission Planning Horizon where relay tripping occurs due to a stable or unstable[1] power swing during a simulated disturbance for a planning even. [1] NERC Reliability Standard FAC-014-3 – Establish and Communicate System Operating Limits, Requirement R3. **R2.** Each **Generator Owner** and **Transmission Owner** shall: **2.1** Within 12 full calendar months of notification of a BES Element pursuant to Requirement R1, determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-2 – Attachment B (Criterion A/ Criterion B) where an evaluation of that Element's load-responsive protective relay(s) based on PRC-026-2 – Attachment B (Criterion A/ Criterion B) criteria has not been performed in the last five calendar years. **2.2** Within 12 full calendar months of becoming aware[3] of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable[4] power

<table>
<tr><td>CEICG-36</td><td>ISO-NE has identified Bulk Electric System (BES) Elements in its Planning Authority / Planning Coordinator (PA/PC) area for which Transmission Owners (TOs) and Generator Owners (GOs) must comply with PRC-026-1 Requirement R2 and provides the list of these Elements to the respective Lead Market Participants of those facilities (CEICG-36).</td></tr>
<tr><td></td><td>swing due to the operation of its protective relay(s), determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-2 – Attachment B (Criterion A/ Criterion B).

[3] Some examples of the ways an entity may become aware of a power swing are provided in the Guidelines and Technical Basis section, “Becoming Aware of an Element That Tripped in Response to a Power Swing.”
[4] An example of an unstable power swing is provided in the Guidelines and Technical Basis section, “Justification for Including Unstable Power Swings in the Requirements section of the Guidelines and Technical Basis.”</td></tr>
<tr><td>Applicable Functional Entities</td><td>Generator Owner, Planning Authority / Planning Coordinator, Transmission Owner</td></tr>
<tr><td>ISO-NE Disposition: PRC-026-2, R1, R2</td><td><u>Explanation of how ISO-NE has identified Bulk Electric System (BES) Elements in its Planning Coordinator Area (PCA) for which Transmission Owners (TOs) and Generator Owners (GOs) must comply with PRC-026-2 Requirements R1 and R2 and provides the list of these Elements to the respective owners of those facilities.</u>

As required by <u>PRC-026-2 R1</u>, ISO-NE conducts assessments to determine the BES Elements (generator, transformer and transmission line) in its PCA that meet one or more of the criteria specified in <u>PRC-026-2 R1</u>.
BES Elements identified by ISO-NE as meeting the criteria must comply with <u>PRC-026-2 R2</u> Requirements to ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions. At least once every calendar year (or more often, as necessary), ISO-NE Transmission Planning provides notification of each generator, transformer, and transmission line BES Element in its PCA that meets one or more of the <u>PRC-026-2 R1</u> criteria, to the respective GO and TO. ISO-NE typically provides these notifications in the fourth quarter of each year.

ISO-NE’s latest list of BES Elements that meet one or more of the criteria specified in <u>PRC-026-2 R1</u> were sent to applicable TOs and GOs listed in the table below. These are TOs and GOs that own applicable terminals of these BES Elements and that must comply with <u>PRC-026-2 R2</u>:</td></tr>
<tr><td>TOs and GOs that Received Notifications from ISO-NE and that Must Comply with PRC-026-2 R2</td><td>
<table>
<tr><th>Entity Name</th><th>Date of Most Recent ISO-NE Notification to TO or Market Participant</th></tr>
<tr><td>American PowerNet Management, LP</td><td>12/13/2023</td></tr>
<tr><td>AVANGRID [Central Maine Power Company (CMP)]</td><td>12/13/2023</td></tr>
<tr><td>AVANGRID [United Illuminating Company (UI)]</td><td>12/13/2023</td></tr>
</table>
</td></tr>
</table>

CEICG-36	***ISO-NE has identified Bulk Electric System (BES) Elements in its Planning Authority / Planning Coordinator (PA/PC) area for which Transmission Owners (TOs) and Generator Owners (GOs) must comply with PRC-026-1 Requirement R2 and provides the list of these Elements to the respective Lead Market Participants of those facilities (CEICG-36).***

