IBERDROLA USA

ELECTRIC TRANSMISSION PLANNING MANUAL – CRITERIA & PROCESSES

New York State Electric & Gas (NYSEG),
Rochester Gas and Electric (RG&E),
Central Maine Power (CMP) and
Maine Electric Power Company (MEPCO)

Reviewed and Approved By: Curtis Beveridge		Date: 11-06-2014
Reviewed and Approved By: Timothy Lynch		Date: 11-06-2014
Approved By: Alonso, Beatriz		Date: 11-06-2014

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00	7-28-2011	Issued for Iberdrola-USA Planning consolidation	IUSA System Planning
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1 Introduction

This document defines transmission system design criteria and guidelines that maintain an acceptable electric transmission system that meets the needs of Iberdrola USA (IUSA) customers in a safe, reliable and economical manner.

Planning criteria allow for the identification of developing problems and ensure that plans adequately address service requirements. The IUSA transmission planning criteria is to be utilized when analyzing the transmission system reliability as part of reliability studies and new transmission interconnections.

Failure to meet any one criterion can justify a system improvement. Some criteria, such as those dealing with safety, require a more immediate response and will take priority over other problems that may be deferred. The transmission planners must evaluate each proposed project against the planning criteria and establish its priority. In addition to the priority of a project, those deemed necessary for compliance with Reliability Standards will be non-discretionary as they are established by deterministic North American Electric Reliability Corporation (NERC) standards.

The System Planning Department reserves the right to routinely amend any of these criteria at any time.

This document is broken down in the following sections:

- Section 1 – Introduction: A description of the use of this document
- Section 2 – Tools: A listing of software utilized by IUSA System Planning
- Section 3 – Description of the Transmission System: An introduction to the IUSA system and operating companies that make up IUSA
- Section 4 – Transmission Planning Criteria: Metrics that the transmission system must perform within.
- Section 5 – Simulation and Assumptions: Assumptions and guidance for simulations, including modeling, scenarios and sensitivities
- Section 6 – Interconnections: Procedures for interconnection to the transmission system for generation, load and transmission ties are explained
- Section 7 – External Drivers: A description of processes external to IUSA that each operating company must adhere to
- Section 8 – Project Prioritization: An overview of how projects are ranked with respect to each other

1.1 Jurisdiction of Criteria

IUSA strives to ensure that its transmission planning criteria does not conflict with jurisdictional authority. When analyzing the transmission system the order in application of authority should be:

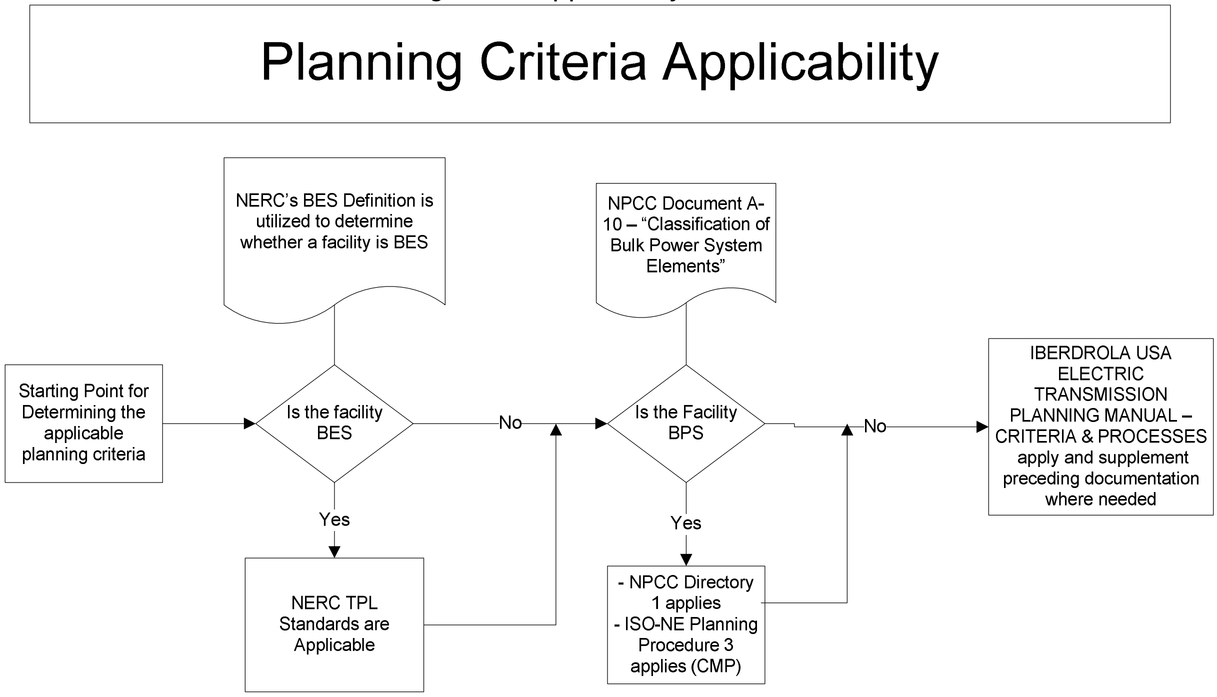
1. NERC Reliability Standards
2. NPCC Standards
3. ISO criteria through Open Access Transmission Tariff (OATT) or legal agreement
4. Local Transmission Planning Criteria

The IUSA Electric Transmission Planning Manual is designed to provide criteria required to supplement federal and regional standards (such as voltage limits). This document is designed to contain all criteria to study the reliability of its local transmission system and maintain compliance with state statutes along with commission orders[1].

