FirstEnergy

76 South Main St.
Akron, Ohio 44308

August 16, 2012

Mrs. Barcy McNeal
Commission Secretary
The Public Utilities Commission of Ohio
180 East Broad Street
Columbus, OH 43215

SUBJECT: Case No. 12-504-EL-FOR

Dear Mrs. McNeal:

On behalf of Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, and American Transmission Systems, Incorporated, ("FirstEnergy Companies") the enclosed document and associated attachments supplements the 2012 Electric Long-Term forecast report to the Public Utilities Commission of Ohio filed on April 16, 2012. The supplemental information provides the key activities of the Commission, FirstEnergy Companies, and PJM and the results to date of changes to the planned transmission system since the generation deactivation announcements in early 2012. More specifically the information is supplemental to section 4901:5-5-04(D) Forecast for Electric Transmission Owners of the 2012 Electric Long-Term Forecast Report.

Sincerely,

Bradley B. Eberts

Bradley D. Eberts
Manager, Load Forecasting

Enclosures

Transmission Project Updates

Long-Term Forecast Report (Case No. 12-0504-EL-FOR)

Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company ("FE Ohio Utilities"), and ATSI (together with FE Ohio Utilities "Companies" or "Company") file a Long-Term Forecast Report ("LTFR") each year with the Public Utilities Commission of Ohio ("Commission"). In order to make the filing in a timely fashion, the Companies used December 31, 2011 as the date to represent the current system and planned transmission projects (as approved by the PJM RTEP). The LTFR was timely filed with the Commission on April 16, 2012.

In early 2012, generation deactivations were announced and as a result there have been multiple activities among the Commission, PJM, and the Companies to address the actions that will be taken to support reliability in the region. This report provides the key activities, processes, and results since the announcement and is divided into these eight sections:

❖ <u>**Section 1: Commission and Companies Activities**</u>

Summary of Commission and Companies' Activities

Multiple Commission and Companies activities resulted from the generation deactivation announcements in early 2012 and they are as follows:

- January 24, 2012 – FES received a letter from the Commission requesting generation unit information for FES plants.
- February 29, 2012 – Commission issued an Entry in Case No 12-0814-EL UNC regarding the May 2012 RPM Auction for the 2015/2016 PJM capacity requirements.
- March 13, 2012 – Companies' representatives conducted several meetings with Commissioners and multiple members of Staff to discuss the Entry and the Company's planned response.
- March 19, 2012 – Companies respond to the letter from the Commission dated January 24, 2012.
- March 29, 2012 - FE Ohio Utilities filed a Report in response to the Entry in Case No 12-0814-EL UNC.
- April 16, 2012 – the Companies filed the 2012 LTFR with the Commission.
- May 31, 2012 - the Companies again conducted several meetings with Commissioners and several members of the Commission Staff to review the status of the PJM analysis regarding the generation deactivations.
- June 1, 2012 - the Companies provided further information to the Commission in response to a letter that was received from the Commission Staff on or about May 15, 2012.
- July 18, 2012 - representatives of the Companies met with numerous members of the Commission Staff to provide a further update of the status of automation of the FE Ohio Utilities distribution system.

Details of Commission and Companies Activities

On January 24, 2012, a letter was received from the Commission requesting generation unit information for plants owned by FirstEnergy Solutions Corp. ("FES") to be included in the Companies' 2012 LTFR. On March 19, 2012, the Companies responded advising that FES does not file an LTFR (See Attachment A). The Companies also indicated that PJM was performing analyses regarding the reliability impact on the transmission system due to the announced generation deactivations.

The Commission issued an Entry on February 29, 2012 in Case No 12-0814-EL UNC initiating a "review to ensure the EDUs inputs to and participation in the May 2012 RPM Auction for the 2015/2016 PJM capacity requirements are reasonable and to the extent possible mitigate potential increases in RPM prices." (Entry at page 3 – See Attachment B1)

On March 13, 2012, representatives from the Companies conducted several meetings with Commissioners and multiple members of Staff to discuss the Entry and the Companies' planned response. The discussion touched on the FE Ohio Utilities' past participation in PJM auctions and the risks facing the FE Ohio Utilities regarding participation in the upcoming PJM Base Residual Auction ("BRA"). Various potential alternatives to achieve load reduction were discussed and the Staff and Commissioners were updated on the status of the PJM generation deactivation study.

On March 29, 2012, the FE Ohio Utilities filed a Report (See Attachment B2) in response to the Entry in Case No. 12-0814-EL-UNC regarding participation by the FE Ohio Utilities in the 2012 PJM BRA. The Report outlined the significant risks faced by the FE Ohio Utilities if they were to offer potential energy efficiency and demand response resources for the 2015/2016 planning year. The FE Ohio Utilities committed to explore opportunities for energy efficiency and peak demand reduction and Volt/VAR controls that could be implemented that might possibly mitigate the impacts of the generation deactivations.

On May 31, 2012, the Companies again conducted several additional meetings with Commissioners and several members of the Commission Staff to review the status of PJM analyses regarding the generation deactivations. In short, the meeting covered the generator deactivation timeline, the identified reliability concerns, the results of the PJM BRA, and a summary of the transmission projects that the PJM Board of Directors had approved on May 17, 2012. Also, the Companies discussed the generation units that had been designated as Reliability Must Run ("RMR") facilities until the associated transmission upgrade projects are completed.

On June 1, 2012, the Companies provided further information (See Attachment C) to the Commission in response to a letter that was received from the Commission Staff on or about May 15, 2012. The letter requested additional information pertaining to the generating plant deactivations and the effect those deactivations may have on transmission congestion and the reliability of supply to Ohio customers. The response described the Companies' close involvement with PJM in the analyses of recommended mitigation projects for the constraints previously identified due to the planned generation deactivations. The Companies' response indicated that the PJM Board of Directors approved certain transmission projects on May 17, 2012 and summarized the timeline up to the date of the letter. The communication also included the results of PJM's analyses and it suggested a follow up discussion.

Most recently, on July 18, 2012 representatives of the Companies met with numerous members of the Commission Staff to provide a further update of the status of distribution automation program on the FE Ohio Utilities' distribution system. This discussion included an overview of the technology associated with Distribution Automation and Volt/Var control, a progress report on the program, and preliminary results noted to date.

❖ Section 2: PJM Generation Deactivation Process - Overview

The following overview is based on publically available information, including information from PJM's Open Access Transmission Tariff ("PJM Tariff") and other PJM documents and data. The Companies do not own generating units in PJM and as such have no direct knowledge of the PJM Generation Deactivation Process. To the extent that there is a difference between this overview and the processes and procedures described the PJM Tariff or other PJM documents and data then the PJM Tariff or other PJM documents and data control.

Summary of the Steps for Generation Deactivation

1. Generator Owner provides to PJM the written notice that is described in Section 113 of the PJM Open Access Transmission Tariff.
2. Within 30 days of the announcement, PJM will summarize adverse reliability effects and proposed transmission mitigation projects.
3. Within 60 days of the announcement, Generator Owner will let PJM know that it intends to run its proposed deactivated facility as an RMR facility.
4. Within 90 days of the announcement, PJM will conduct a detailed reliability assessment of the system and finalize the list of transmission projects required to mitigate the adverse effects of deactivating the generation.

Steps for Generation Deactivation

The first step to the generator deactivation process is for the Generator Owner ("GO") to send written notice of its proposed generator deactivation(s) or generator-output reduction(s) to PJM by no later than 90 days prior to the proposed deactivation date.

Within 30 days of this announcement, PJM will tell the GO whether or not the proposed generation deactivation will adversely affect the reliability of the system and if its generation is assumed to be an RMR facility. If there are any potential adverse reliability effects, then a preliminary list of proposed transmission upgrade projects are also provided by PJM to the GO and Transmission Owner(s) ("TO") having facilities affected by the deactivations.

The GO must let PJM know within 60 days of the announcement that it intends to run its planned retired facilities under an RMR arrangement until transmission facilities are available to address reliability concerns. If the GO is in agreement with PJM's assessment and the need for the generation to continue to operate under an RMR arrangement, the GO is entitled to recover certain costs to keep the facilities in operation pursuant to the PJM tariffs. This may require a rate filing with the FERC.

PJM will identify any adverse reliability issues caused by the generation deactivations through a detailed reliability assessment of the transmission system, and PJM will finalize the listing of projects required to mitigate the issues within 90 days of the announcement. The detailed reliability assessment is an in-depth review comprised of several tests designed to ensure that the generator deactivation(s) will not adversely affect the reliability of the Bulk Electric System ("BES"), which in general, is related to transmission facilities that are at a voltage that is 100 kV or greater. A detailed discussion of these various reliability tests are covered in the next section.

❖ <u>Section 3: PJM Reliability Assessment Process – Overview</u>

The following overview is based on publically available information, including information from the PJM and other PJM documents and data. To the extent that there is a difference between this overview and the processes and procedures described the PJM Tariff or other PJM documents and data then the PJM Tariff or other PJM documents or data control.

General Description of the PJM Reliability Assessment Process

The PJM Reliability Assessment Process consists of several tests to ensure all generation capacity is deliverable to load in PJM without violating any system thermal or voltage limits. If violations are found, mitigation projects are put in place to resolve the issue(s). Limits used in the analysis are consistent with the requirements of NERC standards FAC-010 and FAC-014. The methodology used to determine system operating limits is included in PJM Manual M-14B (See Attachment D2).

PJM conducts this detailed review annually for the near-term, which consists of a detailed reliability analysis review of the current year plus 5 years out. The study years prior to the 5-years out reliability assessment are considered the “in-close” years and have already had analyses conducted in previous years’ study cycles. In addition, for each of these “in-close” years, PJM updates and issues addenda to address changes as necessary throughout the year. For example, planned generation modifications or changes in transmission topology can trigger restudy and the issuance of a baseline addendum. This is referred to as a “retool study” (e.g., generators which drop from the interconnection queue cause restudy and an addendum to be issued for affected baseline analyses).

Each year during the establishment of the assumptions for the new annual baseline analysis, updated assumptions of load, transmission topology and installed generation are assessed for the “in-close” range of years to validate the continued applicability of each of the “in-close” baseline analyses and resulting upgrades (including any addenda). Adjustments to the “in-close” analyses are performed as deemed necessary by PJM. Consequently, PJM annually verifies the continued need for modification of past recommended upgrades through its retool studies, reassessment of current conditions and any needed adjustments to analyses. All criteria thermal and voltage violations resulting from the near term analyses are identified using power flow analysis.

The seven steps in an annual near-term reliability review are as follows:

1. Develop a Reference System Power Flow Case
2. Baseline Thermal
3. Baseline Voltage
4. Load Deliverability - Thermal
5. Load Deliverability - Voltage
6. Generation Deliverability - Thermal

7. Baseline Stability Analysis

These reliability related steps are followed by a scenario analysis that ensures the robustness of the plan by looking at impacts of variations in key parameters selected by PJM. Each of these steps in the PJM Regional Transmission Expansion Planning ("RTEP") process is described in more detail in PJM Manual M-14B Generation and Transmission Interconnection Planning (http://www.pjm.com/planning/rtep-development/expansion-plan-process.aspx). (See Attachment D2.)

1) Developing the Reference System Power Flow Case

The reference power flow case and the analysis techniques comprise the full set of analysis assumptions and parameters for reliability analysis. Each case is developed from the most recent set of Eastern Reliability Assessment Group ("ERAG") system models. PJM revises this model as needed to incorporate all of the current system parameters and assumptions. These assumptions include current loads, installed generating capacity, transmission and generation maintenance, system topology, and firm transmission transactions.

The results of capacity market auction(s) are used to help determine the amount and location of generation or demand side resources to be included in the reliability modeling. Generation or demand side resources that are cleared in the capacity market auction are included in the reliability modeling. Generation or demand side resources that either do not bid or do not clear in any capacity market auction are not included in the reliability modeling. All such modeling comports with the capacity construct provisions approved by the FERC.

Subsequent to subregional stakeholder modeling reviews facilitated by PJM, PJM develops the final set of reliability assumptions presented to the PJM Transmission Expansion Advisory Committee ("TEAC") for review and comment, after which PJM finalizes the reliability review reference power flow case.

2) Baseline Thermal Analysis

The 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 TO facilities being examined. It encompasses an exhaustive analysis of all NERC category A, B, and C 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 from the latest available PJM Load Forecast Report (50% probability that the actual load is higher or lower than the projected load) minus energy efficiency programs. Demand response programs are not considered in the Load Forecast.

For normal conditions (NERC category A), all facilities are loaded within their normal thermal ratings. For each single contingency (NERC Category B), all facilities are loaded within their emergency thermal ratings. After each single contingency and allowing phase shifter, re-dispatch and topology changes to be made, post-contingency loadings of all facilities are within their applicable normal thermal ratings.

For the more severe contingencies (NERC category C), along with only transformer tap and switched shunt adjustments enabled, post-contingency loadings of all facilities are within their applicable emergency thermal ratings as required by the PJM or the TO's planning criteria.

NERC Category C3 "N-1-1" analysis is also conducted as part of the annual RTEP process to determine if all monitored facilities can be operated:

1) Within normal thermal and voltage limits after N-1 (single) contingency assuming re-dispatch and system adjustments.
2) Within the applicable emergency thermal ratings and voltage limits after an additional single contingency ("N-1-1") condition.

The "N-1-1" study is conducted on a 50/50 non-diversified summer peak case. All BES single contingencies as defined in NERC category C3 as well as lower voltage facilities that are monitored by PJM Operations are included in the assessment. Non-BES contingencies, defined by TOs, are included to check for greater than 300 MW load loss. Non-BES facilities that are included in the assessment will also have corresponding contingencies defined.

Areas of the system that become radial post-contingency will be excluded from monitoring, with the following exceptions:

1) If the radial system contains greater than 300 MW of load, or
2) Specific local TO planning criteria require that it be monitored.

The PJM NERC Category C3 (or "N-1-1") thermal analysis will test the outage of every single contingency (N-1 condition) for thermal violations. All violations of the applicable thermal ratings are recorded and reported and solutions are developed.

3) Baseline Voltage Analysis

The baseline voltage analysis parallels the thermal analysis. It uses the same power flow and examines voltage criteria for the same NERC category A, B, and C events. Also, voltage criteria are examined for compliance. PJM examines system performance for both a voltage drop criteria (where applicable) and an absolute voltage 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 TO 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. Static var compensators ("SVCs") are allowed to regulate and fast switched capacitors are enabled.

The absolute voltage criteria is examined for the same contingency set by allowing transformer taps, switched shunts, and SVCs 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.)

The N-1-1 voltage magnitude test procedure follows a similar method as the thermal test method, except all monitored facilities are monitored for the emergency low limit after the second contingency ("N-1-1" condition.). Voltage collapse is considered to be a severe reliability violation and, consequently, each "N-1-1" condition that exhibits voltage collapse is investigated, validated, and resolved with remedial actions, or network upgrades.

4) Load Deliverability Analysis - Thermal

The load deliverability tests are a unique set of analyses designed to ensure that the transmission system provides a comparable transmission function throughout the system. These tests ensure that the transmission system is adequate to deliver each load area's requirements from the aggregate of system generation. The tests develop an expected value of loading after testing an extensive array of probabilistic dispatches to determine thermal limits. A deterministic dispatch method is used to create imports for the voltage criteria test. The transmission system reliability criterion used is 1 event of failure in 25 years. This is intended to design transmission so that it is not more limiting than the generation system which is planned to a reliability criterion of 1 failure event in 10 years.

Each load areas' deliverability target transfer level to achieve the transmission reliability criterion is separately developed using a probabilistic modeling of the load and generation system. The load deliverability tests measure the design transfer level supported by the transmission system for comparison to the target transfer level. Transmission upgrades are specified by PJM to achieve the target transfer level as necessary. Details of the load deliverability procedure can be found in PJM Manual M-14B. (See Attachment D2.)

The thermal test examines each load deliverability area where the deliverability area is under the stressed conditions of a 90/10 summer load forecast (i.e., a forecast that only has a 10% chance of being exceeded) and demand response is implemented (energy efficiency is removed from all areas). The areas not under the test are at the conditions of a 90/10 summer load forecast. The transfer limit to the load is determined for system normal and all single contingencies (NERC category A and B criteria) under ten thousand (10,000) load study area dispatches with calculated probabilities of occurrence. The dispatches are developed randomly based on the availability data for each generating unit. This results in an expected value of system transfer capability that is compared to the target level to determine system adequacy. As with all thermal transmission tests conducted by PJM the applicable TO's normal and emergency ratings are applied. The steady state and single contingency power flows are solved consistent with the similar solutions described for the baseline thermal analyses.

5) Load Deliverability Analysis – Voltage

This testing procedure is similar to the thermal load deliverability test except that voltage criteria are evaluated and a deterministic dispatch procedure is used to increase study area imports. The voltage tests and criteria are the same as those performed for the baseline voltage analyses.

6) Generation Deliverability Analysis – Thermal

The generator deliverability test for the reliability analysis ensures that, consistent with the load deliverability single contingency testing procedure, the transmission system is capable of delivering the aggregate system generating capacity at peak load (50/50 load level in all areas) with all firm transmission service modeled. Energy efficiency is removed from all areas and demand response is not exercised. The procedure ensures sufficient transmission capability in all areas of the system to export an amount of generation capacity at least equal to the amount of certified capacity resources in each area. Areas, as referred to in the generation deliverability test, are unique to each study and depend on the electrical system characteristics that may limit transfer of capacity resources. For generator deliverability, areas are defined with respect to each transmission element that may limit transfer of the aggregate of certified installed generating capacity. The cluster of generators with significant impacts on the potentially limiting element is the area for that element. The starting point power flow is the same power flow case set up for the baseline analysis. Thus the same baseline load and ratings criteria apply. The same contingencies used for load deliverability apply and the same single contingency power flow solution techniques also apply. Details of the generation deliverability procedure can be found in PJM Manual M-14B. (See Attachment D2.)

One additional step is applied after generation deliverability is ensured consistent with the load deliverability tests. The additional step is required by system reliability criteria that call for adequate and secure transmission during certain NERC category C common mode outages. The procedure mirrors the generator deliverability procedure with somewhat lower deliverability requirements consistent with the increased severity of the contingencies.

The details of the generator deliverability procedure including methods of creating the study dispatch can be found in PJM Manual M-14B. (See Attachment D2.)

7) Baseline Stability Analysis

PJM ensures generator and system stability during its interconnection studies for each new generator. In addition, analysis is performed on the RTEP baseline stability cases. These analyses ensure the system is transiently stable and that all system oscillations display positive damping. Generator stability studies are performed for critical system conditions, which include light load and peak load for three phase faults with normal clearing, plus single line to ground faults with delayed clearing. Also, specific TO designated faults are examined for plants on their respective systems. Finally, PJM also initiates special stability studies on an as needed basis. The trigger for such special studies commonly includes, but is not limited to, conditions arising from operational performance reviews or major equipment outages or deactivations.

❖ <u>Section 4: PJM Wholesale Generation Queue – Overview</u>

The following overview is based on publically available information, including information from PJM's Open Access Transmission Tariff ("PJM Tariff") and other PJM documents and data. To the extent that there is a difference between this overview and the processes and procedures described the PJM Tariff or other PJM documents and data then the PJM Tariff or other PJM documents and data control.

Executive Summary of the Generation Queue Process

PJM administers the connection of new generating facilities to the grid as part of its role as a Regional Transmission Organization ("RTO"). PJM coordinates the planning process for connecting new generation, analyzes the reliability impact of proposed generating projects and oversees the construction of the facilities required to interconnect new generation to the grid.

PJM plans the expansion and enhancement of the grid on a regional basis. The long-range RTEP process determines what changes and additions to the system are needed to maintain and enhance reliability. The RTEP process employs a 15-year planning horizon to more effectively deal with reliability needs, upgrades that support economic sales of power across the region, and major developments like power-plant deactivations. Because the planned interconnection of new generating units and proposed increases in the output capability of existing generating units affect the overall operation of the grid and its reliability, they are reviewed as part of the RTEP process.

The process begins with a party proposing a new generating facility or an increase in the capability of an existing generating facility submitting an interconnection request to PJM.

The process proceeds as follows:

1) Interconnection Requests and PJM Queue Position
2) Feasibility Study – PJM conducts feasibility studies to estimate interconnection costs and construction time, and provides feedback to the project owners.
3) System Impact Study – PJM conducts impact studies to perform more detailed analyses and develop more precise recommendations for system additions and costs.
4) Facilities Study – Detailed design work is performed for all required network transmission upgrades and attachment facilities.
5) Interconnection Service Agreement – An Interconnection Service Agreement is executed among the generation developer, the transmission owner to which the generator will be interconnected, and PJM. An Interim Interconnection Service Agreement is optional.
6) Construction Service Agreement

Each step imposes its own financial obligations and establishes milestone responsibilities.

Projects within each time-based queue are evaluated against a baseline benchmark set of studies in order to establish project-specific responsibility for system enhancements, separate from general network upgrades suggested by the results of baseline analyses.

In part because of the volume of newly proposed generating projects, PJM and its members are completing system impact studies for groups of similarly affected projects rather than individually to help expedite the process.

After an extensive stakeholder process, PJM filed proposed changes in the interconnection process with FERC in 2012. The proposed changes further streamline the process, reducing uncertainty for project developers and creating an alternate queue system for smaller projects of 20 megawatts and below that don't require upgrades to the transmission system.

1) Interconnection Requests and PJM Queue Position

The interconnection request must include descriptions of the project location, size, equipment configuration, anticipated in-service date, data as required to complete Attachment F of PJM Manual M-14A (see Attachment D1), as well as proof of right to control the site for the proposed project. The in-service date must be no more than 7 years from the date the interconnection request is received by PJM, unless it is demonstrated that engineering, permitting and construction of the project will exceed this period. Upon receipt of the completed interconnection request, the project is placed in the PJM interconnection queue, in which queue positions are determined by the date of submission of the completed interconnection request.

2) Feasibility Study

The applicant is required to choose a primary point of interconnection and also has the option to specify a secondary point of interconnection to be studied. The primary point of interconnection will be studied per the requirements as set forth in the PJM Tariff, Section 36.2 (see Attachment E) and the PJM manuals for the PJM RTEP process for generation interconnection (PJM Manual M-14A through M-14D (see Attachments D1-D4). The secondary point of interconnection will receive a sensitivity analysis which will include definition of the overloads and no estimated costs.

In general, the study will be completed within 90 days during the next Feasibility Study cycle. It will assess the practicality and cost of incorporating the generating unit or increased generating capacity into the PJM system. The analysis includes short-circuit studies and load-flow analysis. This study does not include stability analysis. The study also focuses on determining preliminary estimates of the type, scope, cost and lead time for construction of facilities required to interconnect the project.

Results of the study for the requested interconnection service are provided to the applicant and the affected TOss, and are published on the PJM web site. Confidentiality of the applicant is maintained in these reports, but the location of the project and size (in megawatts) is identified. After reviewing the results of the Feasibility Study, the applicant must decide whether or not to pursue completion of the System Impact Study.

3) System Impact Study

The System Impact Study is a comprehensive regional analysis of the impact of adding the new generation facility to the system and an evaluation of its impact on deliverability to PJM load in the particular PJM region where the generator is located. This Study identifies the system constraints relating to the project and the necessary attachment facilities, local upgrades, and network upgrades. The Study refines and more comprehensively estimates cost responsibility and construction lead times for facilities and upgrades.

Relationships are studied between the new generator, other planned new generators in the queue, and the existing system as a whole. PJM may decide to group two or more interconnection requests within one System Impact Study if the proposed projects are in electrical proximity. In situations where more than one generation project violates reliability criteria, cost responsibility for network upgrades to mitigate such violations will be allocated among the projects in the course of the System Impact Study.

Results of the study are provided to all applicants who had projects evaluated in the study and to affected TOs and they are posted on the PJM web site. While confidentiality obligations will be honored, the identity of the applicants will not be considered confidential in these reports.

4) Facilities Study

The Facilities Study describes the modifications required to provide the requested generator interconnection service. It's purpose is to provide conceptual (or preliminary) design, and, as appropriate, detailed design, plus cost estimates and project schedules, to implement the conclusions of the System Impact Study regarding the attachment facilities, network upgrades and local upgrades necessary to accommodate the applicant's interconnection request(s).

Examples of typical Facilities Study deliverables are preliminary single line diagrams and general arrangement drawings for substation work, and delineation of proposed study area and proposed conductor and structure designs for transmission line work. Remaining detailed design activities would be completed during the construction phase of the project.

Studies will be performed in order to determine the impact on the increase in fault current for all facilities associated with any new interconnection request. Any reinforcement(s) which are determined to be required for the new generator will be reviewed to determine if the existing generator's contribution causes the need for the reinforcement, and if the reinforcement would not be required if the existing unit was removed from the study.

5) Interconnection Service Agreement

The Interconnection Service Agreement ("ISA") defines the obligation of the generation developer regarding cost responsibility for any required system upgrades. The ISA also confers the rights associated with the interconnection of a generator as a capacity resource and any operational restrictions or other limitations on which those rights depend.

For an interconnection request to maintain its assigned priority, the applicant must respond within 60 days of receiving the ISA. To proceed with the project, the applicant must provide PJM with an acceptable form of security in the amount equal to the estimated costs of new facilities or upgrades for which the applicant is responsible.

PJM may also include other reasonable milestone dates for events such as permitting, regulatory certifications, or third-party financial arrangements. Milestone dates may be extended by the PJM in the event of delays not caused by the applicant, such as unforeseen regulatory or construction delays.

Under certain circumstances, an applicant for an ISA may wish to initiate project construction activities on an expedited basis prior to completion of the Facilities Study. One example of such a circumstance is to request that orders be placed for equipment or materials that have a long lead time for delivery. To initiate such an advance of construction activities, the applicant may request execution of an Interim ISA for those construction activities being advanced.

The Interim ISA would bind the applicant for all costs incurred for the construction activities being advanced pursuant to the terms of the PJM Tariff. While PJM agrees to provide the applicant with the best estimate (determined in coordination with the affected TO(s) of the new facility costs and other charges that may be incurred for the work being advanced, such estimate shall not be binding and the applicant must agree through execution of the Interim ISA to compensate PJM and the affected TO(s) for all costs incurred due to those activities that were advanced.

7) Construction Service Agreement

The construction of any interconnection facilities required to interconnect a generator project with the grid shall be performed in accordance with the standard terms and conditions as specified in an interconnection Construction Service Agreement ("CSA") to be executed among the applicant, PJM and the affected TO(s). The form of an CSA may be found in the PJM Tariff as Attachment P. (See Attachment F.)

❖ Section 5: PJM Reliability Pricing Model ("RPM") Auction

The following overview is based on publically available information, including information from PJM's Open Access Transmission Tariff ("PJM Tariff") and other PJM documents and data. To the extent that there is a difference between this overview and the processes and procedures described the PJM Tariff or other PJM documents and data then the PJM Tariff or other PJM documents and data control.

The PJM Capacity Market is designed to ensure the adequate availability of necessary resources that can be called upon to ensure the reliability of the grid. In PJM, the capacity market structure provides transparent information to enable forward capacity market signals to support infrastructure investment. The capacity market design provides a forward mechanism to evaluate the ongoing reliability requirements in a transparent way to provide opportunity for generation, demand response, energy efficiency, and transmission solutions.

In the PJM region, the basis for the capacity market design is the RPM. The goal of RPM is to align capacity pricing with system reliability requirements and to provide transparent information to all market participants far enough in advance for actionable response to the information. In the RPM, the fundamental elements to achieve this are:

- Locational capacity pricing to recognize and quantify the locational value of capacity.
- Variable Resource Requirement ("VRR") mechanism to adjust price based on the level of resources procured.
- Forward commitment of supply by generation, demand resources and qualified transmission upgrades cleared in a multi-auction structure.
- A reliability backstop mechanism to ensure that sufficient generation, transmission and demand response solutions will be available to preserve system reliability.

The PJM RPM auction process consists of the following components:

1. PJM Capacity Market and RPM Participants
2. RPM and PJM Resource Adequacy
3. PJM Load Deliverability Analysis
4. Constrained Load Deliverability Areas
5. Reliability Pricing Model Auction

The PJM Capacity Market also contains an alternative method of participation, known as the Fixed Resource Requirement ("FRR") Alternative.

1) PJM Capacity Market and RPM Participants

Participants in the PJM Capacity Market, including load serving entities ("LSEs") and resource providers, must comply with all applicable provisions of the PJM Open Access Transmission Tariff, PJM Operating Agreement, and the PJM Reliability Assurance Agreement. PJM Capacity Market participants must be signatories of the appropriate agreements and full members of PJM. All participants must comply with the procedures and requirements as set forth by these agreements and in PJM manuals.

Participation by LSEs in the RPM for load served in the PJM region is mandatory, except for those LSEs that have elected the FRR Alternative and submitted an approved FRR Capacity Plan for their load served in an FRR service area.

Resource providers with existing generation, planned generation, bilateral contracts for unit-specific capacity resources, existing demand resources, planned demand resources, energy efficiency resources, and qualifying transmission upgrades may participate in PJM's Capacity Market, either in PJM's RPM or the FRR Alternative, if these products meet the PJM requirements. Existing generation that is located outside of the PJM market footprint may also be offered into PJM's Capacity Market if they meet the PJM requirements.

Participation is mandatory for resource providers with:

- Available unforced capacity from existing generation located within the PJM market footprint; or
- Bilateral contracts for available unit-specific capacity resources that are existing generation units located within the PJM market footprint.

Participation is voluntary for resource providers with:

- External generation
- Planned generation (including planned upgrades to existing units)
- Planned external generation (including planned upgrades to existing units)
- Existing demand resources
- Planned demand resources
- Energy efficiency resources
- Qualifying transmission upgrades.

2) RPM and PJM Resource Adequacy

PJM performs an assessment of RTO resource adequacy each year for a ten-year future period. The purpose of the resource adequacy study is to determine the amount of capacity resources that can be required to serve the forecast load that satisfies PJM reliability criterion. The analysis considers load forecast uncertainty, forced outages of generation capacity resources, as well as planned and maintenance outages of generation, and assistance from external areas.

In PJM, studies are performed using the installed capacity values of resources. The reliability value of a resource depends on two variables: the installed capacity of the resource and a measure of the probability that a resource will not be available due to forced outages or forced de-ratings. The reliability criterion is based on Loss of Load Expectation ("LOLE") not exceeding one occurrence in ten years. The reserve requirement necessary to meet the reliability criterion is called the Installed Reserve Margin ("IRM") and it is expressed as a percentage of forecast peak load. The IRM is the measure of reserves calculated to establish the level of installed capacity resources that will provide an acceptable level of reliability consistent with the industry guidelines and standards for reliability, as established by the North American Electric Reliability Corporation ("NERC") and the Reliabilty*First* Corporation ("RFC"). Specifically, the applicable RFC standard is BAL-502-RFC-02. The IRM is determined by PJM in accordance with their PJM Resource Adequacy Analysis Manual M-20. (See Attachment G.) PJM also produces peak load forecasts for use in the RPM auction clearing processes in addition to planning purposes. In RPM, the load forecasts are used to determine the RTO reliability requirement. PJM will determine annual peak load forecasts for the RTO and zones for use in the RPM auction clearing process.

Load forecasts are also used in the determination of other planning and auction parameters such as Capacity Emergency Transfer Limit ("CETL"), Capacity Emergency Transfer Objective ("CETO"), and RPM Zonal Scaling Factors.

The process of determining the IRM that meets the PJM reliability criterion assumes that the internal RTO transmission is adequate and any generation can be delivered to any load without transmission constraints. This process helps in determining the minimum possible IRM for the RTO. However, since transmission may have limitations, after IRM is determined, a load deliverability analysis is conducted. The RTO is divided into different sub-regions for this analysis. These sub-regions are referred to as Locational Deliverability Areas ("LDAs") in the RPM. There are currently 25 LDAs defined in the PJM region.

3) PJM Load Deliverability Analysis

The first step in the load deliverability analysis is to determine the transmission import capability required for each LDA to meet the area reliability criterion of LOLE of one occurrence in 25 years. This import capability requirement, or CETO, is expressed in megawatts and valued as unforced capacity. The standard resource adequacy evaluation model is used to determine CETO.

The second step in the load deliverability analysis is to determine the transmission import capability limit for each LDA using the transmission analysis models. This import capability limit, or CETL, is expressed in megawatts and valued as unforced capacity. If CETL value is less than 115% of the CETO value, transmission upgrades are planned under the RTEP process. However, higher than anticipated load growth and unanticipated deactivations may result in the CETL value being less than CETO value with no lead time to build transmission upgrades to increase the CETL value. These conditions could result in locational constraints in the RTO.

When a capacity market does not have the ability to price capacity on a locational basis, all the resources in the market are valued equally throughout the RTO. When this occurs, it is possible to have excess reserves in the RTO and relatively low capacity prices. This market signal may result in greater generation capacity deactivations, all else being equal. In some areas of the RTO, these deactivations will create reliability violations. These conditions will indicate that a higher value for resources is required to be recognized in constrained locations to incent existing generating capacity to remain in service, and new capability to be built in the form of generation resources, demand resources, or transmission upgrades. One of the key features of RPM is the recognition of locational value of capacity.

Locational constraints are localized capacity import capability limitations (low or no CETL margin over CETO) that are caused by transmission facility limitations or voltage limitations that are identified for a Delivery Year in the RTEP process prior to each BRA. Such locational constraints are included in the RPM to recognize and to quantify the locational value of capacity.

4) Constrained Load Deliverability Areas

An LDA with CETL less than 115% of the CETO value will be modeled as a constrained LDA in RPM. In addition, an LDA will be modeled under other circumstances as defined by PJM in its manuals. Reliability Requirement and VRR Curves will be established for each constrained LDA to be modeled in the BRA. The Reliability Requirement and the VRR Curves will be posted on the PJM website by February 1 prior to the commencement of the BRA.

5) Reliability Pricing Model Auction

The purpose of the RPM is to develop a long term pricing signal (three-year forward pricing) for capacity resources and LSE obligations that are consistent with the PJM RTEP process. RPM is also designed to add stability and a locational nature to the pricing signal.

The RPM is a multi-auction structure designed to procure resource commitments to satisfy the region's unforced capacity obligation through the following market mechanisms: a Base Residual Auction ("BRA"), Incremental Auctions and a Bilateral Market.

- *Base Residual Auction* - The Base Residual Auction is held during the month of May three (3) years prior to the start of the Delivery Year. The BRA allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the LSEs through a Locational Reliability Charge.
- *Incremental Auctions* – Up to three Incremental Auctions are conducted after the BRA to procure additional resource commitments needed to satisfy potential changes in market dynamics that are known prior to the beginning of the Delivery Year.
- *The Bilateral Market* – The bilateral market provides resource providers an opportunity to cover any auction commitment shortages. The bilateral market also provides LSEs the opportunity to hedge against the Locational Reliability Charge determined as a result of the RPM auction process.

❖ Section 6: PJM Generation Deactivation Process - Actual Results

The following discussion is based on publically available information, including information from PJM's Open Access Transmission Tariff ("PJM Tariff") and other PJM documents and data, or other publically available information. To the extent that there is a difference between this description of actual results and the processes and procedures described the PJM Tariff or other PJM documents and data, or other publically available information, then the PJM Tariff or other PJM documents and data control or other publically available information control.

1) Generator Deactivations in the FE-ATSI Footprint Announced

On January 26, 2012, FirstEnergy Solutions ("FES") announced its planned generation deactivations and, consistent with the requirements of Section 113 of the PJM Tariff sent written notice to PJM of FES's planned generation deactivations. Based on publically available information, the announcement/request for generation deactivations was for the following generation units and was for September 1, 2012:

- Eastlake Units 1, 2, 3 (deactivation date extended to June 1, 2015)
- Eastlake Units 4 and 5
- Bayshore Units 2, 3, and 4
- Lakeshore Unit 18 (deactivation date extended to June 1, 2015)
- Ashtabula Unit 5 (deactivation date extended to June 1, 2015)

Based on publically available information, on February 29, 2012, GenOn announced its planned generation deactivations as well as advising PJM. The announcement/request for generation deactivations for the Niles generation units was for June 1, 2012 and for the New Castle units was for April 16, 2015:

- Niles Unit 1 (deactivation date extended to October 1, 2012)
- Niles Unit 2 (deactivated as requested)
- New Castle Units 3, 4, 5, A, and B

On March 30, 2012, GenOn announced additional planned generation deactivations as well as advising PJM. The announcement/request for generation deactivations for the Avon Lake generation units was for April 16, 2015:

- Avon Lake Units 7 and 9

Based on publically available information, any generation units in the bullets above that show the deactivation date extended have been designated as RMR units by PJM in its reliability reviews and TEAC presentations. Consequently, on information and belief it appears that the Eastlake Units 1-3, Lakeshore Unit 18, and the Ashtabula Unit 5 will be the RMR units through June 1, 2015. On information and belief it appears that Niles Unit 1 will be an RMR unit through October 1, 2012. (The RMR period for Niles Unit 1 could be extended pending analysis of outages required to implement required system upgrades).

2) PJM Reliability Review and Approvals

On February 24, 2012, PJM completed its initial reliability review of the proposed FES generation deactivations. The study results were compiled and put in a document in the form of a white paper named "FE Retirement Whitepaper," which was presented at the PJM TEAC meeting on March 15, 2012. (See Attachment H.) The document listed the FES generation units that were announced to be deactivated and the study results (criteria violations).

On information and belief it appears that on April 11, 2012, LS Power (a merchant transmission company) announced its proposed transmission project to mitigate some issues due to the generation deactivations. The project consists of a new single circuit 345 kV transmission line in Ohio from the Conesville 345 kV substation to the Star 345 kV substation.

PJM presented a "Reliability Analysis Update" (see Attachment I) with proposed ATSI reinforcements at the April 12, 2012 PJM TEAC meeting. The Reliability Analysis Update showed that the following units were assumed to be RMR: Lakeshore Unit 18, Eastlake Units 1-3, and Ashtabula Unit 5. Also, as of this time, the presentation indicated that Eastlake Units 2-5 are planned to be synchronous condensers. Eastlake Unit 5 is planned to be converted to a synchronous condenser by June 1, 2013. Eastlake Units 2, 3, and 4 are planned to be converted to a synchronous condenser by June 1, 2015. It should be noted that in the final PJM reliability analysis review (referred to in the next paragraph), the date to convert the Eastlake Unit 4 to a synchronous condenser was changed to December 1, 2013, and Lake Shore Unit 18 was added to the list of units to be converted to a synchronous condenser by June 1, 2015.

PJM issued a document to the TEAC that presented updated study results on April 25, 2012 for the reliability review along with the planned mitigation transmission projects related to the January 26, 2012 FES announcement in a document called "FirstEnergy January 2012 Generator Deactivation Request – Study Results and Required Upgrades." (See Attachment J.) The bullets below were taken from that document and list planned mitigation transmission projects for ATSI as they appeared in this reliability review. It should be noted that the projects below did not include generator deactivations for GenOn.