Bear Swamp Power	12/13/2023
Blue Sky	12/13/2023
Boston Energy	12/13/2023
Braintree Electric Light Department, Town of (BELD)	12/13/2023
Brookfield Renewable Energy LP	12/13/2023
Calpine Energy Services, LP	12/13/2023
Connecticut Municipal Electric Energy Cooperative (CMEEC)	12/13/2023
Connecticut Transmission Municipal Electric Energy Cooperative (CTMEEC)	12/13/2023
Constellation Energy Generation	12/13/2023
Dominion Energy Generation Marketing, Inc.	12/13/2023
Dynegy Marketing and Trade, LLC	12/13/2023
Emera Energy Services	12/13/2023
Essential Power Newington, LLC	12/13/2023
Eversource	12/13/2023
FirstLight Power Resources Management, LLC	12/13/2023
GB II New Haven	12/13/2023
GenConn Energy LLC	12/13/2023
Generation Bridge M & M	12/13/2023
Great River Hydro, LLC	12/13/2023
Maine Electric Power Company, Inc. (MEPCO)	12/13/2023
Massachusetts Municipal Wholesale Electric Company (MMWEC)	12/13/2023
National Grid USA (NGRID)	12/13/2023
New Hampshire Transmission, LLC	12/13/2023
NextEra Energy Marketing, LLC	12/13/2023
New Hampshire Transmission	12/13/2023
Pixelle Energy Services	12/13/2023
Revere Power, LLC	12/13/2023
Rhode Island Energy (RIE)	12/13/2023
Stonepeak Kestrel Energy Marketing (SKEM)	12/13/23
Tenaska Power Services Co.	12/13/23
Town of Wallingford CT Department of Public Utilities Electric Division	12/13/23
Vermont Electric Power Company (VELCO)	12/13/23
Versant Power	12/13/23

CEICG-36	***ISO-NE has identified Bulk Electric System (BES) Elements in its Planning Authority / Planning Coordinator (PA/PC) area for which Transmission Owners (TOs) and Generator Owners (GOs) must comply with PRC-026-1 Requirement R2 and provides the list of these Elements to the respective Lead Market Participants of those facilities (CEICG-36).***
	If ISO conducts an assessment that results in a change to this list, ISO-NE will notify the applicable TO(s) or GO(s) within 30 days of the completion of the assessment and will reflect these changes in the next revision of this CEICG. ***Hypothetical examples of R2 Part 2.1 compliance obligations:*** ***Example 1:*** Assuming a change (in year 2021) to ISO's initial list of BES Elements that meet R1 criteria: • ISO performs its 2019 R1 notification to a TO on 12/1/2019. • The TO conducts its R2 Part 2.1 evaluation of an applicable Element's load-responsive protective relay(s) based on PRC-026-2 – Attachment B criteria on 11/1/2020 (to demonstrate its compliance with R2 Part 2.1 prior to the 1/1/2021 Effective Date). • ISO performs its 2020 annual R1 notifications on 12/1/2020, with no changes to the list; and the TO's 11/1/2020 evaluation continues to serve to meet the R2 Part 2.1 Requirements (because the list is unchanged and the evaluation is less than five years old) • ISO performs its 2021 R1 notification on 12/1/2021 and ISO adds a BES Element to the list. • The TO must conduct a new evaluation to meet R2 Part 2.1 within 12 full calendar months of ISO's 12/1/2021 notification (i.e., by 12/31/2022) because an evaluation has not been performed for the newly identified BES Element. ***Example 2:*** Assuming no change (in year 2022) to ISO's initial list of BES Elements that meet R1 criteria: • ISO performs its 2020 R1 notification to a TO on 12/1/2020. • The TO conducts its R2 Part 2.1 evaluation of an applicable Element's load-responsive protective relay(s) based on PRC-026-2 – Attachment B criteria on 11/1/2021 (to demonstrate its compliance with R2 Part 2.1 prior to the 1/1/2022 Effective Date). • ISO continues to perform its annual R1 notifications on December 1st of each year, for the period 2020 through 2023; and the TO's 11/1/2021 evaluation continues to serve to meet the R2 Part 2.1 Requirements (because the list is unchanged and the evaluation is less than five years old) • ISO performs its 2025 R1 notification on 12/1/2025. The TO must conduct a new evaluation to meet R2 Part 2.1 within 12 full calendar months of ISO's 12/1/2025 notification (i.e., by 12/31/2026) because, even though the list is unchanged, its previous evaluation (which was performed on 11/1/2021) would be more than five years old.