1.2 Applicability Flow Chart

To aid in determining the application of standards and criterion, the following flow cart is provided (Figure 1).

Figure 1: Applicability flow chart



[1] Methods for planning and designing the local transmission system are consistent with the Maine Public Utilities Commission order in Docket No. 2011-00494, "Investigation into Maine Electric Utilities Transmission Planning Standards and Criteria"; which established "Safe Harbor" assumptions and practices to support Certificates of Public Convenience and Necessity.

2 Transmission Planning Tools

IUSA utilizes multiple types of power system simulation software. This software allows engineers to conduct reliability testing, analyze potential system deficiencies and test for solutions. The following products are utilized in addition to the standard suite of Microsoft Office and Windows tools.

PSS®E

Siemens Power System Simulator for Engineering (PSS®E) is a power system simulator used for transmission analysis. The primary uses within IUSA are power flow and dynamic simulations. In addition to typical transmission planning analysis, IUSA utilizes PSS/E for studying Geomagnetic Induced Currents (GIC).

ATPDraw

ATPDraw is an Electromagnetic Transients Program (EMTP) utilized occasionally for detailed transmission system analysis. This program can be utilized to simulate many power system actions including back-to-back capacitor switching, switching impulses, transformer energization, etc…

ASPEN – OneLiner™

This program is primarily utilized by the Electric System Engineering (aka System Protection Engineering) department within IUSA. System Planning utilizes the program to calculate short circuit current and system impedance information. This contributes to the required transmission system short circuit analysis and providing input to dynamic simulations performed in PSS®E.

3 Description of the IUSA Transmission System

Iberdrola USA is a subsidiary of the global energy leader Iberdrola, SA. IUSA transmission facilities owned by the companies of Central Maine Power (CMP), New York State Electric and Gas (NYSEG) and Rochester Gas and Electric (RG&E). The IUSA transmission infrastructure supports more than 1.8M customers with ~8200 miles of transmission lines and over 900 substations. As regulated utilities, each company has various obligations and commitments to ensure construction of a reliable transmission system.

The three operating companies of the IUSA family fall under the jurisdiction of the Federal Energy Regulatory Commission (FERC), NERC, and the NPCC. In addition to the federal and regional entities, CMP is under the purview of the New England Independent System Operator (ISO-NE) and the Public Utility Commission of Maine (MPUC). Similarly NYSEG and RG&E are part of the New York Independent System Operator (NYISO), New York State Reliability Council (NYSRC), and New York State Public Service Commission (NYPSC).

The Maine Electric Power Company (MEPCO) is also a transmission owning company located in the state of Maine. It consists of a majority stake ownership of CMP and minority ownership of Emera Maine. Criteria and responsibilities for CMP are also applicable to MEPCO. Together RG&E and NYSEG may be referred to as New York companies throughout this document.

3.1 Definitions of the Transmission System

The broadest definition of the transmission system is given by FERC. This definition is independent of operating voltage and states, “Moving bulk energy products from where they are produced or generated to distribution lines that carry the energy products to consumers.” Generally a FERC seven-factor test, established in FERC Order 888, is applied in the determination of transmission vs. distribution. Further clarification is left to the state for setting boundaries of transmission vs. local distribution.

In 2014 the NERC Bulk Electric System (BES) revised definition became effective. This defines clearly all facilities which are under the purview of the NERC Reliability Standards. All NPCC participants have registered their list of BES facilities with NPCC.

A more narrowly defined set of transmission elements is governed by NPCC’s Document A-10 “Classification of Bulk Power System Elements.” Bulk Power System (BPS) facilities are defined as those facilities whose performance affects the reliability of supply to other utilities and customers beyond the local area. The Bulk Power System is designed based on the requirements of the NPCC “Design and Operation of the Bulk Power System” (NPCC Directory #1) and other NPCC directories and criteria.

All IUSA operating companies participate within the purview of a regional Independent System Operator (ISO). These are ISO-NE for CMP and NYISO for RG&E and NYSEG. As a part of membership in an ISO, each member is bound to construct facilities that maintain reliability on the transmission system. These agreements bind CMP to utilize ISO-NE’s Planning Procedure 3 and approved Reliability Rules in New York.

Local transmission facilities are all other transmission facilities that are primarily used to supply local area load, large industrial customers and/or connect smaller generation. The local transmission system generally consists of facilities that operate between 115 kV and 34.5 kV. Distribution facilities dedicated to serving customers are covered by the IUSA Distribution Planning Criteria[2].

[2] Iberdrola USA Technical Manual, TM 1.61.00, “Distribution Planning Criteria”

RG&E supplies a portion of the City of Rochester from networked transmission facilities that are operated at 11 kV. These bi-directional flow network facilities are operated in parallel with the 115 kV and 34.5 kV transmission systems and are part of the transmission system.

4 Transmission Planning Criteria

This section is designed to house the metrics used to judge system performance. These criteria are to be met when analyzing Planning Events and Normal Contingencies.

4.1 Facility Ratings

IUSA utilizes ratings in its transmission planning studies to ensure safe operation without excessive loss of equipment life. Ratings to be used are consistent with those developed in compliance with the NERC FAC-008-3 standard for the BES and approved methods for local transmission facilities. Facility Rating Methodologies for each operating company are posted in a separate document. CMP utilizes the document “CMP Procedures for Determining and Implementing Ratings for Transmission Facilities.” The CMP procedure relies on ISO-NE’s PP-7 procedure in providing the technical direction of Facility Rating development and is supplemented by input assumptions developed by CMP. The New York operating companies rely on the “New York Tie-Line Rating Guide” for facilities newer than 1995 and the “Report of Task Force on Tie Line Ratings – NYPP” for facilities older than 1995.

