United States Operations

Transmission Group Procedure

TGP28

National Grid Transmission Planning Guide

Authorized by

Date: ***1/27/2020***

Brian Gemmell, Vice President,
Transmission Asset Management &
Planning and Capital Delivery Electric
National Grid USA Service Company, Inc.

National Grid USA Service Company, Inc.
40 Sylvan Road
Waltham, MA 02451

TABLE OF CONTENTS

1.0 Change Control

Version	Date	Modification	Author(s)	Reviews and Approvals by
Issue 1	06 August 2007	Initial Document	Philip J. Tatro	David Wright
Issue 2	29 February 2007	Removed "Confidential" from page header	Philip J. Tatro	David Wright
Issue 3	22 November 2010	Added sections 3.5 (System models), 5.4 (Substation design considerations); provided additional guidance on several other topics interspersed in the document. Added referenced to BPS analysis in section 3.9. Added section 4.5 on generator low voltage ride through. Revised study horizon from up to 10 years to up to 15 years. Added items to section 2.3 on Operational considerations	Philip J. Tatro, Dana Walters	Paul Renaud
Issue 4	07 March, 2018	Updated the entire document to be in-line with the latest NERC, NPCC, ISO's standards, criteria and procedures	Barry Ahern, Carlos Perez-Perez, Mark Domino	Carol Sedewitz
Issue 5	27 January 2020	Updated Section 2.1 to reflect transmission system definition in NY and Section 5.5.2 on Interconnection facilities and Evaluation requirements	Carlo Perez-Perez Abhinav Rawat Mark Domino	Brian Gemmell

2.0 Introduction

2.1 Objective of the Transmission Planning Guide

The objective of the Transmission Planning Guide (the Guide) is to define the criteria used to assess the reliability of National Grid's existing and future transmission system under reasonably anticipated operating conditions. The National Grid transmission system is defined as National Grid owned facilities that are operated at 69 kV and above in both New England and New York The Guide is also intended to provide guidance, with consideration of public safety and safety of operations and personnel, in the design of future modifications or upgrades to the transmission system. The Guide is a design tool and is not intended to address unusual or unanticipated operating conditions.

Application of this guide strives to ensure that all customers receive an acceptable level of reliability. All customers or groups of customers will not necessarily receive uniform reliability due to inherent factors such as differences in customer load level, load shape, proximity to generation, interconnection voltage, accessibility of transmission resources, customer service requirements, and class and vintage of equipment.

The Guide is intended to be an overarching guide, in the sense that it applies to all National Grid transmission system reliability assessments. However, it is not intended to take the place of any of the standards listed in Section 2.2, but rather act as a supplement to them.

2.2 Planning and Design Criteria

National Grid transmission facilities shall be designed in accordance with the latest version of the following standards:

For transmission elements that are part of the NERC Bulk Electric System (BES):

- NERC Reliability Standards, *Transmission System Planning Performance Requirements* (TPL-001) and *Transmission System Planned Performance for Geomagnetic Disturbance Events* (TPL-007)

For transmission elements that are part of the NPCC Bulk Power System (BPS):

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

For transmission elements in New England that are Pool Transmission Facilities (PTF):

- *Reliability Standards for the New England Area Pool Transmission Facilities (ISO-NE Planning Procedure No. 3) PP3*
- *ISO-NE Transmission Planning Technical Guide*

For transmission elements in New York that are Bulk Power Transmission Facilities (BPTF):

- *New York State Reliability Council Reliability Rules for Planning and Operation of the New York State Power System*

For all elements that are part of the National Grid transmission system:

- National Grid *Transmission Planning Guide* (this document).

New generator interconnections to National Grid's transmission system in New England shall be configured and designed in compliance with applicable ISO procedures, including ISO-NE document, "*General Transmission System Design Requirements for the Interconnection of New Generating Facilities and ETU to the Administered Transmission System*" ISO-NE PP5-6,

Appendix A. In New York, all interconnections shall follow the NYISO "*Transmission Expansion Interconnection Manual*".

All National Grid or National Grid transmission customers' facilities which are served by transmission providers other than National Grid shall be designed in accordance with the planning and design criteria of the transmission supplier and the applicable NERC, NPCC, ISO-NE, NYISO, and NYSRC documents.

Detailed design of facilities may require additional guidance from industry or other technical standards, which are not addressed by any of the documents referenced in this guide.

2.3 Operational Considerations in Planning and Design

The system should be planned and designed with consideration for ease of operation and with input from Operations. Such considerations include, but are not limited to:

- Utilization of standard components to facilitate availability of spare parts
- Post contingency switching operations
- Use and location of switching devices (e.g. adding sectionalizing switches on either side of a substation tap to reduce Load At Risk (LAR) for scheduled outages)
- Selection of proposed switch capabilities
- Use of NERC Remedial Action Schemes (RAS), NPCC Special Protection Systems (SPS), Automatic Line Sectionalizing (ALS) and other enhanced protection schemes, in accordance with the National Grid TGP18
- Impact on the underlying distribution system (e.g. thermal, short circuit, automated switching schemes)
- Integrated use in Supervisory Control and Data Acquisition (SCADA) and telemetry to communicate with the Control Center Energy Management System (EMS)
- Impact on system restoration plan
- Need, use, and location of reactive supplies
- Development of any needed operating procedures for new or upgraded facilities
- Longevity of the solution to minimize rework
- Operational and outage issues associated with construction
- Integration of multiple needs to provide an efficient approach to performing upgrades or replacements

3.0 System Studies

3.1 Basic Types of Studies

The basic types of studies are conducted to assess conformance with the criteria and standards stated in this guide, include but are not limited to; power flow, stability, short circuit, and protection coordination.

3.2 Study Horizon

The lead time required to plan, permit, license, and construct transmission system upgrades is typically between one and ten years depending on the complexity of the project. Some very large and complex projects, which are less common, may even require lead times of up to fifteen years. The typical study horizons are referred to as near-term (one to five years) and long-term (six through ten years or beyond). Projects taking less than a year to implement tend to consist of non-construction alternatives that are addressed by operating studies.

3.3 Future Facilities

A planned facility's estimated in-service date can be delayed or canceled for various reasons. Therefore, a sensitivity analysis should be performed to identify system interdependencies of the planned facilities. These interdependencies should be clearly identified in the results and recommendations sections of the report described in section 3.13.

3.4 Facility Ratings

Facility or thermal ratings of each load carrying element in the system are determined such that maximum use can be made of the equipment without damage or undue loss of equipment life. The ratings of each transmission facility reflect the most limiting series elements within the circuit. The principal variables used to derive the ratings include specific equipment design, season, ambient conditions, maximum allowable equipment operating temperatures as a function of time, and physical parameters of the equipment. Refer to the National Grid Transmission Facility Rating document (TGP26) for further information on ratings.

Equipment ratings are summarized in the following table (which is also included in TGP26) by durations of allowable loadings for three types of facilities. Where applicable, actions that must be taken to relieve equipment loadings within the specified time period also are included.

Table 3.1: Application of Ratings

Equipment	RATINGS			
	Normal	Long Time Emergency (LTE)	Short Time Emergency (STE)	Drastic Action Limit (DAL)[4]
Overhead Transmission	Continuous	Loading must be reduced below the Normal rating within 4 hours[2]	Loading must be reduced below the LTE rating within 15 minutes[3]	Requires immediate action to reduce loading below the LTE rating
Underground Transmission[1]	Continuous	Loading must be reduced below the 100 hour or 300 hour rating within 4 hours[2]	Loading must be reduced below the 100 hour or 300 hour rating within 15 minutes	Requires immediate action to reduce loading below the LTE rating
Transmission Transformers	Continuous	Loading must be reduced below the Normal rating within 4 hours[2]	Loading must be reduced below the LTE rating within 15 minutes[3]	Requires immediate action to reduce loading below the LTE rating

Notes to Table 3.1:

[1] In NE, ratings for other durations may be calculated and utilized for specific conditions on a case-by-case basis. Following expiration of the 100 hour or 300 hour period, loading of the cable must be reduced below the Normal rating. Either the 100 hour or the 300 hour rating may be utilized after the transient period, but not both. If the 100 hour rating is utilized, the loading must be reduced below the Normal rating within 100 hour, and the 300 hour rating may not be used.

