IBERDROLA USA
ELECTRIC SYSTEM PLANNING MANUAL – CRITERIA & PROCESSES

NYSEG, RG&E, CMP and MEPCO

Electric System Planning
Revised: July 28, 2011

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Iberdrola USA
Electric System Planning Criteria

1). <u>Introduction</u>

The objective of this document is to establish design criteria and guidelines to maintain an acceptable electric transmission system that meets the needs of Iberdrola USA customers in a safe, reliable and economical manner. This criteria will be utilized when performing planning studies on the local Iberdrola USA transmission systems for New York State Electric & Gas (NYSEG), Rochester Gas & Electric (RG&E), Central Maine Power Company (CMP), and Maine Electric Power Company (MEPCO).

When performing studies on the New York ISO (NYISO) and ISO New England (ISO-NE) jurisdictional transmission systems, the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), New York State Reliability Council (NYSRC) and the planning procedures established by New York ISO and ISO New England will be utilized, as applicable.

2). <u>Definition of the Transmission System</u>

The transmission system consists of Bulk Power System facilities (as defined by NPCC), Bulk Electric System facilities (as defined by NERC & the Federal Energy Regulatory Commission), Pool Transmission Facilities (PTF – ISO New England jurisdictional facilities) for Maine, and additional local transmission facilities.

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 BPS generally includes transmission facilities operating at 230 kV, and above, with a few 115 kV facilities. Lower voltage transmission may also be considered part of the Bulk Power System if the loss of such facilities may result in a measurable negative impact on the reliability outside of the local area. The Bulk Power System is designed based on the requirements of the Northeast Power Coordinating Council (NPCC) *“Design and Operation of the Bulk Power System”* (NPCC Directory #1) and other NPCC directories and criteria.

The Bulk Electric System (BES) generally includes all non-radial transmission facilities operating at 115 kV and above. Note that NERC is in the process of developing a new definition of BES in response to FERC Order 743. The Bulk Electric System is designed based on the requirements of the North American Electric Reliability Corporation (NERC) Reliability Standards, in particular the newly-approved standard TPL-001-2.

In New England, there are ISO New England jurisdictional transmission facilities for CMP and MEPCO. Pool Transmission Facilities (PTF) generally includes all non-radial transmission facilities operating at 115 kV and above. The design of these facilities is based primarily on ISO New England Planning Procedure 3, *“Reliability Standards for* *the New England Area Bulk Power Supply System,"* and Planning Procedure 5-3, *"Guidelines For Conducting And Evaluating Proposed Plan Application Analyses"*.

Local transmission facilities are all other transmission facilities that are primarily used to supply local area load or large industrial customers or connect smaller generation. The local transmission system generally consists of facilities that operate between 115 kV and 34.5 kV. However, some 34.5 kV is dedicated to serving customers. Facilities like these are 'Grounded Distribution' facilities and are not part of the transmission system.

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.

3). Transmission System Operating Conditions

The transmission system is susceptible to facilities being removed from service for circumstances such as equipment failure, weather-related damage, accidents, and for maintenance. Transmission planning studies 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.

System Planning performs most analyses using a computer loadflow program, modeling existing and future system configurations. Engineers analyze simulations for winter and summer peak, as well as off-peak conditions. This ensures that the transmission network will perform adequately under normal and "worst case" conditions.

Normal

Normal conditions are present during "all lines & equipment in" periods. Normal conditions include extremes of customer loads, and generator forced, scheduled outage, 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.

Single Outage

The Iberdrola USA Transmission System is designed to perform well following single outage contingencies. This document defines single outage contingencies as the following:

- Transmission line
- Transformer
- Generator
- Capacitor bank or static VAR compensator
- Double-circuit transmission tower:
    - 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.

Scheduled Maintenance Outage

Frequently, system operators and crews must remove a transmission network element from service to perform maintenance. Effectively, this causes a "single outage" contingency condition. Iberdrola USA should design the transmission system to withstand an *additional* single outage contingency during scheduled maintenance periods. For Central Maine Power, designs need only consider this capability for system loads of 85 percent of studied system peak load or less. For transformer outages, reliance on a mobile transformer, if required to meet criteria, must be noted.

Multiple Contingency

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, 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.

Multiple contingency outages that could result in the widespread loss of load may also be considered for the primary purpose of identifying their impact on the transmission system. These are typically not considered as design contingencies.

4). <u>Transmission System Design Requirements</u>

4.1 Voltage

When analyzing the transmission system, voltage is one of the most critical parameters that must be considered. High or low voltages can result in damage to utility and customer equipment. Low voltages can decrease the reactive power supply capability of switched capacitors. Adequate voltage shall be provided to all customers, as defined within ANSI standard C84.1-2006 and any subsequent revisions.