Three categories of ratings are utilized:

1) **Normal Rating:** This rating is the continuous rating of the transmission facility adjusted to seasonal ambient conditions. There are no restrictions on utilization of the full normal rating for any extent of time.
2) **Long Term Emergency Rating (LTE):** For a time period up to 4 hours in New York and winter in Maine or 12 hours in Maine’s summer season, facilities may be loaded past their Normal Rating and less than their LTE after a contingency. The transmission facility must return to a loading level below its normal rating once the time duration of the LTE has expired.
3) **Short Term Emergency Rating (STE):** This rating is applicable for short term loadings on transmission facilities after a contingency has occurred. This is assuming the pre-contingent loading is within the facility’s normal rating. The maximum length of time that a facility may be loaded utilizing its STE limit is 15 minutes. After which the loading must decrease below LTE.
4) **Drastic Action Limit (DAL):** This rating has been developed for operational use only. It is not intended to be used as design criteria and is included for informational purposes only.

Table 1: Rating Applicability

SYSTEM CONDITION	TIME INTERVAL	MAXIMUM ALLOWABLE FACILITY LOADING
Normal (all facilities in)	Continuous	Normal Rating
Post Contingent	Less than 15 minutes after contingency occurs	Short Time Emergency (STE) Rating
	Between 15 minutes and LTE duration	Long Time Emergency (LTE) Rating

4.2 Voltage

4.2.1 Steady State

When analyzing the transmission system, voltage must remain within the steady state bandwidth of .95 – 1.05 V PU. This range is to be maintained prior to and after a contingency occurs on the transmission system with additions stated below. Performance with this voltage range is applicable to the contingencies described in Section 5.3.

Additions:

1) IUSA strives to provide adequate voltage to all customers. In addition to these limits customer voltage must remain within those specified in ANSI C84.1. The State of Maine also requires that CMP provide service to customers which meet voltage criteria within MPUC 65-407 Chapter 32 Section 2.04.
2) Post Contingent voltage is measure after automatic system actions have occurred (LTC, capacitor, SPS actions…).
3) Voltages on the 115 kV system as low as .92 PU may be accepted after two independent contingencies, such as a TPL-001-4 P6 event, as long as two conditions are met after automatic adjustments occur. a) The number of buses affected is three or less and b) customer voltages are adequately held to MPUC regulations. Modeling of multiple buses for a single voltage at a substation are to be counted as a single bus.
4) In NY, service to regulated distribution facilities allow for an expanded voltage bandwidth. During normal and single contingency conditions voltage supplied to regulated distribution facilities must maintain a voltage between .90 – 1.05 V PU. Service to unregulated distribution facilities requires the standard bandwidth presented of .95 – 1.05 V PU.

4.2.2 Flicker

IUSA considers the normal action of shunt connected transmission devices (either directly or through a transformer) to be within the scope of devices applicable to voltage flicker. The maximum allowable flicker on the transmission system by the starting of large motors, the switching of capacitor banks, or other devices is defined by the IEEE Standard 1453 flicker curve (see Figure 2). The “Borderline of Visibility” curve is used as the design criteria for the transmission system.

With all elements of the transmission system operating and in-service, the instantaneous bus voltages must not change by more than 3% while the number of switching events is limited to less than one per hour. Additionally, as seen on the curve, voltage flicker within the frequency range of 2 to 8 dips per second (characteristics of an arc furnace) shall be less than 0.5%.

In addition to the maximum voltage flicker threshold with all facilities in-service, IUSA also utilizes a criterion to test a facility out-of-service. With one element out of service a 5% flicker is acceptable for switching frequencies of one or less per hour. These criterions will not be applied retroactively to equipment already in-service. When retiring a transmission line, impacts to the magnitude of flicker should be considered.

Figure 2: Voltage flicker limitation curve

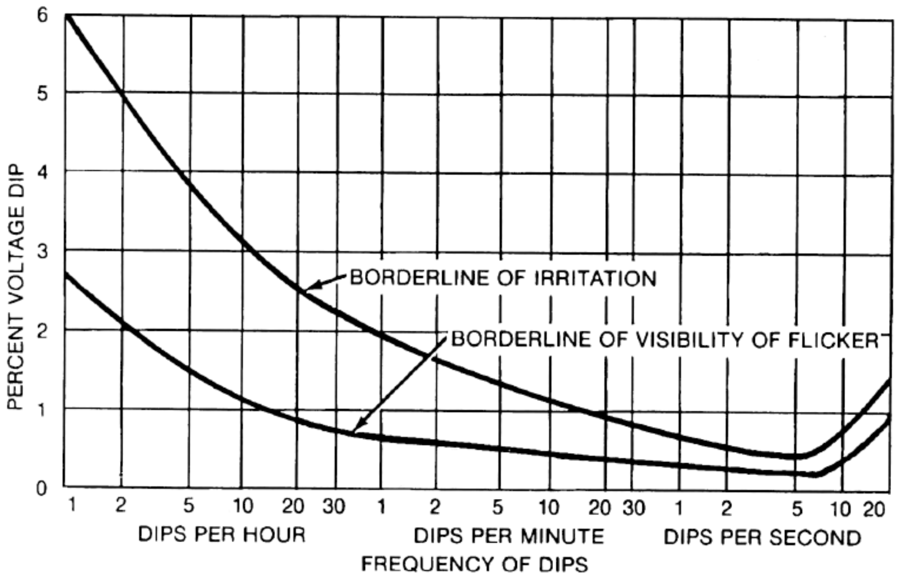


Figure A.1—Flicker tolerance curve from IEEE Std 141-1993/IEEE Std 519-1992

Voltage change during a fault, generation trip, or the operation of a series transmission element is not considered voltage flicker to be bound by this section.