[2] The summer LTE rating duration is 12 hours in New England. The winter LTE rating duration in New England, and the summer and winter LTE rating duration in New York is 4 hours. For overhead transmission the time duration does not affect the calculated value of the LTE rating. The duration difference reflects how the LTE ratings are applied by the ISO in each Area.

[3] In NY, the STE rating can only be used if the loading can be reduced below the LTE rating within 15 minutes and be reduced below the Normal rating within 30 minutes from the initiating event.

[4] The DAL rating is only utilized in New England by operators and not in planning studies.

3.5 System Models

Base case system models for power flow and stability analysis are available from respective ISO’s. These cases are derived from libraries maintained through a process involving the ISOs, NPCC, and the Eastern Interconnection Reliability Assessment Group (ERAG). Entities, such as National Grid, supply their respective ISOs with modeling updates of their system. The ISOs combine system information to develop Area updates and provides the Area updates to NPCC. NPCC combines system information from the five northeast Areas into a regional system update and provides it to ERAG. ERAG, through the Multiregional Modeling Working Group (MMWG), combines all the regional system updates into a master model which is redistributed for use by the industry.

System updates include load forecasts over the ten year study horizon and equipment characteristics (e.g. impedance, line charging, normal and emergency ratings, nominal voltages, tap ratios and regulated buses for transformers, and equipment status). Through the course of the process, the forecasts are modified to recognize the diversity of the aggregate seasonal peak demand relative to the sum of the area seasonal peak demands. Details on this process can be found in NERC Reliability Standard MOD-032 "Data for Power System Modeling and Analysis", and the MMWG Procedure Manual.

The base cases received from the ISOs includes the area load forecast. The load forecast includes the effects of Energy Efficiency, Demand Response, and Distributed Generation. Before utilizing a base case for study purposes, modifications should be made to the case as appropriate (e.g., generation dispatch, capacitor dispatch, phase shifter adjustments, load adjustments to account for Energy Efficiency, Demand Response, and Distributed Generation).

Short circuit models are maintained and available from the ISOs. Entities, such as National Grid, supply their respective ISOs with modeling updates of their system.

The mechanisms of providing modeling updates from National Grid to NYISO and ISO-NE differ. The NYISO document Reliability Analysis Data (RAD) Manual describes the data requirements and the process involved. In New England, updates are handled through the Base Case Database and the Base Case Working Group.

The years and seasons typically modeled vary based on the purpose of the particular study, in some cases per specific instruction from the applicable ISO. Typical models consider:

- Near-term (one to five years out): Summer peak and light load. Winter peak, shoulder peak, fall or spring peak, and/or minimum load may be added as deemed necessary.
- Long-term (six though ten years and beyond): Summer peak. Other cases added as necessary.

3.6 Modeling for Power Flow Studies

The representation for power flow studies should include models of transmission lines, transformers, generators, reactive sources, and any other equipment which can affect power flow or voltage. The representation for fixed-tap, load-tap-changing, and phase shifting transformers should include voltage or angle taps, tap ranges, and voltage or power flow control points. The representation for generators should include reactive capability ranges and voltage control points. Equipment ratings should be modeled for each of these facilities including related station equipment such as buses, circuit breakers and switches. Study specific issues that need to be addressed are discussed below.

3.6.1 Forecasted Load

The forecasted summer and winter peak active and reactive loads should be obtained annually from the Transmission Customers for a period of ten or more years. The forecast should have sufficient detail to distribute the active and reactive coincident loads (coincident with the Customers' total peak load) across the customers' points of delivery. If no specific input is provided for active loads, historical data will be used. Reactive load typically will be determined using historical values and customer input, if any.

The point of delivery for power flow modeling purposes may be different than the point of delivery for billing purposes. Consequently, these points need to be coordinated between National Grid and the Transmission Customer.

To address forecast uncertainty, the peak load forecasts are typically based on normal and extreme weather. The normal weather forecast has a 50 percent probability of being exceeded and the extreme weather forecast has a 10 percent probability of being exceeded. Due to the lead time required to construct new facilities, planning for N-1 contingencies should be based conservatively on the extreme weather forecast.

3.6.2 Load Levels

To evaluate the variability in daily and seasonal load cycles, many studies require modeling several load levels. The typical load levels studied are; peak load forecast, intermediate (“shoulder”) load (70 to 80% of the peak load forecast) and light load (less than 50% of the peak load forecast). For high voltage performance issues, a minimum load case is often needed. In New England the ISO-NE Transmission Planning Technical Guide provides specific fixed MW values for peak, intermediate, light and minimum load. The basis for these levels can be either the summer or winter peak forecast, depending on which season is more limiting. In some areas, both seasons may have to be studied.

Sensitivity to the magnitude of the load assumptions must be evaluated with the assumed generation dispatch to assess the impact of different interactions on transmission circuit loadings and system voltage responses.

In the course of performing a system study, it may become necessary to scale load. When doing so on an area basis, care must be taken to avoid scaling non-conforming load, i.e. load that does not conform to a typical load cycle or load-duration curve such as industrial or generating plant station service load. In some cases, non-conforming loads could be higher in off peak periods, and should be modeled as such.

When a light load case is desired in a year for which a light load base case is not available, a light load case should be developed from an available light load case for another year; this is always preferable to scaling a peak load case down to a light load level. In general, peak load cases should not be scaled below 70 percent of peak load and light load cases should not be scaled above 70 percent of peak load. When scaling load it also is necessary to be sure that load level-specific items, such as generator voltage schedules and dispatch of reactive resources, are appropriate for the load level modeled. In New England in particular, generator units in National Grid’s portion of the New England transmission system have different voltage schedules for heavy and light load levels. In New York, generator voltage schedules are set by NYISO for the case being created. Thus, a case close to the desired load level should be selected.

3.6.3 Load Balance and Harmonics

Balanced three-phase 60 Hz ac loads are assumed at each point of delivery unless a customer specifies otherwise, or if there is information available to confirm the load at the point of delivery is not balanced. Balanced loads are assumed to have the following characteristics:

- The active and reactive load of any phase is within 90% to 110% of the load on both of the other phases
- The voltage unbalance between the phases measured phase-to-phase is 3% or less

- The negative phase sequence current (RMS) in any generator is less than the limits defined by the current version of ANSI C50.13

Harmonic voltage and current distortion is required to be within limits recommended by the current version of IEEE Std. 519.

If a customer load is unbalanced or exceeds harmonic limits, then special conditions not addressed in this guide may apply.

3.6.4 Load Power Factor

Load Power Factor (LPF) for each delivery point is established by the active and reactive load modeled in accordance with Section 3.6.1. Since LPF varies with season and load level, the LPF modeled in a case should be consistent with the period under study. The reactive load may be adjusted as necessary to reflect LPF expected by the Transmission Customer and/or observed historically via the EMS or metered data. The LPF in each area in New England is expected to be consistent with the curves set forth in ISO-NE Operating Procedure 17 (OP17) *Load Power Factor Correction*.

3.6.5 Reactive Shunt Compensation

Due to limitations of power system simulation programs, reactive shunt compensation (capacitors, reactors, and dynamic devices) often cannot be modeled exactly as it is operated on the actual power system. Instead, models of the shunt compensation, on the transmission system and, when modeled, on the low voltage side of the supply transformers should approximate the performance of the installed equipment.