<u>New York</u>

The local transmission system shall be designed to maintain steady state voltages between 105% and 90% of nominal for service to regulated distribution facilities and between 105% and 95% of nominal for service to unregulated distribution facilities during normal and most single contingency conditions.

<u>Maine</u>

The local transmission system shall be designed so that voltages remain between

95% and 105% of nominal (up to 110% for 34.5 kV transmission) during system normal and most single contingency conditions. Voltages above 105% may be allowed in some circumstances where analysis has been conducted to demonstrate acceptable system performance and equipment ratings for voltages above 105% but below 107% if such conditions are present at a limited number of buses.

Automatic voltage regulating devices such as transformer Load Tap Changers, voltage regulators, and automatically-controlled capacitor banks are considered to be regulating when applying the above criteria. Between the first outage contingency or line-out condition and prior to the second or maintenance outage contingency, operator action is permissible and voltage control devices that are remotely controlled can be assumed to be used to posture the system for the second event, provided the voltage criteria stated above are met.

4.2 Thermal

Since transmission lines and power transformers carry high current, they can also experience high temperatures due to resistive heating losses. Power transformers can suffer damage from excessive heat, decreasing their reliability and life expectancy. Overhead conductors can stretch as their temperature increases, decreasing the clearance from the conductor to ground. Extremely high temperatures can cause physical damage to the wire.

The transmission network should be designed so that line and transformer loadings do not exceed their respective ratings. However, under certain extreme conditions, equipment loading may exceed normal ratings to maintain customer service. The following table shows when each rating is applicable.

SYSTEM CONDITION	TIME INTERVAL	MAXIMUM ALLOWABLE FACILITY LOADING
Normal (all lines in)	Continuous	Normal Rating
Single contingency	Less than 15 minutes after contingency occurs	Short Time Emergency (STE) Rating
	More than 15 minutes after contingency occurs	Long Time Emergency (LTE) Rating

It should be noted that all LTE ratings are based on a duration of 4 hours or less for winter periods; and 4 hours or less for summer periods in New York, or 12 hours or less for summer periods in Maine. STE ratings are based on a maximum duration of 15 minutes. Generally, the LTE rating will be used as the limiting rating to identify thermally limited facilities for contingency conditions. However, in generating or exporting areas, thermal loadings up to the STE rating may be considered acceptable as long as automatic actions are in place to reduce all facility loadings below LTE within 15 minutes by ramping down generation or adjusting transfers.

5). Equipment Ratings

To maintain a reliable transmission system, equipment must be sized and operated according to manufacturer's specifications, industry and national standards, and Iberdrola USA guidelines. These guidelines specify everything from maximum operating temperatures, to energy dissipation, to mechanical operation times.

Substation equipment and transmission lines are designed to accommodate specific ratings when operating under normal or emergency conditions. A transformer's "Normal" rating is intended to protect the unit from premature aging caused by excessive heating.

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.

The facilities rating methodology used in New York is outlined in Appendix A.

Maine

For the ratings of all transmission lines and transmission system transformers refer to the most recent CMP "NX-9 Facility Rating Database."

The facilities rating methodology used in Maine is contained in a separate design manual, *Procedures for Determining and Implementing Transmission Facility Ratings.* The procedures adopted in this Manual are used for determining, retaining, and reporting Transmission Facility ratings applicable to all transmission equipment operating at all voltages. The methods used to determine individual equipment ratings are compliant with ISO NE's Planning Procedure 7 (PP7), *Procedures for Determining and Implementing Transmission Facility Ratings in New England.*

6). Voltage Flicker

The maximum allowable flicker on the transmission system (Bulk Power and Local transmission facilities) caused by the starting of large motors, the switching of capacitor banks, etc., is defined by the IEEE Standard 519-1992 flicker curve (see Appendix B). The "Borderline of Visibility" curve, which is used as the design criteria for the transmission system, shows that when large reactive loads (capacitor banks, electric motors, etc.) are switched, steady-state bus voltages must not change by more than 3% and the number of switching events must be limited to less than one per hour. Additionally, as seen on the curve, voltage flicker in the frequency range of 2 to 8 dips per second (characteristics of an arc furnace) shall be less than 0.5%.

7). <u>Capacitor Sizing and Switching</u>

A) The voltage flicker on transmission facilities caused by the normal operation of an automatically controlled switched capacitor bank shall not exceed the "Borderline of Visibility". When a capacitor bank is switched under normal system conditions, steady state bus voltages shall not change by more than 3% and the maximum number of switching events shall be less than one per hour.

B) To allow adequate voltages to all customers following a single outage contingency, voltage flicker on transmission facilities caused by the operation of an automatically or a manually controlled switched capacitor bank may be allowed to exceed 3%.