4.3 Dynamic/Transient/Time Domain Simulation

4.3.1 Transient Voltage Response

CMP has adopted the use of ISO-NE's Transmission Planning Technical Guide Appendix E "Dynamic Stability Simulation Voltage Sag Guideline" as its criteria on transient voltage recovery. This is applicable to BES facilities and response to "Planning Events."

4.4 Frequency

Since the transmission network in the northeastern United States and Canada is well interconnected, frequency deviation is not usually a significant concern. The interconnected transmission systems of eastern North America typically have a frequency variation of a fraction of 1%. The Bulk Power transmission system is designed to comply with NERC/NPCC criteria for under-frequency load-shedding and generator frequency or speed protection. These criteria are designed to help survive islanding and stabilize system frequency at 60 Hz. The under-frequency load-shedding plan is a joint effort between the System Planning, System Protection, and System Operations Departments.

A Normal Operating State exists when the frequency is not less than 59.95 Hz or not greater than 60.05 Hz. An Alert State exists when the frequency is between 60.05 Hz and 60.10 Hz or between 59.90 Hz and 59.95 Hz. Finally, a Major Emergency exists when the frequency increases to 60.10 Hz and is sustained at that level or continues to increase, or declines to 59.90 Hz and is sustained at that level or continues to decline.

4.5 Short Circuit Criteria

System Planning coordinates with the System Protection and Engineering departments to ensure that short circuit analysis and breaker duty studies are conducted when new transmission system and interconnection projects are being considered. IUSA utilizes ASPEN ® to conduct its short circuit analysis. Table 2 contains the assumptions used for simulation of short circuit. Similar assumptions should be used with alternate software.

Table 2. ASPEN assumptions

ASPEN Short Circuit Modeling Assumptions		
X/R Options		
Compute ANSI x/r ratio		**YES**
Assume Z2 equals Z1 for ANSI x/r calculation		**YES**
X-only calculation	If X is 0 use:	0.0001 p.u.
R-only calculation	If R is 0 use:	Method 1
	Rc	0.0001 p.u.
	Typical X/R ratio (g) for generators	60
	Typical X/R ratio (g) for transformers	30
	Typical X/R ratio (g) for all other equipment	10
Fault Simulation options		
Pre-fault voltage	Assumed "Flat" with V(p.u.)	1.05
Ignore shunts	Loads	**YES**
	Transmission line G + jB	**YES**
	Shunts with + sequence values	-
	Transformer line shunts	-
Generator Impedance	Subtransient	-
MOV-protected series capacitor	Iterate short circuit solutions	**YES**
	Acceleration Factor	0.4
Define fault MVA as product of	Current and pre-fault voltage	-
Current limited generators	Ignore current limits	-
ANSI/IEEE Breaker Checking Options		
Fault types		3LG, 2LG, 1LG
For X/R calculation, use		Separate X-only, R-only networks
In 1LG faults, allow up to 15% higher rating for		Symmetrical current rated
Force voltage range factor K=1 in checking	Symmetrical-current rated breakers	**YES**
	Max design or higher	121
Miscellaneous options	Treat all sources as remote	**YES**
All generation modeled online to maximize fault current		**YES**

4.6 Load Loss Acceptability

Loss of Load (LOL) is an important measure of the transmission system dependence on specific system facilities and is one reliability indicator which provides engineers with quantitative methods for revealing system weaknesses.

4.6.1 Consequential Load Loss

Within Maine, during system intact conditions (all lines in service), up to 25 MW of load loss due to the normal operation of protective devices is allowed for a fault with normal clearing. The outages in consideration are listed under NERC TPL-001-4 as Planning Event P1 contingencies and similar outages on non-BES elements. A maximum of 60 MW may be accepted, in anticipation of a P1 outage (single outage on the local system), for consequential load loss while performing maintenance. The impact of consequential loss of load will be considered during planning studies in NY, but a maximum loss is not stipulated.

Customers other than IUSA taking service at a transmission level may elect to have more than 25 MW of load loss when choosing designs for interconnection.

4.6.2 Non-Consequential Load Loss

During a NERC Planning Event on the BES transmission system or single contingency on the Local Transmission system, IUSA does not allow the use of Non-Consequential Load Loss to maintain system performance criteria as a permanent solution[3].

For temporary measures, after the second contingency of a P6 event, Non – Consequential Load Loss will be permitted to bring the system within pre-contingent facility rating operating limits assuming STE ratings have not been exceeded. In addition for temporary reliability improvement, to ensure adequate voltage and protect customer equipment, Under Voltage Load Shedding (UVLS [4]) would be required to bring a low voltage conditions within criteria. In a condition of projected voltage collapse manual or automatic load shedding schemes will be insufficient.

[3] Non-Consequential Load Loss is only accepted on a temporary basis when allowed by NERC standards. A binding commitment to provide a solution must be developed to improve the transmission system post contingent response. Temporary solutions for reducing line loading must be conducted within facility loading capabilities. When voltage criterion is not met, an automatic means of bringing the system within boundaries, such as UVLS, should be temporarily used. Automatic or manual load shedding based on voltage sensing is not sufficient in the case of voltage collapse.

[4] UVLS Loss of load will only be accepted on a temporary basis. A binding commitment to provide a solution must be developed to improve the transmission system post contingent voltage response must exist. Temporary solutions for reducing line loading must be conducted within facility loading capabilities. When voltage criteria are not met, an automatic means of bring the system within boundaries, such as UVLS, should be used. Automatic or manual load shedding based on voltage sensing is not sufficient in the case of voltage collapse.