CEICG-37	***ISO-NE serves as the Planning Authority / Planning Coordinator (PA/ PC) and "Lead" Transmission Planner (TP) for the ISO-NE PC Area and its outage coordination procedures apply to all BES within the ISO-NE PC Area. ISO-NE Outage Coordination has established procedures which support assessment of the impact of selected known outages for the Near-Term Planning Horizon for the P0 and P1 categories identified in Table 1 with the System Peak or Off-Peak conditions that the System is expected to experience when known outages are planned.***
NERC Standard	**IRO-017-1** **Outage Coordination**
Applicable Requirement(s)	**R4.** Each **Planning Coordinator** and **Transmission Planner** shall jointly develop solutions with its respective **Reliability Coordinator**(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.
NERC Standard	**TPL-001-5.1** **Transmission System Planning Performance Requirements**
Applicable Requirement(s)	**R2.1.4.** When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the **Planning Coordinator** or **Transmission Planner**. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the **Planning Coordinator** or **Transmission Planner**'s portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1. **R2.4.4**. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the **Planning Coordinator** or **Transmission Planner**. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System impacts on the **Planning Coordinator** or **Transmission Planner**'s portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.
Applicable Functional Entities	**Planning Authority / Planning Coordinator, Reliability Coordinator, Transmission Planner**

CEICG-37	***ISO-NE serves as the Planning Authority / Planning Coordinator (PA/ PC) and "Lead" Transmission Planner (TP) for the ISO-NE PC Area and its outage coordination procedures apply to all BES within the ISO-NE PC Area. ISO-NE Outage Coordination has established procedures which support assessment of the impact of selected known outages for the Near-Term Planning Horizon for the P0 and P1 categories identified in Table 1 with the System Peak or Off-Peak conditions that the System is expected to experience when known outages are planned.***
ISO-NE Disposition: IRO-017-1 R4 TPL-001-5.1 R2.1.4, TPL-001-5.1 R2.4.4	Explanation of how ISO-NE Outage Coordination business unit has documented outage coordination procedures that apply to all BES elements and therefore the procedures are applicable for all of the New England Transmission Planners. As described in the requirement "known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner". The ISO-NE outage coordination process applies to all BES facilities. BES transmission facilities have been listed as Category A or Category B treated as A per the Transmission Operating Agreement (TOA) and are shown on the ISO-NE Open Access Same-Time Information System (OASIS) website. Additionally, the ISO-NE Tariff, the Market Participant Service Agreement (MPSA) and the Interconnection Operators Agreement between ISO New England Inc. and Hydro-Québec TransÉnergie (Phase I/II IOA) provide ISO-NE Operating Authority over the BES. **Per ISO Operating Procedure OP-3 - Transmission Outage Scheduling IV. Routing Transmission Outage Requests:** Long-Term Transmission Outage: A Planned Transmission Outage submitted for ISO Interim-Approval up to two (2) years and greater than or equal to twenty-one (21) days prior to the day the outage is scheduled to begin. III.B. LCC Authorities and Responsibilities, LCCs shall: Receive TO Long-Term and Short-Term Transmission Outage requests from TOs for all Category A Facilities and for Category B Facilities if Resource output could be affected by the outage. IV. Routing Transmission Outage Requests - The TO or MP requesting work on transmission facilities covered by OP-3 shall initially submit a transmission outage request to the appropriate LCC. Unless the LCC disapproves the transmission outage request, the LCC shall review, study and record assumptions and results for Category A and Category B Facilities prior to forwarding to ISO for assessment. **Per ISO Operating Procedure - OP 5 - Resource Maintenance and Outage Scheduling** Planned Outage (PO) is an outage that must be requested with a minimum of 15-calendar days prior to start date and is typically scheduled for the purpose of performing annual maintenance or more significant work that is planned and coordinated well in advance.