To achieve this, the elements will have to be manually switched on in the model under conditions when the actual equipment would typically be expected in-service and switched off when it would not. Examples include: transmission capacitors which are expected in service at peak summer load and dynamic VAr devices which are expected to be at zero output pre-contingency, ready to respond to a contingency. Switched shunt model control parameters should be selected to mirror this operation to the extent possible. However, it must be recognized that these parameters cannot be matched to any actual specific equipment settings. Reactive compensation on the feeder circuits is assumed to be netted with the load.

3.6.6 Generation Dispatch and Transfer Levels

Customer owned generation should be modeled explicitly when the size is significant compared to the load at the same delivery point, or when the size is large enough to impact system dynamic performance. ISO-NE typically models such generation if it is 5 MW or larger; New York typically nets such generation with load.

Analysis of generation sensitivity is necessary to model the variations in dispatch that routinely occur at each load level. The intent is to bias the generation dispatch such that the transfers over select portions of the transmission system are stressed pre-contingency as much as reasonably possible. An exception is hydro generation that should account for seasonal variation in the availability of water. Also, wind generation should be dispatched according to local ISO study assumptions.

A merit based generation dispatch should be used as a starting point from which to stress transfers. A merit based dispatch can be approximated based on available information such as fuel type and historical information regarding unit commitment. Interface limits can be used as a reference for stressing the transmission system. Inter-Area transfers should reflect a range typical with local ISO experience. Dispatching to the interface limits may stress the transmission system in excess of transfer levels deemed appropriate for the study. Refer to ISO documents for further guidance on generation dispatch and transfer levels.

Analysis should also consider whether specific local generation could be critical to area performance by performing studies with such generation modeled out of service, either in a base case or as a sensitivity case. If a specific generator or generator step-up-transformer (as a grounding source for protection) is determined to be critical to the reliability of an area, consideration should be given to the likelihood of occurrence of the scenario, the attendant risk and opportunities to mitigate or eliminate the adverse system performance.

The reactive capabilities of each generator are modeled in the power flow case by the appropriate ISO, based on data provided by the generator owner. Additional detail on New England generators can be found in ISO documents, such as OP-12 and NX-12.

3.6.7 Facility Status

The initial conditions assume all existing facilities, except for generators, normally connected to the transmission system are operating as designed or expected. Future facilities should be treated as discussed in Section 3.3.

3.7 Modeling for Stability Studies

3.7.1 Dynamic Models

Dynamic models are required for generators and associated equipment, HVdc terminals, SVCs, other Flexible AC Transmission Systems (FACTS), and protective relays to calculate the fast acting electrical and mechanical dynamics of the power system. Dynamic model data is maintained as required by NERC, NPCC, ISO-NE, and NYSRC.

3.7.2 Load Level and Load Models

The load levels studied in stability studies vary between New England and New York consistent with accepted practices in each Area. Transient stability studies within New England typically exhibit the more severe system response under light load conditions. Consequently, transient stability studies are typically performed for several dispatches at light load levels[1]. At least one dispatch at system summer peak load is also analyzed. Other system load levels may be studied when required to stress a system interface, or to capture the response to a particular generation dispatch.

Transient stability studies within New York typically exhibit the more severe system response under summer peak load conditions. Consequently, transient stability studies are typically performed with a system load level of 100% of summer peak system load. Other system load levels may be studied when required to stress a system interface, or to capture the response to a particular generation dispatch.

System loads within New England and New York are usually modeled as constant admittances for both active and reactive power. These models have been found to be appropriate for studies of transient stability for which they are considered to provide conservative results. Other load models are utilized where appropriate such as when analyzing the underfrequency performance of an islanded portion of the system, or when analyzing voltage performance of a local portion of a system. When performing NERC TPL-001 studies, a dynamic load model is required for peak load stability testing. This model is provided by the ISOs.

[1] See ISO-NE Transmission Planning Technical Guide for exact MW load level to test for light load stability simulations.

Loads outside New England and New York are modeled consistent with the practices of the individual Areas and regions. Appropriate load models for other Areas and regions are available through NPCC.

3.7.3 Generation Dispatch and Transfer levels

Generation dispatch for stability studies typically differs from the dispatch used in thermal and voltage analysis. Generation within the area of interest (generation behind a transmission interface or generation at an individual plant) is dispatched at full output within known system constraints. Remaining generation is dispatched to approximate a merit based dispatch. To minimize system inertia, generators are dispatched fully loaded to the extent possible while respecting system reserve requirements.

Interface limits can be used as a reference for stressing the transmission system. Inter-Area transfers should reflect a range typical with local ISO experience. Dispatching to the interface limits may stress the transmission system in excess of transfer levels deemed appropriate for the study. Refer to ISO documents for further guidance on generation dispatch and transfer levels.

3.8 Modeling for Short Circuit Studies

Short Circuit studies are performed to determine the maximum fault duty at a point on the system. Transmission Planning uses this to evaluate circuit breaker fault duty and to determine appropriate fault impedances for modeling unbalanced faults in transient stability studies. Transmission Planning also uses the fault duty to inform substation engineering and others of the short circuit currents to be considered for substation design.

Short Circuit studies for calculating maximum fault duty assume all generators are on line, and all transmission system facilities are in service and operating as designed. When results are used to assess whether the interrupting capability of a circuit breaker will be exceeded, the assessment must consider the switchyard configuration to determine the contribution of the fault current the circuit breaker must interrupt. The assessment also must consider whether the circuit breaker is total-current rated or symmetrical current rated and oil circuit breakers[2] must be derated to account for autoreclosing.

The interrupting capability for symmetrical current rated circuit breakers is assessed using the latest version of IEEE/ANSI standard C37.010. This method uses the system X/R ratio at the fault point as defined by the standard, and the breaker contact parting time to determine a factor that is multiplied by the symmetrical current to arrive at the interrupting current. This current is then compared with the circuit breaker interrupting capability. If the breaker is an oil circuit breaker, the interrupting capability would be derated for reclosing duties. Special consideration may be necessary when assessing generating unit breakers.

National Grid's Circuit Breaker Fault Current Assessment Guide (TGP34) provides more detailed guidance on fault current assessment of circuit breakers.

When a substantial increase in short circuit current is identified during a planning study, the existing substation ground grid should be assessed for accommodation of the additional short circuit current at the substation. Also, the existing bus conductor bracing and switches should be assessed for ability to withstand the additional fault current.

Short Circuit studies for determining impedances for modeling unbalanced faults in stability studies typically assume all generators are on line. Switching sequences associated with the contingency may be accounted for in the calculation.

[2] IEEE C37.010 Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis

3.9 Modeling for Protection Studies

Conceptual protection system design should be performed and/or evaluated to ensure that adequate fault detection and clearing can be coordinated for the proposed transmission system configuration in accordance with the National Grid protection philosophy. Preliminary relay settings should be calculated based on information obtained from power flow, stability, and short circuit studies to ensure the feasibility of the conceptual design. Transmission Planning should work together with Protection Engineering in this effort.

Facilities subject to NPCC BPS Protection Criteria are identified through performance analysis. As a result, analysis may be required to consider whether any of the recommended changes to the system configuration or protection design would impact the NPCC BPS designation of any facility. The NPCC A-10 Criteria describes the classification methodology of BPS elements.

When an increase in the rating of a circuit is required, a review of the associated protection equipment and settings is necessary to ensure that the desired rating is achieved. Additionally, the thermal rating of Current Transformer (CT) secondary equipment must be verified to be greater than the required rating. Also, it is necessary to verify that the protective relay trip settings are not set to trip the protected equipment at a level below the required circuit rating. Consult NERC PRC-023 *"Relay Loadability Standard"* for requirements.