4.7 Harmonics

Harmonic distortion caused by customer load characteristics and capacitor banks shall be limited such that harmonic voltage distortion on the system shall not exceed any applicable ANSI standards for equipment connected to the system. Also, as stated in IEEE Standard 519-1992 (see below), voltage distortions shall not exceed 3% for any single frequency or 5% total harmonic distortion, and shall not injuriously affect equipment or its service to others. However, it is recognized that reasonable engineering judgment must be used in the application of these limits to balance compliance costs against adverse consequences of excess harmonic distortion.

Figure 3: Voltage distortion limits

Table 11-1—Voltage Distortion Limits

Bus Voltage at PCC	Individual Voltage Distortion (%)	Total Voltage Distortion THD (%)
69 kV and below	3.0	5.0
69.001 kV through 161 kV	1.5	2.5
161.001 kV and above	1.0	1.5

NOTE — High-voltage systems can have up to 2.0% THD where the cause is an HVDC terminal that will attenuate by the time it is tapped for a user.

5 Simulation and Assumptions

This section of the IUSA Electric Transmission Planning manual is designed to guide model setup, scenarios, and illustrate general study assumptions to use.

5.1 Model Selection

Selecting a model that represents the area in question is one of the most important steps of a transmission planning study. The model needs to have enough detail to represent the condition and location being studied yet not so much as to inhibit the completion of a study. IUSA System Planning engineers are directed to utilize engineering judgment along with direction from regulating bodies to ensure use of models that are effective in studies. When developing models and studies it is important to:

- Utilize ratings reflective of the time period being analyzed (5.1.1)
- Construct realistic transmission operating conditions (5.2),
- Conduct simulations of the spectrum of required contingencies (5.3)
- Forecast loads to ensure the system performs within the range of loading over time (5.4)
- Take into effect the higher forced outage rate of generation (5.5)

5.1.1 Ratings

Ratings for facilities used in studies need to adhere to the criteria under section 4.1. While monitoring for overloads on facilities, studies need to monitor the duration of ratings in accordance to section 4.1. It is recommended to utilize the normal rating of a facility in studies to ensure all potential issues are reviewed for their ability to reduce loading in applicable timeframes. Transmission Planning Engineers can gain access to ratings in each state by the following methods.

New York

For the ratings of all transmission lines operating between 345 kV and 69 kV refer to the most recent NYSEG and RG&E respective “Tie Line Rating” sheets.

For the ratings of all transmission lines operating at 46 kV or 34.5 kV refer to the NYSEG “Conductor Safe Ampere rating” sheet dated July 25, 1978.

CMP

All ratings to be used are located within the FactilityRatingsDB.mdb Microsoft Access database. The database resides with and is updated by System Engineering.

5.1.2 Flicker Studies

As fault current contributing devices are disconnected from the transmission system, larger changes in voltage are seen for switching components. Testing for system intact (all lines in-service) and strongest source loss should not be conducted using a model with all generation running. To ensure flicker limits are adhered to throughout the year, a spring light load or model representing realistic minimum generation in an area must be used.

5.2 Transmission System Operating Conditions

The transmission system is susceptible to facilities being forced out of service during outages. In addition, many pieces of equipment require routine maintenance or end-of-life replacement for which facilities must be de-energized. To perform construction activities on the transmission system or ensure adequate clearance to energized equipment, facilities may need to be removed from service. Collectively forced outages (contingencies) and Maintenance/Construction outages (Planned outages) may be referred to as “Outages” through the remainder of the planning criteria.

Transmission planning studies are conducted to analyze system Outages and ensure that the transmission system is capable of remaining within specified voltage, thermal, short circuit and stability criterion for various system conditions. When deficiencies are discovered, additional analysis is completed to identify the reinforcements that would allow the transmission system to operate under normal conditions and single outage contingency scenarios, as well as planned maintenance conditions at reduced load levels. Subsequent to their identification, reinforcements are budgeted as projects and constructed.

System Planning performs most analyses using a computer loadflow program. Models include existing and future system configurations. Generally engineers analyze simulations for winter and summer peak, as well as off-peak and minimum load conditions. Additional applicable scenarios may be analyzed to ensure that the transmission network will perform adequately under normal and “worst case” conditions.

5.2.1 Normal Operating Condition

Normal conditions are present during system intact (all lines & equipment in) periods. Normal conditions include extremes of customer loads, generator forced/scheduled outages, and “not dispatched” conditions. While this condition may not be the most common in terms of operating time, it serves as a benchmark against which to measure other conditions.

Both NERC and NPCC require considerations for the loss of equipment that have long lead times or be critical to reliability. An extended outage of a single generating plant or unit or a single bulk power transformer (115 kV and above on the low side) is also considered to be a Normal Operating Condition. Whenever a generating plant or unit or Bulk Power System transformer is going to be out of service for an extended period of time as a planned outage, System Planning will determine what impact the next contingency would have on the transmission system and recommend a solution to any system problems that may be identified.

5.2.2 Scheduled and Maintenance Outage Operating Condition

Frequently, system operators and field crews must remove a transmission network element from service. These elements may be removed to perform maintenance, construct new facilities, or provide electrical clearance for adjacent work being performed. Removal of elements for these conditions shall be considered in Transmission Planning analysis.

Analysis of the BES, BPS and other non-local jurisdictional facilities will be in accordance to applicable governing documents. When considering reliability on the local transmission system, defined single contingencies should be reviewed for facilities being scheduled out of service at a load level 85% of the 90/10 expected peak or at the load level expected for the time of the scheduled outage. It should be expected that mobile transformers will be available to support the transmission or distribution system, if needed for reliability. Also, consideration of the expected loss of load should be made.