- Install a 50 MVAR capacitor bank at the Maclean 138 kV station 6/1/2013
- Install a 345/138 kV transformer at the Inland Q-11 station 6/1/2013
- Install a 138 kV circuit breaker at the Inland Q-11 station 6/1/2013
- Upgrade terminal equipment on the Avon – Crestwood 138 kV line 6/1/2013
- Eastlake unit 5 to be converted to synchronous condenser 6/1/2013
- Eastlake unit 4 to be converted to synchronous condenser 12/1/2013
- Eastlake units 1, 2 and 3 to be converted to synchronous condensers 6/1/2015

- Lakeshore unit 18 to be converted to synchronous condenser 6/1/2015
- Loop the Chamberlin - Mansfield 345 kV line into the Hanna 345 kV substation (existing baseline upgrade b1283) 6/1/2014 (advanced from 6/2015)
- Build new Hayes 345/138 kV substation with new 138 kV lines to: Greenfield #1, Greenfield #2, and Avery (existing baseline upgrade b1281) 6/1/2014 (advanced from 6/2015)
- Build Beaver - Hayes - Davis Besse #2 345 kV line (existing base line upgrade b1282) 6/1/2014 (advanced from 6/2015)
- Re-conductor the Galion – Leaside 138 kV line 6/1/2014
- Re-conductor the Galion – GM Mansfield – Ontario - Cairns 138 kV line 6/1/2014
- Install a 2nd 345/138 kV transformer at the Allen Junction station 6/1/2014
- Install a 2nd 345/138 kV transformer at the Bay Shore station 6/1/2014
- Create a new Northfield Area 345 kV switching station by looping in the Eastlake – Juniper 345 kV line and the Perry - Inland 345 kV line 6/1/2015
- Build a new Mansfield - Northfield Area 345 kV line 6/1/2015
- Create a new Harmon 345/138/69 kV substation by looping in the Star – South Canton 345 kV line 6/1/2015
- Build a new Harmon – Brookside + Harmon - Longview 138 kV line 6/1/2015
- Create a new Five Points Area 345/138 kV substation by looping in the Lemoyne – Midway 345 kV line 6/1/2015
- Install a 50 MVAR capacitor at Hayes 138 kV 6/1/2015
- Install a 138/69 kV transformer at the Avery station 6/1/2015
- Increase design temperature limitation on the Avery – Hayes 138 kV line by raising the existing structures 6/1/2015
- Reconductor Cloverdale - Harmon #2 and #3 138kV lines and Terminal upgrades 6/1/2015
- Change the transformer tap settings on the Maclean 138/69 kV transformers 6/1/2015
- Upgrade the Richland – Naomi 138 kV line 6/1/2015
- ATSI-AEP 138kV Substation on / near territory border and 138kV from new substation to Longview 6/1/2016, working on potential operating procedure to mitigate impacts until this upgrade complete
- Build new Allen Jct - Midway - Lemonye 345kV line 6/1/2016, but operating procedure in place to mitigate impacts until this upgrade complete
- Build a new Leroy Center 345/138 kV substation by looping in the Perry – Harding 345 kV line 6/1/2016, but operating procedure in place to mitigate impacts until this upgrade complete
- Place a portion of the 138 kV Leroy Center 345/138 kV project into service by summer 2015 6/1/2015
- Reconductor the Barberton – West Akron 138 kV line 6/1/2016, but operating procedure in place to mitigate impacts until this upgrade complete

At the PJM TEAC meeting on April 27, 2012, PJM stated that it completed the Reliability Analysis for FES generation deactivations and started its initial review of the

GenOn units (New Castle 3-5, A, B and Niles 1-2). (See Attachment K.) PJM presented the planned mitigation transmission projects (see project list above) for the FES generator deactivations (based on the April 25, 2012 reliability review).

In addition to the project list above, PJM also presented the following transmission projects at the April 27, 2012 TEAC meeting:

- Build a new Toronto to Harmon 345 kV line – 6/1/2017
- Build a new West Fremont – Groton – Hayes 138 kV line - 6/1/2018
- Add a new 150 MVAR SVC and 100 MVAR capacitor at New Castle - 6/1/2015
- Existing RTEP project b1693: Replace the Star 345/138 kV #3 with a larger unit - 6/1/2013
- Reconductor Evergreen-Highland #1 138kV – 6/1/2013
- Reconductor Evergreen-Highland #2 138kV – 6/1/2013
- b1289: Reconductor Evergreen - Niles 138 kV (3 miles) and replace terminal equipment at Evergreen on Evergreen - Niles 138 kV – 6/1/2013
- Reconductor Highland-Salt Springs 138kV – 6/1/2013, possibly 6-1-2014
- Harmon 345-138-69kV Sub project – 6/1/2015
- W. Fremont-Groton-Hayes 138kV line – 6-1-2018

On May 17, 2012, the PJM Board of Directors approved the planned mitigation projects that were presented at the April 27 TEAC meeting (which included both the FES and some GenOn generator deactivations).

On May 29, 2012, PJM completed its reliability review of the proposed GenOn generation deactivations for the Niles units, and issued a document to the TEAC that described this review and the proposed mitigation transmission projects. This document is titled "GenOn February 2012 Generator Deactivation Request (Niles and Elrama) – Study Results and Required Upgrades." (See Attachment L.) Also, in this document, Niles Unit 1 was assumed to be an RMR unit. The bullets below show the list of planned mitigation transmission projects for ATSI as they appeared in this reliability review:

- Existing RTEP project b1693: Replace the Star 345/138 kV #3 with a larger unit - 6/1/2013
- Existing RTEP project b1693: Replace the Star 345/138 kV #3 with a larger unit - 6/1/2013
- Reconductor Evergreen-Highland #1 138kV – 6/1/2013
- Reconductor Evergreen-Highland #2 138kV – 6/1/2013
- b1289: Reconductor Evergreen - Niles 138 kV (3 miles) and replace terminal equipment at Evergreen on Evergreen - Niles 138 kV – 6/1/2013
- Reconductor Highland-Salt Springs 138kV – 6/1/2013, possibly 6-1-2014
- Harmon 345-138-69kV Sub project – 6/1/2015
- W. Fremont-Groton-Hayes 138kV line – 6-1-2018

On May 30, 2012, PJM posted a PJM Board Whitepaper titled "Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board" to its website. (See Attachment M.) This paper was presented at the PJM TEAC meeting on June 14, 2012, which was inclusive of all aforementioned generator deactivations except Avon Units 7 and 9. The PJM Board Whitepaper listed the major transmission projects at this point in time as shown below (which is a combination of projects from the previous lists less some small projects like capacitor banks. This list also shows the cost of the projects.)

- Install a 345/138 kV transformer at the Inland Q-11 station - $7.2M
- Convert Eastlake units 1, 2, 3, 4 and 5 to synchronous condensers - $100M
- Convert Lakeshore 18 to synchronous condensers - $20M
- Re-conductor the Galion – GM Mansfield – Ontario - Cairns 138 kV line - $9.8M
- Install a 2nd 345/138 kV transformer at the Allen Junction station - $7.2M
- Install a 2nd 345/138 kV transformer at the Bay Shore station - $7.2M
- Create a new Northfield Area 345 kV switching station by looping in the Eastlake – Juniper 345 kV line and the Perry - Inland 345 kV line - $37.5M
- Build a new Mansfield - Northfield Area 345 kV line - $184.5M
- Create a new Harmon 345/138/69 kV substation by looping in the Star – South Canton 345 kV line - $46M
- Build a new Harmon – Brookside + Harmon - Longview 138 kV line - $9.2M
- Create a new Five Points Area 345/138 kV substation by looping in the Lemoyne – Midway 345 kV line - $30M
- Build a new 345-138kV Substation at Niles - $32M
- Build a new substation near the ATSI-AEP border and a new 138kV line from new substation to Longview - $17.7M
- Build new Allen Jct - Midway - Lemonye 345kV line - $86.3M
- Build a new Leroy Center 345/138 kV substation by looping in the Perry – Harding 345 kV line - $46M
- Build a new Toronto to Harmon 345 kV line - $218.3M
- Build a new Toronto 345/138 kV substation - $41.8M
- Build a new West Fremont – Groton – Hayes 138 kV line - $45M
- Reconductor the ATSI portion of South Canton – Harmon 345 kV line - $6M
- Add a new 150 MVAR SVC and 100 MVAR capacitor at New Castle - $31.7M

3) PJM Tasks Remaining Regarding the Generation Deactivations

<u>Complete the GenOn Avon Units 7 and 9 Deactivation Study</u>

On information and belief, it appears that for the ATSI Transmission Zone, GenOn made the official request on March 30, 2012 for the deactivation of Avon Units 7 and 9. The deactivation date is April 16, 2015. These two generation deactivation requests are currently in the PJM process of being studied. On May 10, 2012, at the PJM TEAC meeting, the preliminary results of the studies and the proposed mitigation transmission projects were presented. (See Attachment N.) This study has not been approved by the PJM Board nor has it been finalized. The transmission projects that were presented for

ATSI resulting from the study of deactivating Avon 7 and 9 are shown below (most have been identified in the previous generation deactivation studies):

- Build new Toronto 345/138 kV substation by looping in the Sammis – Wylie Ridge 345 kV line and tie in four 138 kV lines (Estimated Project Cost: $41.8M, Projected in-service is 06/01/2015, Previously identified and approved for New Castle 3, 4, & 5; New Castle Diesels A & B deactivations)

- Reconductor Johnson-Lorain 138kV with 954 ACSS + Replace wavetrap (Estimated cost to be determined, Expected in-service date: 6/1/2015)

- Build a new West Fremont-Groton-Hayes 138kV line (Estimated Project Cost: $45M, Projected in-service date: 6/1/2018, Short term: Existing Operating Procedure to open Lakeview-Greenfield from 6/1/2012 through 6/1/2018. Previously identified and approved for Niles 1 & 2; Elrama 1, 2, 3 & 4 deactivations)

- Existing ATSI-AEP 138kV Substation (Brubaker Sub) near territory border + 138kV from new substation to Longview approx. 8 miles + Requires AEP project to R/C Howard-Brubaker 138kV with 477 ACS (Estimated Project Cost: $17.7M, Expected in-service date: 6/1/2016, (Previously identified approved for Armstrong 1 & 2;Ashtabula 5; Bayshore 2-4; Eastlake 1-5; Lake Shore 18; R Paul Smith 3 & 4; New Castle 3, 4, & 5; New Castle Diesels A & B deactivations)

- Reconductor Barberton-W.Akron 138kV (7.3mi 605 ACSR w/ 477 ACSS) (Estimated Project Cost: $4.23M, Expected in-service date: 6/1/2016, Previously identified and approved for Armstrong 1 & 2; Ashtabula 5; Bayshore 2-4; Eastlake 1-5; Lake Shore 18; R Paul Smith 3 & 4 deactivations)

- Existing project to accelerate a portion of already submitted Leroy Center 345-138kV Sub (2016) to (2015). Add (6) 138kV breakers + relaying at Leroy Center (Estimated Project Cost: $3.3M, Expected in-service date: 6/1/2015, Previously identified and approved for Armstrong 1 & 2;Ashtabula 5; Bayshore 2-4; Eastlake 1-5; Lake Shore 18; R Paul Smith 3 & 4 deactivations)

<u>ATSI Transmission Zone Additional Long Term Reinforement</u>

On information and belief, PJM is currently reviewing the following three proposals by ATSI, , LS Power, and AEP:

FE Proposed Solution:
At the April 27, 2012 TEAC meeting, it was noted that the Beaver Valley – Mansfield – Leroy Center transmission project is still under review. (See Attachment K.)

- New Beaver Valley - Leroy Center 345kV + Mansfield - Leroy Center 345kV lines (Estimated Project Cost: $393M, Proposed in-service date: 6-1-2018, Short term: Temporary Operating Procedure to Open Cloverdale-Barberton 138kV until 345kV lines are built)

LS Power Proposed Solution:

At the July 12, 2012 TEAC meeting, LS Power proposed an alternative transmission project: a new Conesville – Harmon 345 kV line. (See Attachment O.) The Conesville – Harmon 345 kV solution should mitigate the overloads identified for the proposed Toronto – Harmon 345 kV line.

AEP Proposed Solutions:

Also at that July 12, 2012 TEAC meeting, AEP proposed several alternative projects (see Attachment P) to compare against the Beaver Valley – Mansfield – Leroy Center transmission project as shown below:

- New Marysville – South Amherst 765 kV line
- New Trivalley – South Amherst 765 kV line
- New Conesville – Beaver 345 kV line

❖ Section 7: PJM Generation Queue - Actual Results

The following discussion is based on publically available information, including information from PJM's Open Access Transmission Tariff ("PJM Tariff") and other PJM documents and data, or other publically available information. To the extent that there is a difference between this description of actual results and the processes and procedures described the PJM Tariff or other PJM documents and data, or other publically available information, then the PJM Tariff or other PJM documents and data control or other publically available information control.

RPM Auction Eligibility for Eastlake CTs – Planned Generation Resources – Internal

On information and belief, FES submitted an interconnection application to PJM on March 8, 2012. The application was for natural gas projects to be interconnected to the ATSI transmission system and located in Eastlake, Ohio. The proposed in-service date for the projects was March 1, 2015. The two applications for interconnection at the Eastlake Substation were placed in the PJM interconnection queue as projects Y1-035 and Y1-036. Each application was for a 462 MW addition at the point of interconnection – for a total generation addition of 924 MW at Eastlake substation.

- Y1-035 application was made for interconnection at 138 kV and
- Y1-036 application was made for a point of interconnection at 345 kV

The Feasibility Studies were completed and issued by PJM to FES in March 2012. The Feasibility Study did not identify any issues with the proposed changes at the point of interconnection.

On information and belief, the projects are currently in the System Impact Study phase of the process.

❖ **<u>Section 8: PJM RPM Auction - Actual Results</u>**

The following discussion is based on publically available information, including information from PJM's Open Access Transmission Tariff ("PJM Tariff") and other PJM documents and data, or other publically available information. To the extent that there is a difference between this description of actual results and the processes and procedures described the PJM Tariff or other PJM documents and data, or other publically available information, then the PJM Tariff or other PJM documents and data control or other publically available information control.

<u>PJM RPM 2015/2016 Auction Results Summary</u>

Overview

The 2015/2016 BRA opened on May 7, 2012 and the results were posted by PJM on May 18, 2012. (See Attachment Q.) The 2015/2016 BRA cleared 164,561.2 MW of unforced capacity in the RTO, representing a 20.6% reserve margin. When the FRR load and resources are considered, the reserve margin for the entire RTO is 20.2%.

On information and belief, environmental rules and the resulting expected resource deactivations significantly impacted the RPM auction results. Over the next three years, an unprecedented amount (over 14,000 MW) of generation deactivations are expected, driven largely by environmental regulations. The announced generation deactivations sent a strong signal that there would be a need for new resources, and this auction witnessed a record number of new generation offers, a record number of demand resource offers, and a record number of energy efficiency resource offers.

In addition, it is possible to interpret the auction results to illustrate the continuing trend, starting with the 2014/2015 BRA, of a significant decline in the amount of coal-fired generation that cleared and a significant shift to increased amounts of new natural gas-fired generation that cleared.

ATSI LDA Clearing Price

According to PJM, the ATSI LDA was locationally constrained in the 2015/2016 BRA. Therefore, clearing prices in this LDA differed from the clearing prices in the rest of the RTO. The clearing price for Annual Resources located in the RTO was $136.00/MW-day. The clearing price for Annual Resources located in the ATSI LDA was $357.00/MW-day.

According to PJM, the annual resource clearing price in the ATSI LDA increased from $125.99 in the 2014/2015 Delivery Year to $357.00 in the 2015/2016 Delivery Year. The annual resource clearing price in the rest of RTO region increased from $125.99 in the 2014/2015 Delivery Year to $136.00 in the 2015/2016 Delivery Year.

Generation Resource Quantities Offered into Auction

According to PJM, this auction resulted in a record number of new generation resources cleared in any single RPM auction. The total quantity of new generation resources offered into the auction was 6,843.7 MW and the total existing generation uprates offered was 478.6 MW. The amount of new generation capacity resources cleared was 4,898.9 MW and the total amount of existing generation uprates that cleared was 447.4 MW. Specific ATSI numbers were not made publicly available by PJM.

According to PJM, total imports offered into the auction from resources located in regions west of the PJM RTO also increased by about 325 MW to 4,335.2 MW.

Demand Resource Quantities Offered into Auction

According to PJM, the total quantity of demand resources offered into the 2015/2016 BRA was 19,956.3 MW, which represented an increase of 4,410.7 MW (28.4%) over the demand resources that offered into the 2014/2015 BRA. Approximately 74% (14,832.8 MW) of these demand resources cleared in the auction.

According to PJM, for the ATSI LDA, the total quantity of demand resources offered into the 2015/2016 BRA was 2,038.5 MW, which represented an increase of 983.4 MW (93.2%) over the demand resources that offered into the 2014/2015 BRA. Approximately 87% (1,763.7) of these demand resources cleared in the auction in the ATSI LDA, which contributed to the Eastlake CTs not clearing the $357.00 ATSI LDA clearing price.

Energy Efficiency Resource Quantities Offered into Auction

According to PJM, the total quantity of energy efficiency ("EE") resources offered into the 2015/2016 BRA was 940.3 MW, which represented an increase of 13% over the EE resources that offered into the 2014/2015 BRA. Approximately 98% (922.5 MW) of these EE resources cleared in the auction.

According to PJM, for the ATSI LDA, the total quantity of EE resources offered into the 2015/2016 BRA was 48.1 MW, which represented an increase of 1,503% over the EE resources that offered into the 2014/2015 BRA. Approximately 93% (44.9 MW) of these EE resources cleared in the auction.

Summary for the ATSI LDA

According to PJM, in the ATSI LDA, there were 11,777.1 MW of total offered MW and ultimately 10,667.6 MW (91%) cleared the BRA. The resources that did not clear (1,109.5 MW) would include potential generation, demand response, and energy efficiency whose bid in prices exceeded the annual resource clearing price in the ATSI LDA of approximately $357.00 for the 2015/2016 delivery year. The resources that did not clear the BRA included the proposed Eastlake CTs discussed in Section 7.

Attachment A

FirstEnergy

76 South Main Street
Akron, Ohio 44308

1-800-646-0400

March 19, 2012

Daniel R. Johnson
Chief, Planning and Market Analysis
Public Utilities Commission of Ohio
180 East Broad Street
Columbus, Ohio 43215-3793

Re: Special Topics Letter for Long-Term Forecast Report

Dear Mr. Johnson:

I've been asked to respond to your letter dated January 24, 2012, addressed to Mr. Michael J. Dowling in which you requested electric generation unit information for plants owned by FirstEnergy Corp.'s competitive affiliate, FirstEnergy Solutions Corp., be included in the 2012 Long-Term Forecast Report

The information requested in questions 1-5 relates solely to plants owned and operated by FirstEnergy Generation Corp., a subsidiary of FirstEnergy Solutions. We do provide an annual Long-Term Forecast Report (LTFR) on behalf of FirstEnergy Corp.'s Ohio electric distribution utilities (Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company) and American Transmission System, Inc. However, neither FirstEnergy Solutions nor any of its subsidiaries file a Long-Term Forecast Report with the Public Utilities Commission of Ohio.

Regarding your questions 6 and 7 that are directed to the FirstEnergy distribution utilities, analysis is underway at PJM to determine whether any planned plant retirements may have any impact on reliability or congestion. Representatives from FirstEnergy distribution utilities met with members of the Staff on March 13, 2012 to discuss issues raised in questions 6 and 7 and expect that dialog to continue. The Companies will file a report on these matters as directed in Case No. 12-814-EL-UNC.

Sincerely,

Bradley D. Eberts

Bradley D. Eberts
Manager, Load Forecasting

Cc: JWBurk
MJDowling
EMMikkelsen
WRRidmann
WEStark

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Commission's Review of the Participation of The Cleveland Electric Illuminating Company, the Ohio Edison Company, and The Toledo Edison Company in the May 2012 PJM Reliability Pricing Model Auction.	)	Case No. 12-814-EL-UNC

ENTRY

The Commission finds:

(1) On January 26, 2012, First Energy Corporation announced that its generation subsidiaries would be retiring the following power plants located in northern Ohio by September 1, 2012: Units 2-4 at the Bay Shore Plant, the Eastlake Plant, the Ashtabula Plant, and the Lake Shore Plant. These generation facilities are in the American Transmission System Inc. (ATSI) zone for the PJM Interconnection, LLC (PJM).

(2) The retirement of this generation in one area of the transmission system could impact the ability to maintain voltage support and result in transmission constraints during peak periods.

(3) On February 2, 2012, PJM posted its initial Planning Parameters for the 2015/2016 Reliability Pricing Model (RPM) Base Residual Auction (BRA) to be held in May 2012. The Parameters indicate that as a result of the removal of approximately 2,200 MW of generation located in the ATSI zone , the ATSI zone for the first time would be modeled separately by PJM for purposes of setting prices in the 2015/2016 RPM BRA. Limited import capabilities and reduced generation located within the ATSI zone could produce a significant increase in capacity prices in the 2015/2016 RPM BRA if appropriate steps are not taken to reduce generation requirements, improve energy efficiency, and expand demand response resources.

(4) Given their obligation to provide adequate service and reasonable and adequate facilities and instrumentalities, and consistent with state policy, the FirstEnergy electric distribution

utilities in the ATSI zone, The Cleveland Electric Illuminating Company, the Ohio Edison Company, and The Toledo Edison Company (collectively, the Companies), have an obligation to take all reasonable and cost-effective steps to avoid unnecessary RPM price increases for their customers. Sections 4905.22, 4905.70, and 4928.02, Revised Code. Moreover, the retirements of First Energy's generation plants could make some measures cost-effective which might not have been considered cost-effective assuming the continued operation of this generation.

(5) Section 4928.66, Revised Code, requires the Companies to implement energy efficiency programs that achieve energy savings equal to increasing annual benchmarks of at least three-tenths of one percent of normalized kilowatt-hour sales for 2009, an additional five-tenths of one percent in 2010, seven-tenths of one percent in 2011, eight-tenths of one percent in 2012, nine-tenths of one percent in 2013, one per cent in each year from 2014 to 2018, and two percent per year thereafter. Similarly, Section 4928.66, Revised Code, requires the Companies to implement peak demand reduction programs designed to achieve a one percent reduction in peak demand in 2009 and an additional seventy-five hundredths of one percent reduction each year through 2018. These annual benchmarks are cumulative and represent statutory minimums. Thus, the Companies are obligated to implement energy efficiency and peak demand reduction programs that would be expected to reduce their normalized kilowatt hour sales and peak demand by more than five percent by 2015. The Commission fully expects the Companies to file timely updates to their portfolio plans that meet or exceed their cumulative energy efficiency and peak demand reduction benchmarks for 2015. By definition cost-effective energy efficiency and peak demand reduction programs will reduce total costs to consumers.

(6) On January 18, 2012, the Commission held a workshop on Volt-VAR Control for Electric Distribution Systems that identified a potential to reduce generation and voltage requirements by monitoring and optimizing voltage on distribution circuits.

(7) The energy efficiency and peak demand reduction portfolio cases covering the period of the 2015/2016 RPM auction will

not be completed prior to the May 2012 BRA. Moreover, PJM's forecast of ATSI zone demand and voltage parameters for the 2015/2016 RPM auction is scheduled to be completed by early April 2012. As a result, the Commission is initiating this review to ensure that the EDUs inputs to and participation in the May 2012 RPM auction for 2015/2016 PJM capacity requirements are reasonable and to the extent practicable mitigate potential increases in RPM prices.

(8) The Commission directs the Companies within thirty days following the date of this Entry to consult with Staff and file a report detailing potential energy efficiency and peak demand reduction offers into the May 2012 PJM RPM auction for the 2015/2016 year. This report should include all cost-effective energy efficiency and peak demand reductions achievable by 2015 and a forecast of the demand and voltage reductions achievable by 2015 as a result of implementing all cost-effective distribution system Volt-VAR controls. Additionally, the Companies should provide PJM with a forecast of the demand and voltage reductions achievable by 2015 so that PJM may consider it in developing its forecast demand and voltage parameters for the May 2012 RPM auction, or report to the Commission reasons why the data will not be provided.

(9) Interested persons may file comments on the Companies proposed energy efficiency and peak demand reduction offers for the May 2012 PJM RPM auction no later than April 10, 2012.

(10) In order to encourage that all cost-effective steps are implemented promptly to offset generation retirements, the Companies are hereby directed under Rule 4901:1-39-04(A), Ohio Administrative Code, to file no later than July 31, 2012, interim energy efficiency and peak demand reduction program portfolio plans, specifically those programs that in the aggregate would have a mitigating impact on the generation retirements.

It is, therefore,

ORDERED, That Companies shall make filings in accordance with finding (8). It is, further, ORDERED, That interested persons may file comments in accordance with finding (9). It is, further,

ORDERED, That the Companies shall move up the date for filing their next energy efficiency and peak demand reduction portfolio plans in accordance with finding (10). It is, further,

ORDERED, That notice of this Entry shall be served on the Companies, the PJM Interconnection LLC., and all parties to Cases No. 09-1947-EL-POR, 09-1948-EL-POR, 09-1949-EL-POR, and 11-5818-EL-POR.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Todd A. Snitchler

Todd A. Snitchler, Chairman

Paul A. Centolella

Steven D. Lesser

Andre T. Porter

Andre T. Porter

Cheryl L. Roberto

Cheryl L. Roberto

GAP/sc

Entered in the Journal
FEB 2 9 2012

Barcy F. McNeal

Barcy F. McNeal
Secretary

BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Commission's Review of the Participation of The Cleveland Electric Illuminating Company, the Ohio Edison Company and The Toledo Edison Company in the May 2012 PJM Reliability Pricing Model Auction	)))))))	**Case No. 12-814-EL-UNC**

REPORT OF OHIO EDISON COMPANY,
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
AND THE TOLEDO EDISON COMPANY

Pursuant to the Commission's February 29, 2012 Entry issued in the above-captioned case, Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company (collectively, the "Companies") hereby respond to the Commission's direction for the Companies to: 1) consult with Staff; and 2) file a report detailing potential energy efficiency and peak demand reduction offers into the 2015/2016 Base Residual Auction ("BRA") conducted by PJM in May 2012 (hereinafter referred to as "2015/2016 BRA"). (Entry at ¶8.) The Commission also requested that the Companies provide PJM with a forecast of the demand and voltage reductions achievable by 2015 so that PJM may consider it in developing its forecast demand and voltage parameters for the 2015/2016 BRA, or report to the Commission reasons why the data will not be provided. (Id.) Lastly, the Commission directed the Companies to file, under Rule 4901:1-39-04(A), Ohio Administrative Code, no later than July 31, 2012, interim energy efficiency and peak demand reduction program portfolio plans. (Id.)

I. CONSULTATION WITH STAFF AND POTENTIAL ENERGY EFFICIENCY AND PEAK DEMAND REDUCTION OFFERS INTO THE 2015/2016 BRA

On March 13, 2012, the Companies and Staff met to discuss the Commission's directive contained in the Entry. Specifically, the Companies informed the Staff that, due to the significant risks surrounding offers into the 2015/2016 BRA, and absent a Commission Entry insulating the Companies from economic harm, the Companies do not plan to offer any potential energy efficiency and peak demand reduction ("EE&PDR") into the 2015/2016 BRA.

A. There is Significant Risk for the Companies to Offer Potential EE&PDR Resources Into the 2015/2016 BRA.

As background, the Companies provide the following summary of the PJM capacity markets construct. Additional information about the PJM capacity markets construct is available in PJM Manual 18,[1] and in relevant provisions of the PJM tariffs and other manuals.

PJM is a Regional Transmission Organization that, through FERC-approved tariffs, operates the PJM Capacity Market for the purpose of ensuring adequate availability of necessary capacity resources to ensure the reliability of the transmission grid. The Companies' service territories are located with PJM, and the Companies are signatory to the PJM Reliability Assurance Agreement, meaning that the Companies participate in the PJM Capacity Market as load-serving entities that purchase their respective capacity requirements from PJM through the PJM Capacity Market.

PJM's Capacity Market design is based on the Reliability Pricing Model or RPM. The goal of RPM is to align capacity pricing with system reliability requirements and to

[1] *Available* http://www.pjm.com/~/media/documents/manuals/m18.ashx.

provide transparent information to market participants. Under RPM, PJM uses a series of auctions to ensure that enough energy producing or reducing resources are available to the grid to meet load on a future date. The main auction, called the Base Residual Auction ("BRA"), is held three years in advance of 12-month periods that are described as "Delivery Years." A Delivery Year runs from June 1st of a given year to May 31st of the following year. A significant majority of the capacity resources necessary to cover a given Delivery Year's requirements are secured through the BRA. Incremental Auctions may be held if needed to true up or adjust the amount of capacity procured in a given BRA against changes in load or resources.

If the Companies offer EE&PDR resources and PJM clears or accepts such resources in a BRA, or in subsequent incremental auctions, the Companies are obligated to supply PJM-qualified Capacity Resources in an amount that is equal to the amount of EE&PDR that was offered by the Companies and taken in the BRA for the given Delivery Year. If the Companies fail to meet their respective capacity supply obligation for all or part of a given Delivery Year, PJM will impose financial penalties, and possibly other sanctions, on the Companies. In addition, the PJM Market Monitor or FERC enforcement staff may investigate the Companies' activities, thus creating a significant financial and legal risk.

As discussed with Staff at the March 13, 2012 meeting, traditionally, because of these risks, the Companies have only offered resources into the BRA when risks were at a minimum. For example the Companies offered demand response that existed under their

Emergency Load Relief (ELR) Rider and that was approved in the Companies' 2010 ESP into a PJM capacity auction for the 2011-12 Delivery Year.[2]

The current ELR Rider approved in the Companies' Case No. 10-388-EL-SSO expires on May 31, 2014, and there is no certainty whether such Rider will be in place beyond that date. Consequently, the Companies did not offer any reduction resources into the May 2011 BRA for the 2014-2015 Delivery Year simply because they did not have any demand response resources under contract to offer into the auction for that time period. Without such a mechanism through the ESP or other Commission-approved plan, the Companies do not have a mechanism to allow them to enter into contractual relationships with customers to provide emergency demand response resources that the Companies could offer into the May 2012 BRA for the 2015-2016 Delivery Year.

There are also significant risks if the Companies were to offer energy efficiency or demand response into the May 2012 BRA for the 2015-2016 Delivery Year. By necessity these resources would come from the Companies' EE&PDR Portfolio Plans mandated by Senate Bill 221. However, the Companies' current EE&PDR Program Portfolio Plan is only approved through 2012. The scope of the Companies' next three-year EE&PDR Program Portfolio Plan is for calendar years 2013 through 2015 – a plan that has yet to be filed or approved by the Commission. And there is no guarantee that any (all) resources that are brought into this future plan will qualify as Capacity Resources under applicable PJM tariffs. Moreover, even if these requirements could be

[2] As the Commission is aware, the capacity auction for the 2011-2012 Delivery Year was conducted by PJM pursuant to FERC direction and approval as part of the Companies' entry into PJM. *See e.g., In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. §4928.143 in the Form of an Electric Security Plan*, Case No. 10-388-EL-SSO, Application at 10-11; August 25, 2010 Order at 4, 9.

cleared (and at this time the Companies do not see how this is possible), because the EE&PDR plan would run only through December 31, 2015, there would not be any assurance that the Companies would have the necessary PJM Capacity Resources to satisfy any supply obligations for the last five months of the 2015-16 Delivery Year.

Speaking to qualification as PJM Capacity Resources, all EE&PDR resources must meet robust PJM measurement and verification (M&V) criteria, meaning that in order to participate in the May 2012 BRA, the Companies would need to submit an Initial Measurement & Verification Plan to PJM for the proposed energy reduction resources no later than 30 days prior the BRA auction, which is April 6, 2012. This is an ambitious task considering the Companies do not have an approved EE&PDR Portfolio Plan for 2015-2016.

The Companies also discussed with Staff during the March 13, 2012 meeting the multiple layers of uncertainty associated with EE&PDR programs. Not only are there uncertainties surrounding program design and technologies that may be offered, but there are also uncertainties as to customer acceptance and participation levels over three years in advance.

As discussed above, because the Companies do not have an approved EE&PDR Portfolio Plan that covers the 2015/2016 BRA, combined with the PJM penalties associated with failure to deliver on reduction commitments, the Companies cannot offer any EE&PDR Portfolio Plan reductions into the 2015/2016 BRA, absent Commission assurances that any such penalties would be recoverable through rates.

For all of those reasons, the Companies do not believe it is prudent to offer any energy reduction resources into the 2015/2016 BRA to be conducted in May 2012.

B. **The Companies Will Explore Opportunities for Energy Efficiency, Peak Demand Reduction and VoltVAR Controls That Can Be Implemented And Possibly Mitigate the Impact on Generation Requirements.**

The Companies will continue to explore opportunities for energy efficiency, peak demand reduction and VoltVAR controls that can be implemented and possibly help to mitigate the impact on generation requirements. This subject was discussed with Staff during the March 13, 2012 meeting.

1. **EE&PDR Measures**

The Companies will be filing, in the second quarter of the year, updated EE&PDR Portfolio Plans. These plans will contain a structure that, if approved by the Commission, will allow the continuation of the Companies' existing EE&PDR activities and include expansion of new programs and measures for the period January 1, 2013 through December 31, 2015 that will be designed to produce additional energy savings and peak demand reductions.

Programs contained in these EE&PDR plans are expected to reduce energy consumption and demand during peak periods through various means including:

- Direct load control programs focusing on cycling or otherwise reducing energy use of residential air conditioners, appliances, or other energy intensive devices;

- Coincident demand reductions achieved from the Companies' energy efficiency program offerings; and

- Curtailable load from large commercial and industrial customers including load that may be contracted through PJM Curtailment Service Providers (CSPs) or directly with customers.

In addition to the programs included in the Companies EE & PDR Portfolio Plans, the Companies are conducting a pilot Consumer Behavior Study as part of the Smart Grid

Modernization Initiative funded by the Department of Energy and customers. The Consumer Behavior Study is examining how advanced metering technology combined with pricing, such as a Peak Time Rebate Rider, and in-home technology can produce residential peak demand reduction. The first phase of this pilot will be conducted in the summer of 2012.

2. Volt-VAr Controls

Volt-VAr Control (VVC) is the dynamic control of a distribution feeder's reactive power and voltage. The goals of VVC are to: (i) optimize voltage and reactive power margin along the distribution system; (ii) minimize reactive power drawn on the transmission system; (iii) maximize voltage losses on the transmission and distribution systems; and (iv) reduce peak demand at times of high loads or emergency.

CEI is currently test deploying, through a pilot study, the VVC distribution and communication hardware infrastructure and software systems with funds from the Commission-approved AMI rider and a Department of Energy Smart Grid Investment Grant. Although this project has just launched, the pilot system has the potential to reduce peak demand during heavy loading. The pilot is scheduled for performance testing in 2013 and production benchmarking in 2014. Because this project has just launched, and its demand reduction potential has yet to be measured, it is not appropriate for the Companies to bid in any peak demand reductions which may result from this program into the 2015/2016 BRA, given the potential penalties surrounding such a bid, should projections of performance not come to fruition, as well as uncertainties of performance and operation in the 2015-2016 Delivery Year.

Another type of voltage reduction mechanism is called Conservation Voltage Reduction ("CVR"), which for purposes of this report, is the one-time reduction of the distribution circuit voltage, where the voltage is reduced and left in this reduced state, with the goal of reducing energy use by consumers on the circuit. In order to implement a CVR program, the Companies would have to carefully analyze their distribution circuit designs and any operational changes so that customers do not experience any degradation of service quality. The Companies would also need to evaluate current equipment settings, loading, voltage levels and other parameters in order to determine if there are circuits where CVR may be implemented while still remaining in compliance with ANSI voltage standards. Only upon such an evaluation would the Companies be able to determine if CVR is appropriate to consider in future EE&PDR Portfolio Plans.

II. FORECAST TO PJM OF DEMAND AND VOLTAGE REDUCTIONS AVAILABLE BY 2015.

As discussed above, the Companies are not in the position to offer EE&PDR reductions into PJM's May 2012 BRA for the 2015-2016 Delivery Year. Likewise, for those same reasons, the Companies do not have a forecast of demand and voltage reductions available by 2015 to give to PJM.

Although the Companies understand the Commission is interested in issues related to the electric generating assets of the Companies' affiliate, FirstEnergy Solutions Corp., the Companies are not the custodian of information related to those assets. The Companies work with PJM to support its peak load forecasting processes consistent with PJM procedures as appropriate.

III. THE COMPANIES WILL FILE THEIR ENERGY EFFICIENCY AND PEAK REDUCTION DEMAND PLANS NO LATER THAN JULY 31, 2012.

In its Entry, the Commission requested that the Companies file no later than July 31, 2012, interim energy efficiency and peak demand reduction program portfolio plans.. As discussed above, and discussed with Staff at the March 13, 2012 meeting, the Companies anticipate filing their next EE&PDR Portfolio Plan in the Second Quarter 2012. Therefore, the Companies will file their plans in advance of the July 31, 2012 deadline contained in the Commission's Entry.

Respectfully submitted,

/s/ Carrie M. Dunn

Carrie M. Dunn, Counsel of Record
Attorney No. 0076952
Kathy J. Kolich
Attorney No. 0038855
FIRSTENERGY SERVICE COMPANY
76 South Main Street
Akron, OH 44308
(330) 761-2352 (telephone)
(330) 384-3875 (fax)
cdunn@firstenergycorp.com
kjkolich@firstenergycorp.com

ATTORNEYS FOR OHIO EDISON COMPANY, THE CLEVELAND ELECTRIC ILLUMINATING COMPANY AND THE TOLEDO EDISON COMPANY

CERTIFICATE OF SERVICE

I hereby certify that a copy of the Report was served this 29th day of March, 2012 via the Commission's DIS System.

/s/ Carrie M. Dunn
Carrie M. Dunn, Esq.

This foregoing document was electronically filed with the Public Utilities

Commission of Ohio Docketing Information System on

3/29/2012 5:15:11 PM

in

Case No(s). 12-0814-EL-UNC

Summary: Report electronically filed by Ms. Carrie M Dunn on behalf of The Cleveland Electric Illuminating Company and Ohio Edison Company and The Toledo Edison Company

Attachment C

FirstEnergy

76 South Main Street
Akron, Ohio 44308

1-800-646-0400

June 1, 2012

Mr. Daniel R. Johnson
Chief, Planning and Market Analysis
Public Utilities Commission of Ohio
180 East Broad Street
Columbus, Ohio 43215-3793

Re: Special Topics Letter: *Utility Decisions and Actions Responsive to U.S. Environmental Protection Agency Rules; MACT, CSAPR, the Ash Rule, and the Cooling Tower Intake Rule.*

I've been asked to respond to your letter sent on May 15, 2012 to Mr. William Ridmann regarding the additional information the Public Utilities Commission of Ohio (PUCO) Staff is seeking pertaining to generating plant closures and the effect those plant closures may have on congestion on the transmission system, and reliability of supply to Ohio customers.

In addition to Ohio Edison's, Toledo Edison's, and CEI's ("Companies") 2012 Electric Long-Term Forecast Report (Case No. 12-504-EL-FOR) filed on April 16, 2012 and the report in Case No. 12-814-EL-UNC filed on March 29, 2012, below is supplemental information to the above filings regarding this topic. Further, the Companies expect to file their next Energy Efficiency and Peak Demand Reduction (EE&PDR) Portfolio Plan on or before July 31, 2012.

PJM planning staff (working closely with FE Energy Delivery staff) recently completed their analysis of recommended mitigation projects for the constraints they previously identified related to area generation deactivation notices. PJM shared the results of their analysis with stakeholders at a special PJM TEAC meeting which was held on April 27, 2012 (*see "http://www.pjm.com/committees-and-groups/committees/teac.aspx"*). In addition, PJM identified multiple units (i.e. Ashtabula 5; Eastlake 1, 2, and 3; Lake Shore 18) to be Reliability Must Run (RMR) for 2013. PJM further recommended many transmission systems upgrades such as converting the retired generators to synchronous condensers, building new lines/substations, installing new transformers/capacitors, etc. These projects (with the exception of the Beaver Valley and Mansfield - Leroy Center 345 kV lines) along with any stakeholder feedback since this meeting were presented to the PJM Board of Directors on May 17, 2012 and were approved, which now creates an obligation for those approved projects to be built as recommended. Note that in order to meet the projected in-service dates needed for these projects, work on the critical path activities associated with these projects was started prior to their approval. These critical path activities include, but are not limited to, the following: development of technical specification for the equipment bidding/procurement process, researching of potential land needs/availability, development of a communications strategy/plan, preparation of the necessary paperwork to begin filing for permits, etc.

PJM recently posted the 2015/2016 RPM Base Residual Auction results. For the ATSI zone, Demand Resources for 2013/2014, 2014/2015 and 2015/2016 was 394.3 MW, 955.7 MW and 1,763.7 MW, respectively. These resources are committed but the specific locations in the ATSI zone are not known at this time. Further, the Energy Efficiency resource for 2015/2016 is 44.9 MW. (See *"http://www.pjm.com/.../20120518-2015-16-base-residual-auction-report.ashx")*.

In general, energy efficiency and peak demand reduction programs, distributed generation, and changes to the distribution system can help to alleviate or partially alleviate the constraints on the transmission system. As mentioned above, the Companies will file their next EE&PDR Portfolio Plan on or before July 31, 2012. This plan will contain various EE&PDR programs designed to meet the Companies' statutory benchmarks. Once that plan is approved and implemented, the Companies will be better positioned to describe the possible impact of their EE&PDR programs on possibly contributing to alleviating any constraints.