3.10 Other Studies

For some applications it may be necessary to include other types of studies. Examples include:

- Switching surge studies to assess voltage transients associated with switching underground cables and capacitors, or to determine minimum approach distances for live-line maintenance on overhead transmission lines.
- Harmonics studies to assess impacts of large converter loads; e.g. HVdc terminals, arc furnaces, or electric rail traction systems.
- Sub-Synchronous Resonance (SSR), Sub-Synchronous Torsional Interaction (SSTI) and Sub-Synchronous Control Interaction (SSCI) studies associated with application of series capacitors or control systems associated with HVdc or Flexible AC Transmission System (FACTS) devices near large turbine-generators.
- Motor starting studies for impact on transmission system voltages.

3.11 Geomagnetic Disturbance Events (GMD)

GMD assessment should be performed in accordance with NERC Reliability Standard TPL-007.

3.12 Development and Evaluation of Alternatives

If the projected performance or reliability of the system does not conform to the applicable planning criteria, then alternative solutions need to be developed and evaluated. Each proposed alternative shall meet all identified needs. Possible strategies to accomplish this could be through a single overarching comprehensive solution or through application of individual upgrades or a combination of the two approaches. The system performance with a proposed alternative should meet or exceed all applicable design criteria, not introducing additional un-met needs.

The evaluation of alternatives shall be summarized concisely in a study report and result in a clear, executable recommendation. Solution development and evaluation shall address a wide range of factors including: safety, constructability, construction outage requirements/cost impacts, expected in-service dates, interface impacts, losses, extreme contingency performance, expansion capabilities, lifetime maintenance requirements, incremental costs for potential retirements, storm hardening, operational performance, reliability, environmental impacts, economics, technical preference and sizing of equipment. Consideration of these factors may require input from study team members beyond that of the transmission planning engineer. To the degree that data is available, and a whole-life assessment of alternatives can be performed, whole - life cost may be a consideration in determining the appropriate solution.

Non-Wires Alternatives (NWA) may need to be evaluated in the course of alternative development and evaluation. The process for this varies by siting jurisdiction. Applicability of NWA depends on size and number of locations of the need identified. Specific National Grid documents and the Permitting and Licensing staff should be consulted.

The system should be planned and designed with consideration for ease of operation and in consultation with input from Transmission System Operations, Asset Management, and Other applicable groups as necessary. Such considerations include, but are not limited to:

3.12.1 Safety

All alternatives shall be designed with consideration to public safety and the safety of operations and maintenance personnel. Characteristics of safe designs include:

- adequate equipment ratings for the conditions studied and margin for unanticipated conditions
- use of standard designs for ease of operation and maintenance
- ability to properly isolate facilities for maintenance
- adequate facilities to allow for staged construction of new facilities or foreseeable future expansion

Consideration shall be given to address any other safety issues that are identified that are unique to a specific project or site.

3.12.2 Constructability

Each proposed alternative should be reviewed at a high conceptual level to gain assurance it can be constructed without significant expansion of scope. Sample actions to take for such review include considering if facility to be upgraded can be removed from service for an extended period, or if a new replacement facility needs to be constructed in parallel, conducting surveys, performing test borings, etc.

3.12.3 Construction Outage Requirements/Cost Impacts

Outage information, such as expected duration, schedule and flexibility, and potential congestion or reliability to load concerns for each proposed alternative should be discussed with Operations Center staff within National Grid and with the applicable System Operator.

3.12.4 Expected In-service Dates

The expected in-service date for the various components of each proposed alternative should be estimated and considered with regard to the date of need. Siting issues may significantly delay the expected in-service date for some proposed alternatives, to the point where interim upgrades may be required. Alternatives evaluation should address this possibility.

3.12.5 Interface Impacts

Material differences of proposed alternatives on Area internal and external interfaces should be analyzed and compared in the solution evaluation.

3.12.6 Losses

Proposed alternatives may have significant differences in system losses, which should be considered.

3.12.7 Extreme Contingency Performance

Screening analysis of system performance for extreme contingencies of each proposed alternative should be considered when differences are likely.

3.12.8 Expansion Capabilities

Differences in ability of proposed alternatives to provide for future system expansion or flexibility should be explored. Some items to consider may include available short circuit margin, costs to extend the system, and limitations in future equipment vendors.

3.12.9 Lifetime Maintenance Requirements

Equipment lifetimes should be considered if evaluating alternatives that employ technologies undergoing significant evolution. Examples include pipe-type cable and power electronics (e.g. HVdc, FACTS).

3.12.10 Incremental Costs for Potential Retirements

If the study area contains generating units or transmission equipment with a high likelihood of retirement, the proposed alternatives should be evaluated for additional requirements needed in such a retirement scenario.

3.12.11 Storm Hardening and Potential Effects of Climate Change

In developing alternatives, it may be prudent to consider avoiding use of flood-prone areas or making provision for such in the elevation of the proposed equipment. Tradeoffs between higher exposure and longer repair times must be recognized. Additionally, use of higher voltage class structures and equipment may be advantageous.

3.12.12 Operational Performance

Differences in expected operational flexibility should be considered and evaluated. Some alternatives may introduce differences beyond the study period.

3.12.13 Reliability

This guide assesses deterministic reliability by defining the topology, load, and generation conditions that the transmission system must be capable of withstanding safely. This deterministic approach is consistent with present NERC, NPCC, ISO-NE, and NYISO practice. Defined outage conditions that the system must be designed to withstand are listed in Table 4.1. The transmission system is designed to meet these deterministic criteria to promote the reliability and efficiency of electric service on the National Grid transmission system, and also with the intent of providing an acceptable level of reliability to the customers.

3.12.14 Environmental

An assessment should be made for each alternative of the human and natural environmental impacts. Assessment of the impacts is of particular importance whenever expansion of substation fence lines or transmission rights-of-way is proposed. However, environmental impacts also should be evaluated for work within existing substations and on existing transmission structures. Impacts during construction should be evaluated in addition to the impact of the constructed facilities. Evaluation of environmental impacts will be performed consistent with all applicable National Grid policies.

3.12.15 Economics

Initial and future investment cost estimates should be prepared for each alternative. The initial capital investment can often be used as a simple form of economic evaluation. This level of analysis is frequently adequate when comparing the costs of alternatives for which all expenditures are made at or near the same time. Additional economic analysis is required to compare the total cost of each alternative when evaluating more complex capital requirements, or for projects that are justified based on economics such as congestion relief. These analyses should include the annual charges on investments, losses, and all other expenses related to each alternative.

Depending on the project or required perspective, economic evaluation based on other models may be required. For example, a cash flow model or net present value model is typically used to assess the impact of each alternative on the National Grid business plan. A cumulative present worth of revenue requirements model is typically used to assess the impact of each alternative on the customer.

If the justification of a proposed investment is to reduce or eliminate annual expenses, the economic analysis should include evaluation of the length of time required to recover the investment. Recovery of the investment within 5 years is typically used as a benchmark, although recovery within a shorter or longer period may be appropriate.

3.12.16 Technical Preference

Technical preference should be considered when evaluating alternatives. Technical preference refers to concerns such as standard versus non-standard design or to an effort to develop a future standard. It may also refer to concerns such as condition of facilities, availability of spare parts, ease of operations and maintenance, ability to accommodate future expansion, ability to implement, or reduction of risk.

3.12.17 Sizing of New Equipment

All new equipment should be sized based on economics, operating requirements, standard sizes used by the company, and engineering judgment. Economic analysis should account for indirect costs in addition to the cost to purchase and install the equipment. Engineering judgment should include recognition of realistic future constraints that may be avoided with minor incremental expense. As a guide, unless the equipment is part of a staged expansion, the capability of any new equipment or facilities should be sufficient to operate without constraining the system and without major modifications for at least 10 years. To account for future load growth and/or system changes, the minimum margin should be at least 20% above the maximum expected demand on the equipment during the study period.