5.3 Scope of Contingencies

IUSA utilizes all NERC TPL defined events for testing the BES, any additionally defined NPCC Directory 1 outages for testing the BPS and Single Outages for testing its local transmission system. These outages are applicable for both steady state and stability analysis.

This document defines Single Outage contingencies[5] as fault and normal clearing of the following:

a. Transmission line
b. Transformer
c. Generator
d. Opening one terminal of a facility without a fault
e. Capacitor bank, Reactor or static VAR compensator
f. Double-circuit transmission tower: [6]

Per the Maine Public Utility Commission's "Safe Harbor" provisions, when simulating outages on the BES other than the single outages defined above result in problems on the local transmission system, justification of the need must be substantiated unless they also cause performance issues on the BES.

5.3.1 Multiple Contingencies

IUSA strives to accurately and realistically assess the occurrence of multiple contingency events on the transmission system. Two time frames emerge as being important to test the system capabilities for a second outage.

30-minute Operator Actions

NPCC and ISO-NE have issued guidance on how to consider the 30 minute operator adjustment time in-between the completion of the first contingency event and in preparation for the second contingency. NPCC applies this criterion to loss of a "critical" facility[7] prior to a second contingency occurring and within ISO-NE this applies to all PTF facilities[8]. During this time period the following actions are allowed.

1. 10 minute quick-start and reserve generation
2. Phase shifting transformers (PARs)
3. HVDC controls
4. LTCs
5. Series and shunt capacitors/reactors

[5] In addition to the list of single contingencies, bus faults should be considered in the planning and construction of the local transmission system. It is recognized that this is a similar scenario to faults on the BES transmission system which are generally less frequent due to increased clearance

[6] A double-circuit transmission tower outage should be considered as a single contingency if the multiple-circuit towers are used for more than station entrance and/or exit purposes and exceed more than five towers in length. However, double-circuit towers may not be considered as a single contingency if a special design is constructed to significantly reduce the likelihood of lightning strikes and/or back-flashes.

[7] NPCC Regional Reliability Reference Directory #1, "Design and Operation of the Bulk Power System," Section 5.4

[8] ISO-NE "Draft Transmission Planning Technical Guide," Section 12.5

Post Operator Actions (May exceed 30 minutes)
Not all operator/field crew actions are expected to take place within the 30 minute operating window established by NPCC. Expected actions that may take longer than 30 minutes due to dispatching line crews to open/close manually operated switches, generation ramping capabilities, calling a generator online, enabling or disabling a non SCADA SPS should be taken into consideration. These conditions could last for days or weeks while equipment is repaired. The following considerations should be realized in testing the system once all expected actions should occur on the transmission system prior to a second contingency.

A) Reduction of generation behind a limiting interface to meet line-out interface limits
B) Restoration of load served from a transmission tap without Motor Operated Disconnects (MOD) and remote or automatic control operation.
C) Distribution field tie operation to restore lost load

5.3.2 Stability
Transmission system studies shall be conducted such that system voltages and transmission line and equipment loadings shall be within normal limits during all pre-disturbance conditions and within applicable emergency limits during all system load and generation conditions that exist following the disturbances discussed below.

Stability of the Bulk Power and Local transmission systems shall be maintained during and after the most severe contingencies stated below.

A) A permanent 3-phase fault on any generator, transmission line, transformer, or bus section with normal fault clearing.

B) A permanent phase to ground fault on a circuit breaker with normal fault clearing.

C) Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission lines on a multiple circuit tower with normal fault clearing. If multiple circuit towers are used only for station entrance and/or exit purposes, and they do not exceed five towers at each station, this condition can be considered as an acceptable risk.

D) A permanent phase to ground fault on any transmission line, transformer, or bus section with delayed fault clearing.

E) Loss of any single system element without a fault.

Extreme contingencies/events are analyzed as applicable under reliability studies. Engineering judgment is utilized to select the contingencies which include the following: 1) a permanent 3-phase fault on any generator, transmission line, transformer, or bus section with delayed fault clearing; 2) the loss of right of way; 3) the loss of a transmission substation; 4) the loss of all of the units at a generating plant; or 5) other relevant Extreme Events listed in TPL-001-4.

5.4 Load

Development and utilization of load information within planning studies has a large impact on results. Within each operating area (ME, NY) of IUSA the development of the loads is handled within the scope of the associated ISO and local process.

For CMP, there is a distinct difference between large area regional study process (such as the TPL reliability assessment or ISO-NE Needs Assessment) and local area studies:

- **System Compliance or Regional study:** The TPL, Need and Solutions type studies are required to utilize the latest "Capacity, Energy, Loads, and Transmission (CELT)" forecast load level over the 1-10 year planning horizon to be accepted by ISO-NE. The ISO-NE develops this forecast for New England which is broken down by state and transmission owner. The CELT report also contains the capacity supply obligations, qualified capacities for the generators that participate in the market, and load demand response data. The CELT report values are updated on an annual basis. There are generally 90/10, 50/50, shoulder, and light loads that are used according to the type of study and Planning Procedures.

- **Local Area Study:** CMP uses an internal peak load forecast that is derived from an energy forecast. This is sub-divided into the various Service Center areas within CMP based on customer field operations. These districts often don't exactly line up with the 14 CMP planning areas, but are comparable. The 90/10 load forecast change over the planning horizon is applied to area historical coincident peaks. The Maine PUC accepted this as a "safe harbor" provision. Spot load additions to the CMP transmission system are included in the forecast where known and studied ad-hoc as necessary.