CEICG-37	***ISO-NE serves as the Planning Authority / Planning Coordinator (PA/ PC) and "Lead" Transmission Planner (TP) for the ISO-NE PC Area and its outage coordination procedures apply to all BES within the ISO-NE PC Area. ISO-NE Outage Coordination has established procedures which support assessment of the impact of selected known outages for the Near-Term Planning Horizon for the P0 and P1 categories identified in Table 1 with the System Peak or Off-Peak conditions that the System is expected to experience when known outages are planned.***
	1. PO Request Processing a. ISO and the respective LCC shall respond to MP PO requests on a first-come, first-served basis for any defined submittal period. The respective LCC shall review the PO request and continue the requested PO progression for ISO review if the impact on local reliability within its area is acceptable b. ISO shall evaluate the impact of the PO request on the OCM (as defined in OP-5A) and evaluate if approved transmission outages would interfere with the PO request. A PO shall not be approved if the security analysis considering all approved transmission network element outage identifies a violation(s) of ISO, LCC, NERC or NPCC criteria. c. If ISO determines that the requested PO is not acceptable, then ISO shall discuss with the LCC alternative dates when the system reliability conditions are projected to be more favorable. The LCC shall work with the TO and the generator, DRR, or DARD MP to reposition the PO. If the MP is not willing or not able to move the PO to a period where capacity and security criteria can be met, the PO request shall be denied. **2. ISO Reporting** ISO shall publish the current AMS, to the ISO external website daily. If the published AMS poses any local system reliability impact within its local area, each LCC shall notify ISO's Long Term Outage Coordination staff by electronic media (email) at opamoreq@iso-ne.com within five (5) Business Days. [Local system reliability issues identified at this point should be minimal since each generator, DRR, or DARD PO request is forwarded to the respective LCC(s) for local review and approval following ISO's initial evaluation.] ISO shall aggregate approved MP PO requests, and ISO shall provide the projected weekly LTOCM for the New England RCA/BAA for two (2) consecutive calendar years. This process provides the MPs with a planning tool for reviewing their maintenance requirements and timing of their own operable capacity needs with the market signals of the New England RCA/BAA. This process provides ISO with a method for coordinating generator, DRR, or DARD maintenance requirements to avoid OP-4 or OP-7 actions, and as a result, ISO can identify potential capacity-deficient periods. Additionally, the process provides ISO and the LCCs with the necessary information to identify situations where generator, DRR, or DARD and transmission outages could potentially be coordinated to reduce Congestion Costs.

CEICG-38	ISO-NE serves as the **Planning Authority / Planning Coordinator (PA/ PC)** and "Lead" **Transmission Planner (TP**) for the ISO-NE **PC** Area and its geomagnetic disturbance analysis procedures which apply to all BES facilities within the ISO-NE PC Area. ISO-NE has established procedures, which support assessment of the impact of selected benchmark and supplemental geomagnetic disturbances for the Near-Term Planning Horizon.
NERC Standard	**TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events**
Applicable Requirement(s)	**R1.** Each **Planning Coordinator**, in conjunction with its **Transmission Planner(s)**, shall identify the individual and joint responsibilities of the **Planning Coordinator** and **Transmission Planner(s)** in the Planning Coordinator's planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard. **R2.** Each **responsible entity, as determined in Requirement R1**, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments. **R3.** Each **responsible entity, as determined in Requirement R1**, shall have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1. **R4.** Each **responsible entity, as determined in Requirement R1**, shall complete a benchmark GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This benchmark GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. **4.1.** The study or studies shall include the following conditions: **4.1.1.** System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and **4.1.2.** System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon. **4.2.** The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning benchmark GMD event contained in Table 1. **4.3.** The benchmark GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later. **4.3.1.** If a recipient of the benchmark GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. **R5.** Each **responsible entity, as determined in Requirement R1**, shall provide GIC flow information to be used for the benchmark thermal impact assessment of transformers

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

CEICG-38	ISO-NE serves as the **Planning Authority / Planning Coordinator (PA/ PC)** and "Lead" **Transmission Planner (TP**) for the ISO-NE **PC** Area and its geomagnetic disturbance analysis procedures which apply to all BES facilities within the ISO-NE PC Area. ISO-NE has established procedures, which support assessment of the impact of selected benchmark and supplemental geomagnetic disturbances for the Near-Term Planning Horizon.
	specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: **5.1.** The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area. **5.2.** The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1. **R6.** Each Transmission Owner and Generator Owner shall conduct a benchmark thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The benchmark thermal impact assessment shall: **6.1.** Be based on the effective GIC flow information provided in Requirement R5; **6.2.** Document assumptions used in the analysis; **6.3.** Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and **6.4.** Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1. **R7.** Each responsible entity, as determined in Requirement R1, that concludes through the benchmark GMD Vulnerability Assessment conducted in Requirement R4 that their System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1, shall develop a Corrective Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall: **7.1.** List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include: • Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment. • Installation, modification, or removal of Protection Systems or Remedial Action Schemes. • Use of Operating Procedures, specifying how long they will be needed as part of the CAP. • Use of Demand-Side Management, new technologies, or other initiatives. **7.2.** Be developed within one year of completion of the benchmark GMD Vulnerability Assessment.