Below are distribution system improvements that have been identified as those that may contribute to mitigating constraints on the transmission system:

- Installation of capacitors on the distribution system as a means of meeting customer var demands, and var loading caused by distribution system components
- Reduction of losses arising from the implementation of standardized distribution system wire sizing recommendations
- CEI is currently test deploying, through a pilot study, the Volt-var Control distribution and communication hardware infrastructure and software systems with funds from the Commission-approved AMI rider and a Department of Energy Smart Grid Investment Grant. Further information regarding this study can be found in the report filed under Case No. 12-814-EL-UNC. As stated in the Companies' pending Electric Security Plan filing with the Commission in Case No. 12-1230-EL-SSO, the pilot is scheduled for performance testing in 2013 and production benchmarking in 2014. The results of the pilot study, including an analysis of the associated costs and benefits, will be shared with the PUCO and DOE as they become available.

Further, you requested information not only about what is under consideration, but also what other measures can be taken within the distribution system which could contribute to alleviating or partially alleviating the constraints identified by PJM. While all such measures that other entities may have considered is unknown, EPRI continues to research electric systems and has prepared a portfolio of distribution system research projects. As an example, the following link provides EPRI's distribution system research portfolios for 2012.

(http://mydocs.epri.com/docs/Portfolio/PDF/2012_P180.pdf).
Research undertaken by EPRI is actively monitored and participated in an effort to maximize the opportunity regarding the applicability of applying research results to the distribution system.

As mentioned above, FE Energy Delivery staff and PJM planning staff recently completed their analysis of recommended mitigation projects for the constraints PJM previously identified related to area generation deactivation notices. Because that process was so recently completed, an answer is not yet available regarding an evaluation framework for determining whether and the degree to which the relative value of distribution centric measures may be determined. If the Staff wishes, I suggest we have follow up discussion regarding the evaluation framework once additional information regarding the transmission projects is available and the EPRI research related to distribution systems.

Sincerely,

Bradley D. Eberts

Bradley D. Eberts ✓
Manager, Load Forecasting

Cc JWBurk
EMMikkelsen
WRRidmann
WEStark
JT Biltz

Working to Perfect the Flow of Energy

PJM Manual 14A

Generation and Transmission Interconnection Process

Revision: 12

Effective Date: May 22, 2012

Prepared by

Planning Division

Generation Interconnection Department

PJM Manual 14A

Generation and Transmission Interconnection Process

Table of Contents

Attachment D1

Table of Exhibits

Approval

Approval Date: 05/22/2012
Effective Date: 05/22/2012

Al Elmy, Manager

Generation Interconnection

Current Revision

Revision 12: (05/22/2012)

Made changes to Table 3-1: Small Generation Interconnection Process deposit requirements (Interconnection requests of 2 – 20MW) and Table 3-2: Small Generation Interconnection Process deposit requirements (Interconnection Requests of 2MW or less).

Revision 11: (05/22/2012)

Revision 11 incorporates (1) language changes associated with the Interconnection Process Senior Task Force recommendations (2) language describing the calculation of Capacity Interconnection Rights being transferred to a new facility, and (3) minor language cleanup to provide additional clarity on existing process elements.

Introduction

Welcome to the Generation and Transmission Interconnection Process Manual. In this Section you will find:

- A table of contents
- An approval page that lists the required approvals and the revision history
- This Introduction
- Sections summarizing the guidelines, requirements and procedures for Generation and Transmission interconnection, including Developer actions and PJM actions.
- Attachments that include additional supporting documents and tables.

About This Manual

This PJM Manual, ***Generation and Transmission Interconnection Process*** is one of the PJM Manual 14 series family. This manual guides developers of generation and merchant transmission projects through the planning up to the request for facility construction.

Intended Audience

The intended audience for this PJM Manual includes the following:

- Developers of generation and merchant transmission facilities and their staffs interested in locating facilities within PJM.
- Existing Generation Owners planning increases to an existing generating resource.
- PJM Transmission Owners and other PJM Members and their staffs.
- PJM Staff.

References

The entire PJM Manual 14 series addresses issues that may be related to or of interest to the Interconnection Customer. The reader of this manual is urged to review the other manuals for additional material of interest. All PJM manuals can be found on PJM.com under the Documents/Manuals links. In addition the reader is urged to also check PJM committee postings for possible draft revisions that may be awaiting posting under the manuals section of PJM.com.

Section 1: Interconnection Process Overview

Entities requesting interconnection of a generating facility (including increases to the capacity of an existing generating unit or decommissioning of a generating unit) or requesting interconnection of a merchant transmission facility within the PJM RTO must do so within PJM's defined interconnection process. This process ensures the successful, timely completion of PJM's planning, facility construction and operational and market infrastructure requirements. For the purposes of this Manual, the term "Developer" is used to encompass any entity which bears responsibility for bulk power system upgrades, whether a third party seeking interconnection or an existing Transmission Owner with responsibility for Baseline Upgrades or self-identified enhancements.

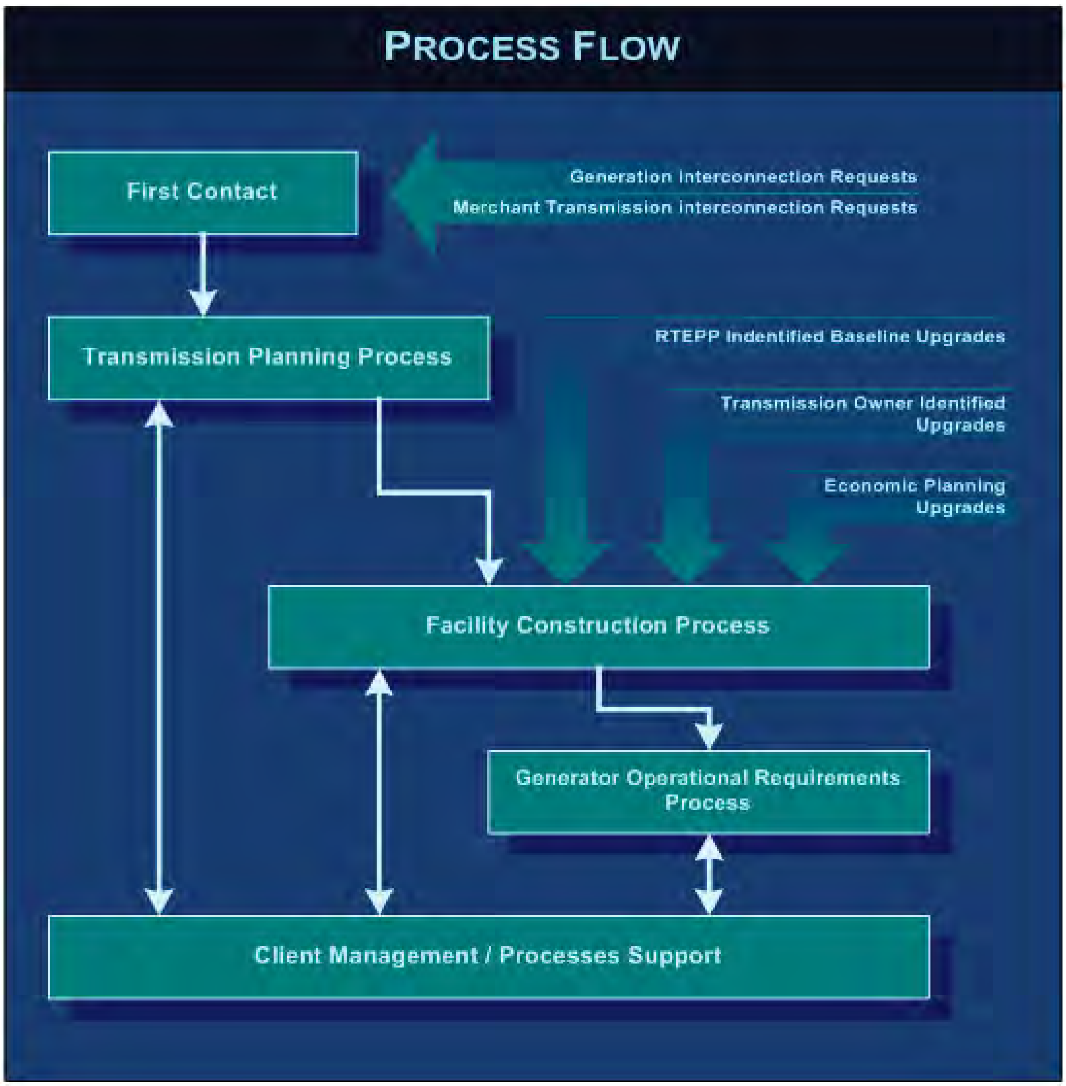


Exhibit 1: Process Flow

These Manuals offer a set of guidelines that ensure successful interconnection and operations within PJM.

The accompanying **Attachment A –** Interconnection Process Flow Diagram - portrays in more detail the pertinent planning steps from the initial request up to the request for facility construction. This includes market and operational steps necessary for participation, as appropriate, in the PJM energy and capacity markets, including the process for acquiring any related or necessary transmission rights.

The PJM Manual 14A content is consistent with and elaborates on the terms and conditions found in the source PJM documents. The primary source documents for Manual 14A are the PJM Open Access Transmission Tariff (OATT) and the PJM Operating Agreement. Other applicable source documents may include the PJM Transmission Owners Agreement and the PJM Reliability Assurance Agreement. The source documents remain the final authoritative documents and these documents control with regard to any inconsistencies between them and the PJM Manuals

1.1 Merchant Transmission Interconnection Facilities

As specified in the PJM OATT and Schedule 6 of the PJM Operating Agreement, the developers of Merchant Transmission Facilities that interconnect with the PJM Transmission System may be entitled, subject to certain restrictions, to elect certain transmission rights that are created by the addition of such facilities. Discussions of these rights and specific design, construction, operational and maintenance aspects of merchant transmission interconnection facilities can be found by referring to Manual 14.

1.2 Initiating the Generation and Transmission Interconnection Planning Process

In order to initiate the Interconnection Planning Process, a Developer must contact PJM through PJM's hotline or through PJM's web site at http://www.pjm.com/home.aspx. The Developer must submit a completed Interconnection Request. This is accomplished via the execution of a Feasibility Study Agreement, per OATT Attachment N, Attachment Y, or Attachment BB for generation interconnection requests and OATT Attachment S for merchant transmission interconnection requests. All Tariff attachments for application of service in the New Services Queue (interconnection queue) can be found in Documents/Agreements section of http://www.pjm.com/home.aspx. Completed Attachments, including the submittal of all required data, must be accompanied by the appropriate fees as detailed in following sections of this Manual in order to reserve a place in PJM's interconnection New Services Queue.

1.3 Project Management and Client Management

After contacting PJM for the first time, PJM assigns a Project Manager. The Project Manager will be responsible for working with each Developer and their respective staff to complete the necessary steps related to interconnection planning. Additional Project Managers will be assigned for subsequent facility construction and operational phases of the project.

After contacting PJM for the first time through PJM's hotline or through PJM's web site at http://www.pjm.com/home.aspx, the Developer will be assigned a Client Manager. Client Managers coordinate PJM activities that facilitate each Developer's membership and market participation, bridging any concerns or coordination issues with appropriate PJM staff including the respective PJM Project Managers who oversee the interconnection process.

1.4 Electing Capacity Resource Status versus Energy Resource Status

A Developer must elect the status type for the generating capability associated with each interconnection request: Capacity Resource Status or Energy Resource Status. A Capacity Resource status designation permits the generator to be utilized by PJM Load Serving Entities to meet capacity obligations under the terms of the PJM Reliability Assurance Agreement (RAA), available in the Documents/Agreements section of http://www.pjm.com/home.aspx.

- ***Capacity Resource Status*****:** Units must meet certain interconnection requirements for being granted this status including requirements for deliverability. Capacity Resource status is granted based on the availability of sufficient transmission capability to ensure the deliverability of generator output to network load and to satisfy the regional reliability requirements of the NERC region in which the generator is located - ReliabilityFirst or SERC. Specific analytical tests performed during the Generation Interconnection Feasibility Study and System Impact Study reveal the specific transmission system upgrades required to meet these reliability criteria. Capacity Resource Status conveys specific capacity interconnection rights enabling a unit to participate in PJM capacity markets. Through these markets, LSEs may procure capacity rights to meet their respective capacity obligations under the terms of the PJM Reliability Assurance Agreement.
- ***Energy Resource Status*****:** The planning studies for generating units seeking this status do not include the deliverability analyses required of those units seeking Capacity Resource status. As such, Energy Resource units are only permitted to participate in the energy market. Such units do not receive capacity interconnection rights and may not participate in PJM capacity markets.

1.5 PJM Membership

Membership in PJM is granted under the terms of the PJM Operating Agreement. The Client Manager assigned to each Interconnection Request will guide each Developer through this process. While PJM membership is not required for the initial planning and construction phases of a given generation or merchant transmission interconnection project, Membership will be required prior to commercial operation. And, in many cases, Membership will be required in order to integrate operational and market infrastructure with PJM. PJM Membership entails certain data requirements, operational and market coordination, committee support and financial obligations

1.6 Membership in NERC Regional Councils

PJM operates within the geographic boundaries of several regions of the North American Electric Reliability Corporation (NERC), including applicable areas of the Reliability*First* and the SERC Reliability Corporation. Any new signatory to the PJM Operating Agreement is obligated to be in compliance with the respective planning, operating and membership requirements of the respective NERC Council in which their facilities are located.

1.7 The Interconnection Request Studies

The PJM Operating Agreement, Schedule 6, and the PJM Open Access Transmission Tariff, Parts IV and VI, describe the procedures used to process requests for interconnection with the PJM transmission system. The Operating Agreement and Tariff establish the statutory basis for the business rules, described in detail in this Manual M14A, for the interconnection request process. These business rules include three analytical steps:

(1) Feasibility Study

(2) System Impact Study

(3) Interconnection Facilities Study.

Each step imposes its own financial obligations and establishes milestone responsibilities.

Projects within each time-based queue are evaluated against a baseline benchmark set of studies in order to establish project-specific responsibility for system enhancements, separate from general network upgrades suggested by the results of baseline analyses. Each Developer is encouraged to participate in the activities of the Transmission Expansion Advisory Committee (TEAC) and its Sub regional RTEP Committee. PJM consults with the TEAC and Sub regional RTEP Committees as part of the larger Regional Transmission Planning Process through which a coordinated regional expansion plan – including expansions necessitated by generation and merchant transmission interconnection - is reviewed.

Important PJM interconnection process steps established to implement provisions of the PJM OATT:

- The interconnection queuing process including the procedures used to initialize the interconnection evaluation process based on the timing of the receipt of all requests
- The cost responsibility for transmission upgrades required for interconnection;
- The rights accorded to a generator after it has satisfied OATT requirements;
- The required Interconnection Service Agreement (ISA) and Construction Service Agreement (CSA). Each of these two agreements is executed by and among three parties: the Developer, the Transmission Owner and the Transmission Provider (PJM).

1.8 Changes to Existing or Proposed Generation

An existing or proposed generating unit may experience changes which will require consideration under PJM's interconnection, process:

- ***New Ownership Requirements:*** If a generating facility is acquired by a new owner, then the transfer of responsibilities and rights in the PJM market for the transferred facility will be conveyed to the new owner following notification to PJM by the selling and purchasing entities.
- ***Unit Output Increases:*** If a Generation Owner plans to increase the Maximum Facility Output (MFO) or the amount of Capacity Interconnection Rights (CIRs) of an existing generating unit or active Interconnection Request in the PJM study queue to a MW value greater than the amount already specified in a generating unit's existing

ISA or active Interconnection Request, then that additional MFO or CIRs will be treated as a new generation Interconnection Request subject to the procedures discussed in Manual 14A. If a proposed generating unit increase is less than 20 MW, the generation owner may be eligible to follow the Small Generation Interconnection Process, set forth in Part IV, subpart G of the PJM Tariff and discussed herein below.

If a Generation Owner changes the electrical characteristics of the existing generating unit(s) that were previously studied by PJM, but is not increasing the MFO or CIRs, then the Generation Owner must request that a necessary study be performed by PJM (See PJM Manual 14A Section PJM Tariff Section 36.2A.4 and Attachment O, Appendix 2, Section 3.1). Even when not increasing MFO or CIRs, if a Generation Owner wishes to parallel generating units in excess of the number of units previously studied by PJM, this would change the electrical characteristic and require a necessary study prior to operating with additional generating units. If a Generation Owner installs a spare generating unit with different electrical characteristics than the primary generating unit, the spare generating unit must be studied with a necessary study prior to being paralleled with the system.

1.9 Small Generation Interconnection Considerations (20 MW or less)

Requests for the interconnection of new resources of 20 MW or less, or for increases of 20 MW or less for existing generation may be processed through expedited procedures, in accordance with Part IV, Subpart G of the PJM Open Access Transmission Tariff. Generating resources of this size fall into one of three categories:

(1) Permanent Capacity Additions: units which are expected to remain connected to the transmission system for the life of the resource, expect to receive capacity interconnection rights, and may be utilized to meet the capacity obligations of LSEs.

(2) Permanent Energy Resource Additions: units which are expected to remain connected to the transmission system for the life of the resource but receive no Capacity Transmission Interconnection Rights and are not permitted to be used to meet capacity obligations of LSEs.

(3) Temporary Energy Resource Additions: units which are only expected to remain connected to the transmission system temporarily (less than six months), participating in spot market activity during peak demand periods and requiring only minimal or no transmission enhancements.

The planning process requirements for each of these are described in more detail in Manual 14B.

An Alternate Queue Process has been developed in order to streamline some of the administrative requirements associated with those small generation projects which meet criteria as established in the PJM Open Access Transmission Tariff. This process is intended for those generation interconnection requests which are not believed to have impact to the Bulk Electric System. The study of these projects may be similar to the process as set forth for other interconnection requests but will not involve studies of the Bulk

Electric System. All required studies will be completed in order to address any impacts to the Transmission Owners lower voltage systems.

1.10 Distributed Generation

Developers who are considering construction of generating facilities within PJM which are 20 MW or less may follow the Small Generator Interconnection process described above. If a plant operator seeks operation as part of a load management arrangement, the operator is directed to PJM's load management program, found on PJM's web site at http://www.pjm.com/home.aspx.

1.11 Behind the Meter Generation

Any Behind the Meter Generation which seeks to be designated in whole or in part as an energy or capacity resource must submit a Generation Interconnection Request for the portion of the unit's output that will participate in the PJM market. Further, sites with 10 MW or more must abide by PJM metering requirements as well as market, operational and settlement requirements. Manual 14D (Appendix A) describes the treatment of Behind the Meter generation, provisions for which are captured in PJM's Open Access Transmission Tariff, Subpart A, Section 36.1.A.

As with any other Interconnection Request, The Developer will be assigned a Project Manager for each process phase captured in Exhibit 2. The Project Manager will be responsible for working with each Developer and staff to complete the respective steps for that particular phase. Attachment B: Interconnection Process Team Role Clarity Diagram captures Implementation Team roles for each interconnection process phase (including a PJM Project Manager for each phase) and shows how each Manual aligns with each phase.

Generating resources operating "behind the meter," in isolation from the PJM bulk power transmission system and which do not intend to participate in the PJM wholesale energy market, need only coordinate planning, construction and/or operation with the host Transmission Owner.

Section 2: Generation and Transmission Interconnection Planning Process

In this section you will find an overview of the generator and transmission interconnection planning process.

- A description of the Feasibility Study Agreement execution and analysis (see "Generation and Transmission Interconnection Feasibility Study Agreement Execution and Analysis").
- A description of the System Impact Study Agreement execution and analysis (see "System Impact Study Agreement Execution and Analysis").
- A description of the Facilities Study Agreement execution and analysis (see "Generation and Transmission Interconnection Facilities Study Agreement Execution and Analysis").
- Specific requirements for interconnection of large generation and transmission projects with a capability greater than 20MW

2.1 Generation or Transmission Interconnection Feasibility Study Agreement Execution and Analysis

2.1.1 Purpose of the Generation or Transmission Interconnection Feasibility Study Agreement's

As a FERC accepted Regional Transmission Organization (RTO), PJM administers the process for the interconnection of all new generators and new transmission facilities to the PJM Transmission Grid. New generation applicants may request either of two forms of interconnection service, Capacity Resource or Energy Resource service. Capacity Resource interconnections receive the right to schedule both capacity and energy deliveries at a Point of Interconnection – Energy Resource interconnections receive the right to schedule only energy deliveries at a specified point on the PJM Transmission System. Capacity allows the generator to be utilized by PJM load-serving entities to meet capacity obligations imposed under the Reliability Assurance Agreement. Capacity resources may participate in PJM Capacity Credit markets and in Ancillary Service Markets. Energy Resource status allows the generator to participate in energy markets based on locational prices.

Capacity Resource status is based on providing sufficient transmission capability to ensure deliverability of generator output to aggregate network load and to satisfy various contingency criteria established by the particular regional reliability council (ReliabilityFirst) in which the generator is located. See PJM Manual 14B, Attachment C for details of the PJM Deliverability Testing Methods. Specific tests performed during the Generation Interconnection Feasibility Study and later System Impact Study will identify those upgrades required to satisfy the contingency criteria applicable at the generator's location.

2.1.2 Interconnection Requests and PJM Queue Position

The Interconnection Request must include descriptions of the project location, size, equipment configuration, anticipated in-service date, data as required to complete

Attachment F of this Manual 14A, as well as proof of right to control the site for the proposed project. The in-service date must be no more than 7 years from the date the Interconnection Request is received by the Transmission Provider, unless it is demonstrated that engineering, permitting and construction of the project will exceed this period. Upon receipt of the completed Interconnection Request, the project is placed in a PJM Interconnection queue, in which queue positions are determined by the date of submission of the completed Interconnection Request.

The Interconnection Customer must provide either of the following associated with a proposed wind facility (The requirements listed below are in addition to the requirements contained in Section 36.1.01 of the PJM Tariff and do not replace the requirement for the Interconnection Customer to provide legal documentation demonstrating rights to the site land):

1. a site plan indicating the layout of all turbines associated with the proposed project including: 1) number of turbines proposed for the site, 2) size, in megawatts (MW), of each turbine, 3) size, in acres, of the proposed site, 4) distance between the hub(s) of all adjacent turbines on the site and, 5) length of blades on the turbine which is proposed for installation.

or

2. a minimum of 3 acres per MW of wind units in a single line or 10 acres per MW for a site consisting of wind units distributed over an area

2.1.3 Generation and Transmission Interconnection Feasibility Study Cost Responsibility

As specified in Part IV, Subparts A and G of the PJM Tariff, a party wishing to connect a new generation resource or a new transmission facility to the PJM system must submit an Interconnection Request in the form of an executed Generation or Transmission Interconnection Feasibility Study Agreement **(OATT at Part VI, Attachment N or Attachment S, respectively)** and a study deposit as specified in the table below (Table 1-1). The amount of the deposit is specified in accordance with the size, in MW, as well as the timing of receipt of the Interconnection Request. Refer to Section 3 of this Manual 14A for further details regarding the interconnection process for small resources of 20 MW or less.

The applicant is obligated to pay the actual costs of studies conducted by PJM on its behalf, and the non-refundable deposit is applied to those costs as work is completed. If the cost of the Generation or Transmission Interconnection Feasibility study is reasonably foreseen to exceed the standard deposit listed below for the Interconnection Request before the study begins, PJM will so advise the applicant.

Table 2-1: Large Generation Interconnection Process deposit requirements

Month of New Services Queue	Non-refundable deposit	Cost per MW of Interconnection Request	Maximum deposit
1st - 4th	$10,000	$100	$110,000
5th	$20,000	$150	$120,000
6th	$30,000	$200	$130,000

Note: The cost per MW of Interconnection Request costs shall be transferable to subsequent studies associated with the individual Interconnection Request. See below for an example of the cost for an Interconnection Request:

Example:

An Interconnection Customer submits a request for interconnection of a 40 MW facility during the first month of the queue period. The deposit costs would be as follows:

Non-refundable deposit:	$10,000
Cost per MW:	$4,000
Total deposit:	$14,000 (To be submitted as a single payment)

2.1.4 Changes to Existing Generators and Transmission Facilities

Transfer of ownership of existing generating units and transmission facilities is not subject to the interconnection queuing process unless pre-existing capacity injection rights for the unit are not transferred with the change in ownership.

Owners of existing generating plants that plan increases in a plant's output capability above that specified in the generating plant's existing ISA must follow the same procedure as new generation specified in the PJM Tariff and the PJM Manuals. These projects will be placed into the interconnection queue and will be evaluated under the same study procedure as new generation.

Some changes, such as improvements to same-site units injecting at a common point, may be aggregated or combined. Such requests are determined on a case-by-case basis.

Owners of existing generating plants that plan to retire or reduce the plant's output capability must notify PJM in order to address capacity credit issues and any potential PJM System economic and/or reliability concerns. After a generator officially notifies PJM of retirement, system upgrades will be identified to resolve any reliability problems associated with the retirement. If the generator subsequently withdraws the request for retirement, PJM may continue to plan the system to accommodate retirement of the generator. The Capacity Interconnection Rights associated with the retired or reduced plant output capability may survive for up to one year following the actual Deactivation Date. **(PJM OATT at Part VI, Section 230.3 - formerly Subpart D, Section 45.3 in Part IV)**

Owners of existing Merchant Transmission Facilities that plan to retire or reduce the capability of a transmission facility must notify PJM in order to address any potential PJM System economic and/or reliability concerns.

2.1.5 Generation and Transmission Interconnection Feasibility Study Analysis and Results

After the Generation or Transmission Interconnection Request and deposit are received, PJM assigns a System Planning Senior Consultant as the Team Leader to initiate and direct the implementation of the Study phases of the Generator and/or Transmission Interconnection Process (see Attachment C for PJM Generation and Transmission Planning Team Role Clarity Diagram). Under the direction of the Team Leader, PJM staff, in coordination with any affected Interconnected Transmission Owner(s), will establish a time to hold a Scoping Meeting as described in Section 36.1.5 of the PJM Tariff and the following. The Interconnection Customer is required to choose a primary Point of Interconnection and also has the option to specify a secondary Point of Interconnection to be studied during the Generation or Transmission Interconnection Feasibility Study phase of the Interconnection Request, and also must identify one Point of Interconnection as the primary and the second as the secondary choice. The primary and secondary Points of Interconnection will be studied as follows:

The primary Point of Interconnection will be studied and the Generation or Transmission Interconnection Feasibility Study will follow the requirements as set forth in the PJM Tariff, Section 36.2 and this manual.

The secondary Point of Interconnection will receive a sensitivity analysis and this will be included in the Generation or Transmission Interconnection Feasibility Study. This sensitivity analysis will include definition of the overloads and no estimated costs.

The decision as to the designation of the primary and secondary Point(s) of Interconnection must be communicated to PJM and the Interconnected Transmission Owner(s) prior to completing the Scoping Meeting. If the Interconnection Customer fails to provide these designated options (primary or primary and secondary Point of Interconnection) prior to completion of the Scoping Meeting, PJM shall consider the Interconnection Request as deficient, as described for other cases of deficiency of an Interconnection Request in the PJM Tariff, Section 36.1.4, and will process the Interconnection Request in accordance with the PJM Tariff, Section 36.1.4.

Following the Scoping Meeting, PJM and the Interconnected Transmission Owner will conduct the Generation or Transmission Interconnection Feasibility Study when no deficiencies exist for an individual Interconnection Request. In general, the study will be completed within 90 days during the next Feasibility Study Cycle. If this is not possible, PJM must so notify the applicant and provide an anticipated completion date. PJM, in coordination with any affected Interconnection Transmission Owner(s), shall conduct Generation and Transmission Interconnection Feasibility Studies two times each year **(PJM OATT at Part VI, Subpart A, Section 36.2 - formerly 36.2** and **41.2, in Part IV)** for completion by:

- Last day of February, for requests received during the six month period ending October 31 of the preceding year.
- August 31, for requests received during the six month period ending April 30.

The Generation or Transmission Interconnection Feasibility Study assesses the practicality and cost of incorporating the generating unit or increased generating or transmission capacity into the PJM system. The analysis is limited to short-circuit studies and load-flow analysis. This study does not include stability analysis. The study also focuses on determining preliminary estimates of the type, scope, cost and lead time for construction of facilities required to interconnect the project.

Results of the study for the requested interconnection service (Capacity Resource or Energy Resource) are provided to the applicant and the affected Interconnection Transmission Owners, and are published on the PJM web site. Confidentiality of the applicant is maintained in these reports, but the location of the project and size (in megawatts) is identified. After reviewing the results of the Generation or Transmission Interconnection Feasibility Study, the applicant must decide whether or not to pursue completion of the System Impact Study.

2.2 Generation or Transmission Interconnection System Impact Study Agreement Execution and Analysis

2.2.1 Impact Study Agreement and Cost

After receipt of the Generation or Transmission Interconnection Feasibility Study results, if the applicant decides to proceed, an executed System Impact Study Agreement must be submitted to PJM with the required deposit as specified in Section 204.3A of the PJM Tariff. If the cost of the System Impact study is reasonably expected to exceed the deposit received before the study begins, PJM will so advise the applicant.

For an Interconnection Request to maintain its assigned priority, the applicant must execute and return the System Impact Study Agreement (and the required deposit), as well as complete the System Impact Study data form located at (http://www.pjm.com/planning/rtep-development/expansion-plan-process/form-impact-study-data.aspx - See Attachment G for a list of the data required to complete this form) within 30 days of receiving the System Impact Study Agreement. If a New Service Customer fails to meet this deadline, the Interconnection Request will be deemed terminated and withdrawn. In general, the study will be completed within 120 days of the date the study begins. If this is not possible, PJM must so notify the applicant, providing an anticipated completion date and an explanation of why additional time is needed.

For generation projects, proof is required at this point of initial application for required air permits, if any, and the applicant must declare whether a generation project is to be connected as a Capacity or Energy Resource.

The System Impact Study is a comprehensive regional analysis of the impact of adding the new generation and/or transmission facility to the system and an evaluation of their impact on deliverability to PJM load in the particular PJM region where the generator and/or new transmission facility is located. This Study identifies the system constraints relating to the project and the necessary Attachment Facilities, Local Upgrades, and Network Upgrades. The Study refines and more comprehensively estimates cost responsibility and construction lead times for facilities and upgrades.

Table 2-2: System Impact Study costs

Project size	Required deposit	
	Non-refundable	Refundable
> 100MW	$50,000	$300/MW – Not to exceed $300,000
>20MW but ≤100MW	$500/MW	None
>2MW and ≤20MW	$10,000	None
≤2MW	$5,000	None

2.2.2 System Impact Study Analysis and Schedule

Relationships are studied between the new generator or the new transmission facility, other planned new generators in the queue, and the existing system as a whole. This study also encompasses an analysis of existing firm and non-firm Transmission Service requests. PJM, in coordination with any affected Interconnection Transmission Owner(s), shall conduct System Impact Studies two times each year **(PJM OATT at Part VI, Section 205.2 - formerly 36.4.1** and **41.4.1, in Part IV)** commencing on:

- June 1, for requests received during the six month period ending October 31 of the preceding year.

December 1, for requests received during the six month period ending April 30 of the same year.PJM may decide to group two or more interconnection requests within one System Impact Study if the proposed projects are in electrical proximity. In situations where more than one generation project violates reliability criteria, cost responsibility for network upgrades to mitigate such violations will be allocated among the projects in the course of the System Impact Study.

2.2.3 System Impact Study Results

Results of the study are provided to all applicants who had projects evaluated in the study and to affected Interconnected Transmission Owners and are posted on the PJM web site. While confidentiality obligations will be honored, the identity of the applicants will not be considered confidential in these reports.

The identity of all applicants, the size and the location of projects for which System Impact Studies have been completed are published on the PJM web site.

After reviewing the results of the study, the applicant must decide whether or not to proceed with either (i) a Generation or Transmission Interconnection Facilities Study or (ii) an Interconnection Service Agreement or Upgrade Construction Service Agreement, whichever is furnished by PJM. If the applicant decides to proceed with the project, the results of the System Impact Study are also rolled into the RTEP Process for development of the RTEP to be submitted to PJM's Board of Managers for approval.

Attachment D1

2.3 Generation or Transmission Interconnection Facilities Study Agreement Execution and Analysis

2.3.1 Generation or Transmission Interconnection Facilities Study Agreement

Upon completion of the System Impact Study, PJM will furnish either (i) a Generation and/or Transmission Interconnection Facilities Study Agreement to the applicant, along with estimated cost of the study and the estimated time of completion or (ii) an Interconnection Service Agreement or Upgrade Construction Service Agreement. For an Interconnection Request to maintain its assigned priority, the applicant must execute and return the Generation and/or Transmission Interconnection Facilities Study Agreement (and the required deposit) within 30 days of receiving it. If an applicant fails to meet this deadline, the Interconnection Request will be deemed terminated and withdrawn. If the applicant has received an Interconnection Service Agreement or Upgrade Construction Service Agreement, please see discussion in Section 4 of this manual for additional information.

The Generation and/or Transmission Interconnection Facilities Study Agreement will provide the estimated cost responsibility and estimated completion date for the study. It may also define reasonable milestone dates that the proposed project must meet to retain its Queue Position while PJM is completing the Generation or Transmission Interconnection Facilities Study. See Attachment D for a General Description of the Facilities Study Procedure.

2.3.2 Generation or Transmission Interconnection Facilities Study Cost

As specified in Part IV, Subparts A and B of the PJM Tariff, if the applicant decides to proceed, the executed Generation and/or Transmission Interconnection Facilities Study Agreement must be returned accompanied by the required deposit as specified in Section 206.3 of the PJM Tariff, and also listed in Table 2-3.

Table 2-3: Facilities Study costs

Project size	Required deposit
>20MW	The greater of: 1. $100,000 OR 2. estimated amount of Facilities Study cost for the first three months
>2MW and ≤20MW	$50,000
≤2MW	$15,000

2.3.3 Generation or Transmission Interconnection Facilities Study Results

When completed, the Generation or Transmission Interconnection Facilities Study will document the engineering design work necessary to begin construction of any required transmission facilities. The Generation or Transmission Interconnection Facilities Study will also provide a good-faith estimate of the cost to be charged to the applicant for Attachment Facilities, Local Upgrades and Network Upgrades necessary to accommodate the project and an estimate of the time required to complete detailed design and construction of the facilities and upgrades.

2.4 Transfer of Capacity Interconnection Rights

2.4.1 Transfer of Capacity Interconnection Rights (CIRs)

The transfer of CIRs is contemplated in Section 230.3.3 and 230.4 of the PJM Tariff. The following processes will be followed to determine the amount of CIRs which can be transferred from an existing operational generator, to an existing or new resource in order to increase or provide CIRs to an existing or new resource. In all cases the transfer of rights will require that the customer or owner enter the New Services Queue with an Interconnection Request.

For the study of the transfer of CIRs as it affects thermal constraints, all load flow studies will be performed in the queue to which the rights are to be transferred up to the Queue Position immediately preceding the project which is seeking to receive the transferred rights (the generator from which the rights are to be transferred would be online during these studies). PJM will then turn off the generator with the existing rights, make the unit unavailable for dispatch, and then study the new Interconnection Request to determine the thermal impacts of the new Interconnection Request. This analysis will insure that any Capacity Interconnection Rights owned by the existing generator will be used by the new Interconnection Request.

For the Study of short circuit impacts to the system, studies will be performed in order to determine the impact on the increase in fault current for all facilities associated with any new Interconnection Request. Any reinforcement(s) which are determined to be required for the new generator will be reviewed to determine if the existing generator's contribution causes the need for the reinforcement, and if the reinforcement would not be required if the existing unit was removed from the study. The new Interconnection Request would not be required to provide reinforcement to the system if the new Interconnection Request does not cause the need for the reinforcement when the existing unit is removed.

For the study of stability impacts to the system, the existing generator would not be dispatched during the study of the new Interconnection Request.

Section 3: Small Resource Interconnection Process

In this section you will find the following:

- A description of the small resource interconnection process (see "*Small Resources (20 MW or less)*").
- Specific provisions applicable to resources of 10 MW or less (see *"Specific Provisions for Resources of 10 MW or Less*").
- Specific provisions applicable to resources greater than 10 MW up to 20 MW (see "*Specific Provisions for Resources Greater than 10 MW up to 20 MW"*).

3.1 Small Resources (20 MW or less)

Requests for the interconnection of new resources which are 20 MW or less, or increases of 20 MW or less to existing generation (over a 24 month period) may be processed through expedited procedures. (Refer to Part IV, Subpart G of the PJM Tariff.) Expedited procedures are defined in the PJM Tariff for five categories of these "very small resource" additions; permanent Capacity Resource additions of 20MW or less, permanent Energy Resource additions of 20 MW or less, temporary Energy Resource additions of 20 MW or less but greater than 2MW, permanent and temporary Energy Resource additions of 2MW or less, and certified small inverter-based facility additions not greater than 10 kW.

Additionally a process has been established for the interconnection of new small resources which are not anticipated to have an impact on PJM monitored transmission facilities. This Alternate Queue Process is provided for those new resources which pass a specified screening criterion, as established in the PJM Tariff in Sections 110.1.1, 111.1.1, or 112.1.1, and is described in Tariff Section 112.5. The evaluation of those new small resource requests which pass the required screening criteria and are include in the Alternate Queue Process will include an evaluation of the load flow, short circuit, and stability impacts to be performed by the applicable Transmission Owner. PJM shall retain overall responsibility to monitor the study process, publish the Transmission owner reports, and provide a Wholesale Market Participation Agreement to the customer as required.

3.1.1 Study Requirements and Cost

In all cases, with the exception of requests for (i) interconnection falling under the process defined in the PJM Tariff applicable to permanent and temporary Energy Resource additions of 2MW or less and (ii) interconnection falling under the process defined in the PJM Tariff applicable to certified small inverter-based facility additions no larger than 10 kW, an Interconnection Customer must submit an Interconnection Request in the form of an executed Generation Interconnection Feasibility Study Agreement **(OATT at Part VI, Attachment N)** and provide the same information required for larger resources. Deposit requirements are listed in the table below (Table 3-1) **(OATT at Part IV, Section 112)**. Further:

- For resources of 2 MW or less, an interconnection customer must submit a completed Form of Screens Process Interconnection Request **(OATT at Part IV, Section 112A, Attachment Y)**. See table 3-2 below for deposit requirements.

- For Certified Inverter-Based resources no larger than 10 kW, an interconnection customer must submit a completed Form of Interconnection Service Agreement for Certified Inverter-Based Facility **(OATT at Part IV, Section 112B, Attachment BB)** and a non-refundable processing fee of $500.

Table 3-1: Small Generation Interconnection Process deposit requirements (Interconnection requests of 2 – 20MW)

Month of New Services Queue	Refundable deposit
1st - 4th	$10,000
5th	$12,000
6th	$15,000

Table 3-2: Small Generation Interconnection Process deposit requirements (Interconnection Requests of 2MW or less)

Month of New Services Queue	Refundable deposit
1st - 4th	$2,000
5th	$3,000
6th	$5,000

The deposit associated with the submission of the executed System Impact Study Agreement shall be in accordance with the requirements of Section 204.3A of the PJM Tariff, which is also listed below in Table 3-3.

Table 3-3: System Impact Study Deposit

Project size	Required deposit
>2MW and ≤20MW	$10,000
≤2	$5,000

The Generation Interconnection Facilities Study deposit amount shall be in accordance with the requirements of Section 206.3 of the PJM Tariff, which is also listed in Table 2-3.

Study Analysis

Analysis conducted during the Generation Interconnection Feasibility and System Impact Studies will be expedited (to the degree possible) for new permanent Capacity Resources of 20 MW or less, or permanent Energy Resources of 20 MW or less, or increases of 20 MW or less to existing resources over any consecutive 24 month period **(OATT at Part VI, Section 36.1.02 - formerly Section 36.12, in Part IV)**.

Power flow analysis will be performed based on a limited contingency set to identify the impact of the resource on the local system and any known violations in the area. Deliverability tests will only be performed for small capacity resources in areas where margins are known to be limited. Similarly, stability analysis will only be performed for small resources where existing stability margins are limited. Generation Interconnection Facilities Studies for small resources can only be expedited consistent with the scope of the required transmission facility additions and upgrades.

Because it is expected that the interconnection of temporary Energy Resources will be based on 'turn-key' installations, the procedures to process such requests are highly expedited. Studies not affecting the regional plan may receive an expedited System Impact Study and be issued when complete.