The NY transmission system is studied, for regional reliability studies, using 90/10, 50/50 load base cases provided by NYISO. Performing more focused area transmission studies may require different load assumptions to capture the more severe operating conditions of the area:

For NYSEG, System Planning NY currently creates summer and winter forecasts using a linear regression of the most recent 10 years of summer and winter peak load data. These are updated annually. For RG&E, System Planning has kept data since 1975 and now has a log of 40 years of summer actual peak loads. Currently System planning is analyzing how many years give the best approach.

IUSA Sales & Load Forecasting group can currently provide Summer and Winter peak forecasts by Opco total only (not by Division). The forecasts are created in an econometric model based on 10 years of actual data with weather normalization and using average and high linear growth assumptions.

System Planning is comparing the different forecast methodologies and will work with Sales & Load to obtain data and develop Division forecasts. The objective is to have high-quality forecasts by Division and OpCo that are consistent with forecasts being used by other groups in IUSA NY.

5.5 Generation

5.5.1 Units Offline

Within Maine, to qualify a need under the ISO-NE “Needs Assessment” and “Solution Study,” the two most impactful generators should be modeled offline and unavailable. For the local transmission system analysis only one unit may be modeled offline to show the need for system improvements, per Maine PUC “safe harbor” provisions. When one of the units being taken out-of-service is physically correlated to another unit, such as a combined cycle plant, removing the correlated generators is counted as one.

5.5.2 Renewable Generation output

Hydro

The hydroelectric generation in IUSA relies primarily upon the run-of-river flow to generate power. As such, these hydro facilities are classified as intermittent resources and therefore system studies should not rely upon their full capability. During summer months a reduced generation assumption should be applied that is derived from two or more years of historical metered data from the months of June through August. Utilizing this data, a flow duration curve will be calculated and the generation output that is exceeded approximately 85% of the time will be selected.

In addition to reviewing the summer expected output of hydro generation, the resultant high generation and low load during the spring should be analyzed. This scenario can create constraints on export and may require Corrective Action Plans. When conditions exist that create more severe conditions than study assumptions stated above, justification on the use of the conditions in planning the transmission system will be provided.

Wind

Using the same methodology for wind output as found to be a safe harbor for CMP’s hydro dispatch in Docket 2011-494, the data shows a considerably high frequency of zero output for wind generators in CMP’s territory. Therefore, the findings of this analysis support IUSA’s recommendation to model wind generators at zero output during low generation dispatch conditions. Wind should not be relied on when studying load or system reactive support.

While the data from CMP wind output shows a low frequency of full nameplate output for the wind generators, modeling this higher output can be vital in determining the limitations of the system under full output conditions. This is especially true in heavy generation export areas. Therefore, analysis should be conducted using high wind generation output levels during studies as well.

5.6 Capacitor Design

a. The voltage flicker for installations after 2014 will be within the criteria of Section 3.2.2.
b. Whenever possible, switched capacitor banks shall be sized and operated in a manner that will minimize system losses and/or optimize the area power factor.
c. In most design situations, switched capacitor banks shall be equipped with automatic controls, typically with “CAP ON,” “CAP OFF,” Time Clock, Voltage Override, and time delay controls.
d. Switched capacitor bank control settings should be calculated to ensure proper operation under normal and first contingency conditions to minimize the need for intervention by operating personnel.
e. Whenever possible, switched capacitor banks shall be sized to avoid potential harmonic resonance during normal system operation, particularly at the 3^{rd}, 5^{th}, 7^{th}, and 11^{th} harmonics. This requirement does not usually apply to capacitor banks that are only used to provide voltage during first contingency conditions.

6 Transmission Interconnections

IUSA is governed by multiple procedures and criteria for transmission interconnections. Most of these procedures are coordinated with NERC and associated ISOs. Procedures are put into place governing FERC defined Large Generator and Small Generator (T-G), transmission to load (T-L) and transmission to transmission (T-T) interconnections. These procedures and processes are developed in compliance with NERC's FAC-001 and FAC-002 standards.

6.1 New York

Transmission Facilities owned by New York State Electric & Gas and Rochester Electric & Gas are governed by the NYISO procedures for interconnecting to the transmission system. Generators requesting to interconnect to the NYSEG & RG&E transmission system are directed to the NYISO so that they may follow NYISO's processes. Large Generator Interconnections and Small Generator Interconnections are governed by NYISO Open Access Transmission Tariff (OATT). Generators that interconnect outside the purview of NYISO are governed by the NYS Public Service Commission's Standardized Interconnection Requirements (SIRs). All generator interconnections processes also incorporate the NYSEG/RGE requirements document "Bulletin 86-01 Requirements For The Interconnection Of Generation, Transmission & End-User Facilities" in an open study process.

T-L and T-T interconnections are required to follow the NYSEG & RG&E document "Bulletin 86-01 Requirements For The Interconnection Of Generation, Transmission & End-User Facilities." All facility modifications to the NYISO jurisdictional transmission system must be done with an Interconnection Request application (IR) to NYISO. This ensures review by the ISO and study within the Regional System Plan.

6.2 Central Maine Power

Pool Transmission Facilities (PTF) owned by Central Maine Power are governed by the ISO-NE procedures for interconnecting to the transmission system. Generators requesting to interconnect to the CMP system are directed towards the ISO-NE processes. Large Generator Interconnections and Small Generator Interconnections are governed by ISO-NE Schedule 22 and Schedule 23 respectively. Generators that interconnect outside the purview of ISO-NE are governed by the MPUC Chapter 324. All generators interconnections impacting transmission incorporate the CMP requirements document "Transmission & Distribution Interconnection Requirements for Generation" in an open study process.