C) 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.

D) 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.

E) 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.

F) 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.

8). <u>Harmonics</u>

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 Appendix C), 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.

9). Dynamic Stability

9.1 Steady State Conditions

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.

9.2 System/Unit Stability

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.

NOTE: Extreme contingencies are generally not analyzed. Extreme contingencies 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, or 4) the loss of all of the units at a generating plant.

10). System 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.

11). <u>Short Circuit Criteria</u>

Although the System Planning Department at Iberdrola USA is not responsible for conducting short circuit analysis and breaker duty studies, 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. All short circuit analyses will be conducted with the assumption of a 105% pre-fault voltage.

12). <u>Load Interruption Criteria</u>

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. In Maine, CMP designs its transmission system so LOL is less than 25 MW for single outage contingencies and less than 60 MW for scheduled maintenance outage contingencies.

13). <u>Prioritization</u>

Iberdrola USA strives to meet all of the previously mentioned planning criteria to provide an adequate continuous supply to all customers. For conditions under which customer loads cannot be adequately served during certain contingencies, areas of impact will be evaluated and available resources will be allocated in a manner that will provide the most benefit our customers. The variables to be evaluated may include, but are not limited to the following:

1) The probability of the event occurring and its associated risk
2) The frequency and duration of the outage
3) The number of customers and amount of customer load affected
4) Lost revenue
5) Damage claims
6) The cost of transmission system upgrades

These variables can provide important insights into prioritizing system risks and solutions.

Appendix A – New York Facility Rating Methodology

In New York, the seasonal LTE rating specifies the amount of load the transformer can potentially carry for up to 4 hours while suffering no more than a 0.25% loss of life. The seasonal STE rating allows the transformer to operate at two times its nameplate rating for no longer than 15 minutes. Most overhead transmission lines and substation equipment also have seasonal normal, LTE, and STE ratings. The ratings for transmission circuits and transformers are based on the most limiting element in the path.

In New York, the transmission engineering group is responsible for providing thermal ratings for overhead transmission lines and cables.

<u>Overhead Transmission Lines</u>

In New York, thermal ratings for all of the Bulk Power System overhead transmission lines are based on the 1995 report entitled "Tie-Line Ratings Task Force Final Report on Tie-Line Ratings" from the New York Power Pool and IEEE Standard 738-1993. In Maine, The following criteria and assumptions are used to establish the ratings for Bulk Power System overhead transmission lines in New York:

A) A 40-year life is assumed for each line.

B) A maximum ambient temperature of 35°C, with an average daily maximum temperature of 30°C is used for summer.

C) A maximum ambient temperature of 10°C, with an average daily maximum temperature of 5°C is used for winter.

D) An ambient wind speed of 3 ft/sec is used for summer and winter.

E) All LTE ratings are established assuming a maximum time period of 4 hours but totaling not more than 300 hours over the life of the line.

F) All STE ratings are established assuming a maximum time period of 15 minutes but totaling not more than 12.5 hours over the life of the line. A normal preload is also used in establishing the STE rating.

In New York, thermal ratings for all of the Local system overhead transmission lines are based on three New York Power Pool Tie-Line Ratings Task Force reports on ratings for electric transmission lines 115 kV and above from 1970, 1982, and 1995. All Local system transmission lines built before 1982 are rated using the 1970 ratings. If a transmission line was built between 1982 and 1995, the line is rated using the 1982 ratings. If a line was built before 1982 and has been checked against the 1982 criteria and passed, then it is rated using the 1982 ratings. Finally, all lines built after 1995 are rated using the 1995 ratings.

Transmission Cables

Underground, aerial, and submarine cables are rated per manufacturer's specifications and recommendations.

In New York, The substation engineering group is responsible for providing the thermal ratings for transformers, circuit breakers, air disconnect switches, substation bus facilities, line traps, series reactors, and series capacitors.

Transformers

Transformer ratings are specified according to ANSI Standard No. C57.91-1995, "IEEE Guide for Loading Mineral Oil-Immersed Transformers". The chart below describes the system conditions used to determine loading capability. When available, actual daily load curves and ambient temperatures should be used instead of the listed standard values. The Planned Loading Beyond Nameplate rating can be applied when the pre-load of the transformer is less than 70% and the peak load duration does not exceed 8 hours. The maximum Top Oil Temperature and Hotspot Temperature, as recommended in ANSI C57.91 for each system condition, limit the loading capability of each transformer.