Analysis and design normally performed within the context of Generation Interconnection Feasibility, System Impact and Generation Interconnection Facilities Studies will be performed within one study. Limited power flow analysis will be performed to ensure that local contingency criteria are not violated. Short circuit calculations will be performed to ensure that circuit breaker capabilities are not exceeded. The Transmission Owner, or contractors acting on their behalf, will evaluate the engineering details of the physical attachment of the resource, as well as the relaying and metering associated with the resource to ensure a safe and reliable interconnection.

All very small resource interconnections require the execution of Interconnection Service Agreements. Permanent, small Capacity Resources and Energy Resources will execute the same form of Interconnection Service Agreement as required for larger resources. A modified form of the Interconnection Service Agreement will be executed for temporary Energy Resources that reflect their interconnection status and their rights with respect to participation in the PJM markets.

3.2 Specific Provisions for Resources of 10 MW or Less

Under certain circumstances, requests for the interconnection of new resources of 10 MW or less may be expedited through the use of pre-certified generation equipment and systems that meet IEEE Standard 1547 technical requirements. See Attachment E for PJM “Small Generator (10 MW and Below) Technical Requirements and Standards” for full details of the specific provisions that apply to all new generator interconnections with an aggregate size of 10 MW and below at the Point of Interconnection.

3.3 Specific Provisions for Resources Greater than 10 MW up to 20 MW

Requests for the interconnection of new resources greater than 10 MW up to 20 MW may also qualify for certain Applicable Standards based on the core IEEE Standard 1547 technical requirements. See Attachment E-1 for PJM "Small Generator (greater than 10 MW up to 20 MW) Technical Requirements and Standards" for full details of the specific provisions that apply to all new generator interconnections with an aggregate size of greater than 10 MW up to 20 MW at the Point of Interconnection.

Section 4: Interconnection Service Agreement and Construction Service Agreement Execution and Other Agreements

In this section you will find the following overviews of the requirements for Interconnection Service Agreements and Interconnection Construction Service Agreements:

- A description of the Interconnection Service Agreement (see "Interconnection Service Agreement").
- A description of the Interconnection Construction Service Agreement (see "Interconnection Construction Service Agreement").
- A description of other agreements (see "Other Agreements").

4.1 Interconnection Service Agreement

After the Generation or Transmission Interconnection Facilities Study is completed (or, if no Interconnection Facilities Study is required, upon completion of the System Impact Study), the Transmission Provider **("PJM")** will furnish an Interconnection Service Agreement (in the form included in **Part VI, Attachment O to the Tariff**) to be executed by the applicant and any affected Interconnected Transmission Owner(s). The Interconnection Service Agreement **("ISA")** defines the obligation of the generation or transmission developer regarding cost responsibility for any required system upgrades. The ISA also confers the rights associated with the interconnection of a generator as a capacity resource and any operational restrictions or other limitations on which those rights depend. For transmission interconnection customers, the ISA confers transmission injection and withdrawal rights (Merchant D.C. and/or Fully Controllable A.C. transmission projects) and applicable incremental delivery, available transfer capability revenue and auction revenue rights. The ISA further identifies any changes in construction responsibility from the Standard Option for Transmission Owner Interconnection Facilities due to the Interconnection Customer/Developer exercising the Negotiated Contract Option or Option to Build.

Upon issuance of the ISA, PJM team leadership for the project is transferred from the study phase System Planning Senior Consultant to an Interconnection Coordination Senior Consultant for the project Interconnection and Construction phases (see Attachment C for PJM Generation and Interconnection Planning Team Role Clarity Diagram). For leadership continuity, the study phase team leader continues active participation in the project as a member of the Interconnection and Construction team.

For an Interconnection Request to maintain its assigned priority, the applicant must respond within 60 days of receiving the ISA. To proceed with the project, the applicant must provide PJM with a Letter of Credit or other acceptable form of security in the amount equal to the estimated costs of new facilities or upgrades for which the applicant is responsible. The applicant must also respond by:

- Executing and returning the Interconnection Service Agreement, or
- Requesting dispute resolution, or
- Requesting, under certain circumstances, that the Interconnection Service Agreement be filed unexecuted.

Further details regarding each of the three response actions may be found in Part VI of the PJM Open Access Transmission Tariff, available from FERC or on the PJM web site at http://www.pjm.com/home.aspx.

Additionally, within the same 60-day period, the applicant must demonstrate:

- Completion of a fuel delivery agreement and water agreement, if necessary.
- Control of any necessary rights-of-way for fuel and water interconnections, if necessary.
- Acquisition of any necessary local, county, and state site permits.
- A signed memorandum of understanding for the acquisition of major equipment.

PJM may also include other reasonable milestone dates for events such as permitting, regulatory certifications, or third-party financial arrangements. Milestone dates may be extended by the PJM in the event of delays not caused by the Interconnection Customer, such as unforeseen regulatory or construction delays.

Additionally, PJM will again ensure that the Generation and/or Transmission Interconnection Customer has access to the Applicable Technical Requirements and Standards of the Interconnected Transmission Owner(s) for parallel operation of generators with the Interconnected Transmission Owner(s) systems and other matters generally included in good utility practice. Technical requirements for generator and transmission interconnections include but are not limited to:

- Engineering design requirements and standards
- Interconnection protection requirements
- Generator under frequency trip settings to coordinate with automatic underfrequency load shedding schemes
- Voltage control and reactive output requirements (OATT at Part VI, Section 4.7 in Att. O, App. 2 - formerly Section 54.7, in Part IV)
- Data and control requirements for transmission system operation
- Equipment specifications and suppliers
- Construction requirements and standards
- Engineering, procurement and construction process requirements and standards

Pursuant to section 1.2C of the PJM Tariff, PJM makes documents containing Applicable Technical Requirements and Standards for each Interconnected Transmission Owner available through its internet site at http://pjm.com/planning/design-engineering/to-tech-standards.aspx .

PJM will file the Interconnection Service Agreement in compliance with applicable Commission guidelines. If the applicant has requested dispute resolution or unexecuted filing, construction of facilities and upgrades shall be deferred until any disputes are resolved, unless otherwise agreed by the applicant and the affected Interconnected Transmission Owner(s).

4.1.1 Interim Interconnection Service Agreements

Under certain circumstances, an applicant for an Interconnection Service Agreement may wish to initiate project construction activities on an expedited basis prior to completion of the Generation or Transmission Interconnection Facilities Study. One example of such a circumstance is to request that orders be placed for equipment or materials that have a long lead time for delivery. To initiate such an advance of construction activities, the applicant may request execution of an Interim Interconnection Service Agreement **(OATT at Part VI, Attachment O-1)** for those construction activities being advanced.

The Interim ISA would bind the applicant for all costs incurred for the construction activities being advanced pursuant to the terms of the PJM Tariff. While PJM agrees to provide the applicant with the best estimate (determined in coordination with the affected Transmission Owner(s) of the new facility costs and other charges that may be incurred for the work being advanced, such estimate shall not be binding and the applicant must agree through execution of the Interim ISA to compensate PJM and the affected Transmission Owner(s) for all costs incurred due to those activities that were advanced.

> **NOTE**: Further information on all required studies and the Interconnection Service Agreement may be found in Part VI, of the PJM Open Access Transmission Tariff (**OATT at Part VI, Section 212 - formerly Subpart A at 36.8, in Part IV** for Generation Interconnections, **OATT at Part VI, Section 212** – formerly **Subpart B at 41.7** for Transmission Interconnections, **OATT at App. 2 of Att. O** – formerly **Subpart E** for Standard Terms and Conditions and **Attachment O** for the form of Interconnection Service Agreement in Part VI – formerly Part IV) available on the PJM Web site, http://www.pjm.com/documents/agreements/pjm-agreements.aspx.

4.2 Interconnection Construction Service Agreement

The construction of any Interconnection Facilities required to interconnect a generator or transmission project with the PJM Transmission Grid shall be performed in accordance with the Standard Terms and Conditions as specified in an Interconnection Construction Service Agreement to be executed among the applicant for Transmission Service (Generation or Transmission Interconnection Customer), PJM and the affected Interconnected Transmission Owner(s). The form of an Interconnection Construction Service Agreement may be found in the PJM Open Access Transmission Tariff as Attachment P.

The party(ies) responsible for installing the Generator and/or Transmission Interconnection Facilities and/or Network Upgrade Facilities shall use Reasonable Efforts to install those facilities in accordance with an agreed Schedule of Work.

> **NOTE**: Further information on all terms and conditions to be incorporated and made part of an Interconnection Construction Service Agreement may be found in **Part VI, Att. P, App. 2 of the PJM Open Access Transmission Tariff** (formerly **Subpart F** for Standard Construction Terms and Conditions and **Attachment P** for the form of an Interconnection Construction Service Agreement in Part VI) available on the PJM Web site, http://www.pjm.com/documents/agreements/pjm-agreements.aspx.

4.2.1 Option to Build

In the event that the Generation and/or Transmission Interconnection Customer and the Interconnected Transmission Owner are unable to agree upon the terms of an Interconnection Construction Service Agreement, the Interconnection Customer shall have the right, but not the obligation ("Option to Build"), to design and install all or any portion of the Transmission Owner Interconnection Facilities.

4.2.2 General Timeline

If the Interconnection Customer chooses to exercise the Option to Build, the Interconnection Parties must adhere to the following timeline:

- The Interconnection Customer must provide PJM and the Interconnected Transmission Owner with written notice of its election to exercise the option by no later than **7 days** after the date that is **30 days** after the Interconnection Customer's execution of the Interconnection Service Agreement.
- Within **10 days** after notifying PJM of its election to exercise Option to Build, Interconnection Customer shall solicit bids from one or more Approved Contractors.
- Prior to commencing construction, the Interconnection Customer shall submit to the Interconnected Transmission Owner and PJM initial drawings, certified by a registered professional engineer, of the Transmission Owner Interconnection Facilities that the Interconnection Customer arranges to build under the Option to Build. After consulting with the Interconnected Transmission Owner, PJM shall provide comments on such drawings to the Interconnection Customer within **60 days** after its receipt thereof, after which time any drawings not subject to comment shall be deemed to be approved.

- Each Constructing Entity shall issue reports to each other Construction Party on a **monthly basis** regarding the status of the construction and installation of the Interconnection Facilities. Each Construction Party shall promptly identify, and shall notify each other Construction Party of, any event that may delay completion or may significantly increase the cost of the Interconnection Facilities. Within **15 days** of such notification, PJM shall convene a technical meeting of the Construction Parties to evaluate schedule alternatives.
- Interconnection Customer and the Interconnected Transmission Owner shall coordinate the timing and schedule of all inspection and testing of the Interconnection Facilities. If inspection or testing identifies any defects or failures to comply with Applicable Standards of (i) Interconnection Facilities constructed by the Interconnection Customer, Interconnected Transmission Owner shall notify the Interconnection Customer and PJM of such defects or failures within **20 days** after receipt of the results of such inspection or testing, or (ii) Interconnection Facilities constructed by the Interconnected Transmission Owner, Interconnected Transmission Owner shall take appropriate action to correct any such defects or failures within **20 days** after it learns thereof.
- Within **10 days** after satisfactory inspection and/or testing of Interconnection Facilities built by the Interconnection Customer/Developer, the Interconnected Transmission Owner shall confirm in writing to the Interconnection Customer and PJM that the successfully inspected and tested facilities are acceptable for energization.
- Within **5 days** after determining that Interconnection Facilities have been successfully energized, the Interconnected Transmission Owner shall issue a written notice to the Interconnection Customer accepting the Interconnection Facilities built by the Interconnection Customer that were successfully energized.
- Within **30 days** after the Interconnection Customer's receipt of notice of acceptance of the Interconnection Facilities, the Interconnection Customer shall deliver to the Interconnected Transmission Owner, for the Interconnected Transmission Owner's review and approval, all of the documents and filings necessary to transfer to the Interconnected Transmission Owner title to any Transmission Owner Interconnection Facilities constructed by the Interconnection Customer, and to convey to the Interconnected Transmission Owner any easements and other land rights to be granted by the Interconnected Customer that have not by then already been conveyed. The Interconnected Transmission Owner shall review and approve such documentation, such approval not to be unreasonably withheld, delayed or conditioned.
- Within **30 days** after its receipt of the Interconnected Transmission Owner's written notice of approval of the documentation, the Interconnection Customer, in coordination and consultation with the Interconnected Transmission Owner, shall make any necessary filings at the FERC or other governmental agencies for regulatory approval of the transfer of title.
- Within **20 days** after the issuance of the last order granting a necessary regulatory approval becomes final, the Interconnection Customer shall execute all necessary documentation and shall make all necessary filings to record and perfect the

Interconnected Transmission Owner's title in such facilities and in the easements and other land rights to be conveyed to the Interconnected Transmission Owner.

4.2.3 Summary of General Conditions

In addition to the other terms and conditions applicable to the construction of facilities under the Option to Build, the Generation and/or Transmission Interconnection Customer must also:

A. Obtain all necessary permits and authorizations

B. Obtain all necessary land rights

C. Accept the exclusive right and obligation of the Interconnected Transmission Owner to perform line tie-in work and to calibrate remote terminal units and relay settings

D. Follow accepted procedures to have those facilities that it builds successfully inspected, tested and energized

E. Arrange for all work to be performed by contractors, and using equipment manufacturers or vendors, that are listed on the Interconnected Transmission Owner's List of Approved Contractors

F. Allow the Interconnected Transmission Owner full site control and reasonable access to its property at all times

G. Allow the Interconnected Transmission Owner to have a reasonable number of appropriate representatives present for all work done on its property/facilities and the right to stop work or order corrective measures for any work with an adverse effect on reliability, safety or security of persons or of property

H. Comply with the Interconnected Transmission Owner's safety, security and work rules, environmental guidelines and training requirements applicable to the area(s) where construction activity is occurring, and

I. Submit to the Interconnected Transmission Owner and PJM initial drawings, certified by a registered professional engineer, of the Transmission Owner Interconnection Facilities that the Interconnection Customer/Developer arranges to build under the Option to Build.

> **NOTE**: Further information on all terms and conditions to be incorporated under the Option to Build may be found in **Part VI, Section 3.2.3 in App. P, App. 2 – formerly Part IV, Subpart F at 83.2.3** of the PJM Open Access Transmission Tariff, available on the PJM Web site at http://www.pjm.com/documents/agreements/pjm-agreements.aspx.

4.2.4 Specific Process Flow and Timeline (See Timeline in Attachment A)

Activity	Activity Duration	Cumulative Duration
Generation and/or Transmission Interconnection Customer (IC) submits an initial Interconnection Request in the form of an executed Generation and/or Transmission Interconnection Feasibility Study Agreement to PJM with all required information including evidence of ownership interest and a deposit to be used for the Interconnection Studies. PJM informs the affected Interconnected Transmission Owner(s) (ITOs) upon receipt of each Generation and/or Transmission Interconnection Request.	Requests received in 2 cycles per year ending on April 30 and October 31.	Up to 182 days (may be accelerated for small resource projects of 20 MW or less)
PJM conducts Generation and/or Transmission Interconnection Feasibility Study in coordination with each affected ITO. Complete studies in 2 cycles per year (complete by April 30 and October 31)	Up to 92 day window, after 30 day modeling period	Up to 304 days
PJM responds to the IC with the Generation and/or Transmission Interconnection Feasibility Study Agreement results, tenders a System Impact Study Agreement to the IC, provides notification to the affected ITOs and posts the results of the Generation and/or Transmission Interconnection Feasibility Study on the PJM web site.		
IC determines response to the Generation and/or Transmission Interconnection Feasibility Study results.	Up to 30 days	Up to 334 days
IC submits an executed System Impact Study Agreement (with proof of application for an air permit if required for a generator installation) and a $50,000 deposit (the $50,000 minimum deposit amount is waived for small resources of 20 MW or less).		
PJM conducts the System Impact Study, in coordination with any affected ITOs, during the next designated cycle and completes the Study within 120 days of commencement. Commence studies in 2 cycles per year (commence by June 1 and December 1)	Up to 120 days for study, after 60 day modeling period	Up to 514 days
PJM advises the IC of the System Impact Study Agreement results, tenders a Facilities Study Agreement to the IC/D, provides notification to the affected ITOs and posts the results of the System Impact Study on the PJM web site.		
IC determines response to the System Impact Study results.	Up to 30 days	Up to 544 days

Activity	Activity Duration	Cumulative Duration
IC submits an executed Generation and/or Transmission Interconnection Facility Study Agreement with a deposit of $100,000 or the estimated cost of its project responsibility, whichever is higher (small resources of 20 MW or less pay a deposit in the amount of the estimated cost of the study).		
If one is required, PJM conducts the Generation and/or Transmission Interconnection Facilities Studies, providing good faith estimates of the cost to be charged to each affected IC for the Attachment Facilities, Local Upgrades and Network Upgrades and a "SCHEDULE OF WORK" to complete construction of the facilities and upgrades.	Based on estimate of the time needed	Up to 544 days + time for Facilities Studies
PJM provides the Generation and/or Transmission Interconnection Facilities Studies results to the IC and tenders an Interconnection Service Agreement to each Generation and/or Transmission Interconnection Customer. PJM posts the results of the Generation and/or Transmission Interconnection Facilities Study on the PJM web site. (If the Transmission Interconnection Facilities Study only identifies the need to upgrade existing network facilites, then PJM shall tender an Upgrade Construction Service Agreement to the Transmission Interconnection Customer for execution)		
IC determines response to the Generation and/or Transmission Interconnection Facilities Studies results and the "SCHEDULE OF WORK".		
IC executes and returns tendered Interconnection Service Agreement or Upgrade Construction Service Agreement	Within 60 days	Up to 604 days + F.S.
IC elects Option to Build	Within 37 days following IC execution of the Interconnection Service Agreement	Up to 641 days + F.S.
PJM tenders and IC executes and returns Interconnection Construction Service Agreement	Within 45 + 90 days	Up to 739 days + F.S.
If the Generation and/or Transmission Interconnection Customer (IC) selects the Option to Build, the following timeline for various independent activities must be adhered to:		
IC solicits bids from Approved Contractors within 10 days after electing the Option to Build	Within 10 days	Up to 651 days + F.S.

Activity	Activity Duration	Cumulative Duration
IC submits initial drawings to the Interconnection Transmission Owner (ITO) and PJM - PJM responds within 60 days	Within 60 days	
Constructing entity submits monthly reports	Monthly	
Constructing entity notifies of delays or cost increases – PJM convenes a technical meeting within 15 days	Within 15 days	
Inspection or testing identifies defects – Corrective action is required within 20 days	Within 20 days	
Written notification by ITO is to be provided within 10 days of satisfactory inspection and/or testing and acceptance for energization	Within 10 days	
After successful energization, ITO provides written notice accepting the Interconnection Facilities built by the IC within 5 days	Within 5 days	
IC delivers all documents and filings to the ITO within 30 days of receipt of notice of acceptance	Within 30 days	
After written notice of approval by ITO, the IC makes filings to FERC or other governmental agencies within 30 days	Within 30 days	
After receipt of all regulatory approvals, the IC makes filings to record easements and land rights to be conveyed to the ITO within 20 days	Within 20 days	
Other Timeline requirements:		
Security for Payment - IC shall provide PJM with Security in the amount that is equal to the estimated cost of the ITO Interconnection Facilities that the ITO is responsible for constructing	Within 60 days after the date of IC's receipt of Facilities Study	
Submit Invoices		
ITO to PJM	Monthly	
PJM to IC	Monthly	
IC payment to PJM	Within 15 days	
Submit Final Invoice		

Activity	Activity Duration	Cumulative Duration
ITO to PJM	Within 120 days of project completion	

Exhibit 2: Process Flow and Timeline

Cross-References to Other Supporting PJM Documents

4.2.5 PJM Manuals

- PJM Manual for Control Center Requirements (M-1)
- PJM Manual for Transmission Service Request (M-2)
- PJM Manual for Transmission Operations (M-3)
- PJM Manual for Rules and Procedures for Determination of Generating Capability (M-21)

4.2.6 PJM Open Access Transmission Tariff – Part VI (Interconnections with the Transmission System)

- Subpart A – Generation Interconnection Procedures
- Subpart B – Transmission Interconnection Procedures (Consolidated with Subpart A)
- Subpart C – (Reserved)
- Subpart D – Interconnection Rights (Moved to Subpart C in Part VI)
- Subpart E – Standard Terms and Conditions for Interconnection (OATT at Part VI, title moved to App. 2 of Att. O. Subpart E – deleted.)
- Subpart F – Standard Construction Terms and Conditions (OATT at Part VI, title moved to Att. P, App. 2. Subpart F – deleted.)
- Subpart G – Small Generation Interconnection Procedure
- Attachment N-3 – Form of Optional Interconnection Study Agreement
- Attachment O – Form of Interconnection Service Agreement
- Attachment O-1 – Form of Interim Interconnection Service Agreement
- Attachment P – Form of Construction Service Agreement
- Attachment S – Form of Transmission Interconnection Feasibility Study Agreement

4.2.7 PJM Operating Agreement

- Schedule 6 – Regional Transmission Expansion Planning Protocol

4.3 Other Agreements

4.3.1 Station Power

All electric generation facilities consume some electric energy, generally referred to as “station power” in their operations. Station power requirements can include, for example, energy used for re-starting generators after they have been shut down for maintenance or other reasons; for emissions control and related monitoring equipment; for pumping and treating cooling water; for fuel handling equipment; and for lighting, heating and air conditioning of plant control rooms and offices.

Station power is defined as energy consumed in the PJM control area by a generating facility or by equipment or facilities located at the site of a generation facility and used in the operation, maintenance, or repair of the generation facility, regardless of whether the facility is operating when the energy is consumed.

Generators may obtain station service from a local utility under retail tariffs or service agreements. Every generator in PJM’s control area remains free (consistent with FERC policy) to purchase any or all of its station power from any seller connected to the grid.

Make certain your contracts or business arrangements for obtaining Station Power are in place before beginning generator operations.

Section 5: Additional Generator Requirements

In this section you will find:

- The definition of Behind the Meter Generation and requirements related to such projects,
- Generator power factor requirements, and
- Wind generator requirements.

5.1 Behind the Meter Generation Projects

Behind the Meter Generation refers to one or more generating units that are located with load at a single electrical location such that no transmission or distribution facilities owned or operated by any Transmission Owner or Electric Distributor are used to deliver energy from the generating unit(s) to the load; provided, however, that Behind the Meter Generation does not include (i) at any time, any portion of such generating unit(s)' capacity that is designated as a Capacity Resource; or (ii) in any hour, any portion of the output of the generating unit(s) that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market. Behind the Meter Generation rules permit load serving entities in PJM to net operating Behind the Meter Generation against load in the calculation of charges for energy, capacity, transmission service, ancillary services and PJM administrative fees. This total netting approach is intended to encourage the use of Behind the Meter Generation during times of scarcity and high prices, thus increasing the opportunity for load to compete in PJM markets.

5.1.1 Behind the Meter Generation Interconnection Requests

Any Behind the Meter Generation that desires to be designated, in whole or in part, as a Capacity Resource or Energy Resource must submit a Generation Interconnection Request. **(OATT at Part VI, in Section 36.1.01 – formerly Subpart A at 36.1A, in Part IV)**

5.1.2 Metering of Behind the Meter Generation

Behind the meter generation consisting of one or more generating units individually rated at ten megawatts or greater or that otherwise have been identified by PJM as requiring metering for operational security reasons must have both revenue quality metering and telemetry equipment for operational security purposes. Behind the meter generation consisting of multiple generating units that are individually rated less than ten megawatts but together total more than ten megawatts at a single site and are identified by PJM as requiring revenue quality metering and telemetry equipment may meet these metering requirements by being metered as a single unit. **(Operating Agreement, Section 14.5)**

5.1.3 Behind the Meter Generation Effects on Market Operations

Market Buyers shall be charged for all load and associated ancillary services based on the Market Buyer's total load (net of operating Behind the Meter Generation, but not to be less than zero.) **(Operating Agreement, Schedule 1)**

Prior to the commencement of the Planning Period, Parties may elect to place ALM associated with Behind the Meter Generation under the direction of PJM. This election shall remain in effect for the entire Planning Period. In the event such an election is made, such Behind the Meter generation will not be netted from load for the purposes of calculating Accounted-For Obligations under the appropriate PJM Regional Reliability Assurance Agreement.

5.2 Generator Power Factor Requirements

Except as PJM may determine otherwise for small generation resources of 20 MW or less, all generators interconnected with the PJM System shall be designed to maintain a composite power delivery at continuous rated power output and reactive capability, at the generator terminal, corresponding to the power factor requirements stated in the PJM Tariff. **(OATT at Part VI, Att. O, App. 2, Section 4.7.1 – formerly 54.7.1 in Part IV)**

5.2.1 Application of Power Factor Requirements to Increases of Existing Generation

PJM Tariff provisions require existing generators to be designed to operate at a specified leading and lagging power factor as measured at the generator terminals.

- Power Factor requirements also apply to capacity or energy increases to existing generation. (OATT at Part VI, Att. O, App. 2, Section 4.7.1.2)
- Increases to existing generators must be designed to maintain the grandfathered Mvar capability for the existing and pre-upgraded gross generator output capability and the Section 4.7.1.2 power factor requirement for all incremental MW increases.

Grandfathered Mvar capability will be determined using the following methodology and considerations.

- If an agreement exists and contains a reference to required Mvar capability, the methodology in the agreement will determine the grandfathered Mvar capability.
- Consideration will be given to the potential interpretations of the language in the agreement. Non-standard or vague terms and conditions will be discussed by PJM and the parties named in the agreement.
- If no agreement exists or there is no reference to required Mvar capability in an existing agreement, PJM will use alternate methods to determine the grandfathered Mvar capability of the machine.
- Examples of potential alternate methods that may be used at PJM's discretion.
- Use of the D-Curve provided by the manufacturer and is on file with PJM.
- Review of the data with the GO and provide an opportunity for the GO provide additional analytical evidence as to the actual Mvar capability, if different from the manufacturer design data.

- Consideration of available test data with acknowledgement that tests are not always performed under ideal conditions and the system may limit the capability during testing. Input from the GO will also be considered as part of the evaluation by PJM.
- Consideration of historical operational data.

Attachment H to this Manual 14A details a process, adhering to the requirements of the PJM OATT, to mitigate the reactive deficiency arising when an increase of capacity or energy to an existing generator results in the generator not being able to meet the PJM power factor requirements for the existing and/or incremental capacity or energy. Note that Attachment H is not applicable to capacity or energy increases of 20 MW or less of which the power factor is measured at the Point of Interconnection (POI). Requirements to such increases will be addressed in future tariff revision.

5.3 Wind-Powered Generation Projects

Because of the intermittent nature of wind-power generation, a specific procedure is required to determine an appropriate capacity value for wind generator output. Further, the use of induction-type generators for wind-powered projects requires the application of specific reactive power requirements.

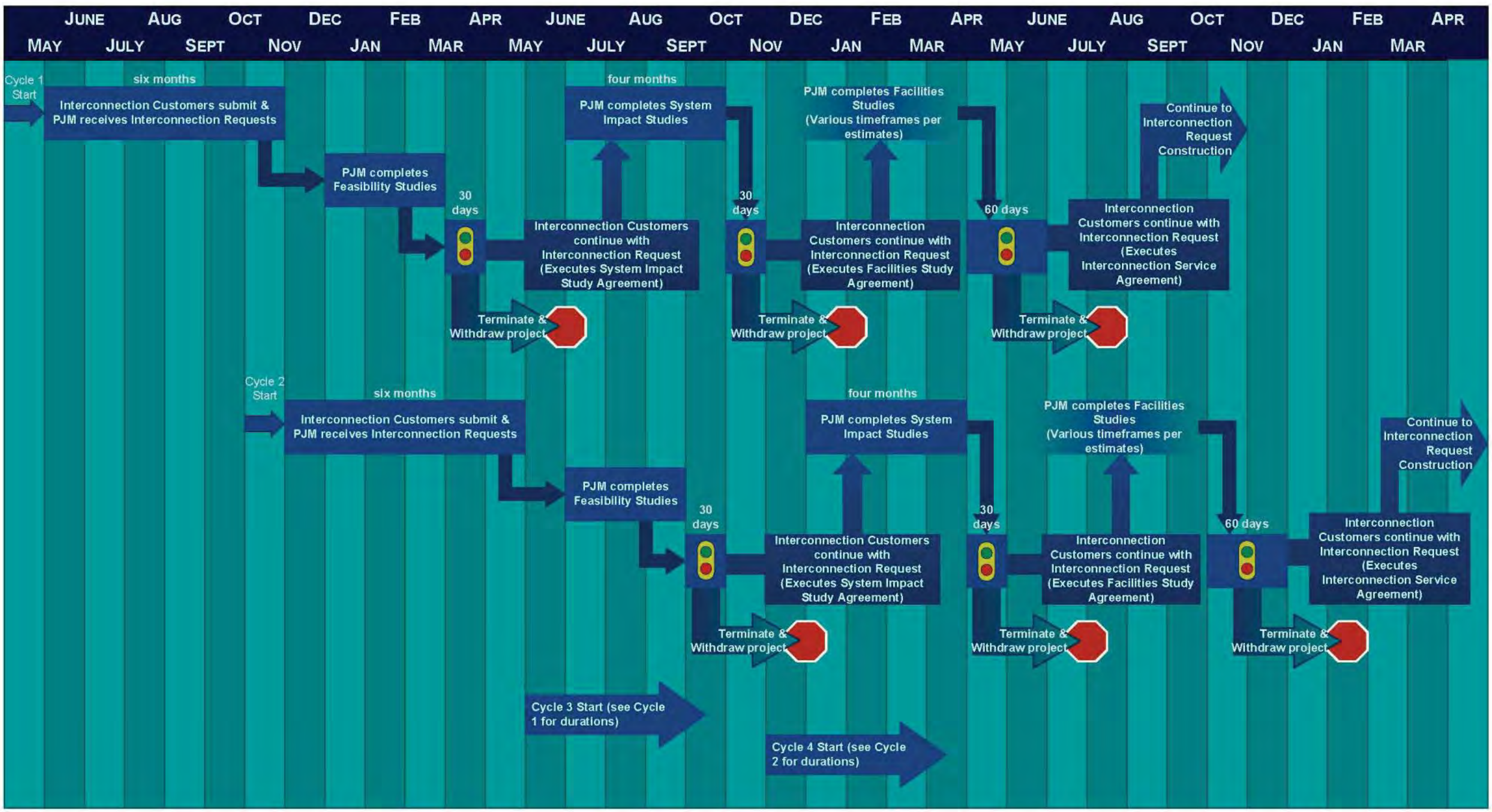
5.3.1 Wind Generation Capacity Credit Rules

PJM business rules allow for wind-powered generation projects to qualify for Capacity Resource status. Refer to PJM Manual 21 – "Rules and Procedures for Determination of Generating Capability" for details of PJM procedures for calculating Capacity Credits for Wind Farms.

5.3.2 Wind Generation—Specific Technical Requirements Without exception, all Customer Facilities will be subject to the provisions of the PJM **OATT at Part VI, in Section 4.7.2 and Section 4.7.3 in Att. O, App. 2 – formerly 54.7.2** and **54.7.3 in Part IV,** which describes real-time obligations to supply reactive power and the consequences of deviations from voltage schedules and/or reactive power schedules.

Wind projects connected to lower voltage systems must be designed to operate to a voltage schedule, reactive schedule or power factor schedule designed to meet local transmission owner criteria. When applicable, non-standard terms and conditions will be included in a project's Interconnection Service Agreement to address individual power factor requirements.

Attachment A: PJM Generation and Transmission Interconnection Planning Process Flow Diagram



Attachment B: PJM Request Cost Allocation Procedures

B.1 Purpose

One of the responsibilities of PJM as an RTO is to allocate the cost responsibility for all system reinforcement projects including projects required for Customer interconnection requests, baseline transmission reliability upgrades and market efficiency upgrades. The cost allocation procedures used by PJM to allocate costs due to requests are described below. Manual 14B addresses baseline-driven upgrade cost allocation procedures.

B.2 Scope

The RTEP encompasses two types of enhancements: Network Upgrades and Direct Connection Attachment Facilities. Network Upgrades can be required in order to accommodate the interconnection of a merchant project (generation or transmission) or to eliminate a Baseline problem as a result of system changes such as load growth, known transmission owner facility additions, etc. The PJM Cost Allocation Procedures are presented in two parts: “PJM Generation and Transmission Interconnection Cost Allocation Methodologies” discusses the cost allocation methodology for projects required for generator and transmission interconnections, below and: “Schedule 12 Cost Allocation Process for Baseline Transmission Reliability and Market Efficiency Upgrades” discusses the cost allocation process for baseline transmission reliability and market efficiency upgrade project requirements in Manual 14B.

The results of the System Impact Studies reveal Direct Connection Attachment Facilities required for new generation to “get to the bus”, Local and Network Upgrades to mitigate any “network impact” effects which the addition of such new generation or new transmission facilities may have on the power system itself.

- Each respective generator or transmission project bears the cost responsibility for Direct Connection Attachment facilities required for interconnection.
- The cost responsibility for Local and Network Upgrades identified through System Impact Study analysis is allocated among parties according to the following:
- For Local and Network Upgrades which are required due to overloads associated with the System Impact Studies of an individual New Services Queue, and have a cost less than $5,000,000, the cost of the Local and Network Upgrades will be shared by all proposed projects which have been assigned a Queue Position in the New Services Queue in which the need for the Local and Network Upgrades was identified. The Load Flow Cost Allocation methods discussed in this manual, including cutoffs, still apply to the individual projects.
- For Local and Network Upgrades which are required due to the overloads associated with the System Impact Studies of an individual New Services Queue, and have a cost of $5,000,000 or greater, the cost of the Local and Network Upgrades will be allocated according to the order of the Interconnection Requests in the New Services Queue and the MW contribution of each individual Interconnection Request for those projects which cause or contribute to the need for the Local or Network Upgrades. The Load Flow Cost Allocation methods discussed in this manual, including cutoffs, still apply to the individual projects.

B.2.1 Definitions

- Interconnection Queue Close Date – The date on which an Interconnection Queue ends. Currently, in the PJM Open Access Transmission Tariff, the Interconnection Queue Close Dates are January 31st and July 31st.
- Interconnection Customer – The responsible party for a generator or merchant transmission project that is in the PJM Interconnection Process.
- Queue Date – The date on which PJM receives a valid Interconnection Request from an Interconnection Customer.

B.3 PJM Generation and Transmission Interconnection Cost Allocation Methodologies

The cost allocation procedure will continue to be evaluated and modified, if required, as the generator and transmission interconnection process proceeds.

B.3.1 Load Flow Cost Allocation Method

Interconnection Customer requests are studied as a single study for all active projects in an individual New Services Queue. System Upgrades are identified to maintain system reliability.

<u>Individual Local & Network Upgrades which cost less than $5,000,000</u>

All Interconnection Customers with active Interconnection Requests in an individual New Services Queue will be allocated a cost for these System Upgrades based upon the following criteria:

- Contingent to the individual Interconnection Request contributing MW impact being greater than 5 MW AND greater than 1% of the applicable line rating OR (if its Distribution Factor (DFAX) on the facility is greater than 5% AND its MW impact on the facility's rating is greater than 3%), the contribution of an Interconnection Customer is determined by the voltage level of the facility that it impacts:
- For a transmission facility whose rated voltage level is below 500 kV, an Interconnection Customer/Developer will have some cost allocation if its Distribution Factor (DFAX) on the facility is greater than 5% OR if its MW impact on the facility's rating is greater than 5%.
- For a transmission facility whose rated voltage level is 500 kV or above, an Interconnection Customer/Developer will have some cost allocation if its DFAX on the facility is greater than 10% OR if its MW impact on the facility's rating is greater than 5%.
- Allocation of costs to Interconnection Customers for a System Upgrade which has a cost of less than $5,000,000 will not occur outside of the New Services Queue in which the need for the System Upgrade was identified

Individual Local & Network Upgrades which cost $5,000,000 or greater

All Interconnection Customers after and including the Interconnection Customer under study, that contribute to the need for the System Upgrade are identified and their MW impact on the need for the System Upgrade is determined. The MW impact will be based on the condition that causes the need for a System Upgrade.

- The first Interconnection Customer/Developer to cause the need for the System Upgrade will in all cases have some cost allocation. The cost allocation for this Interconnection Customer/Developer will only consider the loading above the facility's capability.
- Contingent to the contributing MW impact being greater than 5 MW AND greater than 1% of the applicable line rating, the contribution of an Interconnection Customer/Developer following the first Interconnection Customer/Developer to cause the need for the System Upgrade is determined by the voltage level of the facility that it impacts:
- For a transmission facility whose rated voltage level is below 500 kV, an Interconnection Customer/Developer will have some cost allocation if its Distribution Factor (DFAX) on the facility is greater than 5% OR if its MW impact on the facility's rating is greater than 5%.
- For a transmission facility whose rated voltage level is 500 kV or above, an Interconnection Customer/Developer will have some cost allocation if its DFAX on the facility is greater than 10% OR if its MW impact on the facility's rating is greater than 5%.
- Interconnection Customer/Developers will be assigned costs in proportion to their contributing MW impacts.

For System Upgrades with an "as-built" cost of $5.0 million or greater, Interconnection Customer will be responsible for allocated costs, within previously stated cost allocation guidelines, if their Interconnection Queue Close Date occurs less than 5 years following the execution of the first Interconnection Service Agreement which identifies the need for this System Upgrade.

No depreciation of the "as-built" System Upgrade cost will be used when allocating costs between Interconnection Customer/Developers.

Cost allocation for the engineering design of System Upgrades will terminate based on the completion of the applicable Generation and/or Transmission Interconnection Facility Study.

A complete list of Distribution Factors for all PJM modeled substations will be developed during System Impact Studies for each identified System Upgrade. This Distribution Factor list will be used for all cost allocation pertaining to the identified System Upgrade.

B.3.2 Short Circuit Cost Allocation Method

All Interconnection Customer/Developer projects are studied in queue order.

A Generation and/or Transmission Interconnection Customer/Developer will have some cost allocation if it results in a greater than 3% increase in fault current at the substation where a System Upgrade is required.

A Generation and/or Transmission Interconnection Customer/Developer will be assigned costs in proportion to its fault level contribution.

For Queue D and thereafter, the first Generation and/or Transmission Interconnection Customer/Developer to cause a System Upgrade due to increased fault current will in all cases have some cost allocation. The cost allocation for this Generation and/or Transmission Interconnection Customer/Developer will only consider the loading above the equipment's capability.

For System Upgrades with an "as-built" cost of $5.0 million or greater, Interconnection Customer will be responsible for allocated costs, within previously stated cost allocation guidelines, if their

Interconnection Queue Close Date occurs less than 5 years following the execution of the first Interconnection Service Agreement which identifies the need for this System Upgrade.

No depreciation of the “as-built” System Upgrade cost will be used when allocating costs between Generation and/or Transmission Interconnection Customer/Developers.

Cost allocation for the engineering design of System Upgrades will terminate based on the completion of the applicable Generation and/or Transmission Interconnection Facility Study.

PJM will consider application of an individual component cost vs. an aggregate cost when determining the cost allocation window.

B.3.3 Cost Allocation Method for Generator and/or Generator Step Up (GSU) Changes

The generator and generator step up transformer (GSU) characteristics provided by the developer prior to the initiation of the System Impact Studies for a given queue will be used for all cost allocation during the System Impact Study phase. If a developer changes the generator or GSU characteristics after initiation of the System Impact Studies, any additional system problems and any resulting reinforcements will be assigned completely to the Generation Interconnection project that made the changes. Future queued generation may share some cost allocation based on when the generator or GSU changes were provided to PJM.