3.13 Reporting Study Results

A transmission system planning study shall culminate in a concise report describing the assumptions, procedures, problems/risks, alternatives, economic comparison, conclusions, and recommendations resulting from the study. If potential issues are identified, the study should recommend a course of action. The recommended action should be based on composite consideration of factors as noted in section 3.12. Recommendation should not be based solely on cost.

4.0 Design Criteria

4.1 Objective of the Design Criteria

The objective of the Design Criteria is to define the design contingencies and measures used to assess the adequacy of the transmission system performance.

4.2 N-1 Design Contingencies

N-1 analyses include the simulation of all applicable contingencies defined in the NERC standards, NPCC criteria, and ISO procedures referenced in section 2.2. In addition to those contingencies, the Design Contingencies in Table 4.1 are also used to assess the performance of the National Grid transmission system. Allowable facility loading information is also included for each contingency.

Control actions may be available to mitigate some contingencies listed in Table 4.1.

Table 4.1: Design Contingencies

Ref.	CONTINGENCY (Loss or failure of:)	Allowable Facility Loading
a	A permanent three-phase fault on any generator, transmission circuit, shunt device, transformer, or bus section	LTE
b	Simultaneous permanent single-line-to-ground faults on different phases of two adjacent transmission circuits on a multiple circuit tower (> 5 towers)[2]	LTE[1]
c	A permanent single-line-to-ground fault on any generator, transmission circuit, shunt device, transformer, or bus section, with a breaker failure	LTE[1]
d	Opening of a circuit breaker without a fault	LTE
e	A permanent single-phase-to-ground fault on a circuit breaker with normal clearing	LTE[1]
f	Simultaneous permanent loss of both poles of a bipolar HVdc facility without an ac system fault	LTE[1]
g	Loss of a system common to multiple transmission elements (e.g., cable cooling)	LTE[1]
h	Permanent single-line-to-ground faults on two cables installed in a manner that can lead to a common mode failure	LTE[1]

Notes to Table 4.1:

[1] Loading above LTE, but below STE, is acceptable for momentary conditions provided automatic actions are in place to reduce the loading of equipment below the LTE rating within 15 minutes.

[2] If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded. Other similar situations can be excluded on the basis of acceptable risk, subject to approval in accordance with Regional (NPCC) and Area (NYSRC or ISO-NE) exemption criteria, where applicable.

4.2.1 Fault Type

As specified in Table 4.1, some contingencies are modeled without a fault; others are modeled with a three phase or a single phase to ground fault. All faults are considered permanent with due regard for reclosing and before making any manual system adjustments.

4.2.2 Fault Clearing

Design criteria contingencies involving ac system faults on NPCC BPS facilities are simulated to ensure that stability performance criteria are met when either of the two independent protection groups, that perform the specified protective function, operates to initiate fault clearing. In practice, design criteria contingencies on the NPCC BPS are simulated assuming clearing by the slower of the two independent protection groups, if there is any difference in clearing time between the two groups.

Design criteria contingencies involving ac system faults on facilities that are not part of the NPCC BPS are simulated using clearing by the faster of the two protection groups (if more than one exists), based on correct operation of the faster group protecting the faulted element.

4.2.3 Allowable Facility Loading

The normal rating of a facility defines the maximum allowable loading at which the equipment can operate continuously. The LTE and STE ratings of equipment may allow an elevation in operating temperatures over a specific period provided the emergency loading is reduced back to, or below, a specific loading in a specific period of time (for specific times, see Section 3.4).

The system shall be designed to prevent loading equipment above the normal rating prior to a contingency. Further, the system should be designed to prevent loading equipment above the LTE rating following a design contingency (see Table 4.1 contingencies a through h). Under limited circumstances, however, it is acceptable to design the system such that equipment may be loaded above the LTE rating, but lower than the STE rating. Loading above the LTE rating up to the STE rating is permissible for contingencies b, c, e, f, g, and h, for momentary conditions, provided automatic actions are in place to reduce the loading of the equipment below the LTE rating within 15 minutes, and it does not cause any other facility to be loaded above its LTE rating. Such exceptions to the criteria will be well documented and require acceptance by National Grid Network Operations.

In New England an additional rating, the Drastic Action Limit (DAL), is calculated for use in real-time operations. The DAL is an absolute operating limit, based on the maximum loading to which a piece of equipment can be subjected over a five-minute period. Although the DAL is computed based on a five minute load duration, if equipment loadings reach a level between the STE and DAL limits, then immediate action is required to reduce loading to below LTE. The DAL is not used in planning studies or for normal operating situations. In some cases when the STE rating may be exceeded, it may be necessary to provide redundant controls to minimize the risk associated with failure of the automated actions to operate as intended.

4.2.4 Reliability of Service to Load for N-1 Contingencies

The transmission system is designed to allow the loss of any single element without a resulting loss of load, except in cases where a customer is served by a single supply. Where an alternate supply exists, interruption of load is acceptable for the time required to transfer the load to the alternate supply. Power flow simulations should assume the restoration of load through a load transfer scheme or manual operator action, when conducting contingency analysis on the transmission system.

Loss of load is acceptable for contingencies that involve loss of multiple elements such as simultaneous outage of multiple circuits on a common structure, or a circuit breaker failure resulting in loss of multiple elements. For these contingencies, measures should be evaluated to mitigate the frequency and/or the impact of such contingencies when the amount of load interrupted exceeds 100 MW. Such measures may include differential insulation of transmission circuits on a common structure or automatic switching to restore unfaulted elements. Where such measures are already implemented, they should be assumed to operate as intended, unless a failure to operate as intended would result in a significant adverse impact outside the local area.

A higher probability of loss of customer load is acceptable during an extended generator or transformer outage, maintenance, or construction of new facilities. Widespread outages resulting from contingencies more severe than those defined by the Design Contingencies may result in higher loss of load and/or extended duration of outages.

4.2.5 Load Shedding for N-1 Contingencies

Manual or automatic shedding of any load connected to the National Grid transmission system in response to a design contingency listed in Table 4.1 may be employed to maintain system security as a temporary solution to a reliability problem. However, shedding of load is not acceptable as a long term solution to design criteria performance issues, and recommendations will be made to construct adequate facilities to maintain system security without shedding load.

4.2.6 Expected Restoration Time

The transmission restoration time for the design contingencies encountered most frequently is typically expected to be within 24 hours. Restoration times are typically not more than 24 hours for equipment including overhead transmission lines, air insulated bus sections, capacitor banks, circuit breakers not installed in a gas insulated substation, and transformers that are spared by a mobile substation. For some contingencies however, restoration time may be significantly longer. Restoration times are typically longer than 24 hours for generators, gas insulated substations, underground cables, and large power transformers.

4.2.7 Generation Rejection or Ramp Down for N-1 Contingencies

Generation rejection or ramp down refers to tripping or running back the output of a generating unit in response to a disturbance on the transmission system. As a general practice, generation rejection or ramp down should not be included in the design of the transmission system. However, generation rejection or ramp down may be considered if the following conditions apply:

- acceptable system performance (voltage, current, and frequency) is maintained following such action
- the interconnection agreement with the generator permits such action
- the expected occurrence is infrequent (the failure of a single element is not typically considered infrequent)
- the exposure to the conditions is unlikely or temporary (temporary implies that system modifications are planned in the near future to eliminate the exposure or the system is operating in an abnormal configuration)

Generation rejection or ramp down may be initiated manually or through automatic actions depending on the anticipated level and duration of the affected facility loading. Plans involving generation rejection or ramp down require review and approval by National Grid Network Operations and may require approval of the ISO.

4.2.8 Generator Ride Through

All generators shall ride through voltage and frequency excursions as per Section 4.4.1 of National Grid's Electric System Bulletin No. 756 (ESB 756), Requirements for Parallel Generation Connected to a National Grid Owned EPS and the applicable ISO requirements.

