2.3.6 Baseline Thermal Analysis

Baseline thermal analysis is a thorough analysis of the reference power flow to ensure thermal adequacy based on normal (applicable to system normal conditions prior to contingencies) and emergency (applicable after the occurrence of a contingency) thermal ratings specific to the Transmission Owner facilities being examined. It is based on a 50/50 load forecast from the latest available PJM Load Forecast Report (50% probability that the actual load is higher or lower than the projected load.) It encompasses an exhaustive analysis of all NERC P0-P7 events and the most critical common mode outages. Final results are supported with AC power flow solutions. The PJM Load Forecast uses a 50/50 distribution minus Energy Efficiency. Demand Response is not considered in the Load Forecast.

For normal conditions (NERC P0), all facilities shall be loaded within their normal thermal ratings. For each single contingency (NERC P1), all facilities shall be loaded within their emergency thermal ratings. For the more severe NERC P2, P3, P4, P5, P6 and P7 contingencies, along with only transformer tap and switched shunt adjustments enabled, post-contingency loadings of all facilities shall be within their applicable emergency thermal ratings as required by the PJM or the Transmission Owner planning criteria. The study procedure for the NERC P3 and P6 contingencies (N-1-1) is described in detail in section 2.3.8.

2.3.7 Baseline Voltage Analysis

Baseline voltage analysis parallels the thermal analysis. It uses the same power flow and examines voltage criteria for all the same NERC P0, P1, P2, P3, P4, P5, P6 and P7 events. Also, voltage criteria are examined for compliance. Analysis will simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. Those devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors. PJM examines system performance for both a voltage drop criteria (where applicable) and a voltage magnitude criteria. The voltage drop is calculated as the decrease in bus voltage from the initial steady state power flow to the post-contingency power flow. The post-contingency power flow is solved with generators holding a local generator bus voltage to a pre-contingency level consistent with specific Transmission Owner specifications. In most instances this is the pre-contingency generator bus voltage. Additionally, all phase shifters, transformer taps, switched shunts, and DC lines are locked for the post-contingency solution. SVC’s are allowed to regulate and fast switched capacitors are enabled.

The voltage magnitude criteria is examined for the same contingency set by allowing transformer taps, switched shunts and SVC’s to regulate, locking phase shifters and allowing generators to hold steady state voltage criteria (generally an agreed upon voltage on the high voltage bus at the generator location.)

In all instances, specific Transmission Owner voltage criteria are observed. All violations are recorded and reported and tentative solutions will be developed. These study results will be presented to and reviewed with stakeholders.

Post-Contingency voltage analysis shall also include the impact of tripping generators where the simulated generator bus voltages or the high side of the generation step up (GSU) transformer are less than known or assumed minimum generator steady state of ride
this Subregional RTEP Committee meeting, interested parties will have had the opportunity for ongoing participation in the **February through August** process of violation review and solution identification along with PJM and Transmission Owners. This subregional criteria violations and upgrade meeting is the forum for a final open discussion of the subregional reviews which have been occurring, prior to presentation to TEAC.

**PJM TEAC Committee RTEP review**

PJM expects that about **August** of each year, the final RTEP upgrade facilities will be available for presentation, review and endorsement at a scheduled TEAC meeting. PJM will post its recommendations of RTEP upgrades for identified violations as early as possible in the month prior to the TEAC meeting at which the final RTEP facilities will be reviewed (see **RTEP@pjm.com**). This posting will distinguish facilities that are deemed Supplemental RTEP Projects. After the TEAC RTEP review meeting, there will be about a month of additional time for final written comments on the proposed RTEP facilities, after which the PJM Board will consider the final RTEP plan excluding Supplemental Projects for approval.

### 2.3.18 Corrective Action Plan

PJM will prepare an annual Planning Assessment of its portion of the BES. For planning events shown in Table 1, when the analysis indicates an inability of the system to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned system shall continue to meet the performance requirements in Table 1. The Corrective Action Plan shall list system deficiencies and associated actions need to achieve required system performance. Examples of such actions include:

- Installation, modification, retirement or removal of Transmission and Generation facilities and any associated equipment

- Installation, modification or removal of Protection Systems or Remedial Action Schemes.

- Installation or modification of automatic generation tripping as a response to a single or multiple contingency to mitigate Stability performance violations.

- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple contingency to mitigate steady state performance violations.

- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan

Additionally, the Corrective Action Plan shall include action to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

### 2.4 RTEP integrates Baseline Assumptions, Reliability Upgrades and Request Evaluations
thermal, voltage and stability violations. Remediation plans are developed to mitigate the violations that exceed the established SOL limits.

PJM’s develops models for specific planning horizons using the latest Eastern Reliability Assessment Group (ERAG formerly MMWG) modeling information available for the applicable planning period. A detailed model is utilized for PJM’s internal system (transmission owner under PJM’s footprint) while the latest ERAG model for that planning period is used for facilities outside of PJM to incorporate critical modeling details of other control areas. Additional information about PJM’s base case development procedures can be found in section 2 of this manual.

PJM reliability planning criteria requires that the system be tested for all BES single contingency outages and all common mode outages. Common mode outages consist of line faults coupled with a stuck breakers that result in multiple facility outages, double circuit towerline outages and bus faults in the PJM system. PJM’s planning procedures require all NERC P0, P1, P2, P3, P4, P5, P6 and P7 conditions be tested.

When appropriate PJM will identify and implement Remedial Action Schemes. If the scheme is required for reliability purposes, operational performance, or to restore the system to a reliable state following a significant transmission facility event, operation of the scheme will be tested in the on-going planning analysis. See the Transmission Operations Manual (M-03) (http://www.pjm.com/~media/documents/manuals/m03.ashx) for additional information concerning Remedial Action Schemes.

The PJM planning process includes a series of detailed analyses to ensure reliability under the most stringent of applicable NERC, PJM or local criteria. Through this process, violations of system operating limits are identified. System reinforcements required to mitigate the violations are developed and included in the Regional Transmission Expansion Plan for implementation. As a result PJM’s application of its System Operating Limits for the planning horizon ensures system operation within Interconnection Reliability Operating Limits.

PJM Planning will communicate to PJM Operations any potential IROL facilities resulting from PJM deliverability criteria analysis. PJM Planning and Operations work to develop new IROL Reactive Interfaces and associated operating procedures as required.
Attachment G: PJM Stability, Short Circuit and Special RTEP Practices and Procedures

G.1 Stability

PJM Planning conducts stability studies to ensure that the planned system can withstand NERC criteria disturbances and maintain stable operation throughout the PJM planning horizon.

NERC criteria disturbances are those required by the NERC planning criteria applicable to system normal, single element outage and common-mode multiple element outage conditions. These conditions are specified in the NERC approved Transmission Planning (TPL) Reliability Standards that can be found on the NERC website (www.NERC.com). Because these standards change from time to time they are included here by reference. In addition, PJM’s analyses also satisfy the Transmission Owner specific stability practices and procedures as may be applicable when these are more demanding tests than the standard NERC criteria tests applied by PJM. All Transmission Owner specific information and criteria that exceed standard testing of NERC criteria and are applicable to PJM reliability based RTEP stability analyses are included or referenced in the Appendix to this Attachment. Transmission Owner stability criteria filed as FERC Form No. 715 and posted on PJM’s website and not included in the Appendix may be used to support Transmission Owner funded upgrades. The currently approved version of this Appendix at the commencement of the RTEP process will be the basis for that baseline RTEP and related generator queue assessments. PJM’s stability analyses verify satisfactory projected system performance over the range of anticipated load levels and identify any need for upgrades, operating guides, or Remedial Action Schemes that may be indicated based on stability or short circuit performance as a primary driver. In general, the most appropriate remedy to NERC criteria violations is a system upgrade. In circumstances involving criteria that go beyond PJM’s standard testing of NERC criteria, operating guides or Remedial Action Scheme remedies may also be considered as discussed further in this Attachment and its Appendix. New Remedial Action Schemes, however are generally avoided and, if considered, require case-by-case review and justification. Also certain specific areas of PJM have been identified through PJM or Transmission Owner analysis as stability limited areas of the system. In such areas of the system, stability operating guides may apply. For related information see PJM Manual 03 at http://www.pjm.com/library/manuals.aspx.