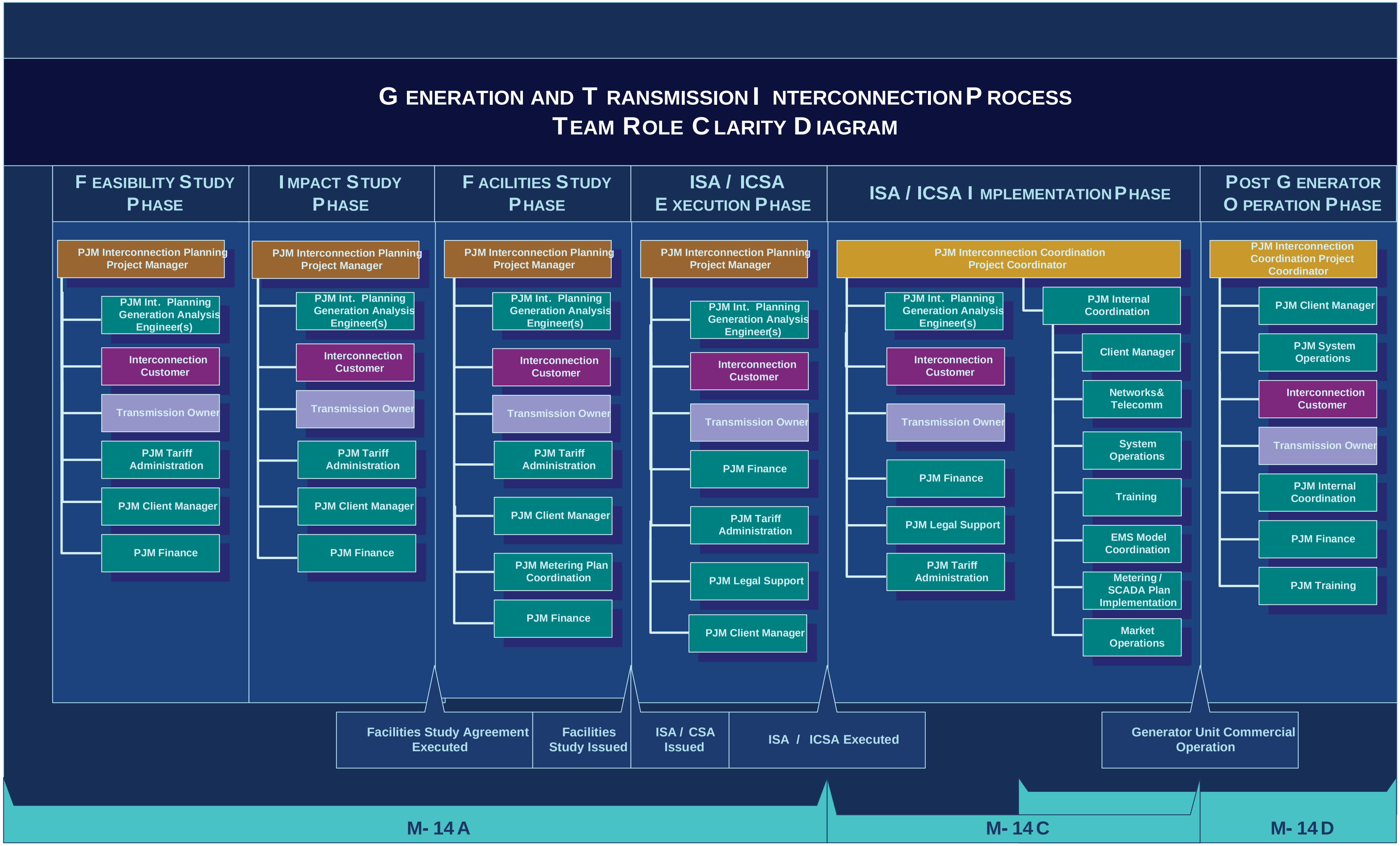
- Example 1: Impact studies for Queue Z started on May 10, 2010. Five 230 kV breakers at substation Alpha were required to be replaced due to several projects in Queue Z. Project Z2 which had some cost allocation for the five 230 kV breakers provided new GSU data on May 25, 2010. The new GSU has higher impedance. If all five breakers are determined to still be needed with the new GSU impedance, the original cost allocation will not change. If only four breakers are now required, the cost allocation for the four breakers that are still required will not change.
- Example 2: Impact studies for Queue Z started on May 10, 2010. Five 230 kV breakers at substation Alpha were identified to be replaced due to several projects in Queue Z. Project Z2 which had some cost allocation for the five 230 kV breakers provided new GSU data on May 25, 2010. The new GSU has a lower impedance. Now six 230 kV breakers at substation Alpha need to be replaced. Project Z2 will be assigned 100% of the cost for the sixth breaker and the cost allocation for the original five 230 kV breakers will not change.
- The rules concerning generator and GSU changes will be applied to generators in Queue B and thereafter.

B.3.4 Generation Project Excess MW Capabilities

The machine data provided by generation projects often contain MW capabilities that exceed the queued Capacity Interconnection Rights for that project. These additional MWs may result in a system that does not meet ReliabilityFirst Criteria for certain contingencies not “observed” in operations such as bus faults, and ReliabilityFirst Standard IIC contingencies (tower line, line fault with stuck breaker, faulted breaker). Consequently, after all generation projects in a given queue have executed a Generation Interconnection Facility Study Agreement, the PJM system will be evaluated using the MW capabilities provided by the developers to determine whether there are any bus fault or ReliabilityFirst Standard IIC violations. Any additional system problems will need to be rectified through either limiting the generator capability via hardware or upgrade of the Transmission System to eliminate the violation.

- The rules concerning excess project MW capabilities will be applied to generators in Queue B and thereafter.

Attachment C: PJM Generation and Transmission Interconnection Planning Team Role Clarity Diagram



Attachment D: General Description of Facilities Study Procedure

Introduction

A Facilities Study is an engineering study conducted by the Transmission Provider to describe the modifications required to the Transmission Provider's (PJM's) Transmission System to provide the requested Generator and/or Transmission Interconnection Service. PJM may contract with consultants, including the Interconnected Transmission Owner (ITO) and any other affected Transmission Owners (TO), to obtain services or expertise.

The purpose of the Facilities Study is to provide, commensurate with any mutually agreed parameters regarding the scope and degree of specificity described in Schedule A of the Facilities Study Agreement, conceptual (or preliminary) design, and, as appropriate, detailed design, plus cost estimates and project schedules, to implement the conclusions of the System Impact Study regarding the Attachment Facilities, Network Upgrades and Local Upgrades (i.e. upgrades related to non-OATT designated facilities) necessary to accommodate the Interconnection Customer's Interconnection Request(s).

Examples of typical Facilities Study deliverables are preliminary single line diagrams and general arrangement drawings for substation work, and delineation of proposed study area and proposed conductor and structure designs for transmission line work. Remaining detailed design activities would be completed during the construction phase of the project.

The Facilities Study Agreement (FSA) between the Interconnection Customer/Developer ("the Customer") and PJM will identify the scope of facility additions and upgrades to be included in this study. The FSA may also include milestones for completion of the Customer's facility study, where such work completion is critical to PJM's Facilities Study schedule.

General Guidelines

Facilities Study work will be initiated by a Kickoff meeting attended by the ITO, affected TO(s), the Customer, and PJM. The following types of information will be communicated at the Kickoff meeting:

The Customer shall provide a schedule for construction and anticipated commercial operation of the Customer's facilities. The Customer's schedule shall include the date when backfeed power is required, and the dates for anticipated test and commercial operation of each generating unit or transmission facility.

Interconnection specific information, including but not limited to:

- a one-line diagram showing the location of the Point of Interconnection,
- a customer facility location/site plan,
- a list of Interconnection Facilities and Ownership,
- if applicable, a list and ownership of Merchant Network Upgrades,
- a one-line diagram showing location and ownership of Metering Equipment,
- the Applicable Technical standards that apply to the Customer Facility and the Interconnection Facilities, and

- the Maximum Facility Output and/or the Nominal Rated Capability of the Customer Facility.

The scope of the Customer's, PJM's, ITO's and other affected TO's facilities study work will be delineated, and a schedule for completion of Facilities Study elements will be established. The scheduled completion of the Facilities Study shall not extend beyond the time estimate provided by the FSA.

A tentative schedule for Status meetings will be established. Status meetings may be necessary in those instances where information about one or more completed elements of the Facilities Study may be critical to the Customer's decision to continue the Facilities Study.

Results of PJM's Facilities Study shall be reported to the Customer in the form of a Facilities Study Report ("the Report"). The Report must contain a good-faith estimate of costs and construction schedules for each new or upgraded facility. In addition, the Report must contain sufficient detail about the engineering design of each facility. This will provide the Customer with information necessary to perform due diligence on the work to be performed by PJM, the ITO and other affected TO(s). The Report, less confidential or sensitive material, will be integrated with other Reports from other Transmission Owners (if applicable), and will also be posted on PJM's Web site.

All Report materials must be capable of being included in an MS Word document, formatted for 8 ½ in. by 11 in. printing. The Report shall identify the Customer's project by the queue number assigned to the project on PJM's web site. For example: "Project A57".

Facilities Study reports submitted to PJM shall consist of two primary sections:

Transmission Owner Facilities Study Summary

Transmission Owner Facilities Study Results

A. Transmission Owner Facilities Study Summary

1. Description of Project

   Provide a general description of the Customer's project that resulted in the need for the addition and/or upgrade of facilities. The information under the *General* paragraph of the System Impact Study Report shall be used as the basis for the Project description. Changes to the information provided in the System Impact Study shall be noted and recorded.

2. Amendments to the System Impact Study data or System Impact Study Results

   In general, significant changes to a Customer's project will not be allowed within the existing queue position for the Customer's interconnection request. However, changes to generator data or generator step-up transformer data, withdrawal of an interconnection Request with a lower queue number, or other changes allowed by PJM's business rules can cause the need to re-evaluate the Customer's System Impact Study and amend the results.

3. Interconnection Customer's Submitted Milestone Schedule

The Customer's submitted project schedule will be documented in this portion of the Report. This schedule will be used as the basis for developing the schedules for the purchase of equipment and the construction of facilities upgrades and additions contained in PJM's scope of Facilities Study work.

4. Scope of Customer's Work

In general, the scope of the Customer's facility study work will be limited to the direct connection facilities up to, but not including, the point of interconnection to a TO's facilities. The Customer's facilities study results will be included in the Report to the extent required to adequately support PJM's Facility Study results.

5. Description of Facilities Included in the Facilities Study

A general description of transmission lines, substations, protection systems, etc. that are included in the Facilities Study Report.

6. Total Costs of Transmission Owner Facilities included in Facilities Study

A summary level statement indicating the total estimated costs for both Attachment Facilities and Network Upgrades included in the Facilities Study.

7. Summary of Milestone Schedules for Completion of Work Included in Facilities Study:

Summary level schedule for detailed design, material & equipment procurement, and construction & testing for Attachment Facilities and Network Upgrades included in Facilities Study. This section should include a statement of comparison (i.e. alignment or misalignment) with Interconnection Customer's milestone schedule.

B. Transmission Owner Facilities Study Results

1. Transmission Lines – New

The Report shall include a "purpose and necessity" statement as well as a general description of alternative routes, terminal points, geographic description of terrain traversed by the new line, right-of-way width by segment, potential use of common corridors where such use exists, and a description of the permits required.

The following information must also be described; design criteria (may be summarized and reference published documents), nominal voltage rating, physical characteristics (overhead, underground, single circuit, double circuit, AC, DC, etc), line MVA normal and emergency rating, BIL, line impedance (positive and zero sequence), line and shield conductor type and size, type of support structure, and grounding design.

Applicable Transmission Owner Technical Standards should be referenced in the Report.

A specific reference to "PJM Transmission and Substation Design Subcommittee Technical Requirements" (note: upon approval) must be made for new or upgraded facilities.

Material specifications and a materials list, if available, may be included in the report or referenced.

All permit requirements must be identified.

Attachments required: geographic map with Customer facility location/site plan, with proposed transmission line study area superimposed.

Attachments optional: drawings for typical structure types.

2. <u>Transmission Line – Upgrades</u>

   As applicable, the same information, as listed above for “Transmission Lines – New”, distinguishing between existing and new equipment.

   Attachments: As applicable, same as above for “Transmission Lines – New”.

3. <u>New Substation/Switchyard Facilities</u>

   The Report shall include a “purpose and necessity” statement, a general description of the functional station design and layout, proposed location, and a description of the potential permits required.

   Also included shall be a description of the structural design, the electrical design including rating specifications and rating for all major electrical equipment (e.g. power transformers, circuit breakers, switches, instrument transformers, capacitor voltage transformers, etc.), and the protective relaying, communications, metering, and instrumentation requirements.

   Applicable Transmission Owner Technical Standards should be referenced in the Report.

   A specific reference to “PJM Transmission and Substation Design Subcommittee Technical Requirements” (note: upon approval) must be made for new or upgraded facilities.

   A Specific reference to the “PJM Relay Philosophy and Design Standards” (note: upon approval) must be made for new or upgraded protective relay equipment.

   Material specifications and a materials list, if available, may be included in or referenced in the Report.

   All permit requirements must be identified.

   Attachments required: One-line diagram for each substation / switchyard where facilities are to be added or upgraded. General arrangement diagram showing the physical layout of the new substation facilities.

   Optional Attachment: Relay, Instrumentation, and Control one-line diagram.

4. <u>Upgrades to Substation / Switchyard Facilities</u>

   As applicable, the same information listed above for “New Substation / Switchyard Facilities”, distinguishing between existing and new equipment.

   Attachments: As applicable, same as above for “New Substation / Switchyard Facilities”.

5. <u>Metering & Communications</u>

   General requirements for revenue and telemetry metering, SCADA RTU, and telecommunications, coordinated with PJM requirements.

6. <u>Environmental, Real Estate and Permitting Issues</u>

   Assessment of environmental impacts related to Attachment Facilities and/or Network Upgrades (i.e. Environmental Impact Study requirements, environmental permitting, sediment & erosion control issues), real estate ownership / easement issues, siting and Right-of Way issues for Transmission Owner side of Point of Interconnection.

7. Summary of Results of Study

Cost Estimates

A table listing construction cost estimates for each new or upgraded facility shall be provided. As applicable, identify and include all taxes and additional charges such as CIAC.

At a minimum, cost estimates shall be included with the following level of detail, along with the total costs (note: keep applicable CIAC tax gross-up amounts separate from total costs). Include both direct and indirect costs in each cost category:

- Attachment Facilities:
    - Detailed Design Costs
    - Material and Equipment Costs
    - Construction and Testing Costs
    - Miscellaneous Costs (i.e., real estate fees, environmental studies, contingencies, project management/oversight – specify details)
    - CIAC Tax Gross-up (if applicable)
- Each Network Upgrade:
    - Detailed Design Costs
    - Material and Equipment Costs
    - Construction and Testing Costs
    - Miscellaneous Costs (i.e., real estate fees, environmental studies, project management/oversight, contingencies – specify details)
    - CIAC Tax Gross-up (if applicable)

  Additional level of detail for cost estimates shall be provided if indicated in Schedule A of the Facilities Study Agreement.

Schedules

A milestone schedule, including major milestones (e.g. completion of final design, prepare specifications, solicit bids, construction completion) shall be provided for all facilities within PJM's and the TO's scope of work.

A statement concerning the ability to meet the Customer's scheduled milestones must be included.

Additional level of detail for project scheduled shall be provided if indicated in the Facilities Study Agreement.

Assumptions

A list of assumptions, uncertainties and / or qualifiers,that may adversely impact the estimated costs and/or schedules must be identified.

Some examples of items to be detailed in this section are environmental permitting, real estate/easement acquisition, public / customer opposition, equipment availability/system constraints/time of year limitations, scope definition with respect to accelerated schedule, contractor cost variability.

8. Information Required for Interconnection Service Agreement

A table with a cost breakdown for the FERC filing of the Interconnection Service Agreement must be provided. The table shall include the total cost for all facilities to be constructed by the TO. The costs must be itemized in the following categories:

Attachment Facilities
Direct Charges Labor
Direct Charges Material
Indirect Charges Labor
Indirect Charges material
Carrying Charges*

Network Facilities
Direct Charges Labor
Direct Charges Material
Indirect Charges Labor
Indirect Charges material
Carrying Charges*

* The Carrying Charge Rate must be specified.

Note: The cost breakdown indicated above is for use in the ISA in accordance with FERC guidelines, and is in addition to the cost breakdown detailed in Section 7.

The following are definitions for the above cost types:

Direct Costs: These are costs directly associated with the project. These costs need to be separated into “Direct Labor” costs which include the cost of labor to design/build/install the upgrades or facilities, and “Direct Material” costs which include the cost of the physical upgrades and equipment.

Indirect Costs: These costs include A&G expenses such as the salary of the payroll clerk.

Carrying Charges: These costs are the time value of money associated with the project (i.e., AFUDC). The interest rate must be specified.

Attachment E: Small Generator (10 MW or Less) Technical Requirements and Standards

E.1 Scope

The PJM Small Generator Interconnection Applicable Technical Requirements and Standards ("Small Generator Standards") shall apply to all new generator interconnections, within the PJM footprint, with an aggregate size of 10 MW or less at the point of interconnection.

The Small Generator Standards shall be read and construed as to be consistent with the PJM Open Access Transmission Tariff ("Tariff"). In the event of any inconsistency between the terms and conditions of the Small Generator Standards and the terms and conditions of the Tariff, the terms of the Tariff shall control. All terms contained in the Small Generator Standards shall be defined as defined by the Tariff. While PJM strives to ensure that the information reflected herein is complete, accurate and reliable, it expressly disclaims any warranty, whether express or implied, as to information contained. Entities relying on the information contained herein do so at their own risk.

E.2 Purpose

To align the applicable technical requirements used within PJM with the IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, and to facilitate the pre-certification of manufactured generation equipment and systems for use within PJM.

E.3 Background and Discussion

Developed by the PJM Small Generator Interconnection Working Group ("SGIWG"), the Small Generation Standards define the uniform technical requirements that each Interconnected Transmission Owner ("ITO") and Electric Distribution Company ("EDC") requires for interconnecting to their facilities. The requirements as defined herein will govern for the interconnection of distributed generation 10 MW or less.

ITOs and EDCs may, by mutual agreement, elect to waive certain IEEE 1547 requirements and associated exceptions and conditions stated herein, but may not add requirements to IEEE 1547 other than the exceptions and conditions contained herein. For small generators qualifying for interconnection under state rules, the state-approved technical requirements and procedures shall govern. In the event that a small generator has interconnected under state rules and thereafter elects to participate in any PJM market, such small generator must comply with the terms of PJM's Small Resource Interconnection Procedure Manual and these Small Generation Standards. The small generator must submit a completed Feasibility Study Request (Attachment N of the Tariff) and will be responsible for any subsequent study costs. Additionally, the small generator will be required to execute PJM's three-party Interconnection Service Agreement with PJM and the local Transmission Owner, and to the extent applicable, an Electric Distribution Company, as the case may be.

E.4 General Application Note for Transmission System Interconnections

In its present form IEEE Standard 1547 is primarily intended to address generator interconnections of 10 MVA or less to radial distribution systems. In order to extend the use of IEEE Standard 1547 beyond this scope to include connection to transmission[1] facilities, it is necessary to clarify the meaning of Section 4.2.1 to assure that system protection requirements are compatible with the established reliability criteria used for those systems.

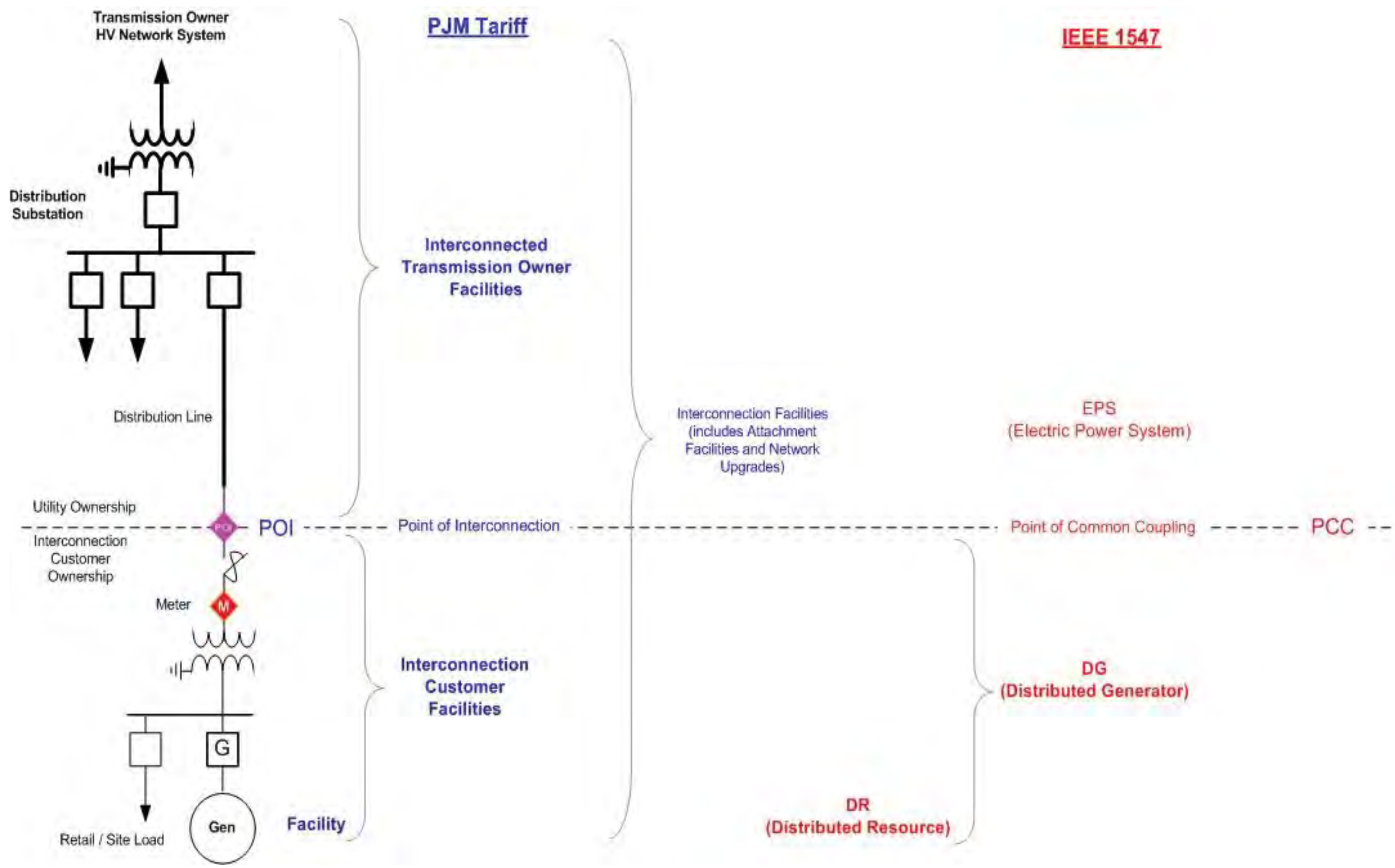
IEEE Standard 1547 Section 4.2.1 (Area EPS Faults) requires that “the DR unit shall cease to energize the Area EPS for faults on the Area EPS circuit to which it is connected.” For transmission Interconnections, this implies that the protection scheme(s) be compatible and coordinate with the Area EPS protection scheme(s) used for the line or substation to which they are interconnected, or be compatible and coordinate with new protection equipment installed due to the connection of the generation to this facility.

1 In the context used here, transmission systems are systems 69 kV or greater or networked lower voltage systems that are used for backbone energy delivery within smaller geographic areas, much the same as most 69 kV systems.

E.5 PJM Tariff / IEEE 1547 Definition Cross-Reference

IEEE Standard 1547	PJM Tariff
PCC (Point of Common Coupling)	POI (Point of Interconnection)
Point of DR Connection	Not Applicable
EPS (Electric Power System)	Interconnected Transmission Owner Facilities
Area EPS Operator	Interconnected Transmission Owner
Not Applicable	Transmission Provider (PJM)
DG (Distributed Generation)	Interconnected Generation Customer Facilities which are not connected to the Bulk Power Transmission System
DR (Distributed Resources)	Interconnected Generation Facility which is not connected to the Bulk Power Transmission System
Interconnection Equipment	Not Applicable
Interconnection System	Interconnection Facilities
Not Applicable	Interconnection Customer Facilities
Electric Power System, local	Not Applicable
Electric Power System, area	Not Applicable
Cease to Energize (Cessation of energy outflow capability)	Not Applicable

Note: The illustration below is for cross-reference of PJM Tariff and IEEE 1547 terms only.



E.6 Applicable Technical Requirements and Standards

IEEE Standard 1547 shall constitute the total technical requirements and standards for interconnection of small generators of 10 MW and below with the following noted exceptions, additions, and clarifications. IEEE Standard 1547.1 constitutes the requirement for test conformance to IEEE Standard 1547.

IEEE Standard Requirement		Exceptions or Additions
4.1.1	Voltage Regulation	None. See Application Note 1.
4.1.2	Integration with Area EPS Grounding	None. See Application Note 2.
4.1.3	Synchronization	None. See Application Note 3.
4.1.4.1	Distribution Secondary Grid Networks (under development)	None. See Application Note 4.
4.1.4.2	Distribution Secondary Spot Networks	Exception. ComEd only allows Spot Network interconnections on an exception basis or where state commission regulations specify requirements.
4.1.5	Inadvertent Energization of the Area EPS	None.
4.1.6	Monitoring	None. See Application Note 5.
4.1.7	Isolation Device	None. See Application Note 6.
4.1.8.1	Protection from EMI	None.
4.1.8.2	Surge Withstand Performance	None.
4.1.8.3	Paralleling Device Withstand	None.
4.2.1	Area EPS Faults	PEPCO and PSEG exception for Islanding protection. See Application Notes 7 and 12.
4.2.2	Area EPS Reclosing Coordination	None. See Application Note 13.
4.2.3	Voltage	None. See Application Note 8.
4.2.4	Frequency	None.

IEEE Standard Requirement		Exceptions or Additions
4.2.5	Loss of Synchronism	None.
4.2.6	Reconnection to Area EPS:	
	(a) Voltage Requirement	None. See Application Note 9.
	(b) Frequency Requirement	None. See Application Note 9.
4.3.1	Limitation of DC Injection	None.
4.3.2	Limitation of Flicker induced by the DR	None. See Application Note 10.
4.3.4	Harmonics	PPL exception. See Application Note 11.
4.4.1	Unintentional Islanding	PEPCO and PSEG exceptions. See Application Note 12.
5.1	Design Test	None. See Application Note 14.
5.2	Production Tests	None. See Application Note 14.
5.3	Interconnection Installation Evaluation	None.
5.4	Commissioning Tests	None.
5.5	Periodic Tests	None.

E.6.1 Application Notes

4.1.1 Voltage Regulation.

Depending on size of generation (relative to EPS strength) and location of interconnection, the interconnected generation may be required to provide or absorb reactive power and/or follow a voltage schedule to maintain an acceptable voltage profile on the EPS with the addition of the new generating facility.

4.1.2 Integration with Area EPS grounding.

Where new transformers are required:

- AP requires a wye-grounded connection on the T.O. side of the DG step up transformer; and
- PEPCO's requirement for an isolation transformer including its configuration at 13.8 kV and above, will be determined on a case by case basis and will depend on the generating facility's location and system configuration.

AP and PEPCO requirements specified above do not apply if a generator is being connected to a system on the low voltage side of an existing Interconnection Customer transformer.

Other Transmission Owners within PJM will accept a delta or wye-ungrounded connection provided that adequate protection is provided by the DG to detect a ground and limit any overvoltage to an acceptable level on the TO's system. Adequate protection includes voltage monitoring on the high side of the DG main transformer using phase to ground connected VTs. Also see Application Note 5 for an additional AEP Application Note for grounding coordination related to operation of isolating devices.

4.1.3 Synchronization.

IEEE 1547 Synchronization voltage fluctuation requirement of +/- 5% is applicable as stated. Flicker requirement 4.3.2 guidance is provided by IEEE Standard 519 and IEEE Flicker Task Force P1453. However, the requirement which must be met for 4.3.2 is to not cause voltage and /or frequency disturbances which are objectionable to other EPS customers during actual operation of DR.

4.1.4.1 Distribution Secondary Grid Networks.

IEEE 1547 presently does not address the requirements for Secondary Grid Networks. These interconnection requests will be evaluated on a case by case basis.

4.1.6 Monitoring.

"Each DR unit of 250 kVA or more or DR aggregate of 250 kVA or more at a single PCC shall have provisions for monitoring its connection status, real power output, reactive power output, and voltage at the point of DR connection." Local monitoring provisions, such as panel meters and indicating lights, may be acceptable to meet these requirements in certain cases.

A. An Internet-based SCADA alternative (see Informative Annex #2) was developed as a reliable and economical alternative to direct SCADA communications with the TO. In addition to generally lower installed cost for the "Internet SCADA alternative," the Internet ongoing communication costs may be more cost effective to other alternatives, especially those that require leased telephone circuits.

> **NOTE:** Informative Annex #2 is available on the PJM Web site (http://www.pjm.com/planning/rtep-development/expansion-plan-process.aspx) and select from among the 10 specific documents listed under the heading "Information Annex #2 References for Manual 14D, Attachment H."

B. When full-time dedicated SCADA communications are required (see Transmission Owner ("TO") listing below and refer to the SCADA REQUIREMENTS spreadsheet - Informative Annex #1) the DG Owner, PJM or the TO will provide and/or install a suitable SCADA Remote Terminal Unit in accordance with the specifications provided in Informative Annex #2 or an alternative mutually suitable to the DG Owner, Transmission Owner and PJM.

C. The PJM TOs agree to accept the "Internet SCADA alternative" (see Informative Annex #2), in lieu of direct SCADA communications with the TO, except in circumstances where the "Internet SCADA alternative" does not meet certain TO technical requirements specified and justified by the TO.

D. If the TO, PJM and DR owner mutually agree, specifications for other suitable interfaces between the DG and TO SCADA can be acceptable. Where applicable, this approach would allow a DR owner to use a SCADA protocol of their choice and provide an interface closer to the Transmission Owner's SCADA facility. Such an installation must provide adequate communication performance, suitable to PJM and the TO.

Installation of communications facilities (internet service, leased telephone circuits, fiber optics, etc.), communications facility Operation and Maintenance, and other ongoing costs are the responsibility of the Interconnection Customer.

Installation of communications facilities (typically leased telephone circuits), communications facility Operation and Maintenance, and other ongoing costs are the responsibility of the Interconnection Customer.

PJM requires real-time telemetry data (MW and MVAR) for Capacity Resources, Energy Resources 10MW and above, or Energy Resources able to set LMP. PJM also requires interval revenue metering data (KWH and KVARH data at 5 minute intervals provided hourly).

See the following for specific interconnection requirements based on Transmission Owner Zone:

Allegheny Power—Requirement for SCADA is determined on a case-by-case basis by Allegheny Power.

American Electric Power—Real-time telemetry (SCADA) generally required for generation greater than 2.5 MW connected to the distribution system and all connections at transmission voltages.

Baltimore Gas and Electric—Requires BG&E specified telemetry (periodic, not real time), installed by BG&E, for all generator interconnections.

Commonwealth Edison Company—Requires real-time telemetry for any interconnection of 10 MW or greater, or for interconnections where transfer trip is required (generally 2.5 MW and above) for the interconnection.

Dayton Power and Light—Determines real-time telemetry (SCADA) requirements on a case-by-case basis.

Dominion—Requires a SCADA RTU compatible with Dominion's SCADA system when the ratio of "Light Local Load" to Maximum Rated Generation Capacity ratio is less than 5.

Duquesne Light Company—At DLC's discretion the Interconnection Customer can be required to install and maintain a dedicated communications link, compatible with DLC's equipment, to provide telemetry (SCADA) to DLC's Operation Center. The preferred communications protocol for RTU communications is DNP 3.0. The installed SCADA shall comply with the current NERC Cyber Security standards.

First Energy—FE determines real time telemetry (SCADA) requirements on a case by case basis for interconnection to the radial distribution system. Real time telemetry is required for all interconnections to the Transmission System, generally 23 kV and above.

Old Dominion Electric Cooperative—ODEC requires real-time SCADA for DG resources in the 2-10 MW range, to include MW and MVAR and status of the interconnecting circuit breaker. This does not necessarily imply a full RTU but could be a data link with the plant / unit control system. DNP 3.0 is the supported protocol.

Orange and Rockland—All facilities over 1,000 kW connected to the distribution system must have equipment to continuously telemeter the following data to Orange and Rockland's Energy Control Center via a leased telephone line. This data will be provided through the installation of a REMOTE TERMINAL UNIT (RTU) in the applicant's facility. The RTU shall use DNP 3.0 protocol (unless otherwise stated).

<u>PECO Energy</u> requires real-time telemetry for interconnections of 5 MW or greater.

PHI Companies (Atlantic City Electric Co., Delmarva Power & Light Co. and Potomac Electric Power Co.)—Atlantic City Electric Co. and Delmarva Power & Light Co. require a RTU for all generator interconnections, and real-time MWH and MVH telemetry for all interconnections for which generators participate in PJM markets. For generators not participating in PJM markets real-time telemetry is required for generators 3 MW and above.

> **Note:** The specific location and circumstances of a generator interconnection may make telemetry necessary, even when telemetry would not ordinarily be required.

PEPCO requires a RTU for all generator interconnections, and real time telemetry for all interconnections that participate in PJM markets. For generators not participating in PJM markets real-time telemetry is required for generators 10 MW and above.

PPL—Requires full-time dedicated SCADA RTU compatible with PPL EU's SCADA system for interconnections 2.5 MW and above or at 69 kV and above.

PSEG—Real-time telemetry (SCADA) requirement is determined on a case-by-case basis. Smaller MW size generator interconnections usually require a low-cost alternative system.

UGI—Requires real-time telemetry (SCADA) compatible with the UGI SCADA system for all interconnections 1MW or greater and for all 66 kV and above interconnections.

4.1.7 Isolation Device Requirement.

When the Area EPS operating practices require an isolation device, that device must be readily accessible to the Area EPS operator, lockable in the open position, and must provide a visible break in the electrical connection between the generator and the Area EPS. The Isolation Device must be rated for the voltage and current requirements of the installation. The Isolation Device may be electrically located anywhere between the point of common coupling and the generator. However, the customer should consider the impact of the electrical location of the Isolation Device. If the Isolation Device is electrically at or near the generator, and the Area EPS Operator uses the Isolation Device to provide clearance for worker safety, the customer will be unable to operate its generator to maintain electric supply to all or a portion of its load on the Local EPS during an outage of the Area EPS.

A drawout breaker may be used to meet the Isolation Device requirement if it is lockable in the withdrawn position and has a visible position indicator.

For facilities interconnecting at voltages exceeding 600 volts, when required by the EDC, the Isolating Device required to allow EDC personnel to safely isolate the generator must have a ground grid designed and installed in accordance with IEEE 80 and to specifications to be provided by the EDC. This ground grid limits the ground potential rise should a fault occur during switching operations. Operation of this Isolation Device must be restricted to EDC personnel and properly trained operators designated by the Customer. Designated Customer personnel may be required to learn and adhere to the EDC's "Switching and Tagging" procedures.

4.2.1 Area EPS Faults.

Area EPS Fault Protection requirement for typical interconnection: (Figures 7A, 7B and 7C on the following pages are intended to be representative of typical connections to radial and networked lines, specific requirements will be determined by PJM and the T.O during PJM Feasibility and Impact Studies on a case-by-case basis.)

Figure 7A – One-Line Diagram for a Typical Interconnection to a Radial Distribution System

Typical Protective Relaying Functional Requirements	
27	Undervoltage (3 phases, 1 phase if 50/51G can be applied)
59	Overvoltage (3 phases, 1 phase if 50/51G can be applied)
81O	Overfrequency (1 phase required)
81U	Underfrequency (1 phase required)
25	Synchronizing check (1 phase required)
32*	Power* (If required, 1 or 3 phase depending on type)
50/51**	Phase instantaneous and time overcurrent (3 phases if required), or
21**	Phase distance relay (3 phases if required)
50/51G***	Ground instantaneous and time overcurrent (1 if applicable)

* If required due to reverse power limitations.
** 50/51 or 21 but not both required.
*** Only if transformer / generator connection allows ground fault current contribution to EPS ground fault

Additional Protective Relaying Functional Requirements (as Required)

- Dead line closing control (27 and/or 25 function) at EPS source breaker(s), line recloser(s), etc.
- Larger facilities may require the installation of additional equipment such as directional relaying at the substation feeding the circuit.
- Also see Application Notes 7 and 10 for transfer trip and unbalance functional requirements.
- Voltage Unbalance Protection—In accordance with ANSI C84.1, Annex D, Section D.2 Recommendation, voltage unbalance at the point of common coupling caused by the DG equipment under no load conditions shall not exceed 3% (calculated by dividing the maximum deviation from average voltage by the average voltage, with the result multiplied by 100).

Note: The present version of IEEE 1547 is primarily intended to be applicable to interconnection of DR on radial distribution systems (Section 1.3 Limitations - "Installation of DR on radial primary and secondary distribution systems is the main emphasis of this standard,…"). From a practical standpoint, this represents an upper limit of 2.5 to 5 MW on typical 13 kV EDC distribution circuits, unless it is a dedicated circuit constructed for the sole purpose of interconnecting the DR. Larger facilities will generally require interconnection to the EDC's sub-transmission or transmission system. These larger facilities may require additional or specific protection equipment necessary to coordinate with the EDC's protection practices.

Additional AEP Application Note: In its review of the proposed small generator interconnection request, AEP may determine that a lesser percent unbalance limit is required due to voltage unbalance already present from existing customer loads, such as certain compressor motors and power electronic loads, in the electrical vicinity.

Figure 7B – One-Line Diagram for a Typical Interconnection to a Looped (Network) System

Typical and Additional Protective Relaying Functional Requirements

- Same as Figure 7A above and others as may be required to be compatible with and coordinate with EPS transmission system protection.
- In general, requirements developed to connect 10 MVA and smaller generation to looped networked sub-transmission systems will be more involved and diverse than those needed for radial distribution systems. Additional considerations may be required.

Figure 7C – One-Line Diagram for a Typical Interconnection to a Radial Transmission System

Typical and Additional Protective Relaying Functional Requirements

- Same as Figure 7A above and others as may be required to be compatible with and coordinate with EPS transmission system protection.