All power flow and stability testing shall simulate the tripping of generators where simulations show generator voltage (bus voltages or voltages on the high side of the Generator Step Up (GSU) transformer) are less than known or assumed minimum generator steady state or ride through voltage limitations.

4.2.9 Performance of RAS/SPS/ALS/Enhanced Protection Systems

Assessments of transmission system performance assume correct operation of all RAS, SPS, ALS and other enhanced protection schemes.

4.2.10 Exceptions

These Design Criteria do not apply if a customer receives service from National Grid and also has a connection to any other transmission provider regardless of whether the connection is open or closed. In this case, National Grid has the flexibility to evaluate the situation and provide interconnection facilities as deemed appropriate and economic for the service requested.

National Grid is not required to provide service with greater deterministic reliability than the customers provide for themselves. As an example, if a customer has a single transformer, National Grid does not have to provide redundant transmission supplies unless requested and paid for by the customer.

In New York, some limited exceptions to this planning guide are allowed for specific conditions documented in the Exceptions to the NYSRC Reliability Rules.

4.2.11 N-1-1 Design Contingencies

N-1-1 is a sequence of events consisting of the initial loss of a single generator or transmission element identified in Section 4.1 (N-1), followed by system adjustments (N-1-0), and then followed by a second contingency. N-1-1 evaluations are performed in accordance with the NERC standards, NPCC criteria, and ISO procedures.

4.3 Voltage Response

Acceptable voltage response is defined in terms of maximum and minimum voltage in per unit (p.u.) for each transmission voltage class (Table 4.2), and in terms of percent voltage change from pre-contingency to post-contingency (Table 4.3). The values in these tables allow for automatic actions.

The voltage response also must be evaluated on the basis of voltage transients.

In New England, where applicable, both the steady state and transient voltage responses should comply with the ISO-NE Transmission Planning Technical Guide. In New York, the transient voltage response criterion is a recovery of 0.90 per unit by five seconds after the fault has cleared.

Table 4.2: Voltage Range

CONDITION	345 & 230 kV		115 kV & Below	
	Low Limit (p.u.)	**High Limit (p.u.)**	**Low Limit (p.u.)**	**High Limit (p.u.)**
Normal Operating	0.98	1.05	0.95	1.05
Post Contingency & Automatic Actions	0.95	1.05	0.90	1.05

Table 4.3: Maximum Percent Voltage Variation at Delivery Points

CONDITION	345 & 230 kV (%)	115 kV & Below (%)
Post Contingency & Automatic Actions	5.0	10.0
Switching of Reactive Sources or Motor Starts (All elements in service)	2.0 *	2.5 *
Switching of Reactive Sources or Motor Starts (One element out of service)	4.0 *	5.0 *

*These limits are maximums, which do not include frequency of operation. Actual limits will be considered on a case-by-case basis and will include consideration of frequency of operation and impact on customer service in the area.

Notes to Tables 4.2 and 4.3:

a. Buses that are part of the BPS, and other buses deemed critical by Network Operations shall meet requirements for 345 kV and 230 kV buses
b. Voltages apply to facilities that are still in service post contingency
c. Site specific operating restrictions may override these ranges
d. These limits do not apply to nuclear unit off site supplies
e. These limits do not apply to automatic voltage regulation settings, which may be more stringent
f. These limits only apply to National Grid facilities

4.4 System Stability

Transient stability of the transmission system shall be maintained during and following the most severe of the Design Contingencies in Table 4.1. Stability shall also be maintained if the faulted element, as described in Table 4.1, is re-energized by autoreclosing. For the analysis, all faults must be cleared in the manner described in Section 4.2.2 Fault Clearing.

In evaluating the system response, it is insufficient to merely determine whether a stable or unstable response is exhibited. There are some system responses which may be considered unacceptable even though the transmission system remains stable. Each of the following responses is considered an unacceptable response to a design contingency:

- Transiently unstable response resulting in widespread system collapse
- Transiently stable response with undamped power system oscillations
- In New England, the following responses are also unacceptable:
  - Transiently unstable generator response (other than those units tripped as a part of the fault clearing)
  - Less than a 53% reduction in the magnitude of a remaining single mode of oscillation observed over four periods of the oscillation
  - Voltage response that violates the ISO-NE Voltage Sag Guideline (Transmission Planning Technical Guide, appendix E)

- In New York, for a stability simulation to be deemed stable, oscillations in angle and voltage must exhibit positive damping within ten seconds after initiation of the disturbance. If a secondary mode of oscillation exists within the initial ten seconds, then the simulation time shall be increased sufficiently to demonstrate that successive modes of oscillation exhibit positive damping

5.0 Facility Design Requirements

5.1 Objective

The objective of this section is to provide guidance on the minimum acceptable configurations to be applied when a new generator, transmission line, or substation is to be interconnected with the National Grid transmission system or when the existing system is being modified as a result of equipment replacement or retirement. The goal is to assure that reliability and operability are not degraded as a consequence of the changes. The design shall appropriately address safety, reliability, operability, maintainability, and expandability, consistent with this Transmission Planning Guide for each new or revised installation.

5.2 Criteria

5.2.1 Safety by Design

Substation arrangements shall be designed with safety as a primary consideration. Standard designs shall be utilized for ease of operation and maintenance and to promote standardization of switching procedures. Substation arrangements shall also provide means to properly isolate equipment for maintenance and allow appropriate working clearances for installed equipment as well as for staged construction of future facilities. Consideration shall be given to address any other safety issues that are identified that are unique to a specific project or site.

5.2.2 Planning and Operating Criteria

Substation arrangements shall be designed such that all applicable Planning and Operating Criteria are met. These requirements may require ensuring that certain system elements do not share common circuit breakers or bus sections so as to avoid loss of both elements following a breaker fault or failure; this can be accomplished either by relocating one or both elements to different bay positions or bus sections or by providing two circuit breakers in series. These requirements may also require that existing substation arrangements be reconfigured, e.g. from a straight bus or ring bus to a breaker-and-a-half configuration.

5.2.3 System Protection

Substation arrangements shall provide for design of dependable and secure protection systems. Designs that create multi-terminal lines shall not be pursued except in cases where Protection Engineering verifies that adequate coordination and relay sensitivity can be maintained when infeed or outfeed fault current is present.

To ensure reliable fault clearing, it generally is desirable that no more than two transmission circuit breakers be required to be tripped at each terminal to clear a fault on a line or cable circuit. For transformers located within the substation perimeter, the incidence of faults is sufficiently rare that this requirement may be relaxed to permit transformers to be connected via appropriate switching directly to the buses in breaker-and-a-half or breaker-and-a-third arrangements, provided any applicable ISO procedures are met.

5.2.4 Operability

Substation switching shall be configured to prevent the loss of generation for normal line operations following fault clearing. Generators shall not be connected directly to a transmission line through a single circuit breaker except as noted in Section 5.5.2.

5.2.5 Reliability

Factors affecting transmission reliability shall be considered in interconnection designs. These factors include, but are not limited to:

- Additional exposure to transmission outages resulting from additional transmission line taps, with consideration to length of the proposed tap
- The number of other taps already existing on the subject line and the impact on reliability indices. In general, New England limits the number of taps to three per line and New York should review the number of taps on a case by case basis with focus on minimizing reliability impacts.
- The number and type of customers already existing on the subject line and potential impacts to these customers resulting from a proposed interconnection
- The existing performance of the subject line and how the proposed interconnection will affect that performance
- The impact on the complexity of switching requirements, and the time and personnel required to perform switching operations

Periodic transmission assessments should consider whether system modifications are necessary to improve reliability.

5.2.6 Maintainability

Substations shall be configured to permit circuit breaker maintenance to be performed without taking lines or generators out of service, recognizing that a subsequent fault on an element connected to the substation might result in the isolation of more than the faulted element. At existing substations with straight bus configurations, consideration will be given to modifying terminations in cases where an outage impacts the ability to operate the system reliably.