T-L and T-T interconnections are incorporated into the CMP requirements document "Requirements for Connection of Non Generating Facilities to The Central Maine Power Company Transmission System." All facility modifications to the ISO-NE jurisdictional transmission system must be done with a Proposed Plan Application (PPA). This ensures review by the ISO and study within the Regional System Plan.

7 Iberdrola USA Electric System Planning External Drivers

7.1 New York

On a biannual basis, as a means of being compliant with the NYISO Tariff and FERC Order 890, NYSEG and RG&E conducts a 10-year long term transmission system study. The results of the "NYSEG and RG&E Local Transmission Owner Planning Process and Results" study are then summarized and presented to the joint meeting of the Transmission Planning Advisory Subcommittee and Electric System Planning Working Group at the NYISO. The purpose of the 10-year study is to identify all of the long range system problems due to forced or maintenance outages that may occur on the NYSEG and RG&E transmission and sub-transmission systems over the next ten years and to recommend system reinforcements that would be required to correct these system problems. Those study results are also posted on the NYISO website.

All NY system upgrades are determined in accordance with Iberdrola-USA Electric Transmission Planning Criteria. Planning studies may result from:

- Periodic assessment of the NY local planning areas
- Load growth
- Retail or wholesale customer request
- Generator interconnection request
- System-wide contingency analysis

Studies utilize NYISO library base cases which are posted and retrieved by IUSA-NY system planners.

7.2 Maine

The Federal Energy Regulatory Commission (FERC) Order No. 890 directed all transmission providers with Open Access Transmission Tariffs (OATT) to adopt an open, transparent and fully coordinated transmission planning process. In compliance with Order 890, the participating transmission owners in New England developed and filed with FERC a new Appendix 1 – Local System Planning Process (Attachment K – Local or LSP Process) to the ISO New England, Inc Attachment K – Regional System Planning Process (Attachment K – Regional or RSP Process). The LSP and RSP processes are located in Section II of the OATT. Consistent with the responsibilities delineated in the Transmission Operating Agreement, the participating transmission owners have Section 205 rights over the LSP.

Attachment K – Local prescribes the local system planning process for the non-PTF (Pool Transmission Facilities) in New England for projects not already included within the Regional System Plan. Significant coordination is required between the ISO NE planning for PTF and CMP's planning for the non-PTF in Maine. To accommodate this coordination, ISO NE expanded the Project Advisory Committee (PAC) forum to allow an opportunity for CMP and the other participating transmission owners to conduct our own open stakeholder meetings to review LSP matters and LSP Project Lists.

On an annual basis, CMP complies with the Attachment K – Local requirements by performing a local system needs assessment and developing a Local System Plan and project list. This plan describes projected improvements to the non-PTF that are needed to maintain reliable customer service according to our local system planning criteria. The LSP is communicated to the PAC at an ISO NE PAC RSP meeting once a year. PAC, transmission customers, and other stakeholders have 30 days to provide written comments for consideration to CMP. The LSP project list is a cumulative listing of proposed solutions intended to meet identified needs. The LSP project list contains a status of each non-PTF project that follows the RSP convention:

Concept	Project is under consideration as a possible solution to a need, but little or no analysis is available
Proposed	CMP has determined that the project is an appropriate solution to a need, but has not yet obtained internal budget approval
Planned	Budgetary approval has been obtained
Under Construction	Project is approved and is under design/construction
In-Service	Project is complete

All CMP system upgrades are determined in accordance with Iberdrola-USA Electric System Planning Criteria. Planning studies may result from:

- Periodic assessment of CMP’s 14 local planning areas
- Load growth
- Retail or wholesale customer request
- Generator interconnection request
- System-wide contingency analysis

Studies may utilize both ISO NE library base cases from Model on Demand (MOD) and/or local CMP base cases. Generator interconnections on the non –PTF transmission system are guided by the CMP Transmission and Distribution Interconnection Requirements for Generation manual.

8 Project Prioritization

Through the System Planning process, deficiencies are identified, solutions are developed and tested and projects are initiated based on the recommended solution. Once the recommended system reinforcements to the system problems have been identified, the IUSA System Planning department will prioritize projects utilizing the "Iberdrola USA Reliability Project Prioritization Methodology."

The prioritization process takes into effect:

1. Projects which are deemed to be mandated by a regulatory agency, external customer, safety rule regulation, standard violation, etc, receive the highest rank
2. Overloaded Projects. Equipment that has exceed its normal operating rating under normal system operations
3. Voltage problems under normal system operations
4. Reliability projects: N-1
5. Reliability projects: N-1-1

Then System Planning will utilize three separate metrics to compare and prioritize these recommended projects in each of the above categories. The three metrics used are as follows:

1) MW Load at Risk – the MW load at risk is determined by identifying the substation(s) that are affected by the given critical contingency or normal condition problem and quantify the amount of load that is supplied from the circuits out of affected substation(s).
2) Number of Customers at Risk – the number of customers at risk is determined by again identifying the substation(s) that are affected by the critical contingency or normal condition problem and quantifying the number of customers that are supplied from the affected substation(s).
3) Hours of Exposure – the hours of exposure are determined by analyzing a load duration curve for the study area. The hours of exposure are determined by identifying the critical load level at which there is a problem and then using the load duration curve to calculate the number of hours that the load level in the study area exceeds the critical load level.

When situations are identified that cannot be adequately served during certain forced or maintenance contingencies, selected areas of impact are evaluated and available resources are allocated in a manner that will maximize the benefit to NYSEG and RG&E customers. The variables evaluated in addition to the System Planning metrics can include, but are not limited to: the probability of the event occurring and its associated risk, the frequency and duration of the outage, the number and criticality of customers impacted, lost revenue, damage claims, and the cost of system upgrades.