Figure 7A – One-Line Diagram for a Typical Interconnection to a Radial Distribution System

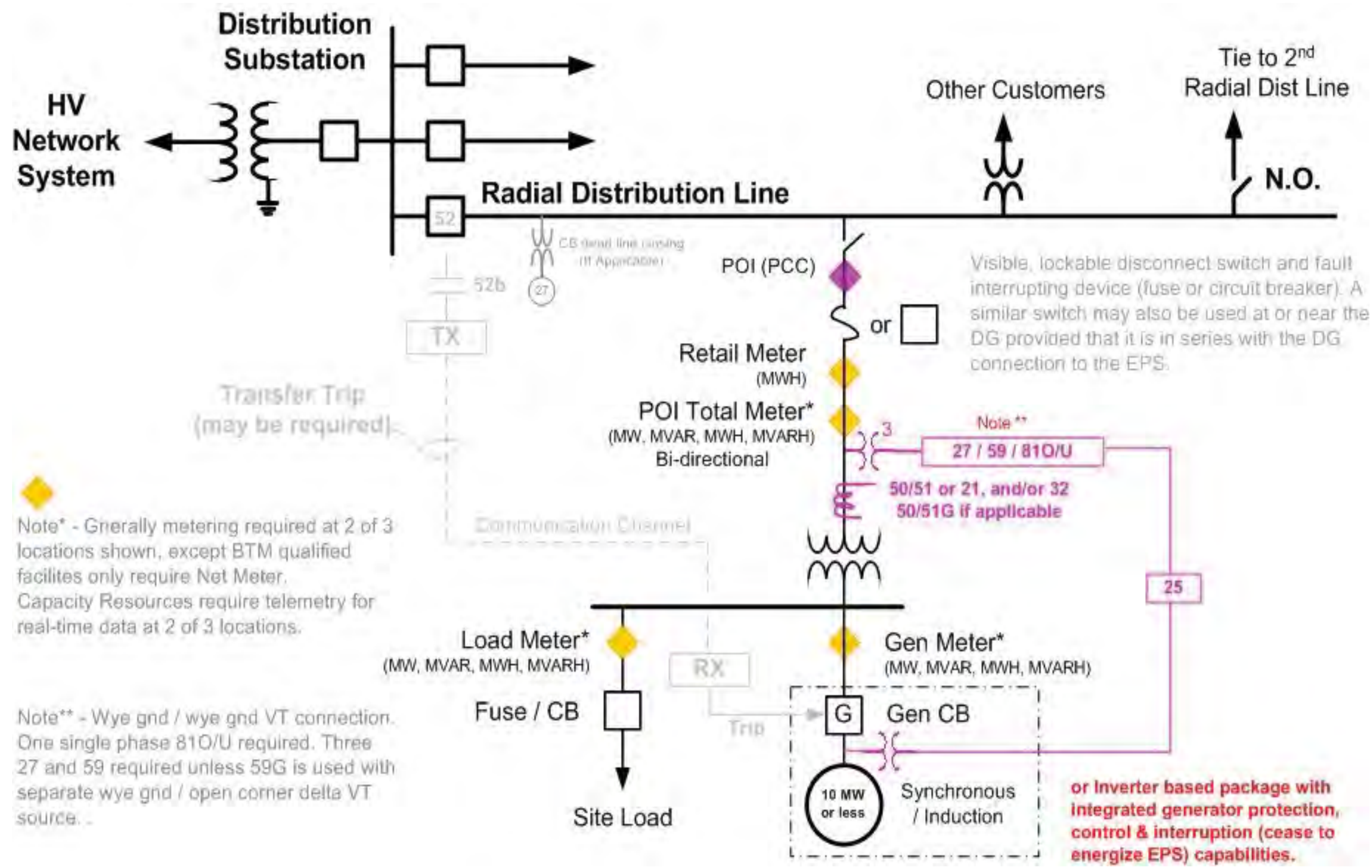


Figure 7B – One-Line Diagram for a Typical Interconnection to a Looped (Network) System

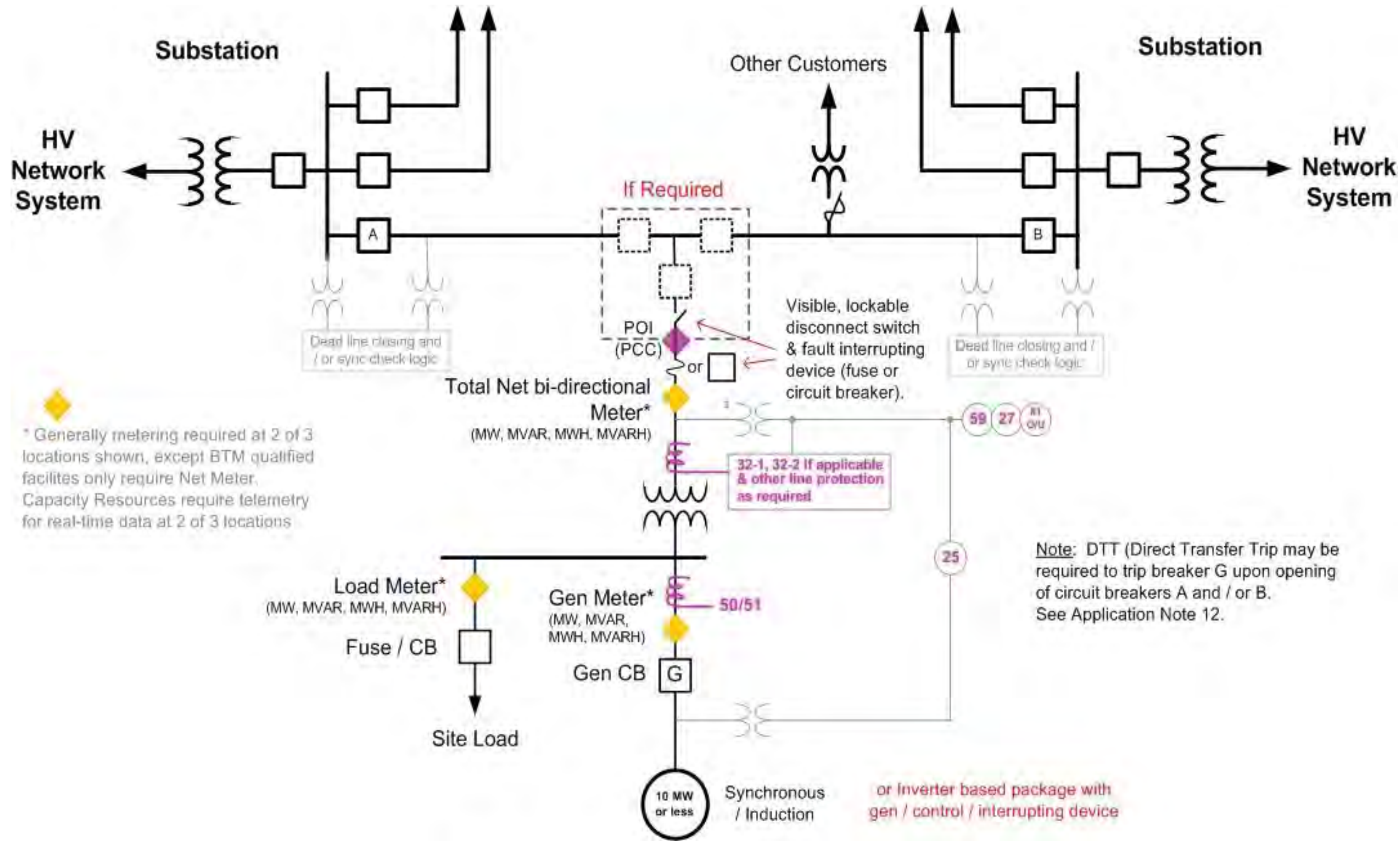
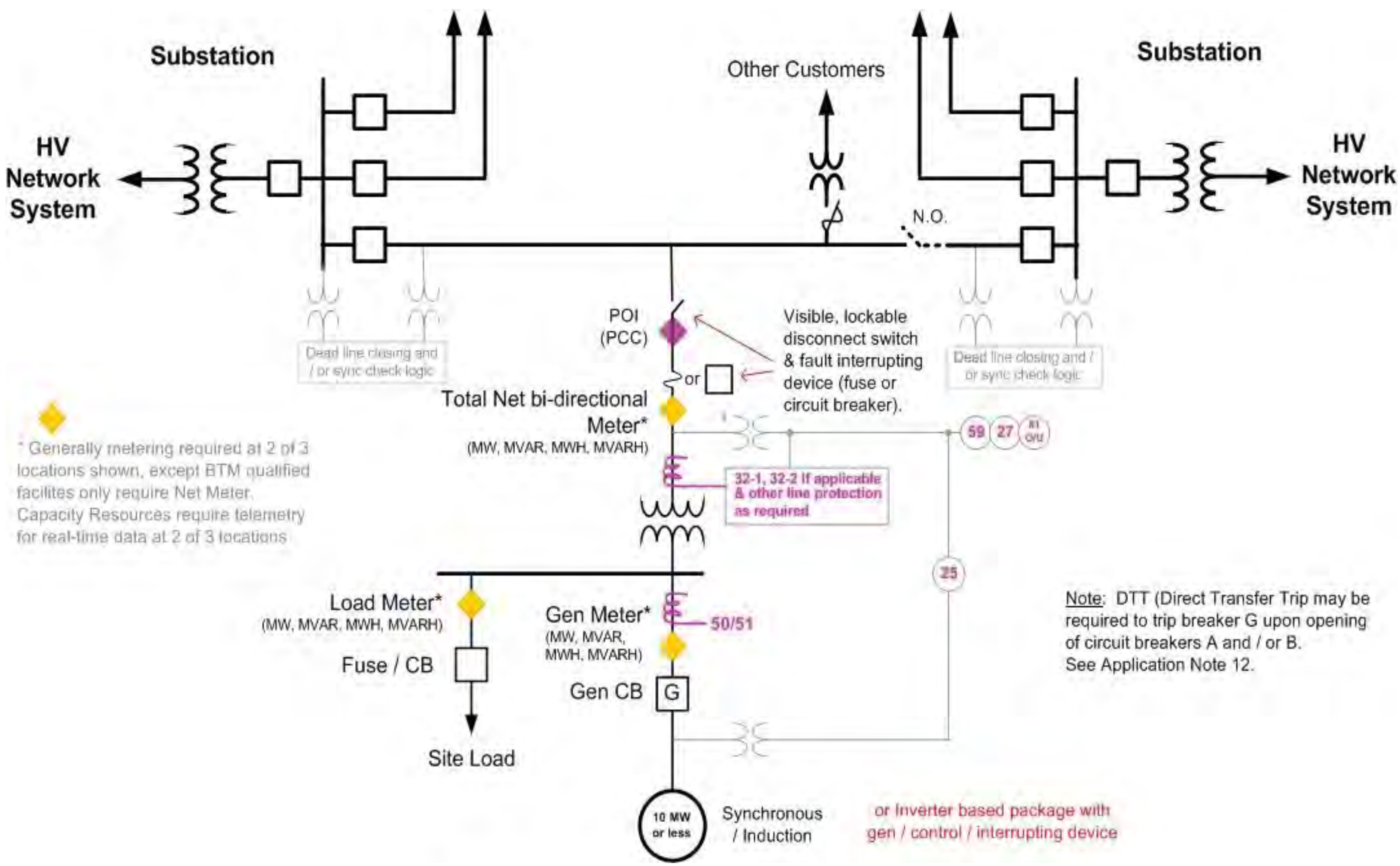


Figure 7C – One-Line Diagram for a Typical Interconnection to a Radial Transmission System



4.2.3 Voltage.

In cases where the DG interface is via an ungrounded transformer connection at the PCC, the voltage sensing must be done on the T.O. side of the transformer. This voltage sensing must be Phase - Ground connected for all three phases.

Voltage Unbalance Protection. In accordance with ANSI C84.1, Annex D, Section D.2 Recommendation, voltage unbalance at the point of common coupling caused by the DG equipment under no load conditions shall not exceed 3% (calculated by dividing the maximum deviation from average voltage by the average voltage, with the result multiplied by 100).

4.2.6 Reconnection to Area EPS.

For larger generating units, an Area EPS may require verbal communication with the System Operator before returning generation to the system.

4.3.2 Limitation of Flicker induced by DR.

Requirement 4.3.2 guidance is provided by IEEE Standard 519 and IEEE Flicker Task Force P1453. However, the requirement which must be met for 4.3.2 is to not cause voltage and /or frequency disturbances which are objectionable to other EPS customers during actual operation of DR.

4.3.3 Harmonics.

In addition to the IEEE 1547 Harmonics requirement [i.e., each DG installation must, at its PCC, meet the injected harmonic current distortion limits provided in IEEE 1547 Table 3 (excerpt IEEE 519 Table 10.3)] when multiple DG units are operating at different PCCs, each alone may meet the preceding current injection limit. However, the aggregate impact of all the DG units could still cause voltage distortion, which would impact other non-DG customers. Therefore, the aggregate voltage distortion at EACH PCC must also not exceed IEEE 519, Table 11.1. If the limits described in IEEE 519, Table 11.1 are exceeded, the offending DG is responsible for any appropriate corrective actions taken by the interconnecting transmission owner to mitigate the problem. Studies will be performed to determine if excessive harmonic distortion will occur prior to installation of the DG. However, it may not be possible to predict the net level of voltage distortion before each new DG installation on a given circuit. Voltage distortion in excess of IEEE 519 can be used as a benchmark to trigger corrective action (including disconnection of DG units) if service interference exists.

Additional PPL Application Note: PPL has a requirement for any one Customer (load, generation, etc.) to limit the voltage THD (Total Harmonic Distortion) to 2.5% or less for distribution voltages and 1.5% at 69 kV. PPL allows a smaller fixed limit for each customer thereby sharing allowable harmonic contribution rather than applying a first-come first-served principle to successive interconnection requests.

4.4.1 Unintentional Islanding.

The Unintentional Islanding requirement can be met by the following:

A. Transfer trip.

B. Sensitive Frequency and Voltage relay settings, with a short tripping time delay, where the maximum DR aggregate generation net output to the EPS is considerably less than the expected minimum islanded EPS load. Typically the islanded load must be greater than two to three times the maximum net islanded DR output.*

C. DR certified to pass an anti-islanding test.

D. Reverse or minimum power flow Relay limited.

E. Other anti-islanding means such as forced frequency or voltage shifting.

* Exceptions to B above:

PSEG—Option B only applicable to aggregate DR interconnections of 1MW and below.

PEPCO—Option B generally not applicable for DR interconnections which export energy to the PEPCO system regardless of generation and load mismatch.

1. In accordance with Section 4.2.2 Area EPS reclosing coordination, a 2-second response time may not be adequate to coordinate with the Area EPS reclosing practices. This may result in damage to the generator upon reclosing of the EPS source. In some instances, on a case-by-case basis, the EPS operator may allow the reclosing time to be increased or add synchronism check supervision to provide coordination. Increasing the reclosing time in some cases will have an unreasonable impact on other customers. Other means, such as transfer trip, must then be used to insure isolation of the generator before automatic circuit reclose.

2. Options for Satisfying 5.1 Design and 5.2 Production Test Requirements.

   Design and Production tests requirements may be satisfied with certified equipment, although certified equipment is not required, consistent with the following criteria:

   A. The small generating facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with IEEE 1547.1 and the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed below, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its Web site and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

   B. The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

   C. Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the parties to the interconnection nor follow-up production testing by the NRTL or periodic tests per IEEE 1547 Section 5.5.

D. If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an interconnection customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

E. Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of common coupling shall be required to meet the requirements of this interconnection procedure.

F. An equipment package does not include equipment provided by the utility.

G. Any equipment package approved and listed in a state by that state's regulatory body for interconnected operation in that state prior to the effective date of these small generator interconnection technical requirements shall be considered certified under these procedures for use in that state.

E.7 Relevant Codes and Standards

- IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)
- UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems
- IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems
- NFPA 70 National Electrical Code
- IEEE Std C37.90.1-1989 (R1944) IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems
- IEEE Std C37.90.2 (1995) IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers
- IEEE Std C37.108-1989 (R2002) IEEE Guide for the Protection of Network Transformers
- IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors
- IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits
- IEEE Std C62.45-1992 (R2002) IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V) and Less) Power Circuits
- ANSI C84.1-1995 Electric Power Systems and Equipment -Voltage Ratings (60 Hertz)
- IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic
- NEMA MG 1-1998, Motors and Small Resources, Revision 3
- IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems
- NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

Attachment E-1: Small Generator (greater than 10 MW up to 20 MW) Technical Requirements and Standards

Scope

The PJM Small Generator Interconnection Applicable Technical Requirements and Standards ("Small Generator Standards – Attachment E-1 ") shall apply to all new generator interconnections, within the PJM footprint, with an aggregate size of greater than 10 MW up to 20 MW at the point of interconnection.

Attachment E-1 shall be read and construed as to be consistent with the PJM Open Access Transmission Tariff ("Tariff"). In the event of any inconsistency between the terms and conditions of Attachment E-1 and the terms and conditions of the Tariff, the terms of the Tariff shall control. All terms contained in Attachment E-1 shall be defined as defined by the Tariff. While PJM strives to ensure that the information reflected herein is complete, accurate and reliable, it expressly disclaims any warranty, whether express or implied, as to information contained. Entities relying on the information contained herein do so at their own risk.

Purpose

To align the applicable technical requirements for Small Generator Interconnections (Small Generators are 20 MW and less per PJM's FERC-approved Tariff) used within PJM with the IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems to facilitate transparency for perspective Generator Interconnection Customers, pre-certification entities (see 5.1 and 5.2) and equipment manufacturers doing business within the PJM footprint.

Because IEEE Standard 1547 and PJM's Applicable Standard "Attachment H" to PJM Manual 14B are limited to a maximum of 10 MW and primarily intended for generator interconnections to radial distribution systems, PJM stakeholders, through the Small Generator Interconnection Working Group, recognized a need to fill the gap between 10 MW and 20 MW by developing a companion Applicable Standard based on the core IEEE 1547 requirements with changes and additions as required to address the larger MW size and greater diversity of Electric Power System configurations to be included.

Background and Discussion

Attachment H-1 was developed by the PJM Small Generator Interconnection Working Group ("SGIWG"). The Small Generation Standards define the uniform technical requirements that each Interconnected Transmission Owner ("ITO") and Electric Distribution Company ("EDC") require for interconnecting to their facilities. The requirements as defined herein will govern for the interconnection of distributed generation greater than 10 MW up to 20 MW. Attachment E-1 is a companion document to Attachment E: Small Generator (10 MW or Less) Technical Requirements and Standards.

ITOs and EDCs may, by mutual agreement, elect to waive certain IEEE 1547 requirements and associated exceptions and conditions stated herein, but may not add requirements to

IEEE 1547 other than the exceptions and conditions contained herein. For Small Generators qualifying for interconnection under state rules, the state-approved technical requirements and procedures shall govern. In the event that a Small Generator has interconnected under state rules and thereafter elects to participate in any PJM market, such Small Generator must comply with the terms of PJM's Small Resource Interconnection Procedure Manual and these Small Generation Standards. The Small Generator must submit a completed Feasibility Study Request (Attachment "N" of the Tariff), and will be responsible for any subsequent study costs. Additionally, the Small Generator will be required to execute PJM's three-party Interconnection Service Agreement with PJM and the local Transmission Owner, and to the extent applicable, an Electric Distribution Company as the case may be.

General Application Note for Transmission System Interconnections

In its present form IEEE Standard 1547 is primarily intended to address generator interconnections of 10 MVA or less to radial distribution systems. In order to extend the use of IEEE Standard 1547 beyond this scope to include connection to transmission[1] facilities, it is necessary to clarify the meaning of Section 4.2.1 to assure that system protection requirements are compatible with the established reliability criteria used for those systems.

IEEE Standard 1547 Section 4.2.1 (Area EPS Faults) requires that “the DR unit shall cease to energize the Area EPS for faults on the Area EPS circuit to which it is connected.” For Transmission Interconnections this implies that the protection scheme(s) be compatible and coordinate with the Area EPS protection scheme(s) used for the line or substation to which it is interconnected or compatible and coordinates with new protection equipment installed due to the connection of the generation to this facility.

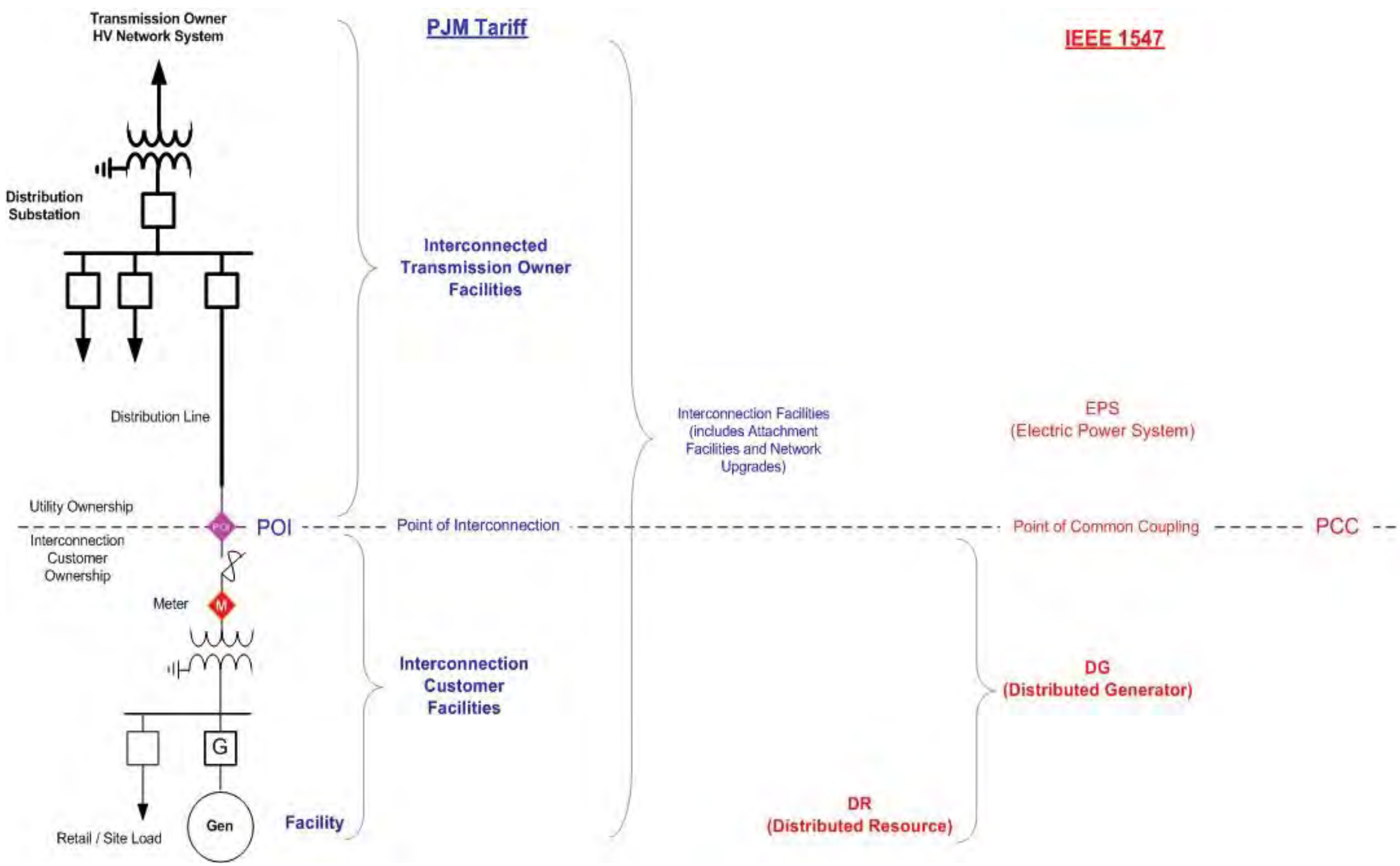
Generator installations greater than 10 MW are not typically interconnected to radial distribution circuits of nominal 13 kV or less. 10 MW to 20 MW generator interconnections will generally be to system voltages of 26 kV and higher which may be operated radially with normally open ties to other lines or networked and operated more similar to higher voltage transmission systems.

1 In the context used here, transmission systems are systems 69 kV or greater, or networked lower voltage systems which are used for backbone energy delivery within smaller geographic areas much the same as most 69 kV systems.

PJM Tariff / IEEE 1547 Definition Cross-Reference

IEEE Standard 1547	**PJM Tariff**
PCC (Point of Common Coupling)	POI (Point of Interconnection)
Point of DR Connection	Not Applicable
EPS (Electric Power System)	Interconnected Transmission Owner Facilities
Area EPS Operator	Interconnected Transmission Owner
Not Applicable	Transmission Provider (PJM)
DG (Distributed Generation)	Interconnected Generation Customer Facilities which are not connected to the Bulk Power Transmission System
DR (Distributed Resources)	Interconnected Generation Facility which is not connected to the Bulk Power Transmission System
Interconnection Equipment	Not Applicable
Interconnection System	Interconnection Facilities
Not Applicable	Interconnection Customer Facilities
Electric Power System, local	Not Applicable
Electric Power System, area	Not Applicable
Cease to Energize (Cessation of energy outflow capability)	Not Applicable

Note: Illustration below is for cross-reference of PJM Tariff and IEEE 1547 terms only.



Applicable Technical Requirements and Standards

IEEE Standard 1547 shall constitute the total technical requirements and standards for interconnection of small generators greater than 10 MW up to 20 MW with the following noted exceptions, additions, and clarifications. IEEE Standard 1547.1 constitutes the requirement for test conformance to IEEE Standard 1547.

IEEE Standard Requirement		Exceptions or Additions
4.1.1	Voltage Regulation	None. See Application Note 1.
4.1.2	Integration with Area EPS Grounding	None. See Application Note 2.
4.1.3	Synchronization	None. See Application Note 3.
4.1.4.1	Distribution Secondary Grid Networks (under development)	Not applicable for generator interconnections 10 MW and above.
4.1.4.2	Distribution Secondary Spot Networks	Generally not applicable for generator interconnections of 10 MW and greater. Rare exceptions to be handled on a case-by-case basis.
4.1.5	Inadvertent Energization of the Area EPS	None.
4.1.6	Monitoring	None. See Application Note 4.
4.1.7	Isolation Device	None. See Application Note 5.
4.1.8.1	Protection from EMI	None.
4.1.8.2	Surge Withstand Performance	None.
4.1.8.3	Paralleling Device Withstand	None.
4.2.1	Area EPS Faults	PEPCO and PSEG exception for Islanding protection. See Application Notes 6, 7 & 11.
4.2.2	Area EPS Reclosing Coordination	None. See Application Note 12.
4.2.3	Voltage	None. See Application Note 7.
4.2.4	Frequency	None.

IEEE Standard Requirement		Exceptions or Additions
4.2.5	Loss of Synchronism	None.
4.2.6	Reconnection to Area EPS	
	Voltage Requirement	None. See Application Note 8.
	Frequency Requirement	None. See Application Note 8.
4.3.1	Limitation of DC Injection	None.
4.3.2	Limitation of Flicker induced by the DR	None. See Application Note 9.
4.3.4	Harmonics	PPL exception. See Application Note 10.
4.4.1	Unintentional Islanding	PEPCO and PSEG exceptions. See Application Note 11.
5.1	Design Test	None. See Application Note 13.
5.2	Production Tests	None. See Application Note 13.
5.3	Interconnection Installation Evaluation	None.
5.4	Commissioning Tests	None.
5.5	Periodic Tests	None.

Application Notes

4.1.1 Voltage Regulation.

Depending on size of generation (relative to EPS strength) and location of interconnection, the interconnected generation may be required to provide or absorb reactive power and/or follow a voltage schedule to maintain an acceptable voltage profile on the EPS with the addition of the new generating facility.

4.1.2 Integration with Area EPS grounding.

Where new transformers are required:

- AP requires a wye-grounded connection on the T.O. side of the DG step up transformer; and
- PEPCO's requirement for an isolation transformer including its configuration at 13.8 kV and above, will be determined on a case-by-case basis and will depend on the generating facility's location and system configuration.

AP and PEPCO requirements specified above do not apply if a generator is being connected to a system on the low voltage side of an existing Interconnection Customer transformer.

Other Transmission Owners within PJM will accept a delta or wye-ungrounded connection provided that adequate protection is provided by the DG to detect a ground and limit any overvoltage to an acceptable level on the TO's system. Adequate protection includes voltage monitoring on the high side of the DG main transformer using phase to ground connected VTs. Also see Application Note 5 for an additional AEP Application Note for grounding coordination related to operation of isolating devices.

4.1.3 Synchronization.

IEEE 1547 Synchronization voltage fluctuation requirement of +/- 5% is applicable as stated. Flicker requirement 4.3.2 guidance is provided by IEEE Standard 519 and IEEE Flicker Task Force P1453. However, the requirement which must be met for 4.3.2 is to not cause voltage and /or frequency disturbances which are objectionable to other EPS customers during actual operation of DR.

4.1.6 Monitoring.

Aggregate DR interconnection greater than 10 MW at a single PCC shall have SCADA provisions for monitoring its connection status, real power output, reactive power output, and voltage at the point of DR connection. (See Informative Annex #1 for specific monitored quantities required by each Area EPS Operator.)

A. An Internet-based SCADA alternative (see Informative Annex #2), was developed as a reliable and economical alternative to direct SCADA communications with the Area EPS Operator. In addition to generally lower installed cost for the "Internet SCADA alternative," the Internet ongoing communication costs may be more cost effective to other alternatives, especially those that require leased telephone circuits.

B. When full-time dedicated SCADA communications are required (see Informative Annex #1) the DG Owner, PJM or the Area EPS Operator will provide and/or install a suitable SCADA Remote Terminal Unit in accordance with the specifications provided in Informative Annex #2 or an alternative mutually suitable to the DG Owner, Area EPS Operator and PJM.

C. The PJM Transmission Owners (TOs) agree to accept the "Internet SCADA alternative" (see Informative Annex #2) in lieu of direct SCADA communications with the TO, except in circumstances where the "Internet SCADA alternative" does not meet certain TO technical requirements specified and justified by the TO.

D. If the TO, PJM and DR owner mutually agree, specifications for other suitable interfaces between the DG and TO SCADA can be acceptable. Where applicable, this approach would allow a DR owner to use a SCADA protocol of their choice and provide an interface closer to the TO's SCADA facility. Such an installation must provide adequate communication performance, suitable to PJM and the TO.

E. The Interconnection Customer is responsible for the protection of the communications circuit in accordance with IEEE 487-2000, or later revisions, and any additional requirements of the communications circuit provider.

F. Area EPS Operators will typically require SCADA monitoring at the Point of Interconnection as well as at the generating units.

4.1.7 Isolation Device Requirement.

When the Area EPS operating practices require an isolation device, that device must be readily accessible to the Area EPS operator, lockable in the open position, and must provide a visible break in the electrical connection between the generator and the Area EPS. The Isolation Device must be rated for the voltage and current requirements of the installation. The Isolation Device may be electrically located anywhere between the point of common coupling and the generator. However, the customer should consider the impact of the electrical location of the Isolation Device. If the Isolation Device is electrically at or near the generator, and the Area EPS Operator uses the Isolation Device to provide clearance for worker safety, the customer will be unable to operate their generator to maintain electric supply to all or a portion of their load on the Local EPS during an outage of the Area EPS.

A drawout breaker may be used to meet the Isolation Device requirement if it is lockable in the withdrawn position and has a visible position indicator.

The Isolating Device required to allow Area EPS Operator personnel to safely isolate the generator must have a ground grid designed and installed in accordance with IEEE 80 and to specifications to be provided by the EDC. This ground grid limits the ground potential rise should a fault occur during switching operations. Operation of this Isolation Device must be restricted to the Area EPS Operator's personnel and properly trained operators designated by the Customer. Designated Customer personnel may be required to learn and adhere to the Area EPS Operator's "Switching and Tagging" procedures.

4.2.1 Area EPS Faults.

Area EPS Fault Protection requirement for typical interconnection: (Figures 6A, 6B and 6C on the following pages are intended to be representative of typical connections to radial and networked lines. Specific requirements will be determined by PJM and the Area EPS Operator during PJM Feasibility and Impact Studies on a case-by-case basis.)

Figure 6A – One-Line Diagram for a Typical Interconnection to a Radial Distribution System

Typical Protective Relaying Functional Requirements	
27	Undervoltage (3 phases, 1 phase if 50/51G can be applied)
59	Overvoltage (3 phases, 1 phase if 50/51G can be applied)
81O	Overfrequency (1 phase required)
81U	Underfrequency (1 phase required)
25	Synchronizing check (1 phase required)
32*	Power* (If required, 1 or 3 phase depending on type)
50/51**	Phase instantaneous and time overcurrent (3 phases if required), or
21**	Phase distance relay (3 phases if required)
50/51G***	Ground instantaneous and time overcurrent (1 if applicable)
* If required due to reverse power limitations. ** 50/51 or 21 but not both required. *** Only if transformer / generator connection allows ground fault current contribution to EPS ground fault.	

Additional Protective Relaying Functional Requirements (as Required)

- Dead line closing control (27 and / or 25 function) at EPS source breaker(s), line recloser(s), etc.
- Larger facilities may require the installation of additional equipment such as directional relaying at the substation feeding the circuit.
- Also see Application Notes 7 and 11 for transfer trip and unbalance functional requirements.
- Voltage Unbalance Protection. In accordance with ANSI C84.1, Annex D, Section D.2 Recommendation, voltage unbalance at the point of common coupling caused by the DG equipment, under no load conditions shall not exceed 3% (calculated by dividing the maximum deviation from average voltage by the average voltage, with the result multiplied by 100).

Note: The present version of IEEE 1547 is primarily intended to be applicable to interconnection of DR on radial distribution systems (Section 1.3 Limitations - "Installation of DR on radial primary and secondary distribution systems is the main emphasis of this standard,…"). From a practical standpoint, this represents an upper limit of 2.5 to 5 MW on typical 13 kV EDC distribution circuits, unless it is a dedicated circuit constructed for the sole purpose of interconnecting the DR. Larger facilities will generally require interconnection to the EDC's sub-transmission or transmission system. These larger facilities may require additional or specific protection equipment necessary to coordinate with the EDC's protection practices.

Additional AEP Application Note: In its review of the proposed small generator interconnection request, AEP may determine that a lesser percent unbalance limit is required due to voltage unbalance already present from existing customer loads, such as certain compressor motors and power electronic loads, in the electrical vicinity.

Figure 6B – One-Line Diagram for a Typical Interconnection to a Looped (Network) System

Typical and Additional Protective Relaying Functional Requirements

- Same as Figure 6A above and others as may be required to be compatible with and coordinate with EPS transmission system protection.
- In general, line protection requirements to connect generation greater than 10MW to looped networked sub-transmission systems will be more involved and diverse than those needed for connection to radial distribution systems. Additional considerations may be required.

Figure 6C – One-Line Diagram for a Typical Interconnection to a Radial Transmission System

Typical and Additional Protective Relaying Functional Requirements

- Same as Figure 6A above and others as may be required to be compatible with and coordinate with EPS transmission system protection.

Figure 6A – <u>One-Line Diagram for a Typical Interconnection to a Radial Distribution System</u>

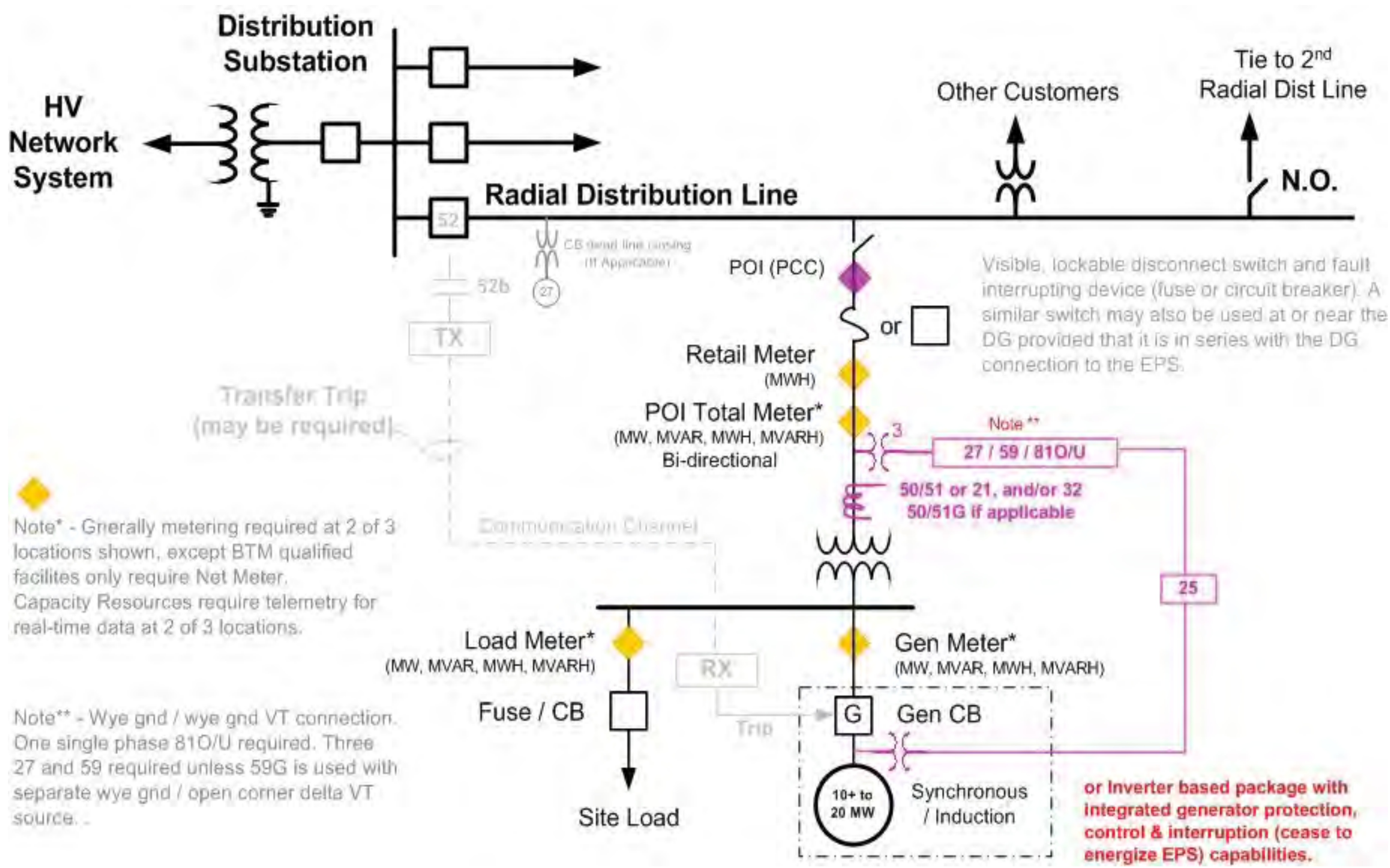


Figure 6B – One-Line Diagram for a Typical Interconnection to a Looped (Network) System

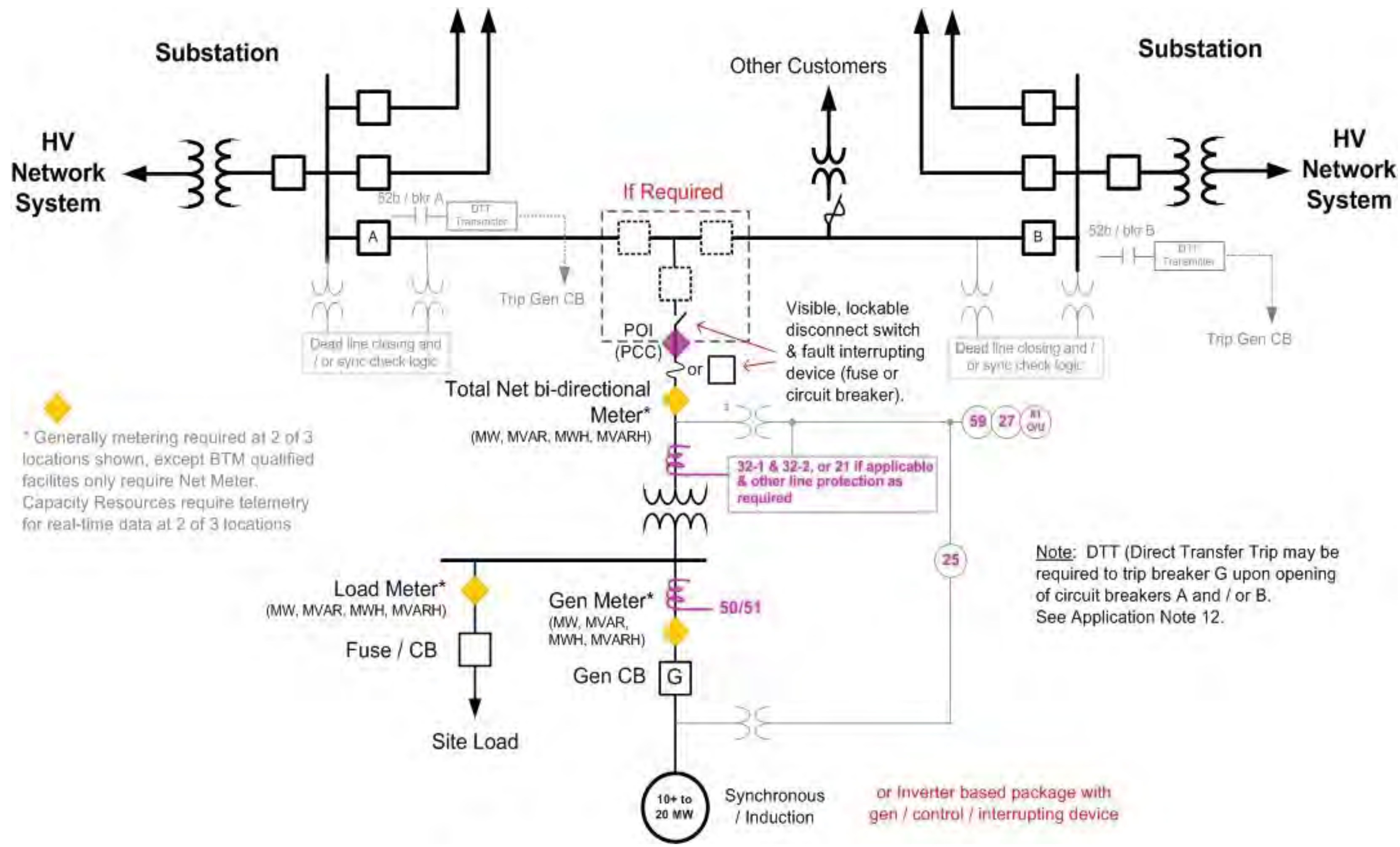
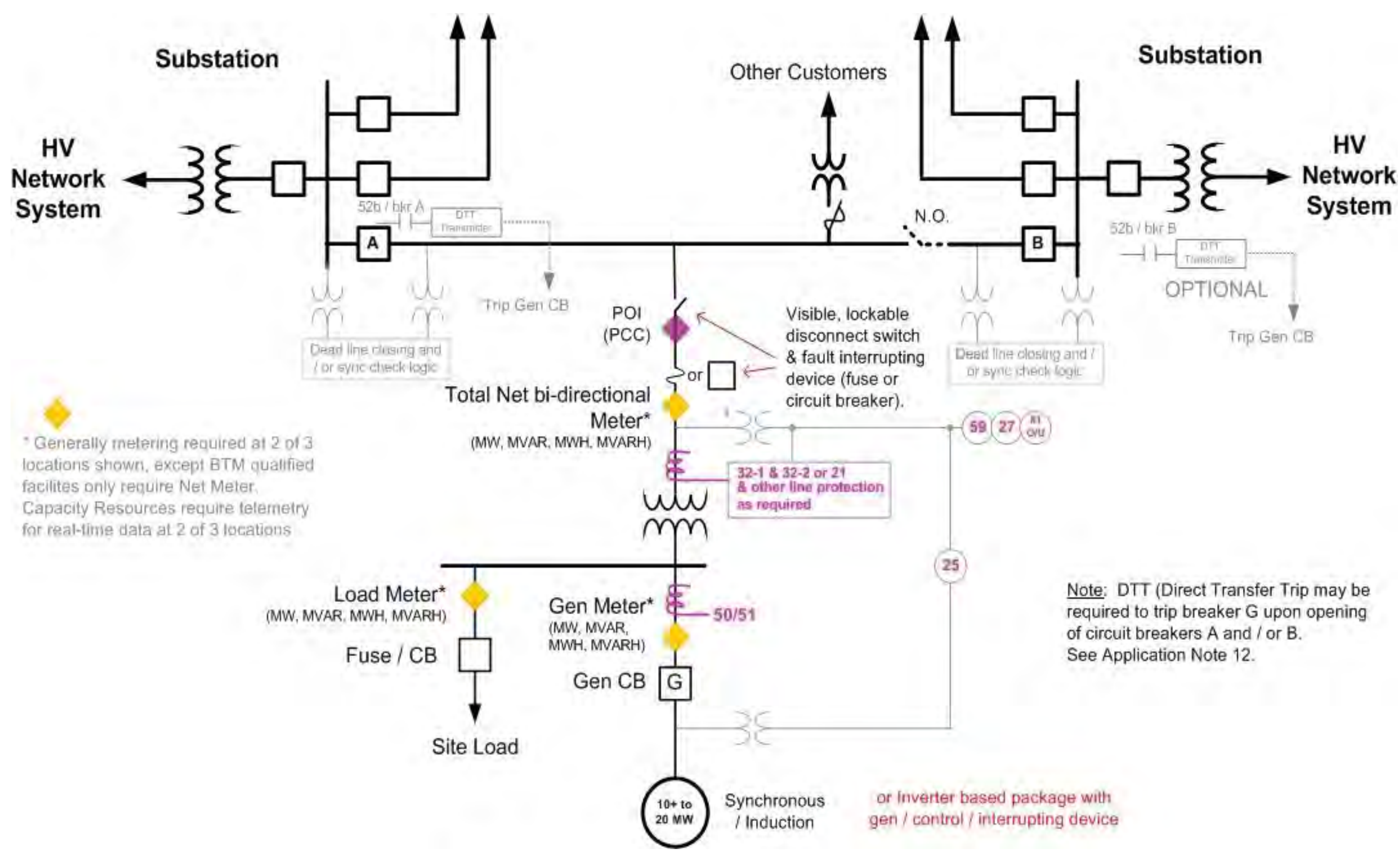


Figure 6C – One-Line Diagram for a Typical Interconnection to a Radial Transmission System



4.2.3 Voltage.

In cases where the DG interface is via an ungrounded transformer connection at the PCC, the voltage sensing must be done on the T.O. side of the transformer. This voltage sensing must be Phase - Ground connected for all three phases.