Critical system conditions for stability analysis on the PJM system are generally characterized by light load and peak load. System peak load levels shall include a load model where applicable which represents the expected dynamic behavior of loads that could impact the study area, considering the behavior of induction motor loads. An aggregate system load model which represents the overall dynamic behavior of the load is also acceptable where applicable. In exceptional cases, PJM may add alternate load testing when PJM determines that an alternate load level may be the critical load level for system stability for the limitation under review. Peak load stability analysis related to new interconnections of wind turbines and their low voltage ride through performance will also be performed.

System conditions most critical for stability analysis on the PJM system are generally characterized by light load. Peak load analysis is added for stability reviews that involve new
1.2. The electrical Point of Interconnection (POI) of the project. For projects that tap an existing transmission line, the feasibility power flow generally assumes a line POI is at the line midpoint. Stability analysis will require the actual location information to determine the tap point.

1.3. A detailed fault list testing all applicable NERC and Transmission Owner criteria faults. Fault specification will include fault:
   1.3.1. location
   1.3.2. phase involvement
   1.3.3. impedance
   1.3.4. actual timing for clearing and reclosing
   1.3.5. explicit timing or other margins to be added
   1.3.6. justification of any procedures that exceed PJM standard methods

1.4. Dispatch in the vicinity of the study location.

1.5. Selection of the appropriate base case, light load or peak load, for study of the interconnection request.

2. Study scope will be supplied to the affected Transmission Owner. Affected parties have one week to provide input to the study scope after which time PJM will issue the final scope and a date that the study will begin. All special study conditions, scenarios or simulations, if any, required by guides or sensitive areas and accurate clearing times must be included in this final scope. The study will progress to completion based on the final scope document.

2.1. The study scope for interconnection studies will consider standard NERC criteria faults and Transmission Owner criteria faults, as a general rule, including the POI bus and one bus away from that bus. In other words if a new POI is cut-in at the midpoint of an existing line, faults will be examined at the POI, and up to and including faults at the adjacent existing system substations and lines. If a project interconnects to an existing system bus location, then faults at that location and including adjacent substations and lines will be examined. When new interconnection requests are considered, in PJM's judgment, in a cluster study, they will consider intervening bus location faults (further than one bus from any new interconnection) at PJM's discretion when the electrical configuration indicates that the added locations could pose a more severe test and that a contributing cause of the stability concern is the new interconnection. In a similar fashion, PJM may use its judgment in any stability analysis to expand the fault locations outside the general "one bus removed" criteria when system electrical configurations dictate and the interconnecting project poses the concern.

2.2. The stability scope for interconnections in areas affected by established operating guides or Remedial Action Schemes (RAS) (for example see Manual 03) may include scenarios designed to test the proper operation of the existing guides or RAS. In such cases, the scope may be augmented to examine and specify modified procedures or facilities that ensure the integrity of the system operation.
(ii) If an N-1 contingency is transient unstable, the N-1 stability issue must be resolved first. For each N-1-1 contingency pair, create an N-1 base case by solving a power flow after the N-1 contingency is applied to the N-0 base case. If there are any thermal or voltage violations, resolve them through system adjustments. Also if available, apply existing operating guidelines for the N-1 outage condition to the N-1 base case.

(iii) Conduct comprehensive time-domain simulation for the N-1-1 contingency and assess stability.

I. Following standard PJM stability criteria, both transient stability and damping will be monitored.

(iv) Consider RASs or other specific operating guidelines.

STUDY PLANTS SELECTION

The factors taken into account in prioritizing plants include the size of a plant, N-1 baseline stability study results, plant fuel type, and the unavailability rate of neighboring branches of the study plant. The following plants are given the highest priority for the N-1-1 stability study.

- Nuclear plants take the highest priority and will be studied if they are in the scope of the annual baseline stability study.
- Plants with the maximum output of 1000 MW or above.
- Plants having weak stability performance in baseline stability study.
- Plants that experienced operational stability issues in real-time.
- Plants having neighboring branches with high unavailability rate due to planned and/or unplanned outages.

N-1-1 CONTINGENCY SELECTION

Due to the number of combinations of N-1-1 contingencies, only single contingencies that are 1-bus away from the high-tension buses of the study plant are considered. In the example below, five single transmission line outages are considered in the N-1-1 stability study as shown in Fig. 1.
It is necessary to analyze total 25 (5 N-1 and 20 N-1-1 contingency scenarios) contingency scenarios for the example plant in Figure 1. It is also noted that 3-phase fault cleared by primary relays is considered for all single contingencies. Fault clearing times are in form of possible ranges for different areas, kV and fault clearance options and the upper values of the respective ranges are used. Existing Remedial Action Schemes are, if available, incorporated in the N-1-1 contingency scenarios.