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	7.3. Include a timetable, subject to approval for any extension sought under Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall: **7.3.1.** Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and **7.3.2.** Specify implementation of hardware mitigation, if any, within four years of development of the CAP. **7.4.** Be submitted to the Compliance Enforcement Authority (CEA) with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 7.3. The submitted CAP shall document the following: **7.4.1.** Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1 and how those circumstances are beyond the control of the responsible entity; **7.4.2.** Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures, if applicable; and **7.4.3.** Updated timetable for implementing the selected actions in Part 7.1. **7.5.** Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later. **7.5.1**. If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. **R8.** Each **responsible entity, as determined in Requirement R1**, shall complete a supplemental GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This supplemental GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. **8.1.** The study or studies shall include the following conditions: **8.1.1.** System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and **8.1.2.** System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon. **8.2.** The study or studies shall be conducted based on the supplemental GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning supplemental GMD event contained in Table 1.

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	8.3. The supplemental GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later. **8.3.1.** If a recipient of the supplemental GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. **R9.** Each **responsible entity, as determined in Requirement R1**, shall provide GIC flow information to be used for the supplemental thermal impact assessment of transformers specified in Requirement R10 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: **9.1.** The maximum effective GIC value for the worst case geoelectric field orientation for the supplemental GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area. **9.2.** The effective GIC time series, GIC(t), calculated using the supplemental GMD event described in Attachment 1 in response to a written request from the **Transmission Owner** or **Generator Owner** that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 9.1. **R10.** Each Transmission Owner and Generator Owner shall conduct a supplemental thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater. The supplemental thermal impact assessment shall: **10.1.** Be based on the effective GIC flow information provided in Requirement R9; **10.2.** Document assumptions used in the analysis; **10.3.** Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and **10.4.** Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1. **R11.** Each responsible entity, as determined in Requirement R1, that concludes through the supplemental GMD Vulnerability Assessment conducted in Requirement R8 that their System does not meet the performance requirements for the steady state planning supplemental GMD event contained in Table 1, shall develop a Corrective Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall:

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	11.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include: • Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment. • Installation, modification, or removal of Protection Systems or Remedial Action Schemes. • Use of Operating Procedures, specifying how long they will be needed as part of the CAP. • Use of Demand-Side Management, new technologies, or other initiatives. **11.2.** Be developed within one year of completion of the supplemental GMD Vulnerability Assessment. **11.3.** Include a timetable, subject to approval for any extension sought under Part **11.4,** for implementing the selected actions from Part 11.1. The timetable shall: **11.3.1.** Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and **11.3.2.** Specify implementation of hardware mitigation, if any, within four years of development of the CAP. **11.4.** Be submitted to the CEA with a request for extension of time if the responsible entity is unable to implement the CAP within the timetable provided in Part 11.3. The submitted CAP shall document the following: **11.4.1.** Circumstances causing the delay for fully or partially implementing the selected actions in Part 11.1 and how those circumstances are beyond the control of the responsible entity; **11.4.2.** Revisions to the selected actions in Part 11.1, if any, including utilization of Operating Procedures, if applicable; and **11.4.3.** Updated timetable for implementing the selected actions in Part 11.1. **11.5.** Be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later. **11.5.1.** If a recipient of the CAP provides documented comments on the CAP, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. **R12**. Each **responsible entity, as determined in Requirement R1**, shall implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model.