Voltage Unbalance Protection. In accordance with ANSI C84.1, Annex D, Section D.2 Recommendation, voltage unbalance at the point of common coupling caused by the DG equipment, under no load conditions shall not exceed 3% (calculated by dividing the maximum deviation from average voltage by the average voltage, with the result multiplied by 100).

4.2.6 Reconnection to Area EPS.

For larger generating units, an Area EPS may require verbal communication with the System Operator before returning generation to the system.

4.3.2 Limitation of Flicker induced by DR.

Requirement 4.3.2 guidance is provided by IEEE Standard 519 and IEEE Flicker Task Force P1453. However, the requirement that must be met for 4.3.2 is to not cause voltage and /or frequency disturbances that are objectionable to other EPS customers during actual operation of DR.

4.3.3 Harmonics.

In addition to the IEEE 1547 Harmonics requirement (i.e., each DG installation must, at its PCC, meet the injected harmonic current distortion limits provided in IEEE 1547 Table 3 [excerpt IEEE 519 Table 10.3]) when multiple DG units are operating at different PCCs, each alone may meet the preceding current injection limit; however, the aggregate impact of all the DG units could still cause voltage distortion that would adversely impact other non-DG customers. Therefore, the aggregate voltage distortion at EACH PCC must also not exceed IEEE 519 limits. If the limits described in IEEE 519 are exceeded, the offending DG (in most cases the last to connect) is responsible for any appropriate corrective actions taken by the interconnecting transmission owner to mitigate the problem. Studies will be performed to determine if excessive harmonic distortion will occur prior to installation of the DG. However, it may not be possible to predict the net level of voltage distortion before each new DG installation on a given circuit. Voltage distortion in excess of IEEE 519 can be used as a benchmark to trigger corrective action (including disconnection of DG units) if service interference exists.

> **Additional PPL Application Note:** PPL has a requirement for any one Customer (load, generation, etc.) to limit the voltage THD (Total Harmonic Distortion) to 2.5% or less for distribution voltages and 1.5% at 69 kV. PPL allows a smaller fixed limit for each customer, thereby sharing allowable harmonic contribution rather than applying a first-come first-served principle to successive interconnection requests.

4.4.1 Unintentional Islanding.

The Unintentional Islanding requirement can be met by the following:

A. Transfer trip.

B. Sensitive Frequency and Voltage relay settings, with a short tripping time delay, where the maximum DR aggregate generation net output to the EPS is considerably less than the expected minimum islanded EPS load. Typically, the islanded load must be greater than two to three times the maximum net islanded DR output.*

C. DR certified to pass an anti-islanding test.

D. Reverse or minimum power flow relay limited.

E. Other anti-islanding means such as forced frequency or voltage shifting.

* Exceptions to B above:

PSEG – Option B only applicable to aggregate DR interconnections of 1MW and below.

PEPCO – Option B generally not applicable for DR interconnections that export energy to the PEPCO system regardless of generation and load mismatch.

4.2.2 Area EPS Reclosing Coordination.

In accordance with Section 4.2.2 Area EPS reclosing coordination, a 2-second response time may not be adequate to coordinate with the Area EPS reclosing practices. This may result in damage to the generator upon reclosing of the EPS source. In some instances, on a case-by-case basis, the EPS operator may allow the reclosing time to be increased or add synchronism check supervision to provide coordination. Increasing the reclosing time in some cases will have an unreasonable impact on other customers. Other means, such as transfer trip, must then be used to insure isolation of the generator before automatic circuit reclose.

Options for Satisfying 5.1 Design and 5.2 Production Test Requirements.

Design and Production tests requirements may be satisfied with certified equipment, although certified equipment is not required, consistent with the following criteria:

A. The small generating facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with IEEE 1547.1 and the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed below, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification and with consumer approval, the test data itself. The NRTL may make such information available on its Web site and by encouraging such information to be included in the manufacturer’s literature accompanying the equipment.

B. The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

C. Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the parties to the interconnection nor follow-up production testing by the NRTL or periodic tests per IEEE 1547 Section 5.5.

D. If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an interconnection customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

E. Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of common coupling shall be required to meet the requirements of this interconnection procedure.

F. An equipment package does not include equipment provided by the utility.

G. Any equipment package approved and listed in a state by that state’s regulatory body for interconnected operation in that state prior to the effective date of these small generator interconnection technical requirements shall be considered certified under these procedures for use in that state.

Relevant Codes and Standards

- IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)
- UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems
- IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems
- NFPA 70 National Electrical Code
- IEEE Std C37.90.1-1989 (R1944) IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems
- IEEE Std C37.90.2 (1995) IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers
- IEEE Std C37.108-1989 (R2002) IEEE Guide for the Protection of Network Transformers
- IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors
- IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits
- IEEE Std C62.45-1992 (R2002) IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V) and Less) Power Circuits
- ANSI C84.1-1995 Electric Power Systems and Equipment -Voltage Ratings (60 Hertz)
- IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic
- NEMA MG 1-1998, Motors and Small Resources, Revision 3
- IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems
- NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

Attachment F: Generation Interconnection Feasibility Study data

F.1 Scope

This Generation Interconnection Feasibility Study data attachment to Manual 14A is intended to provide a listing of the data which is required so that an Interconnection Customer may complete the data form located on the PJM website (link given below). Completion of the form on the web site, and submission of the additional data as listed at the link provided below, is necessary for an Interconnection Request to be deemed a valid request.

Link location for data submittal: http://www.pjm.com/planning/rtep-development/expansion-plan-process/form-feas-study-data.aspx

F.2 Data Requirements for PJM RTEPP Feasibility Studies

Feasibility Studies are conducted to identify transmission expansion needed to maintain the system reliability given your generation onto the network. The data submitted is required to perform the power flow, and short circuit analysis which are necessary for the Feasibility Study Phase.

PJM uses the following programs to perform the Feasibility Analysis:

1. PSS/E program from PTI, Inc. (power flow)
2. Aspen from Advanced Systems for Power Engineering, Inc. (short circuit)

All data must be provided on an individual unit basis.

For example, a combined cycle plant with two identical Combustion Turbines (CTs), and one Steam Turbine (ST), would have 2 submissions of the data request form. One submission for the CTs, and one submission for the ST.

If the final unit specifications are not certain an approximation must be made.

When more information is available, the Interconnection Customer must provide an update to PJM so that the typical model may be replaced with a detailed model based on the actual unit purchased.

Following is the information required to complete the data which is required for a Generation Interconnection Feasibility Study:

General and identifying information

- Interconnection Customer name *
- Name of Individual Completing Form *
- Email Address (Individual Completing the Form) *
- Phone # (Individual Completing the Form) *
- Queue Letter & Position / Unit ID *
- Primary Fuel Type *

- Interconnection Customer's proposed location (if known) for Point of Interconnection (POI) to PJM System*
- Maximum Gross MW Output *
- Maximum Net MW Output *
- Station Service Load (MW/MVAR)
- Load connected to High Side of GSU (Yes/No)
- Load connected to Low Side of GSU (Yes/No)

Main Transformer Data

- Number of machines per GSU *
- Generator Step-up Transformer MVA Base *
- Generator Step-up Transformer Impedance (R+jX, or %, on transformer MVA Base) *
- Generator Step-up Transformer Reactance-to-Resistance Ration (X/R)
- Generator Step-up Transformer FOA Rating (MVA)
- Generator Step-up Transformer Low-side Voltage (kV) *
- Generator Step-up Transformer High-side Voltage (kV) *
- Generator Step-up Transformer Off-nominal Turns Ratio
- Generator Step-up Transformer Number of Taps and Step Size

Transmission Line Data

- Line Length from Main Transformer High-Side to Interconnection Point
- Voltage Level (kV)
- Conductor Type
- Transmission Line MVA Base
- Positive Sequence Impedance (R+jX %, per mile on line MVA base)
- Zero Sequence Impedance (R+jX %, per mile on line MVA base)
- Zero Sequence Reactance-to-Resistance Ratio (X/R)
- Positive Sequence Charging Admittance (in % per mile on line MVA base)

Plant Data- Non-Wind Generators

- Generator MVA Base (upon which all reactances, resistance and inertia are calculated) *
- Generator Nominal Power Factor *
- Generator Terminal Voltage (kV) *
- Generator Saturated Sub-transient Reactance, X"d(v) (on MVA Base) *

- Provide Site Plan (on tax map, USGS topo map, etc.) for Interconnection Customer's Facilities (electronic file if available) and a one-line diagram of the Facility electrical arrangement via email attachment to the email address(es) specified at the link on the PJM website listed above when the data on the data form at the link location listed above is submitted

Wind Plant Data

PJM has on file the manufacturer data sheets for the following Wind Turbines:

Acciona AW 82 1.5 MW, Clipper C93 2.5 MW, Gamesa C920 2 MW, GE 1.5 MW, GE 2.5XL 2.5 MW, Mitsubishi MWT92/95 2.3 MW, Siemens MK II 2.3 MW, Suzlon S88 2.1MW, Vestas V82 1.65 MW, Vestas V90 3.0 MW.

If the Interconnection Customer intends to install any of the turbines listed above, then that Interconnection Customer must only supply the information listed below which is applicable to a wind plant data request and which is accompanied by an asterisk. If an Interconnection Customer intends to install a turbine other than one (or more) of the models listed above, then all data which follows as being required by a wind plant will be required.

- Queue Letter/Position/Unit ID
- MW Size (each turbine) *
- MVA Base (each turbine) *
- Number of Turbines *
- Type of Turbines (Manufacture and Model Type) *
- Terminal Voltage (kV) *
- Saturated Sub-transient Reactance, X"d(v) (on MVA Base) *
- Control Mode (Power Factor Control/ Voltage Control)
- If the turbines will be operated in PF Control Model, Power Factor Range at the Generator Terminal
- Size of Additional Capacitor If Any
- Location of Additional Capacitor If Any
- Type of Additional Capacitor If Any (regular/ switching shunts)
- Steps of Switching Shunts
- Size of Dynamic Var If Any
- Location of Dynamic Var If Any
- Cable Length for Wind Farm Collection System
- Cable Type and Impedance Per Mile
- Embedded Relay for Each Turbine (Yes or No)
- Voltage relay (Yes or No)
- Manufacturer default Voltage relay setting

- Frequency relay (Yes or No)
- Manufacturer default Frequency relay setting

Wind Turbine Unit GSU (each turbine)

- Number of turbine's per unit GSU*
- Generator Step-up Transformer MVA Base*
- Generator Step-up Transformer Impedance (R+jX, or %, on transformer MVA Base)*
- Generator Step-up Transformer Reactance-to-Resistance Ration (X/R)
- Generator Step-up Transformer FOA Rating (MVA)
- Generator Step-up Transformer Low-side Voltage (kV)*
- Generator Step-up Transformer High-side Voltage (kV)*
- Generator Step-up Transformer Off-nominal Turns Ratio
- Generator Step-up Transformer Number of Taps and Step Size

Attachment G: System Impact Study data

G.1 Scope

This System Impact Study data attachment to Manual 14A is intended to provide a listing of the data which is required so that an Interconnection Customer may complete the data form located on the PJM website (link given below). Completion of the form on the web site, and submission of the additional data as listed at the link provided below, is necessary for an Interconnection Request to be deemed a valid request.

Link location for data submittal: http://www.pjm.com/planning/rtep-development/expansion-plan-process/form-impact-study-data.aspx

<u>Data Requirements for PJM RTEPP System Impact Studies</u>

The data listed below must be submitted to ensure proper modeling of Interconnection Requests in the System Impact Study phase. System Impact Studies are conducted to identify transmission expansion needed to maintain the system reliability given the addition of your generation on to the network. The data that is submitted is required to perform the power flow, short circuit and dynamic simulation analyses which are necessary for the Impact Study phase.

PJM uses the following programs to perform the System Impact Study Analysis:

1. PSS/E from PTI, Inc. (power flow and dynamic simulation)
2. Aspen from Advanced Systems for Power Engineering, Inc. (short circuit)

Minimum requirement fields are indicated by *

All data must be provided on an individual unit basis.

For example, a combined cycle plant with two identical Combustion Turbines (CT), and one Steam Turbine (ST), would have 2 submissions of the data request form. One submission for the CT, and one submission for the ST.

If the final unit specifications are not certain an approximation must be made. When more information is available, the Interconnection Customer must provide an update to PJM so that the typical model may be replaced with a detailed model based on the actual unit purchased.

Interconnection Customer Name*
Name of Individual Completing Form*
Email Address (Individual Completing the Form) *
Phone # (Individual Completing the Form)*
Queue Letter & Position / Unit ID *
Primary Fuel Type *
Selected Point of Interconnection*
Maximum Summer (92º F ambient air temp.) Net MW Output*
Maximum Summer (92º F ambient air temp.) Gross MW Output *
Minimum Summer (92º F ambient air temp.) Gross MW Output *
Maximum Winter (30º F ambient air temp.) Gross MW Output *
Minimum Winter (30º F ambient air temp.) Gross MW Output *
Gross Reactive Power Capability at Maximum Gross MW Output
Submit Reactive Capability Curve (Leading and Lagging) *
Individual Unit Auxiliary Load at Maximum Summer MW Output (MW/MVAR) *
Individual Unit Auxiliary Load at Minimum Summer MW Output (MW/MVAR) *
Individual Unit Auxiliary Load at Maximum Winter MW Output (MW/MVAR) *
Individual Unit Auxiliary Load at Minimum Winter MW Output (MW/MVAR) *
Station Service Load (MW/MVAR)

Unit Generator Dynamics Data Request Form
MVA Base (upon which all reactance's, resistance and inertia are calculated) *
Nominal Power Factor *
Terminal Voltage (kV) *

Unsaturated Reactances (on MVA Base)
Direct Axis Synchronous Reactance, Xd(i) *
Direct Axis Transient Reactance, X'd(i) *
Direct Axis Sub-transient Reactance, X"d(i) *
Quadrature Axis Synchronous Reactance, Xq(i) *
Quadrature Axis Transient Reactance, X'q(i) *
Quadrature Axis Sub-transient Reactance, X"q(i) *
Stator Leakage Reactance, Xl *
Negative Sequence Reactance, X2(i) *
Zero Sequence Reactance, X0 *

Saturated Reactances (on MVA Base)
Saturated Sub-transient Reactance, X"d(v) (on MVA Base) *
Negative Sequence Reactance, X2(v)
Zero Sequence Reactance, X0(v)

Resistance Values
DC Armature Resistance, Ra (ohms) *
Positive Sequence Resistance, R1 (on MVA Base)
Negative Sequence Resistance, R2 (on MVA Base)
Zero Sequence Resistance, R0 (on MVA Base)

<u>Time Constants (seconds)</u>
Direct Axis Transient Open Circuit, T'do *
Direct Axis Sub-transient Open Circuit, T"do*
Quadrature Axis Transient Open Circuit, T'qo*
Quadrature Axis Sub-transient Open Circuit, T"qo*
Inertia, H (kW-sec/kVA, on KVA Base) *
Speed Damping, D*
Saturation Values at Per-Unit Voltage*
a. S(1.0)
b. S(1.2)

<u>Main GSU Data Request Form</u>
Number of Machine's per GSU *
Generator Step-up Transformer MVA Base *
Generator Step-up Transformer Impedance (R+jX,as a percentage) *
Generator Step-up Transformer Reactance to-Resistance Ratio (X/R)
Generator Step-up Transformer FOA Rating (MVA)
Generator Step-up Transformer Low-side Voltage (kV) *
Generator Step-up Transformer High-side Voltage (kV) *
Generator Step-up Transformer Tertiary Voltage (kV)
Generator Step-up Transformer Off-nominal Turns Ratio
Generator Step-up Transformer Number of Taps and Step Size
High Voltage Winding Connection (i.e. wye grounded, delta) *
Low Voltage Winding Connection (i.e. wye grounded, delta) *
Tertiary Voltage Winding Connection (i.e. wye grounded, delta)

<u>Transmission Line Data</u>
Line Length from Main Transformer High-Side to the Point of Interconnection
Voltage Level (kV)
Conductor Type
Transmission Line MVA Base
Positive Sequence Impedance (R+jX, or %, per mile on line MVA base)
Positive Sequence Reactance-to-Resistance Ratio (X/R)
Zero Sequence Impedance (R+jX, or %, per mile on line MVA base)
Zero Sequence Reactance-to-Resistance Ratio (X/R)
Positive Sequence Charging Admittance (in % per mile on line MVA base)

<u>Part D: Wind Plant Data</u>
Interconnection Customer name *
Name of Individual Completing Form
Email Address Individual Completing the Form) *
Phone #(Individual Completing the Form) *
Queue Letter/Position/Unit ID *
Primary Fuel Type
Maximum Net MW Output (plant) *
Maximum Gross MW Output (plant) *
Station Service Load (MW/MVAR)

PJM has on file the manufacturer data sheets for the following Wind Turbines:

Acciona AW 82 1.5 MW, Clipper C93 2.5 MW, Gamesa C920 2 MW, GE 1.5 MW, GE 2.5XL 2.5 MW, Mitsubishi MWT92/95 2.3 MW, Siemens MK II 2.3 MW, Suzlon S88 2.1MW, Vestas V82 1.65 MW,Vestas V90 3.0 MW

If the Interconnection Customer intends to install any of the turbines listed above, then that Interconnection Customer must only supply the information listed below which is applicable to a wind plant data request and which is accompanied by an asterisk. If an Interconnection Customer intends to install a turbine other than one (or more) of the models listed above, then all data which follows as being required by a wind plant will be required.

Queue Letter/Position/ Unit ID
MW Size (each turbine) *
MVA Base (each turbine) *
Number of Turbines *
Type of Turbines (Manufacture and Model Type) *
Terminal Voltage (kV) *
Positive Sequence Resistance, R1 (on MVA Base)
Saturated Sub-transient Reactance, X"d(v) (on MVA Base) *
Control Mode (Power Factor Control/ Voltage Control)
If in PF Control Model, Power Factor Range at the Generator Terminal
Size of Additional Capacitor If Any
Location of Additional Capacitor If Any
Type of Additional Capacitor If Any (regular/ switching shunts)
Steps of Switching Shunts
Size of Dynamic Var If Any
Location of Dynamic Var If Any
Cable Length for Wind Farm Collection System
Cable Type and Impedance Per Mile
Embedded Relay for Each Turbine (Yes or No)
Voltage relay (Yes or No)
Manufacturer default Voltage relay setting
Frequency relay (Yes or No)
Manufacturer default Frequency relay setting

Wind Turbine Unit GSU (each turbine)

Number of turbines per unit GSU
Generator Step-up Transformer MVA Base *
Generator Step-up Transformer Impedance (R+jX, or %, on transformer MVA Base) *
Generator Step-up Transformer Reactance-to-Resistance Ratio (X/R)
Generator Step-up Transformer FOA Rating (MVA)
Generator Step-up Transformer Low-side Voltage (kV) *
Generator Step-up Transformer High-side Voltage (kV) *
Generator Step-up Transformer Off-nominal Turns Ratio
Generator Step-up Transformer Number of Taps and Step Size
High Voltage Winding Connection (i.e. wye grounded, delta) *
Low Voltage Winding Connection (i.e. wye grounded, delta) *

Transmission Line Data:

Line Length from Main Transformer High-Side to the Point of Interconnection
Voltage Level (kV)
Conductor Type
Transmission Line MVA Base
Positive Sequence Impedance (R+jX, or %, per mile on line MVA base)
Positive Sequence Reactance-to-Resistance Ratio (X/R)
Zero Sequence Impedance (R+jX, or %, per mile on line MVA base)
Zero Sequence Reactance-to-Resistance Ratio (X/R)
Positive Sequence Charging Admittance (in % per mile on line MVA base)

PSS/E simulation information

The equipment models listed below are those available for use in PSS/E. Each model can have unique data requirements. The minimum modeling required for dynamic simulation is a generator model, and an exciter model. These must be identified / submitted by the Interconnection Customer.

The manufacturer of the equipment to be incorporated in the design of a facility should be able to provide the proper model or an equivalent for the Interconnection Customer to identify. If you cannot determine the exact PSS/E model, you must submit a Control/Block Diagram for the piece of equipment in question.

Generator Models

GENROE Round rotor generator model.
GENROU Round rotor generator model.
GENSAE Salient pole generator model.
GENSAL Salient pole generator model.
GENDCO Round rotor generator model with DC offset torque component.
GENCLS Classical generator model.
GENTRA Transient level generator model.
CIMTRl Induction generator model with rotor flux transients.
CIMTR3 Induction generator model with rotor flux transients.

Static Var Compensator (SVC) and Frequency Changer Models

CSVGNl SCR controlled static VAR source model.
CSVGN3 SCR controlled static VAR source model.
CSVGN4 SCR controlled static VAR source model.
CSVGN5 WSCC controlled static VAR source model.
CSVGN6 WSCC controlled static VAR source model.
FRECHG Salient pole frequency changer model.

If the model for the SVC to be employed by the Interconnection Customer is not present on the list above, then the Interconnection Customer must provide the model to PJM, otherwise the Interconnection Customer must identify to PJM the correct model to be used from the list above.

Excitation System Models

An exciter model is a minimum modeling requirement for dynamic simulation.

Additionally, the exciter model in certain cases is needed to ensure that the unit is transiently stable.

PJM maintains the following model information.

EXDC2 1981 IEEE type DC2 excitation system model.
EXAC1 1981 IEEE type AC1 excitation system model.
EXAClA Modified type AC1 excitation system model.
EXAC2 1981 IEEE type AC2 excitation system model.
EXAC3 1981 IEEE type AC3 excitation system model.
EXAC4 1981 IEEE type AC4 excitation system model.
EXST1 1981 IEEE type ST1 excitation system model.
EXST2 1981 IEEE type ST2 excitation system model.
EXST2A Modified 1981 IEEE type ST2 excitation system model.
EXST3 1981 IEEE type ST3 excitation system model.
ESAC1A 1992 IEEE type AC1A excitation system model.
ESAC2A 1992 IEEE type AC2A excitation system model.
ESAC3A 1992 IEEE type AC3A excitation system model.
ESAC4A 1992 IEEE type AC4A excitation system model.
ESAC5A 1992 IEEE type AC5A excitation system model.
ESAC6A 1992 IEEE type AC6A excitation system model.
ESDClA 1992 IEEE type DClA excitation system model.
ESDC2A 1992 IEEE type DC2A excitation system model.
ESST1A 1992 IEEE type ST1A excitation system model.
ESST2A 1992 IEEE type ST2A excitation system model.
ESST3A 1992 IEEE type ST3A excitation system model.
EXPIC1 Proportional/integral excitation system model.
IEEETl 1968 IEEE type 1 excitation system model.
IEET1A Modified 1968 IEEE type 1 excitation system model.
IEET1B Modified 1968 IEEE type I excitation system model.
IEEET2 1968 IEEE type 2 excitation system model.
IEEET3 1968 IEEE type 3 excitation system model.
IEEET4 1968 IEEE type 4 excitation system model.
IEEET5 Modified 1968 IEEE type 4 excitation system model.
IEET5A Modified 1968 IEEE type 4 excitation system model.
IEEEXl 1979 IEEE type 1 excitation system model and 1981 IEEE type DC1 model.
IEEEX2 1979 IEEE type 2 excitation system model.
IEEEX3 1979 IEEE type 3 excitation system model.
IEEEX4 1979 IEEE type 4 excitation system model, 1981 IEEE type DC3 model and 1992 IEEE type DC3A model.
IEEX2A 1979 IEEE type 2A excitation system model.
SCRX Bus or solid fed SCR bridge excitation system model.
SEXS Simplified excitation system model.

If the model for the excitation system to be employed by the Interconnection Customer is not present on the list above, then the Interconnection Customer must provide the model to PJM, otherwise the Interconnection Customer must identify to PJM the correct model to be used from the list above.

Prime Mover and Governor Models

The prime mover governor model is required to demonstrate long-term stability of the unit in response to frequency oscillations.
PJM maintains the following model information:

CRCMGV Cross compound turbine governor model.
DEGOV Woodward diesel governor model.
DEGOV1 Woodward diesel governor model.
GAST Gas turbine governor model.
GAST2A Gas turbine governor model.
GASTWD Woodward gas turbine governor model.
HYGOV Hydro turbine governor model.
IEESGO 1973 IEEE standard turbine governor model.
IEEEG1 1981 IEEE type 1 turbine governor model.
IEEEG2 1981 IEEE type 2 turbine governor model.
IEEEG3 1981 IEEE type 3 turbine governor model.
SHAF25 25 mass torsional-elastic shaft model.
TGOV1 Steam turbine governor model.
TGOV2 Steam turbine governor model with fast valving.
TGOV3 Modified IEEE type 1 turbine governor model with fast valving.
TGOV5 Modified IEEE type 1 turbine governor model with boiler controls.
WEHGOV Woodward Electric Hydro Governor Model.
WESGOV Westinghouse Digital Governor for Gas Turbine.
WPIDHY Woodward P.I.D. hydro governor model.

If the model for the governor system to be employed by the Interconnection Customer is not present on the list above, then the Interconnection Customer must provide the model to PJM, otherwise the Interconnection Customer must identify to PJM the correct model to be used from the list above.

Power System Stabilizer Models

Power System Stabilizer must be added to the exciter circuits to force stability. However, devices such as Power System Stabilizers, as well as Excitation Limiters and Compensating devices, are less frequently applied, and are modeled if the equipment will be used.

PJM maintains the following model information.

IEEEST 1981 IEEE power system stabilizer model.
IEE2ST Dual input signal power system stabilizer model.
PTISTI PTI microprocessor based stabilizer model.
PTIST3 PTI microprocessor based stabilizer model.
PSS2A 1992 IEEE duel input signal stabilizer model.
STAB1 Speed sensitive stabilizer model.
STAB2A ASEA power sensitive stabilizer model.
STAB3 Power sensitive stabilizer model.
STAB4 Power sensitive stabilizer model.

STBSVC WSCC supplementary signal for static VAR system.
ST2CUT Dual input signal power system stabilizer model.

Minimum Excitation Limiter ModelsPJM maintains the following model information.

MNLEXl Minimum excitation limiter model.
MNLEX2 Minimum excitation limiter model.
MNLEX3 Minimum excitation limiter model.

Maximum Excitation Limiter Models

PJM maintains the following model information.

MAXEX1 Maximum excitation limiter model.
MAXEX2 Maximum excitation limiter model.

Compensating Models
PJM maintains the following model information.

COMP Voltage regulator compensating model.
COMPCC Cross compound compensating model.
IEEEVC 1981 IEEE voltage compensating model.
REMCMP Remote bus voltage signal model.

Attachment H: Generator Reactive Deficiency Mitigation Process

H.1 Scope

The mitigation process is to address a reactive deficiency of an existing synchronous generator caused by an increase of its output resulting in that the generator reactive capability cannot meet the existing PJM power factor requirements as stated in the PJM Tariff. The mitigation process and the associated business rules will be applied to all new interconnection requests regarding an increase of capacity or energy to an existing generator.

The mitigation process is not intended for:

- Wind or non-synchronous generators,
- Existing generators not requesting an increase of capacity or energy,
- Previous requests for capacity or energy increases, or
- Increases of 20MW or less of which the power factor is measured at the POI.

The process is in compliance with the existing PJM tariff requirements and the associated business rules and does not require a change in the existing PJM tariff.

Reactive Deficiency Definition

A Reactive Deficiency is defined as the difference between the Mvar capability of a generator after the upgrade for meeting the PJM power factor requirements and the actual Mvar capability of a generator after the requested increase in capacity or energy.

For existing generators that do not have a signed FERC Proforma Interconnection Service Agreement (ISA), the Mvar capability before the upgrade is the grandfathered Mvar capability determined by PJM. For generators that have a signed ISA, the Mvar capability before the upgrade is determined by the Mvar for meeting the power factor requirements as stated at Part VI, Att. O, App. 2, Section 4.7.1 of the PJM Tariff.

For the incremental MW increase, the corresponding power factor requirements can be calculated according to the requirements stated at Part VI, Att. O, App. 2, Section 4.7.1.2 of the Tariff. Hence, the Mvar capability of a generator after the upgrade for meeting the PJM power factor requirements is defined as the sum of the grandfathered Mvar capability or the Mvar requirements stated in the Tariff and the Mvar requirement corresponding to the incremental MW increase.

Finally, after the upgrade, the actual Mvar capability of the generator is the Mvar, defined by the generator's reactive capability curve, corresponding to the gross generator output (i.e. Winter rating) of the generator before the upgrade plus the incremental MW increase.

The reactive deficiency, if any, is determined during the Feasibility and the System Impact Study phases of an interconnection request regarding an increase of capacity or energy to an existing generator. The Interconnection Customer will be notified of the deficiency and the proposed mitigation before the execution of the Construction or Interconnection Service Agreement.

Mitigation Process

Currently, the PJM Tariff allows the Interconnection Customer, at its expense, to install power factor correction or other equipment at the generation plant to mitigate the reactive deficiency and to enable the generator to meet the PJM reactive power design criteria during operation. (OATT at Part VI, Att. O, App. 2, Section 4.7.3) If the Interconnection Customer fails to mitigate the reactive deficiency, PJM can request the affected Transmission Owner to install Static Var Compensator (SVC) or similar dynamic reactive devices, at the Interconnection Customer's expense in the form of a Reactive Deficiency Charge, to mitigate the identified reactive deficiency. A shunt capacitor application could be considered but its application will require PJM review on a case by case basis.

For a generator reactive deficiency less than 50 Mvar, the Reactive Deficiency Charge will be equal to the reactive deficiency (in Mvar) multiplied by the most recent average cost estimates (in $/Mvar) for installing SVCs on the PJM system. There will be two SVC cost estimates to be developed and updated annually by PJM – one for installations at or above 230kV and one for installations below 230kV. The applicable deficiency charge is based on the voltage at the high side of the generator step up transformer. In the event that a shunt capacitor application is allowed, the charge will be based on the most recent cost of similar shunt capacitor installation.

For a generator reactive deficiency greater than or equal to 50 Mvar, the affected Transmission Owner will be responsible to provide either the cost estimate (in $/Mvar) for installing a SVC in its system which will be used to calculate the Reactive Deficiency Charge or the cost estimate (in $) of a specific SVC or SVCs necessary to mitigate the reactive deficiency as determined by PJM and the affected Transmission Owner in the System Impact Study.

Reactive Deficiency Charge Payments

The Reactive Deficiency Charges can be paid in cash or via a letter of credit. The collected charges will be used to fund reactive projects in the Transmission Owner's zone in which the Interconnection Customer's generator is located. The Transmission Owners shall be responsible to construct, own and maintain these reactive projects.

If the Reactive Deficiency Charge for an individual Interconnection Request is less than $2M and is insufficient to fund a planned reactive project, PJM can choose to use the collected charge to provide partial funding to this project. Alternatively, PJM can hold the collected charges in an account until sufficient funds have been collected to fund the entire project.

If the Reactive Deficiency Charge for an individual Interconnection Request is more than the cost of a planned reactive project, PJM can choose to use the collected charge to fund this project and hold the remaining fund in cash (not to exceed $2M) or in a letter of credit as a security for use to fund future reactive projects. These funds will be used as soon as a reactive upgrade has been identified. Alternatively, PJM can develop a different reactive project to be funded entirely by the collected charge.

If the Reactive Deficiency Charge is more than $2M and a reactive project has not been developed, PJM will require the Interconnection Customer to provide a letter of credit for use to fund a reactive upgrade as soon as it has been identified.

Review of and Modification to the Mitigation Process

NERC standards require that PJM, as the Transmission Operator, shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and contingency conditions. PJM will continue to assess the reactive capability of the system and serve as the backstop to recommend modifications to the mitigation process and the associated business rules when and if there are insufficient reactive resources on the system to maintain system reliability.

Annex 1: SCADA Requirements by Transmission Owner Region

	MW and Voltage Threshold for SCADA Requirement		Must match Legacy SCADA[1]	SCADA POINTS													
	Distribution	Transmission		Gen[2] CB Control	PQ data[3]	CB Status	Volts	TT Status	Amps	MW	MVAR	MWH	MVARH	Harmonics	Freq.	V Flicker	Sag & Swell
PJM	All Capacity Resources, Energy Resources >10 MW and all Resources able to set LMP.	All Capacity Resources, Energy Resources >10 MW and all Resources able to set LMP.	No	No	No	No	No	No	No	Yes	Yes	Yes	Yes	No	No	No	No
AE	3MW & above	3MW & above	No	No	No	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	No	No	No	No
AP	case by case basis	All require full SCADA & RTU	No	No	Yes	Yes	Yes (3ph)	No	Yes (3ph)	Yes	Yes	Yes	No	Y-32 orders	No	Yes	Yes
AEP	generally > 2MW	All	No	Yes - trip only	Yes	Yes	No	No	No	Yes	Yes	Yes	No	No	No	No	No
BG&E	All	All	No	Yes - trip only	Yes	Yes	No	Yes	No	Yes	Yes	Yes	No	No	No	No	No
ComEd	2.5MW & up if TT is req'd or 10MW & up	All	No	No	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes
Dayton	As determined by Dayton	As determined by Dayton	No	Yes	No	Yes	No	No	No	Yes	Yes	Yes	No	No	No	No	No
Delmarva	3MW & above	3MW & above	No	No	No	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	No	No	No	No
Dominion	If Local Light load to Gen MWs ratio < 5	3MW & above	No	Yes - Trip only	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	No	No	No
Duquesne	Case by case, all 5 MW & above	1 MW & above	Yes	No	No	Yes	Yes	No	Yes	Yes	Yes	Yes	No	No	No	No	No
FE	case by case basis	All	No	Yes - trip only	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	No	No	No
ODEC	2 MW & above	2 MW & above	No	No	No	Yes	No	Yes	No	Yes	Yes	Yes	No	No	No	No	No
O&R	1 MW & above	All	No	No	No	Yes	No	No	No	Yes	Yes	Yes	No	No	Yes	No	No
PECO	5 MW & above	5 MW & above	No	No	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	No	No	No	No	No
PEPCO	All - case by case exceptions	All - case by case exceptions	No	Yes - Trip only	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	No	No	No	No	No
PPL	2.5 MW & above	All - 69 kV & above	Yes	Yes - Trip only	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	Yes	No	No
PSEG	case by case basis	All	No	Yes - Trip only	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	No	No	No
UGI	1 MW & above	1 MW & above, and All 66 kV & above	Yes	Yes - Trip only	No	Yes	Yes (3ph)	No	Yes (3ph)	Yes	Yes	Yes	No	No	Yes	No	No

1 PPL and Duquesne (69kV and above) and UGI (1MW and above or 66kV and above) require that customer matches their company's SCADA equipment. SGIWG Internet option not permitted.
2 May be generator CBs (interrupting devices) and/or main CB (interrupting device)
3 May also require installation of Power Quality monitoring device

Revision History

Revision 10: (04/05/2012)

Revision 10 incorporates (1) increased detail regarding section 1.8 Changes to Existing or Proposed Generation and (2) minor language cleanup to promote consistency throughout Manual 14A.

Revision 09: (04/12/2011)

Revision 09 incorporates (1) increased detail regarding Generator Power Factor Requirements, (2) a new Attachment H: Generator Reactive Deficiency Mitigation Process, and (3) a clarification to the interconnection cost allocation process.

Revision 08: (05/01/2009)

Revision 08 incorporates (1) corrections and clarifications to items entered under revisions 06 and 07, (2) changes to the deposit requirements for the System Impact Study and Facilities Study phases of interconnection project development, and (3) modifies references to the PJM web site following the PJM web site redesign.

Revision 07: (1/15/2009)

Revision 07 changes incorporate a description of the requirements associated with the submittal of site control in conjunction with the submission of an Interconnection Request for wind generation to be studied for interconnection in PJM. This change was produced as a result of recommendations from the Regional Planning Process Working Group.

Additional revisions incorporate editorial corrections.

Revision 06: (08/08/2008)

Material related to the Interconnection process has been split from Manual 14B and located here. General material introducing the Manual 14 Series has been relocated to a new draft under construction which will be called Manual 14. Manual 14 will be devoted to introductory material for the entire PJM Manual 14 series.

The following Interconnection process material includes extensive revisions related to improvements to the Queue study processes and procedures pursuant to applicable FERC and stakeholder proceedings as well as an accumulation of ongoing “housekeeping” updates.

Revision 05 (06/07/06)

Revision 05 includes text revisions to state that PJM Transmission Expansion Planning 1) accommodates requests for new interconnections and 2) identifies the need for transmission system equipment replacements and/or upgrades through probability risk assessment (PRA) analysis of bulk power transformers as an input to the Regional Planning Process. Replaced references to “ECAR, MAAC and MAIN” with ReliabilityFirst,

Revisions were made on page 6, 7, 11 and 12.