**MITIGATION**

Any violation of PJM or other applicable stability criteria as described in this Attachment will be addressed and documented as part of the annual RTEP process.

**G.5 Impact Study Procedures Applicable to Wind Turbine Analyses**

PJM follows a process of procedures and studies when handling requests to interconnect to the transmission system. These procedures are outlined in PJM Manuals and agreements, particularly PJM’s Manuals 14A and 14B and the PJM Open Access Transmission tariff (OATT.) In recognition of some of the unique characteristics and challenges posed by wind projects, however, the PJM OATT procedures include certain special provisions applicable to wind farm interconnection requests. Interconnection Customers should familiarize themselves with all applicable PJM procedures and requirements, in consultation with their assigned PJM project manager. Some provisions of particular interest to wind
The short circuit analysis is performed in accordance with the following industry standards:

- ANSI/IEEE C37.5-1979 “IEEE Guide for Calculation of Fault Currents for Applications of AC High-Voltage Circuit Breakers Rated on a Total Current Basis”

The system condition most critical for short circuit analysis on the PJM system is all available generation in-service. This condition is modeled in short circuit reference cases that are specially configured for short circuit analysis. The PJM Transmission Planning Department maintains the following short circuit base case representations and associated data:

- 2 year planning representation consisting of the current system plus all facilities planned to be in-service within the next 2 years.
- 5 year planning representation using the 2 year planning representation as the base model and including all system upgrades, generation projects, and merchant transmission projects planned to be in-service from years 2 through 5. This 5 year planning representation is consistent with the PJM RTEP 5 year load flow base case.
- Data file containing current circuit breaker interrupting ratings and other relevant circuit breaker nameplate data for all BES circuit breakers.

The short circuit base cases are maintained using Aspen One Liner and short circuit analysis is performed using the Aspen Breaker Rating Module. The PJM short circuit 2 year planning representation is developed annually with the assistance of the designated transmission owner short circuit contacts and maintained by the PJM Transmission Planning Department.

**G.8 Nuclear Plant Specific Impact Study Procedures**

Stability analysis of nuclear facilities is conducted during PJM's three-year cycle of stability review of all existing generating units. Also, interconnections or transmission modifications in the vicinity of existing generating stations, including nuclear stations, may necessitate additional reviews. PJM conducts these reviews consistent with the NERC criteria and certain added criteria specified by the Transmission Owner or plant operator or owner. PJM stability studies take into account coordination with any applicable Remedial Action Schemes. Results of PJM Planning analyses can be found under the “planning” tab material and “committees & groups” tab material on PJM.com particularly:

http://www.pjm.com/planning/planning-criteria.aspx
based on *standard NERC criteria* and standard margins must be remedied by upgrade modifications to the system. Operating curtailments will generally be an available remedy for issues found for line maintenance outage tests.

**G.9.1 Testing of Transmission Owner Criteria**

For interconnection queue studies that pass the *standard NERC and PJM criteria* but produce localized violations based on criteria that are beyond the *standard NERC criteria* and/or margins that exceed standard PJM margins, PJM, in consultation with the affected Transmission Owners, will determine lower cost remedies. For these Transmission Owner tests, planned load loss or interruption of firm transmission service is not allowed when lower cost remedies are available. An available lower cost remedy will be required to address such violations. For example, lower cost remedies that may be considered include:

- Relaying modifications
- Sectionalizing schemes
- Breaker upgrades
- Independent pole tripping
- High speed breaker failure schemes
- High speed reclosing
- Fast closing of steam intercept valves
- Braking resistors.

If the search for lower cost upgrades produces none, or in the case of wide-spread system violations such as may be encountered during RTEP baseline stability analysis, then PJM, in consultation with the affected Transmission Owners, will make a more detailed assessment of the violation(s) including factors such as the extent of violations, the events' likelihood, system impact and cost to remedy. Based on the gathered information, PJM will specify a remedy including possible consideration of operating guides, Remedial Action Schemes, and more extensive high voltage upgrade options.