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	R13. Each **responsible entity, as determined in Requirement R1**, shall implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.
Applicable Functional Entities	**Planning Authority / Planning Coordinator, Transmission Planner, Transmission Owner, Generator Owner**
ISO-NE Disposition: TPL-007-4 All Requirements	ISO-NE has developed a Split of Responsibilities matrix in conjunction with Transmissions Planners operating in the New England region for maintaining models and performing studies needed to complete GMD Vulnerability Assessments. The Initial Split of Responsibilities for TPL-007-4 were finalized and agreed upon following a TOP/TSP working group meeting on June 22, 2023. In addition to the Split of Responsibilities matrix, ISO-NE has drafted an additional document, Planning Procedure 11, to provide more information to Applicable TOs and Applicable GOs required to implement TPL-007-4 within the New England Region. PP11 outlines the responsibilities for TOs/TPs with equipment rated over 200kV. PP11 also provides procedural details on providing GIC data, some supporting information on GIC modeling data, and a template for providing the data to ISO. ISO-NE has already identified and notified entities that must provide GIC modeling data as described in PP-11. Upon receipt of a notification from ISO-NE, entities identified in the Transmission Planner Split of Responsibilities are given 90 days to provide ISO-NE with the entity's GIC modeling data for their applicable facilities. A benchmark GMD Vulnerability assessment is completed in accordance with **Benchmark and Supplemental GMD 2026 Needs Assessment – Scope of Work**. For the purposes of R4.1.1 and R4.1.2, The Near-Term Transmission Planning Horizon represents a study horizon from year one to year five at the time the benchmark assessment was performed. The actual benchmark GMD Vulnerability Assessment is based on the Table 1 Steady State Planning GMD Event in TPL-007-4. ISO-NE notifies via email the Planning Advisory Committee (PAC) of the GMD Needs Assessment Study Initiation, after the Benchmark GMD Needs Assessment was reviewed by ISO-NE, that a draft report is available for comments, and when the final version of the Benchmark Needs Assessment is posted to the "New England-Wide Geomagnetic Disturbance Key Study Area" website found at https://www.iso-ne.com/system-planning/key-study-areas/new-england-wide-geomagnetic-disturbance-key-study/. ISO Transmission Planning provides GIC flow information to be used for the transformer thermal impact assessment specified in Requirement R6 to all entities that own applicable transformers, which include GOs and the NERC registered Transmission Planners within New England (the only TOs that own applicable BES power transformers – AvanGrid UI/CMP, Emera Maine, Eversource, National Grid and Velco). The GIC flow information shared with all applicable TOs and GOs includes the maximum effective GIC

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	value for the worst case geoelectric field orientation for the benchmark and supplemental GMD events described in TPL-007-4 Attachment 1. A supplemental GMD Vulnerability assessment is completed in accordance with **Benchmark and Supplemental GMD 2026 Needs Assessment – Scope of Work**. For the purposes of R4.1.1 and R4.1.2, The Near-Term Transmission Planning Horizon represents a study horizon from year one to year five at the time the supplemental assessment was performed. The actual supplemental GMD Vulnerability Assessment is based on the Table 1 Steady State Planning GMD Event in TPL-007-4. ISO-NE notifies via email the Planning Advisory Committee (PAC) of the GMD Needs Assessment Study Initiation, after the Supplemental GMD Needs Assessment was reviewed by ISO-NE, that a draft report is available for comments, and when the final version of the Supplemental Needs Assessment is posted to the "New England-Wide Geomagnetic Disturbance Key Study Area" website found at https://www.iso-ne.com/system-planning/key-study-areas/new-england-wide-geomagnetic-disturbance-key-study/. As described in Benchmark and Supplemental GMD Needs Assessment – Scope of Work Section 5, the benchmark and supplemental GMD Vulnerability Assessments conducted for Requirement R8, the New England System meets the performance requirements for the steady state planning benchmark and supplemental GMD event contained in Table 1, and therefore a Corrective Action Plan (CAP) is not required.

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

ACRONYMS	
AC	Alternating Current
ACE	Area Control Error
ACS	Automatic Control Schemes
AGC	Automatic Generation Control
ANDC	DC Neutral Amperes
ATC	Available Transfer Capability
ATCID	Available Transfer Capability Implementation Document
ATRR	Alternative Technology Regulation Resources
AVR	Automatic Voltage Regulator
BA	Balancing Authority
BAA	Balancing Authority Area
BES	Bulk Electric System
BPS	Bulk Power System
CCP	Corporate Compliance Program
CDAA	CMEP Data Administration Application
CEICG	ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards
CEII	Critical Energy Infrastructure Information
CIP	Critical Infrastructure Protection
CMEP	Compliance Monitoring and Enforcement Program
DBR	Designated Blackstart Resource
DDR	Dynamic Disturbance Recorder
DP	Distribution Provider
DRA	Demand Response Asset
EMS	Energy Management System
EPA	Environmental Protection Agency
ERO	Electric Reliability Organization
FERC	Federal Energy Regulatory Commission, the Commission
FPA	Federal Power Act
GIC	Geomagnetically Induced Current
GMD	Geomagnetic Disturbance
GO	Generator Owner
GOP	Generator Operator
GSU	Generator Step-Up (Transformer)
HVDC	High Voltage Direct Current
ICC	Interpersonal Communications Capabilities