Transformer Overload Criteria

Standard System Conditions

Description	**Normal**		**Planned Loading Beyond Nameplate**		**Long Term Emergency**		**Short Term Emergency**	
	Summer	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**
Ambient Temperature In Degrees C	30	5	30	5	35	10	35	10
Pre-Load % Of Top Nameplate	100%	100%	70%	70%	100%	100%	100%	100%
Load Duration	24 hrs	24 hrs	8 hrs	8 hrs	4 hrs	4 hrs	15 min	15 min

Circuit Breakers

The rating for circuit breakers is based on ANSI standard C37.010-1979, "Application Guide for AC High Voltage Circuit Breakers" and its supplement C37.010b-1985 on "Emergency Load Current – Carrying Capability which covers the LTE and STE conditions.

Air Disconnect Switches

The standard requirements for high voltage air disconnect switches are covered in ANSI Standards C37.30 to C37.37. These standards specify, in addition to other requirements, the rated current, the conditions under which the rated current is determined and the maximum allowable temperature rise limitations of the various components in the switch. A formula is provided in ANSI Standard C37.30 for the calculation of the allowable continuous current at ambient temperature at which the switch can operate without exceeding its temperature rise limitations.

Substation Bus Facilities

Ampacity rating factors for rigid bus conductors are based on information provided in ANSI/IEEE Standard 605-1987 (Reference #1). Ampacity rating factors for bare cable bus conductors are determined using the rating factors for transmission line conductors, except that for ampacity calculations of the substation bus conductors, a wind velocity of 2 ft/sec must be considered.

Line Traps

A line trap usually consists of an air-core inductance coil in series with a power line conductor. It is tuned to parallel resonance by means of a tuning pack. The ANSI Standard for line traps is titled “Requirement for Power Line Carrier Line Traps” ANSI C93.3-1981, dated September 12, 1980. Prior to 1981, the line trap requirements were specified in NEMA Standard SG-11-1955.

Series Reactors

The standard covering the use of series reactors is the American Standard Requirement, Terminology, and Test Code for Current-Limiting Reactors, C57.16-1958. The ANSI’s Appendix C57.99, The Guide for Loading Dry-Type and Oil-Immersed Current-Limiting Reactor published in 1965 is currently being used by the industry.

Series Capacitors

The standard requirements for series capacitors are covered in ANSI Standards 824-1985. This standard applies to capacitors and assemblies of capacitors, insulation means, switching and protective equipment, and control accessories that form a complete installation for inserting in series with a transmission or distribution line.

Current Transformers/Relays

Current transformers and relays are rated per manufacturer specifications and design recommendations. The System Protection and Control group of the System Engineering Department is responsible for providing these ratings.

Appendix B – Flicker Tolerance Curve

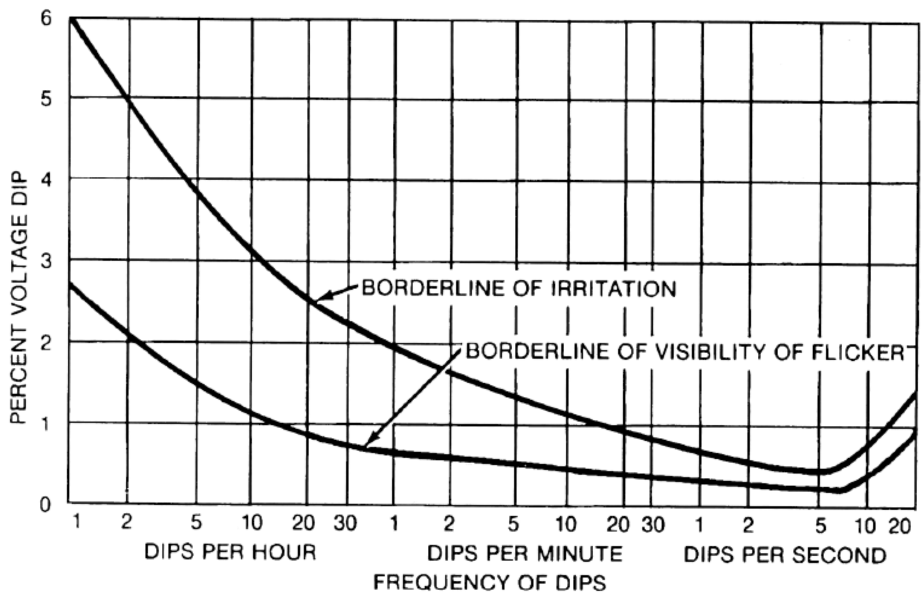

Figure A.1—Flicker tolerance curve from IEEE Std 141-1993/IEEE Std 519-1992

Appendix C – 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.

Iberdrola USA
Electric System Planning Processes

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 subtransmission 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.

Once the recommended system reinforcements to the system problems have been identified, the System Planning department at NYSEG/RG&E then utilizes three separate metrics to compare and prioritize these recommended projects. 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 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 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.

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.