5.2.7 Future Expansion

Substation designs shall be based on the expected ultimate layout based on future system needs and physical constraints associated with the substation parcel.

5.3 Standard Bus Configurations

Given the development of the transmission system over time and through mergers and acquisitions of numerous companies, several different substation arrangements exist within the National Grid system. Future substation designs are standardized on breaker-and-a-half, breaker-and-a-third, and ring bus configurations, depending on the number of elements to be terminated at the station. Other substation configurations may be retained at existing substations, but are evaluated in periodic transmission assessments to consider whether continued use of such configurations is consistent with the reliable operation of the transmission system.

Determination of the appropriate substation design is based on the total number of elements to be terminated in the ultimate layout, and how many major transmission elements will be terminated. In New England, requirements are specified in ISO-NE Planning Procedure "*Major Substation Bus Arrangement Requirements and Guidelines"* (PP9). Major transmission elements include networked transmission lines 115 kV and above and power transformers with at least one terminal connected at 230 kV or 345 kV.

5.3.1 Breaker-and-a-Half

A breaker-and-a-half configuration is the preferred substation arrangement for new substations with an ultimate layout expected to terminate more than four major transmission elements or more than six total elements. If the entire ultimate layout is not constructed initially, the substation may be configured initially in a ring bus configuration. Cases will exist where a breaker-and-a-half configuration is required with fewer elements terminated in order to meet the criteria stated above.

Major transmission elements are terminated in a bay position between two circuit breakers in a breaker-and-a-half configuration. Other elements such as capacitor banks, shunt reactors, and radial 115 kV transmission lines may be terminated on the bus through a single circuit breaker. Transformers with no terminal voltage greater than 115 kV may be terminated directly on a bus. It may be permissible to terminate 345-115 kV or 230-115 kV transformers directly on a 115 kV bus if there is no reasonable expectation that more than two such transformers will be installed. Such a decision requires careful consideration however, given the difficulty of re-terminating transformers to avoid tripping two transformers for a breaker fault or failure in the event that a third transformer is installed at a later time.

5.3.2 Breaker-and-a-Third

A breaker-and-a-third configuration is an acceptable alternate to a breaker-and-a-half configuration in cases where a breaker-and-a-half arrangement is not feasible due to physical or environmental constraints. Considerations for terminating elements on a bus are the same as for breaker-and-a-half, except that 345-115 kV or 230-115 kV transformers may be terminated directly on a 115 kV bus since additional transformers may be terminated in a bay without a common breaker between two transformers.

5.3.3 Ring Bus

A ring bus may be utilized for new substations where four or fewer major elements will be terminated or six or fewer total elements will be terminated. A ring bus also may be utilized as an interim configuration during staged construction of a substation.

5.3.4 Straight Bus

Many older substations on the system have a straight bus configuration, with each element terminating on the bus through a single breaker. Variations exist in which the bus is segmented by one or more bus-tie breakers, provisions are provided for a transfer bus, or the ability exists to transfer some or all elements from the main bus to an emergency bus. Periodic transmission assessments shall consider whether continued use of existing straight bus configurations is consistent with maintaining reliable operation of the transmission system.

New NPCC BPS substations shall not utilize a straight bus design. Straight bus designs may be utilized at NPCC non-BPS substations subject to the following conditions:

- A transfer bus is provided to facilitate circuit breaker maintenance
- The transfer breaker protection system is capable of being coordinated to provide adequate protection for any element connected to the bus
- Justification is provided to support deviating from the standard breaker-and-a-half, breaker-and-a-third, or ring bus configuration
- All requirements of Section 5.2 are met

5.4 Substation Design Considerations

5.4.1 NPCC BPS Design Considerations

When an element has been identified as part of the NPCC BPS, the protection system for that element must be designed to meet the NPCC Directory #4 "*Bulk Power System Protection Criteria*". These criteria require redundancy and separation of protection system components and have a significant impact on physical space requirements as well as project scope, schedule, and cost. These impacts typically are greatest when modifications are required at existing substations. Given that these impacts can be significant, it is appropriate to consider designing and in some cases pre-building facilities to meet these requirements to avoid more costly retrofitting at a later time. The following guidance is provided for cases where facilities have been identified as part of the NPCC BPS, have the potential to become BPS facilities, or are unlikely to become BPS facilities.

5.4.1.1 Existing or New NPCC BPS facilities

These facilities have been identified as part of the BPS through application of the NPCC A-10 "*Criteria for Classification of Bulk Power System Elements*".

Such facilities are always designed and constructed to meet NPCC Criteria.

5.4.1.2 Potential NPCC BPS facilities

These facilities have not been identified as part of the BPS through application of the NPCC A-10 "*Criteria for Classification of Bulk Power System Elements*", but have been identified as potential BPS facilities through the results of testing (e.g. marginally acceptable results), proximity to existing BPS facilities, or are reasonably expected to become part of the BPS due to proposed transmission reinforcements within the 10-year planning horizon. The extent to which facilities will be designed and constructed to meet NPCC Criteria must consider scope, schedule, and cost of future modifications of the facilities compared to the incremental scope, schedule, and cost of designing or constructing to meet NPCC Criteria as part of the project.

Such substations are expected to be designed to meet NPCC Criteria, but are not expected to be constructed to meet NPCC Criteria except where the incremental cost is minimal, e.g. circuit breakers purchased with two current transformers per bushing and two trip coils. Locations are identified for future batteries, cable conduits, etc. and incorporated into drawings.

Modifications at existing substations must consider the extent of work related to the project compared to future work that may be required to meet NPCC Criteria.

If major modifications are being made at a substation and deferring design to meet NPCC Criteria would significantly increase future scope, schedule, and cost; then incorporating the design changes in the project to meet NPCC Criteria must be considered.

If minor modifications are being made at a substation, then the facilities are designed to meet NPCC Criteria only when there will not be a significant impact on the scope, schedule, or cost of the project.

5.4.1.3 Existing or New facilities Unlikely to be Classified as NPCC BPS

These facilities have not been identified as bulk through application of the NPCC A-10 "*Criteria for Classification of Bulk Power System Elements"*, and are unlikely to become part of the BPS within the 10-year planning horizon.

Such facilities are not designed or constructed to meet NPCC Criteria.

5.4.2 Independent Pole Tripping Circuit Breakers

Circuit breakers with Independent Pole Tripping (IPT) capability may be installed to mitigate the impact of an extreme contingency three-phase fault accompanied by a breaker failure. The independent operating mechanisms and control circuitry for each pole of this circuit breaker type result in a low probability that a breaker failure will result in a failure to interrupt the fault current in more than one breaker pole. In simulations of these extreme contingencies the fault is downgraded from three-phase to single-line-to-ground after failure of a circuit breaker with IPT capability and clearing of other sources contributing to the fault.

The National Grid standard design specification for 345 kV circuit breakers requires IPT capability for all applications. At transmission voltages 230 kV and below, circuit breakers with IPT capability are installed based on a case-by-case review considering the potential impact to be mitigated and the incremental cost of the circuit breaker application. The incremental cost consists of two components. The first component is the incremental equipment cost for purchasing the circuit breaker. The second component is associated with additional auxiliary relays and increased control wiring requirements.

Circuit breakers with IPT capability are applied at transmission voltages at or below 230 kV when transient stability simulations of three-phase faults accompanied by a breaker failure indicate a basic system weakness that jeopardizes the integrity of the overall NPCC BPS. In these cases, adding or replacing circuit breakers with IPT capability is justified to comply with NPCC Directory #1 "*Design and Operation of the Bulk Power System"*.