ICPF	Initial Cranking Path Facility
IROL	Interconnection Reliability Operating Limit
ISO-NE	Independent System Operator - New England
LCC	Local Control Center
M/LCC	Master/Local Control Center
MOU	Memorandum of Understanding
MP	Market Participant
MPSA	Market Participant Service Agreement
MTA	Maximum Torque Angle
MVA	Megavolt Ampere
MVAr	Megavolt Ampere Reactive
MW	Megawatt
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council Inc.
NPGOP	Nuclear Plant Generator Operator
NPIR	Nuclear Plant Interface Requirement
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OP	Operating Procedure
PA	Planning Authority
PC	Planning Coordinator
PCA	Planning Coordinator Area
Phase I/II IOA	Interconnection Operators Agreement between ISO New England Inc. and Hydro-Quebec TransÉnergie
PPA	Proposed Plan Application
PTO	Participating Transmission Owner
RAS	Remedial Action Scheme
RC	Reliability Coordinator
RCA	Reliability Coordinator Area
RDA	Regional Delegation Agreement
RE	Regional Entity
ROC	Reliability & Operations Compliance
ROP	(NERC) Rules of Procedure
ROW	Rights-of-Way
RP	Resource Planner
RTCA	Real Time Contingency Analysis

RTO	Regional Transmission Organization
SDT	Standard Drafting Team
SOL	System Operating Limit
SOP	System Operating Procedure
SPS	Special Protection System
SRWG	System Restoration Working Group
TE	Transmission Entity
TFSS	Task Force on System Studies
TO	Transmission Owner
TOA	Transmission Operating Agreement
TOP	Transmission Operator
TP	Transmission Planner
TSP	Transmission Service Provider
UFLS	Underfrequency Load Shedding
UVLS	Undervoltage Load Shedding
VAr	Volt-Ampere Reactive

*Acronym list is included in the ISO-NE_CEICG_Index

ISO-NE Corroborating Evidence Interpretations and Compliance Guidance for NPCC Compliance Audits of NERC Reliability Standards

DOCUMENT HISTORY		
REVISION #	DATE	REASON
Rev 9a	01/31/2020	List names of generator facilities per CIP-002-5.1a criterion 2.3, 2.6 and 2.9 in CEICG-30. Eliminated references to Pilgrim Nuclear Power Station and M/LCC1 Attachment A Updated Appendix A – ISO-NE Corroborating Evidence Interpretations and Compliance Guidance (CEICG) Document Index (rev. 9a, January 31, 2020).
Rev 10	07/01/2020	Annual review of CEICG content. Verified use of term Generator/s; relevant instances changed to Generator Asset. Updated all tables for notifications. Updated for PRC-006-NPCC-2 effective 04/01/20.
Rev 11	07/01/2021	Annual review of document. INT-004-2 became inactive; removed associated language. Updated all tables for notifications. Updated for 04/01/21 enforcement date Standards.
Rev 11a	10/01/2021	Intermediate update of document FAC-008-5 – Facility Ratings R7 eliminated. Clarification to provision of ISO-NE Operating Documents as audit evidence.
Rev 12	07/01/2022	Annual review of document – edits as needed. Added CEICG 37 Added CIP-014-2 to CEICG-30 per NPCC request. Added CEICG Summary table. Added Acronym table. Moved Attachment A to a lead-in role at the request of the M/LCC Heads. Included Requirements referred to within specified CEICG-related Requirements for easier Business Owner reference.
Rev 13	07/01/2023	Annual Review of Document – minor edits as needed Major formatting changes Added CEICG Index by CEICG Added Cross Reference Links to CEICG Index by Standard and to CEICG Index by CEICG Reordered CEICGs by number Removed Active/Inactive CEICG List (Added Status List to CEICG Index) Removed Retired CEICG List (Added retired list to CEICG Index) Removed Revisions 1-9 (Added Complete Revision History to CEICG Index) Added Acronyms to CEICG Index Formatted all CEICG Tables to Font: Calibri, 10 pt

Rev 14	09/01/2024	Annual Review of Document – minor edits as needed Major and minor formatting changes Reordered CEICGs by alphabetical order Updates to NERC Standards and Requirements that are Subject to Enforcement Added CEICG-38 for NERC Standard TPL-007-4 Transmission System Planned Performance for Geomagnetic Disturbance Events

*A Complete Revision History is included in the ISO-NE_CEICG_Index