**G.9.2 Nuclear Station Testing**

With regard to nuclear station related planning stability analysis, in addition to the *standard NERC criteria* and specific Transmission Owner criteria testing, PJM reviews and enforces criteria testing that can be found under the Planning section of the Nuclear Plant Interface Requirement (NPIR) documents. In some cases the Transmission Owner also performs special nuclear unit stability testing as described in PJM Manual 39 and the NPIR. Together, the analyses that may be performed by the Transmission Owner and PJM's testing incorporate the voltage and stability requirements of the station. PJM ensures Transmission System performance to the specified criteria that enables the station equipment and systems to perform as designed. Nuclear voltage criteria at the Transmission System level, including any voltage drop criteria, are enforced on a system normal and post-contingency
basis as described in the NPIR planning requirements. Observed criteria violations during planning assessments affecting nuclear stations will be evaluated jointly by PJM Planning and PJM Operations consistent with procedures outlined in PJM Manual 39. Appropriate remedies, consistent with this Attachment and the PJM Manuals and Agreements, will be specified to ensure applicable criteria are met. The nuclear owner will be responsible for reinforcements necessary to comply with criteria that are specific to the Nuclear Plant and that are more stringent than the standard PJM and Transmission Owner tests.

The specific nuclear unit planning criteria contained in the NPIR documents are included in the Appendix to this Attachment G when the nuclear plant owner has consented to these excerpts being included here for convenient planning reference. In any instances of a nuclear plant owner preference to maintain confidentiality of this information, it is not reproduced in this manual but is still evaluated and enforced during planning studies.

G.9.3 BG&E Specific Criteria

Additional stability testing applicable to interconnections with BG&E transmission facilities includes tests of three-phase faults at a point 80% of the circuit impedance away from the station under study with delayed (zone two) clearing.

G.9.4 ComEd Specific Criteria

Additional stability testing applicable to interconnections with ComEd transmission facilities includes:

- Three-phase fault on any transmission or generation element with delayed clearing due to a stuck breaker or other protective equipment failure. For situations involving independent pole operated breakers, it is assumed that only one phase of the breaker fails to open and the delayed clearing time is used for the remaining single-phase fault.

- Three-phase fault on any transmission or generation element with delayed clearing due to failure of a Remedial Action Scheme.

- Three-phase fault on all transmission lines on a multiple circuit tower with normal clearing.

- Three-phase fault on any transmission or generation element during the scheduled outage of any other transmission or generation element.

It should be noted that a one-cycle margin is included in all primary-clearing times for faults on the ComEd system, instead of the PJM margins. For more severe, lower probability events such as faults occurring during maintenance outages or faults cleared in delayed time, if lower cost remedies are not available, PJM will retest with the PJM’s standard margins as a possible remedy.
G.10 NERC Standard PRC-023 – Transmission Relay Loadability

Background

The purpose of the standard is to ensure that protective relay settings shall not limit transmission loadability; not interfere with system operators’ ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults. There are a number of requirements that specify how protective relays should be set so that they will not limit loadability of a circuit. One of the requirements of the Standard (R6) is for the Planning Coordinator to determine the facilities that must comply with requirements R1 through R5 of NERC standard PRC-023.

In accordance with Attachment B of PRC-023, the following circuits are subject to Requirement R6:

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

- Transmission lines operated below 100kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

**Process to determine PRC-023 Critical Facilities**

PJM staff will conduct an assessment at least once each calendar year, with no more than 15 months between assessments applying the criteria in accordance with Attachment B or PRC-023 to determine the circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. PJM will maintain a list of circuits subject to PRC-023 per application of Attachment B and provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 days of any changes to that list. The test will monitor all required facilities in accordance with Attachment B of PRC-023 as described below.

**NERC Standard PRC-023 Transmission Relay Loadability - Attachment B**

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
• The circuit is a monitored Facility of an IROL, where the IROL was determined in the planning horizon pursuant to FAC-010.

• The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

• The circuit is identified through the following sequence of power flow analyses performed by the Planning Coordinator for the one-to-five-year planning horizon
  o Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
  o For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
  o When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
  o The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.
  o If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
  o If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
  o If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
  o The Radially operated circuits serving only load are excluded.

• The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in the NERC Standard PRC-023 Transmission Relay Loadability - Attachment B Criteria above, in consultation with the Facility Owner

• The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.