When 230 kV or 115 kV circuit breakers are added or replaced at NPCC BPS substations, IPT capability should be considered when there will not be a significant impact on the scope, schedule, or cost of the project. In these cases the incremental cost is justified to avoid the potential for significant cost to replace the circuit breakers later if system changes result in a basic system weakness that jeopardizes the integrity of the overall NPCC BPS.

5.4.3 Placement of Surge Arresters

Surge arresters are sometimes applied on substation buses at air-insulated substations. Surge arresters also are applied on equipment terminals when the element connected to the bus is an underground cable or transformer.

Surge arresters also may be applied on line terminals at air-insulated substations to limit transient overvoltage at 230 kV and 345 kV. The need for line arresters is determined on case-by-case basis either instead of or in addition to pre-insertion closing resistors or synchronous closing controls in the circuit breakers at the remote line terminal. In these cases a line arrester may be necessary to control switching surges when the line is energized from the remote terminal when the local terminal is open (in which case the bus arrester cannot control the switching surge).

Surge arresters are applied on equipment terminals for all elements connected to a gas-insulated substation via SF6 to air bushings.

5.5 Issues Specific to Generator Interconnections

5.5.1 Interconnection Voltage

It is desirable to connect generators at the lowest voltage class available in the area for which an interconnection is feasible. In general, small generators no larger than 20 MW will be interconnected to the transmission system only when there is no acceptable lower voltage alternative in the area and it is not feasible to develop a lower voltage alternative.

5.5.2 Interconnection Facilities

5.5.2.1 General

The minimum interconnection required for all generation shall be a three-breaker ring bus, unless an exception is granted for any of the conditions noted below. Additional circuit breakers and alternate substation configurations may be required when interconnecting multiple generating units.

5.5.2.2 New England Interconnections

For generators interconnecting to PTF facilities, which are under ISO-NE jurisdiction, the guidance in ISO-NE Planning Procedures and ISO-NE Transmission Planning Technical Guide shall be followed.

Generation may be granted an exception, and allowed to connect with a single circuit breaker or circuit switcher, subject to acceptable evaluations noted below, for any of the following conditions:

1. Generation connected to a radial transmission line.[3]
2. Generation connected to a tap from a radial transmission line.
3. Generation no larger than 20 MW connected to:
   a. A network transmission line;
   b. An existing tap from a network transmission line; or
   c. A dedicated distribution circuit(s), tapped from a network transmission line via a step-up transformer, with no load served (except for station service) on the circuit(s).
4. Generation connected to existing distribution circuits or systems serving existing load (except for station service).

Note regarding exception #3:
Incremental generation additions at an existing substation (at either transmission or distribution voltage), which will result in greater than 20 MW of total generation at that substation, with no load served on the circuit(s) (except for station service), shall trigger the minimum three-breaker ring bus requirement.

These exceptions shall be evaluated on a case-by-case basis and shall be granted only when the conditions in section 5.5.2.4 are met.

[3] A radial transmission line is defined as a transmission line that emanates from a single station with one or more breakers that are capable of switching the transmission line in and out of service. Note that a radial tap from a network transmission line is part of that network transmission line.

5.5.2.3 New York Interconnections

Generation interconnecting to facilities operated at 200kV or less, or to radial transmission lines greater than 200kV, may be granted an exception and allowed to connect with a single circuit breaker or circuit switcher. These exceptions shall be evaluated on a case-by-case basis and shall be granted only when the conditions in section 5.5.2.4 are met:

5.5.2.4 Conditions for exceptions to ring bus requirements

- Protection Engineering verifies that the transmission line and interconnection facilities can be protected adequately, while ensuring that transmission system protective relay coordination and relay sensitivity can be maintained
- Transmission Planning verifies that transmission reliability and operability are not adversely impacted by assessing the Design Criteria listed in Section 5.2 pertaining to safety, planning and operating criteria, reliability, and maintainability
- As deemed necessary by Transmission Planning, provisions acceptable to National Grid are made to accommodate the future expansion of the interconnection to (at least) a three-breaker ring bus

5.5.3 Distributed Generation (DG)

Distributed Generators 20 MW and below, should follow the National Grid "*Specifications for Electrical Installations – Electric System Bulletin No. 756 (ESB 756)".* In New England, interconnection studies need to incorporate ISO-NE Transmission Planning Technical Guide and ISO-NE Operating Procedure No. 14 when modeling and assessing the impact of distributed generation.

5.5.4 Status of Interconnection Design

The design for any generator interconnection is valid only for the generating capacity and unit characteristics specified by the developer at the time of the request. Any modifications to generating capacity and unit characteristics require a separate system impact study and may result in additional interconnection requirements.

Modifications to the interconnection design may be required as a result of future modifications to the transmission system. National Grid will notify the generation owner when such modifications are required.

5.5.5 Islanding of Load and Generation

System operation with generation and customer load islanded from the transmission system is undesirable due to frequency and voltage fluctuations that likely will occur as a result of an imbalance between load and generation. When the potential exists for islanding load and generation for design contingencies, the interconnection protection must be designed to detect when the generation is islanded with load to ensure tripping of the generator. The protection requirements are relatively straight-forward when the maximum output of the generation is less than the minimum connected load. When it is possible for the load and generation to be balanced, detection is more difficult and direct transfer tripping of the generator may be required.

6.0 Glossary of Terms

Area (NPCC)

An Area (when capitalized) refers to one of the following: New England, New York, Ontario, Quebec or the Maritimes (New Brunswick, Nova Scotia and Prince Edward Island); or, as the situation requires, area (lower case) may mean a part of a system or more than a single system. Within NPCC, Areas (capitalized) operate as control areas as defined by the North American Electric Reliability Council (NERC) (the definition of control area can be found in the NPCC Glossary of Terms Not Used by any Directories section of this NPCC Glossary of Terms.)

Bulk Electric System (NERC)

All Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. See NERC definition Glossary of Terms Used in NERC Reliability Standards for BES definition which includes Inclusions and Exclusions.

Bulk Power System (NPCC)

The interconnected electrical system comprising generation and transmission facilities on which faults or disturbances can have a significant impact outside the local area.

Contingency

An event, usually involving the loss of one or more elements, which affects the power system at least momentarily.

Element

Any electric device with terminals which may be connected to other electric devices, such as a generator, transformer, transmission circuit, circuit breaker, an HVdc pole, braking resistor, a series or shunt compensating device or bus section. A live-tank circuit breaker is understood to include its associated current transformers and the bus section between the breaker bushing and its free standing current transformer(s).

Fault Clearing - Delayed

Fault Clearance consistent with correct operation of a breaker failure protection group and its associated breakers or of a backup protection group with an intentional time delay.

Fault Clearing - Normal

Fault Clearance consistent with correct operation of the protection system and with correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that protection system.
Note: Zone 2 clearing of line-end faults on lines without pilot protection is normal clearing, not delayed clearing, even though a time delay is required for coordination purposes.

High Voltage dc (HVdc) System, Bipolar

An HVdc system with two poles of opposite polarity and negligible ground current.

Interface

A group of transmission lines connecting two areas of the transmission system.

Load Cycle

The normal pattern of demand over a specified time period (typically 24 hours) associated with a device or circuit.

Load Level
A scale factor signifying the total load relative to peak load or the absolute magnitude of load for the year referenced.

Loss of Customer Load (or Loss of Load)
Loss of service to one or more customers for longer than the time required for automatic switching.

NPCC Special Protection Systems (SPS)
See NPCC glossary for SPS definition

NERC Remedial Action Scheme (RAS)
See NERC glossary for RAS definition

Supply Transformer
Transformers that only supply distribution load to a single customer.

Transfer
The amount of electrical power that flows across a transmission circuit or interface.

Transmission Customer
Any entity that has an agreement to receive wholesale transmission service from the National Grid transmission system.

Transmission Transformer
Any transformer with two or more transmission voltage level windings or a transformer serving two or more different customers.