Revision 04 (10/01/05)

Revision 04 includes text that has been amended to accommodate the following: (1) clarification of small generation procedures; (2) clarification of Project Manager and Client Manager roles; and (3) additional explanatory information on treatment of generator deactivations.

Revision 03 (10/01/04)

Revision 03 includes text revisions to accommodate the following: (1) changes necessitated by compliance with FERC Order 2003 on Standardized Generator Interconnection Agreements and Procedures; (2) changes necessitated by integration with AEP, Dayton, Dominion and Duquesne; (3) capacity and energy unit status text clarification; and (4) recent process changes to address behind-the-meter generation and economic planning.

Revision 02 (12/01/03)

Revision 02 includes changes to include the Merchant Transmission Interconnection process description; also, the role clarity diagram in Attachment B has been revised.

Changed all references from "*PJM Interconnection, L.L.C.*" to "*PJM*."

Reformatted to new PJM formatting standard; Renumbered pages to consecutive numbering; Renumbered Exhibit numbers.

Revision 01 (02/26/03)

Change manual title from "PJM Manual for ***Generation Interconnection Process Overview" (M14A)*** to "PJM Manual for ***Generation and Transmission Interconnection Process Overview" (M14A)***; also, text changes throughout to conform to new Manuals M-14C and M-14D.

Revision 00 (12/18/02)

This document is the initial release of the PJM Manual for ***Generation Interconnection Process Overview (M14A)***.

Manual M14, Revision 01 (03/03/01) has been restructured to create four new manuals:

(1) M14A: "Generation Interconnection Process Overview"

(2) M14B: "Generation Interconnection Transmission Planning"

(3) M14C: "Generation Interconnection Facility Construction"

(4) M14D: "Generation Operational Requirements"

Working to Perfect the Flow of Energy

PJM Manual 14B:

PJM Region Transmission Planning Process

Revision: 21

Effective Date: April 26, 2012

Prepared by

Planning Division

Transmission Planning Department

PJM Manual 14B:

PJM Region Transmission Planning Process

Table of Contents

Table of Exhibits

Approval

Approval Date: 04/26/2012
Effective Date: 04/26/2012

Paul McGlynn, General Manager

System Planning

Current Revision

Revision 21 (04/26/2012):

- Revised Generator Deliverability procedure to limit the "Adder" contribution based on an estimated CETO for generation in the receiving end area.

Introduction

Welcome to the **PJM Region Transmission Planning Process** Manual. In this Introductory Section you will find information about PJM manuals in general, an overview of this PJM Manual in particular and information on how to use this manual.

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by PJM for the operation, planning, and accounting requirements of the PJM RTO and the PJM Energy Market. The manuals are grouped under the following categories:

- Transmission
- PJM Energy Market
- PJM Regional Transmission Expansion
- Reserve
- Accounting and billing
- PJM administrative services

For a complete list of all PJM manuals, go to www.pjm.com and select "Manuals" under the "Documents" pull-down menu.

About This Manual

The **PJM Region Transmission Planning Process Manual** is one of the PJM manuals in the PJM Regional Transmission Expansion group. This manual focuses on the process for planning baseline expansion facilities under the PJM Region Transmission Planning Process. Capitalized terms not defined as they are used have the meaning defined in the PJM's Open Access Transmission Tariff (OATT) and in the Operating Agreement (OA.)

This **PJM Region Transmission Planning Process Manual** consists of two sections and related attachments. All sections and attachments are listed in the Table of Contents.

> **NOTE**: While the PJM Manuals provide instructions and summaries of the various rules, procedures and guidelines for all phases of PJM's planning process, the PJM Operating Agreement and the PJM Open Access Transmission Tariff (OATT) contain the authoritative provisions.

Intended Audience

The intended audiences for this PJM Region Transmission Planning Process Manual include:

- Generation and Transmission Interconnection Customers and their engineering staff

NOTE: The term "**Transmission Interconnection Customer**", as defined in the PJM Open Access Transmission Tariff, refers to those separate and independent entities proposing to install new or upgrade existing transmission facilities rather than an existing Transmission Owner on the PJM System that installs Regional Transmission Expansion Plan "baseline," "economic," "system performance" or "Supplemental projects".

- Transmission Customers

NOTE: The term **"Transmission Customer"** refers to any entity requesting or utilizing transmission service on the PJM Transmission System, as defined in the PJM Open Access Transmission Tariff.

- Transmission Owners and their respective engineering staff
- Federal and state regulatory bodies
- PJM Members
- PJM staff

References

There are other PJM documents that provide both background and detail on specific topics that may be related to topics in this manual. References with related information include:

- PJM Manual 1: *Control Center and Data Exchange Requirements*
- PJM Manual 2: *Transmission Service Request*
- PJM Manual 3: *Transmission Operations*
- PJM Manual 14A: *Generation and Transmission Interconnection Process*
- PJM Manual 14C: *Generation and Transmission Interconnection Facility Construction*
- PJM Manual 14D: *Generator Operational Requirements*
- PJM Manual 14E: *Merchant Transmission Specific Requirements*
- PJM Manual 21: *Rules and Procedures for Determination of Generating Capability*

Using This Manual

We believe that explaining concepts is just as important as presenting procedures. This philosophy is reflected in the way we organize the material in this manual. We start each section with an overview. Then we present details, procedures or references to procedures found in other PJM manuals. The following provides an orientation to the manuals' structure.

What You Will Find In This Manual

- A table of contents.
- An approval page that lists the required approvals and a brief outline of the current revision.
- This Introduction and sections containing the specific transmission planning process details including assumptions, criteria, procedures and stakeholder interactions.
- Attachments that include additional supporting documents, forms, or tables.
- A section at the end detailing all previous revisions of this PJM Manual.

About Critical Energy Infrastructure Information (CEII)

PJM Critical Energy Infrastructure Information Release Guidelines

Background

The Federal Energy Regulatory Commission ("FERC" or "Commission") considers the information filed in the FERC-715, Part 2, Part 3, and Part 6 (http://www.ferc.gov/legal/ceii-foia/ceii.asp) to be Critical Energy Infrastructure Information (CEII). This information contains electrical models, detailed one-line diagrams and analysis of the filer's actual transmission system including potential weaknesses of the filer's transmission system. PJM treats all such power flow and associated system modeling data as CEII. This includes all power flow models that are developed using or including filed data and related information used in transmission analysis such as contingency and monitored element files. Power flows specifically configured for short circuit analysis that do not contain load and typical generation dispatch are not considered CEII. Regarding all types of PJM information, however, additional consideration must be given to whether or not PJM received or originated the information as Confidential Information prior to decisions regarding its release. Confidential information is discussed in PJM documents including the Operating Agreement §18.17 and the Open Access Transmission Tariff §§222 – 223. Power flows may but generally do not contain Confidential information. Confidential information of individual members, if any, will be redacted prior to release. Some PJM power flows are special cases that contain both confidential information and CEII. For example PJM power flows originating from system operations and used for near-term operational studies often contain confidential information in addition to CEII. These cases can only be obtained with authorization through the CEII process and authorization from the responsible Operating Committee and/ or working group.

The events of 2001 prompted the Commission to reconsider its previous policy of making the FERC form 715 report publicly available. Subsequent to September 11, 2001, the Commission removed from public files all documents likely to contain detailed specifications of facilities licensed or certified by the Commission. This restriction was later expanded to include information about proposed facilities as well as those already licensed or certificated by the Commission, excluding information that simply identified the location of the infrastructure. After the events of September 11, 2001, FERC Form 715 information became subject to CEII review prior to its release. In its October 2007 Order, the Commission issued revisions to the treatment of CEII and reclassified FERC Form No. 715, Parts 1, 4, and 5 as public. The remaining portions of the report are CEII. In the FERC Order Nos. 890 and 890A the Commission directed Transmission Providers to develop a process for handling CEII while implementing the Orders' requirements for open, transparent and participatory planning.

The PJM power flow information is a combination of CEII information filed or provided by a number of "owners" and additional information introduced by PJM, PJM Members, and non-members.

The Commission's treatment of CEII has evolved over a progression of Orders that must be read together to understand the procedures applicable to the determination and handling of CEII. In consideration of the multiple-owner nature, the sensitivity of the information, and the essential role of this information in PJM's Tariff procedures and participatory planning, PJM has implemented a process for handling and documenting such material. PJM's intent is to provide a process for eligible recipients to access CEII consistent with the Commission's standards for handling CEII material.

Procedure to Request Access to PJM CEII

PJM will act as the first point of contact to process CEII requests from Members, Interconnection Customers (as defined in the PJM OATT) or active participants in PJM's eFTR or eRPM markets. In addition, employees of other RTO's, similar independent transmission organizations recognized by FERC, and NERC Planning Coordinators (interregional planning entity) may also come to PJM as a first point of contact for access to PJM CEII. PJM accommodates other RTO's and Planning Coordinators in order to carry out interregional planning responsibilities pursuant to applicable FERC orders and interregional planning agreements between and among the parties. These interregional planning entities, similar to PJM, are those that have primary responsibility for creating and protecting CEII and have their own FERC compliant processes for handling CEII in their possession. Interregional transmission planning creates the need for unique interregional business processes that accommodate Interconnection-wide exchange and sharing of CEII among eligible persons while enforcing the standards for non-disclosure of such information. When necessary, PJM establishes interregional CEII procedures that uphold the essential underlying tenants of PJM's process.

All CEII requests must be from individuals. Each individual who may view or discuss the requested CEII must complete the PJM process. To request CEII in PJM's possession, a requestor must complete a PJM CEII Request Form identifying the requestor and the need for and planned use of the requested information. The request must also be accompanied by an executed CEII Non-disclosure Agreement (NDA). These two PJM CEII documents are available from your PJM Planning contacts, the PJM CEII Contact in the NERC and Regional Coordination department or the Planning area of the PJM website. If a PJM Member or PJM Interconnection Customer desires to coordinate a consultant's access to CEII on behalf of the organization, the organization's authorized representative must submit an Authorization Form (in addition to the authorized representative's Request and CEII NDA) that identifies each individual consultant who may make individual requests for CEII on the organization's behalf. The consultant additionally must submit a Request Form and CEII NDA requesting access to the same information specified on the form of the organization's authorized representative. Entities who are not PJM members, Interconnection Customers, registered PJM auction participants, or employees of another RTO are encouraged to first seek authorization from FERC by following the procedures outlined at www.ferc.gov/legal/ceii-foia.asp.

The field on the PJM Request Form for the FERC CEII Identification Number must be completed by individuals who have first received authorization from the Commission. This field is not applicable for any requestor who uses PJM as the first point of contact for a request. The FERC link is also useful to review the definition of CEII and the Commission's process for handling CEII and useful in understanding the PJM process.

Requirements to become an Authorized Recipient of CEII

PJM's process provides for release of CEII information to authorized individuals of organizations engaged in business with PJM, as detailed above. The information provided on the required documents should be sufficiently detailed to enable PJM's CEII Contact to identify the individual, the specific information requested, the need for the information, and the proposed use of the information. The requester's explanations will be used by PJM staff (i) to establish whether a requester has presented a legitimate need for the information and (ii) to weigh the need for the information against the potential harmful effects of its release. PJM reserves the right to revise its process from time-to-time, to limit access to CEII as may be appropriate in any specific instance, and to require any requestor to first seek authorization for CEII access from the Commission.

Section 1: Process Overview

In this section you will find an overview of PJM's transmission planning process that culminates in the Regional Transmission Expansion Plan (RTEP). This process (referred to in this Manual interchangeably as the RTEP process or more generically as the PJM Region transmission planning process) is one of the primary functions of Regional Transmission Organizations (RTOs.) As such, PJM implements this function in accordance with the Regional Transmission Expansion Planning Protocol set forth in Schedule 6 of the PJM Operating Agreement.

As further described in following portions of this manual, the PJM RTEP process consists of baseline reliability reviews as well as analysis to identify the transmission needs associated with generation interconnection and merchant transmission interconnection. PJM implements the planning of interconnections as part of the broader RTEP process pursuant to the PJM Open Access Transmission Tariff (OATT.) The relationship between Interconnection planning and the RTEP is discussed in later sections of this manual and in related manuals.

1.1 Planning Process Work Flow

The Manual 14 series provides information regarding PJM's Planning Process to complement Schedule 6 of the PJM Operating Agreement and the planning provisions of the PJM Open Access Transmission Tariff (OATT.) These agreements can be found on-line at http://www.pjm.com/documents/agreements.aspx.

The PJM planning process activities, culminating in PJM's annual Regional Transmission Expansion Plan, constitute PJM's single, Order No. 890 compliant, transmission planning process. All PJM Open Access Transmission Tariff (OATT) facilities are planned through and included in this open, fully participatory, and transparent process.

PJM planning is implemented through an annual cycle centered on activities of PJM's Planning and Market Simulation functions and their interactions with members, regulatory bodies, and other interested parties primarily through the PJM Transmission Expansion Advisory Committee (TEAC), the Subregional RTEP Committee, and the PJM Planning Committee (PC) forums. This ongoing process has continued to evolve since 1997, when PJM's Regional Transmission Expansion Planning (RTEP) Protocol (codified in Schedule 6 of PJM's Operating Agreement) was approved by the Federal Energy Regulatory Commission. Since that time, the process has been expanded and enhanced in response to member and regulatory input as documented in the revisions to the OATT, PJM Manual 14 series, and the Operating Agreement Schedule 6. The current PJM Region transmission planning process includes ample opportunity for Stakeholder input through frequent oral and written exchange of information and reviews via the TEAC organizational structure. The process culminates in PJM's presentation of the RTEP for approval by the PJM Board of Managers.

There are four planning paths that ultimately culminate in the PJM RTEP. Facilities in each path allow the opportunity for early, full and transparent participation by interested PJM stakeholders. The four paths are reliability planning, economic planning, interconnection planning, and local planning.

Reliability and economic planning facilities are produced from PJM's annual planning cycle activities described in this manual, Operating Agreement Schedule 6, and portrayed in Exhibit 1. PJM leads this analysis and development of upgrades related to reliability and market efficiency planning for all facilities 100 kV and above. These facilities are designated as Bulk Electric System (BES) facilities and are subject to the NERC requirements and criteria for such facilities. The PJM analyses ensure compliance with NERC, PJM and regional criteria. In addition, the PJM led analyses also include analysis and upgrade of transmission facilities with nominal voltages below 100kV to the extent they are under PJM's operational control (see http://www.pjm.com/markets-and-operations/transmission-service/transmission-facilities.aspx). The TEAC, Subregional RTEP Committee, and stakeholder opportunities to engage the process are described in this manual.
The analysis of OATT transmission facilities below 100kV and not under PJM operational control is led by the Transmission Owner (TO.) This is appropriate since local Transmission Owner operations, maintenance and planning personnel oversee these local systems. These facilities typically provide only local transmission function of interest to the customers in the nearby electrical vicinity. The TO analysis ensures local facilities meet NERC and local reliability criteria. In addition, the local Transmission Owner personnel may also develop recommended modifications to transmission facilities that are not required by PJM reliability, market efficiency or operational performance criteria (the non-criteria based upgrades are called Supplemental RTEP Projects.) The Transmission Owner will initiate all reliability-based and supplemental upgrade requests for facilities not under PJM's control. All such projects will be introduced to the PJM Regional planning process through PJM's TEAC and Subregional RTEP Committees. In this way these TO initiated projects will be subject to the same open, transparent and participatory PJM committee activities as PJM initiated projects (see discussion of TEAC and Subregional RTEP Committee.)

Interconnection planning encompasses generator and merchant transmission requests for Interconnections and rerates as well as requests for long-term firm transmission service. Studies of these transmission requests and any resulting transmission modifications are posted to PJM's website in the project queue area (http://www.pjm.com/planning/generation-interconnection.aspx). In addition, any necessary facility modifications are brought to the TEAC for presentation and stakeholder participation. Interconnection planning is discussed in more detail in Manual 14A.

1.2 TEAC and Subregional RTEP Committee and Related Activities

The PJM TEAC functions in accordance with its established charter and provisions of Schedule 6 of the Operating Agreement. Additionally, in 2008 PJM began to facilitate more localized planning functions through the Subregional RTEP Committee. The Subregional RTEP Committee, including any local reviews that may be initiated, will follow TEAC procedures and other applicable PJM committee procedures. All PJM stakeholders will be provided with the opportunity for participation in the TEAC and Subregional RTEP Committees and related activities.

The subregional and any related meetings allow more focused and meaningful stakeholder participation and attention to subregional and local transmission issues. RTEP projects are labeled as Regional RTEP Projects and Subregional RTEP Projects, as defined in the Operating Agreement, to make an initial categorization and posting of violations and upgrades that will enable stakeholders to more easily sort through and review issues of interest. Regional RTEP Projects are those transmission expansions or enhancements rated at voltages 230 kV and above. Subregional RTEP Projects are those rated below 230 kV. This differentiation by voltage between Regional RTEP Projects and Subregional RTEP Projects is made only for administrative convenience.

The Subregional RTEP Committee is responsible for the initial review of Subregional RTEP Projects. PJM will facilitate meetings as necessary for TEAC and Subregional RTEP Committee review and evaluation of reliability and market efficiency reinforcements. The Subregional RTEP Committee will forward all Subregional RTEP Projects to the TEAC. TEAC or the Subregional RTEP Committee, as appropriate will also have the opportunity to provide advice and recommendations regarding the study scope, assumptions and procedures at an initial assumptions setting meeting. This meeting will cover both reliability and market efficiency assumptions, as appropriate. Initially, a minimum of three PJM RTEP subregions will be established: one each for the Mid Atlantic, South, and West subregions of PJM. When a Subregional RTEP Committee meeting is scheduled it is understood that this generally will be implemented as a separate meeting for each subregion. In this way, the TEAC and Subregional RTEP Committees provide a transparent and participatory planning process throughout the RTEP development, from early assumptions-setting stages, through discussion of criteria violations, review of recommendations for alternative solutions, and review and comment on the final RTEP facilities.

All RTO stakeholders can participate in any or all subregional activities on a voluntary basis, with one exception. The Transmission Owners that comprise each of the various subregions must participate in the subregional meeting that includes their area. PJM, with stakeholder input, may initiate additional subregional or local review as may be necessary or beneficial. Local meetings or more localized review occurs in the event that PJM, taking into account stakeholder input, decides that it is appropriate to address issues in a forum other than or in addition to the context of one of the initial subregions. In addition to their participation in the TEAC and Subregional RTEP Committee meetings, stakeholders can also provide written comments on the development of the RTEP. Written comments can be forwarded to RTEP@pjm.com.

There are various categories of facilities that enter the PJM plan through distinct paths, however, each path is transparent and open to all interested stakeholder participation through TEAC and Subregional RTEP Committee processes. All four planning paths to the PJM RTEP; reliability planning, economic planning, interconnection planning, and local Transmission Owner Planning; flow through the TEAC and Subregional RTEP Committee planning process.

PJM Committee review of all RTEP projects, regardless of the path of origin of the project, will occur during the February through August RTEP Stakeholder analysis and review periods (see Exhibit 1.) Stakeholders will be provided all the information necessary for full participation in the discussions and evaluations, including: (1) the criteria and assumptions used as the basis for projects, (2) the procedure to access the study information necessary to participate in the project’s evaluation and discussion, (3) a detailed description of the timing, need and justification of the project, (4) a description of the cost and construction responsibility for the project, and (5) a detailed description of the proposed modifications to facilities.

In addition, projects that originate through local Transmission Owner planning will be posted on the PJM web site. This site will include all currently planned transmission owner RTEP projects (including both newly planned Supplemental RTEP projects and Transmission

Owner Initiated projects from past RTEP cycles that are yet to be placed in-service.) This website will provide tracking information about the status of listed projects and planned in-service dates. It will also include information regarding criteria, assumptions and availability of study cases related to local planning.

1.3 Planning Assumptions and Model Development

1.3.1 Reliability Planning

PJM's planning analyses are based on a consistent set of fundamental assumptions regarding load, generation and transmission built into power flow models. Load assumptions are based on the annual PJM entity load forecast independently developed by PJM (found at http://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.aspx.) This forecast includes the basis for all load level assumptions for planning analyses throughout the 15 year planning horizon. Generation and transmission planning assumptions are embodied in the base case power flow models developed annually by PJM and derived from the Eastern Reliability Assessment Group processes and procedures pursuant to NERC standards MOD-010-0, -011-0, and -012-0. As necessary, PJM updates those models with the most recent data available for its own regional studies. All PJM base power flow and related information are available pursuant to applicable Critical Energy Infrastructure Information, Non-Disclosure and OATT-related requirements (accessible via http://www.pjm.com/planning/rtep-development/powerflow-cases.aspx or by contacting the PJM Planning Committee contacts.) Each type of RTEP analysis (e.g., load deliverability, generator deliverability etc.) encompasses its own methodological assumptions as further described throughout the rest of this Manual. Additional details regarding the reliability planning criteria, assumptions, and methods can be found in following sections and this manual's Attachments.

1.3.2 Market Efficiency Planning

PJM will perform a market efficiency analysis each year, following the completion of the near-term reliability plan for the region. PJM's market efficiency planning analyses are based on the same starting assumptions applicable to the reliability planning phase of the RTEP development. In addition, key market efficiency input assumptions, used in the projection of future market inefficiencies; include load and energy forecasts for each PJM zone, fuel costs and emissions costs, expected levels of potential new generation and generation retirements and expected levels of demand response. PJM will input its study assumptions into a commercially available market simulation data model that is available to all stakeholders. The data model contains a detailed representation of the Eastern Interconnection power system generation, transmission and load. In addition, the market efficiency analysis of the cost/benefit of potential market efficiency upgrades will also include the discount rate and annual revenue requirement rate. The discount rate is used to determine the present value of the enhancements' annual benefits and annual cost. The annual revenue requirement rate is used to determine the enhancements' annual cost. PJM will finalize the market efficiency analysis input assumptions soon after the development of the PJM load forecast that is generally available approximately in late January. Prior to finalizing, PJM will review the proposed assumptions at the same PJM Subregional RTEP Committee assumptions meetings that address the reliability analysis assumptions, expected to occur in December preceding the year of the annual RTEP cycle. This review will provide the opportunity for stakeholder review of and input to all of the key assumptions that form the basis of the market efficiency analysis. In this way, PJM will facilitate a comprehensive stakeholder review and input regarding RTEP study assumptions. All final assumptions and analysis parameters will be presented to the TEAC for discussion and review and to the PJM Board for approval.

1.4 RTEP Process Key Components

PJM's goal is to ensure electric supply adequacy and to enhance the robustness of energy and capacity markets. Achieving these objectives requires the successful completion of PJM's planning, facility construction and operational and market infrastructure requirements.

Key components of PJM's 15-year transmission planning process discussed in this Manual include:

1. Baseline reliability analyses:

   The PJM Transmission System ("PJM System") provides the means for delivering the output of interconnected generators to the load centers in the PJM energy and capacity markets. Baseline reliability analyses ensure the security and adequacy of the Transmission System to serve all existing and projected long term firm transmission use including existing and projected native load growth as well as long term firm transmission service. RTEP baseline analyses include system voltage and thermal analysis, and stability, load deliverability, and generation deliverability testing. These tests variously entail single and multiple contingency testing for violations of established NERC reliability criteria regarding stability, thermal line loadings and voltage limits. Baseline reliability analyses are discussed in more detail in Section 2 and Attachment C.

2. Generation and transmission interconnection analyses:

   All entities requesting interconnection of a generating facility (including increases to the capacity of an existing generating unit) or requesting interconnection of a merchant transmission facility within the PJM RTO must do so within PJM's defined interconnection process. In addition to the baseline analyses discussed above, as resources or merchant transmission requests interconnection, deliverability in the local area of the request is restudied and updated. The generation and transmission interconnection process and deliverability testing procedures are discussed in Attachment C and Manual 14A. The evaluation of generation and merchant transmission interconnection requests is codified in the PJM Open Access Transmission Tariff (available on the PJM Web site at www.pjm.com).

3. Market efficiency analyses:

   In addition to reliability based analyses PJM also evaluates the economic merit of proposed transmission enhancements. These analyses focus on the economic impacts of security constraints on production cost, congestion charges to load and other econometric measures of market impacts. PJM's market efficiency analyses are discussed in Section 2 of this Manual and Attachment E. PJM development of economic transmission enhancements is also codified under Schedule 6 of the PJM Operating Agreement.

4. Operational performance issue reviews and accompanying analyses:

Maintaining a safe and reliable Transmission System also requires keeping the transmission system equipment in safe, reliable operating condition as well as addressing actual operational needs. On an ongoing basis, PJM operating and planning personnel assess the PJM transmission development needs based on recent actual operations. This may lead to special studies or programs to address actual system conditions that may not be evident through projections and system modeling.

To ensure that system facilities are maintained and operated to acceptable reliability performance levels, PJM has implemented an Aging Infrastructure Initiative to evaluate appropriate spare transformer levels and optimum equipment replacement or upgrade requirements. This initiative, based on a Probability Risk Assessment (PRA) process, is intended to result in a proactive, PJM-wide approach to assess the risk of facility failures and to mitigate operational and market impacts. Section 2 of this manual provides further discussion of the PRA process.

5. The final RTEP Plan:

Based on all of the requirements for firm transmission service on the PJM System, PJM annually develops a Regional Transmission Expansion Plan to meet those requirements on a reliable, economic system development and environmentally acceptable basis. Furthermore, by virtue of its regional scope, the RTEP process assures coordination of expansion plans across multiple transmission owners' systems, permitting the identification of the most effective and efficient expansion plan for the region. The RTEP plan developed through this process is reviewed by PJM's independent Board of Managers who has the final authority for plan's approval and implementation. The following Section 2 describes the PJM RTEP Process analysis.

1.5 Planning Criteria

1.5.1 Reliability Planning

Stakeholders have the opportunity at a national level through the participatory standards development process of the North American Electric Reliability Corporation (NERC) to influence the industry planning criteria that form the basis of PJM's planning process (found at http://www.nerc.com/page.php?cid=2.) NERC regional criteria development, applicable to PJM, is also open to stakeholder input through the open and participatory process of ReliabilityFirst Corporation (found at https://www.rfirst.org/standards/Pages/StandardsDocuments.aspx.)

Additionally, regional and local criteria that go beyond and complement the NERC obligations can be created and incorporated into PJM planning through participation in PJM's Planning Committee and other related stakeholder processes (please refer to http://www.pjm.com/committees/pjm.html.) In this manner, PJM, as the independent planning authority, avails stakeholders full opportunity to participate in the planning process from assumptions setting to the final plan. The PJM annual regional plan is based on the effective criteria in place at the time of the analyses, including applicable standards and criteria of the NERC and the applicable regional reliability council[1], the various Nuclear Plant Licensees' Final Safety Analysis Report grid requirements and the PJM and local Reliability Planning Criteria (Attachment D.) Section 2 details the specific criteria applicable to each transmission planning process study phase. Criteria are comparably applicable to all similarly situated Native Load Customers and other Transmission Customers.

1.5.2 Market Efficiency Planning

Market efficiency planning is an evaluation process that results in facilities planned to achieve economic efficiencies rather than an analysis that produces violations measured against criteria. This process compares alternative plans' cost effectiveness in improving transmission efficiency and produces RTEP recommendations from this process. The metrics of economic inefficiency include historic and projected congestion. The measures of historic congestion are gross congestion, unhedgeable congestion, and pro-ration of auction revenue rights. The measure of projected congestion is based on a market analysis of future system conditions performed with a commercially available security constrained, economic dispatch market analysis tool. This market analysis results in future projections of the congestion and its binding constraint drivers. These congestion measures are posted and available to stakeholders by binding constraint and form the basis for PJM and stakeholder development of remedies. Transmission plans from the reliability analysis or a new plan presented that economically relieves historical or projected congestion are candidates for market efficiency solutions. The successful candidates will be those facilities that pass PJM's threshold test and bright line economic efficiency test. This test specifies that a proposed solution's savings in the sum of the weighted production cost of energy and capacity plus the weighted load cost of energy and capacity (weighted 70%, 30% respectively) must exceed its projected revenue requirements, on a 15 year present worth basis, by at least 25% (the threshold cost/benefit test.) Each of this process' elements, its underlying assumptions and its methods is described in more detail in the accompanying sections of this manual 14B and in Attachment E.

[1] The Reliability*First* Regional Reliability Corporation (RRC) for the PJM Mid-Atlantic and Western Regions (which replaced the former ECAR, MAAC and MAIN RRCs on January 1, 2006) and the Virginia-Carolinas (VACAR) Area Reliability subregion of the SERC Reliability Corporation for PJM Southern Region.

Section 2: Regional Transmission Expansion Plan Process

In this section you will find an overview of the PJM Region transmission planning process, covering the following areas:

- Components of PJM's 15-Year planning
- The need and drivers for a regional transmission expansion plan
- Reliability planning overview
- Specific components of reliability planning and the Stakeholder process
- Interconnection request drivers of RTEP
- Cost responsibility for reliability related upgrades
- Market efficiency planning review
- Specific components of market efficiency planning and the Stakeholder process.
- Operational performance driven planning
- Specific components of operational performance driven planning

2.1 Transmission Planning = Reliability Planning + Market Efficiency

Effective with the 2006 RTEP, PJM, after stakeholder review and input, expanded its RTEP Process to extend the horizon for consideration of expansion or enhancement projects to fifteen years. This enables planning to anticipate longer lead-time transmission needs on a timely basis.

Fundamentally, the Baseline reliability analysis underlies all planning analyses and recommendations. On this foundation, PJM's annual 15-year planning review now yields a regional plan that encompasses the following:

1. Baseline reliability upgrades, discussed in this Section 2;
2. Generation and transmission interconnection upgrades, discussed in Attachment C and Manual 14A.
3. Market efficiency driven upgrades, discussed in this Section 2.
4. Operational performance issue driven upgrades, discussed in this Section 2.

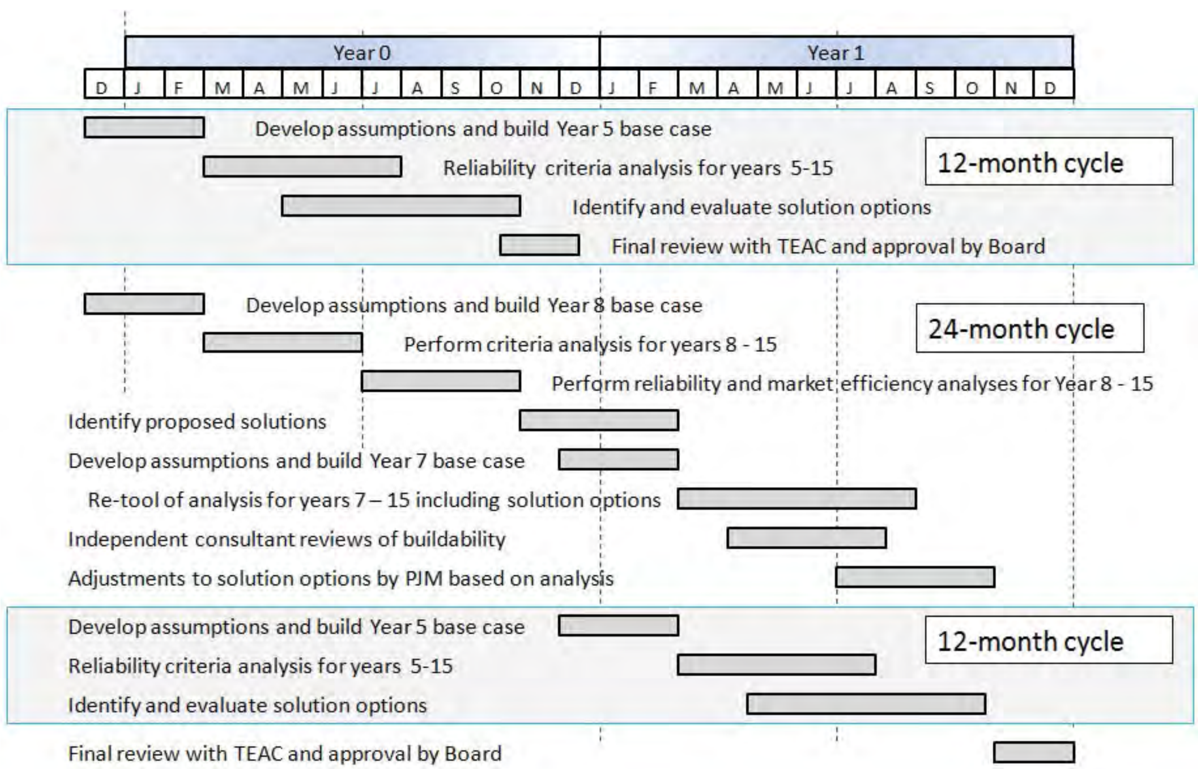
Exhibit 1 shows the 24-month planning process used for the 15-year RTEP horizon. This 24-month planning process integrates the upgrades noted above with information transparency, stakeholder input and review and PJM Board of Manager approvals. Activities shown on this diagram and their timing are for illustrative purposes. The actual timeline may vary to some degree to be responsive to the RTEP and stakeholder needs.

The 24-month planning process is made up of two similar 12-month planning cycles to identify and develop shorter lead-time transmission upgrades and one 24-month planning cycle to provide sufficient time for the identification and development of longer lead-time transmission upgrades that may be required to satisfy planning criteria. Consistent with the requirements of the NERC TPL Reliability Standards the 24-month planning process includes both near- term (years one through five) and long-term (years six through fifteen) assessments of the transmission system as described below.

The first step in the process is to develop the set of assumptions that will be used for the subsequent analyses. These assumptions are vetted with stakeholders at TEAC and Subregional RTEP Committee meetings. A series of power-flow base cases are then developed based on the assumptions. The yearly series of cases include the latest information and assumptions available related to load, resources and transmission topology. A new 5-year base case is developed for near-term baseline reliability analysis. Base cases for retool analyses of years closer than 5-years are developed as required.

In addition to these near-term base cases additional power-flow base cases are developed for long-term planning. These long-term cases are used to evaluate the need for more significant projects requiring a longer time to develop. These longer lead time projects generally provide a more regional benefit. The long-term base case developed at the start of each 24-month planning cycle is based on the system conditions that are expected to exist in 8 years. As noted in Exhibit 1, this 8-year out base case is updated and retooled at the start of the second year of the 24-month planning cycle (i.e. at that point a 7-year out base case), with additional criteria analysis being run to validate the findings from the analysis that was conducted during the first year of the 24-month planning cycle.

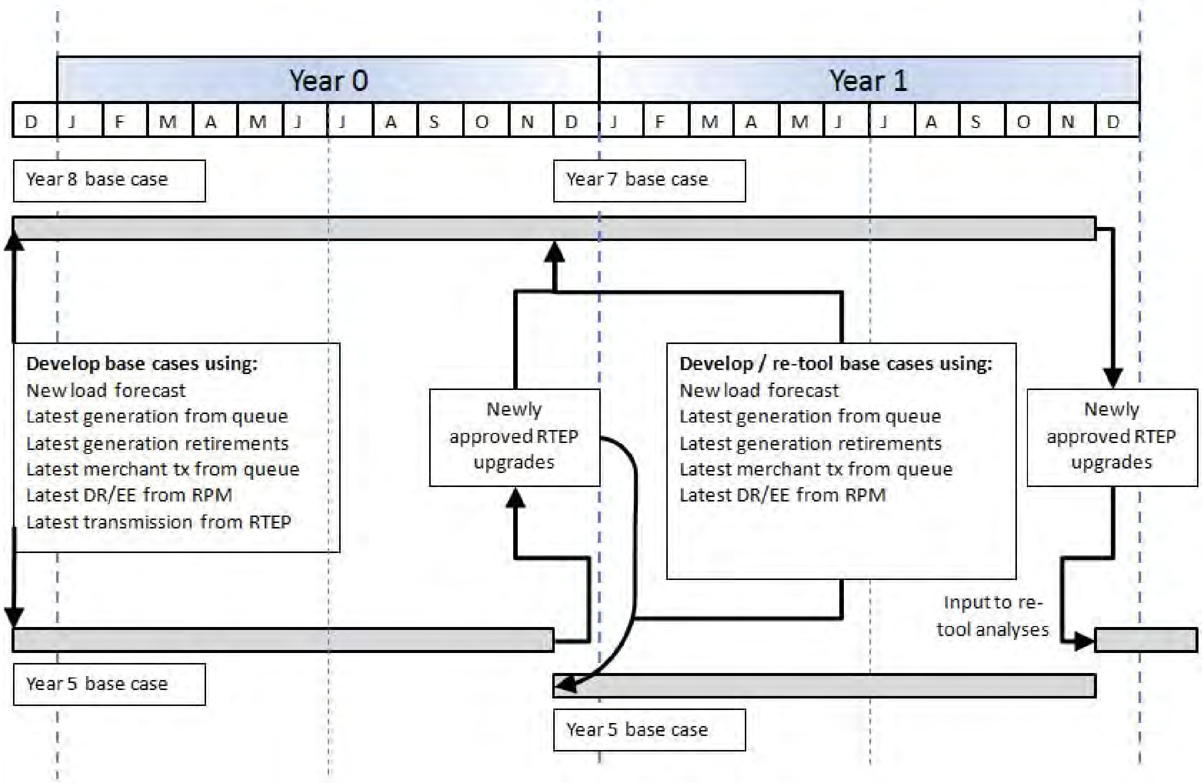
Exhibit 1: 24-Month Planning Cycle



The scope of the near-term baseline analysis that is completed as part of each 12-month planning cycle includes an exhaustive review of applicable reliability planning criteria on all BES facilities as described in section 2.3 of this manual. As noted above, PJM typically performs this near-term analysis on a 5-year out base case. Retool analyses of previous near-term assessments are also completed, as required. Any identified criteria violations are reviewed with stakeholders throughout the planning process. Ultimately, solutions to address the criteria violations are developed, reviewed with the TEAC and/or Sub-regional RTEP Committee as applicable, and submitted to the PJM Board of Managers for approval. Through this planning process, a baseline system without any criteria violations is developed for the near-term (i.e., 5-year baseline). This baseline system, without any criteria violations, is then used for subsequent interconnection queue studies.

Long-term planning is also completed as part of the development of the RTEP to identify solutions to planning criteria violations that require longer lead times to implement. As part of the 24-month planning cycle PJM initially develops an 8-year out base case that is used to evaluate planning criteria for the long-term planning horizon. Long term criteria analysis is completed on this base case during the first year of the 24-month cycle. A combination of a full AC powerflow solution and linear analysis, as described in this manual, is used to determine the loading on facilities for years 8 through 15. Violations and proposed solutions to address them are developed by stakeholders and PJM staff during the first year of the 24-month planning cycle. As shown in Exhibit 2, during the second year of the 24-month planning cycle, the base case used for the long-term analysis during the first year (i.e., now year 7) is updated to reflect the latest assumptions about load, generation, DR, EE, and transmission topology. Long term criteria analysis is completed on this base case during the second year of the 24-month cycle. A combination of a full AC powerflow solution and linear analysis, as described in this manual, is again used to determine the loading on facilities for years 7 through 15. Potential violations identified during the first year are validated and the proposed solutions to address those violations are refined during the second year of the 24–month planning cycle. An independent consultant may be used to develop an independent cost estimate and evaluate the buildability of proposed solutions. Results from these long-term analyses, including potential violations and their solutions, are reviewed with the TEAC throughout the 24-month planning process. Ultimately, any required long-lead time solutions that are identified through this planning process are presented to the PJM Board of Managers for approval.

Exhibit 2: Base Case Development



2.2 The RTEP Process Drivers

The continuing evolution and growth of PJM's robust and competitive regional markets rests on a foundation of bulk power system reliability, ensuring PJM's ongoing ability to meet control area load-serving obligations. It also includes a commitment to enhance the robustness and competitiveness of Energy and Capacity markets by incorporating analysis and development of market efficiency projects. Schedule 6 of the PJM Operating Agreement describes the PJM RTEP process, governing the means by which PJM coordinates the preparation of a plan for the enhancement and expansion of the Transmission Facilities – on a reliable and environmentally sensitive basis and in full consideration of available economic and market efficiency factors and alternatives - in order to meet the demands for firm transmission service in the PJM region. PJM's FERC-approved RTEP process preserves this foundation through independent analysis and recommendation, supported by broad stakeholder input and approval by an independent RTO Board in order to produce a single RTEP.

The PJM Region transmission planning process is driven by a number of planning perspectives and inputs, including the following:

- ReliabilityFirst Regional Reliability Corporation[2] (RFC) Reliability Assessment – forward-looking assessments performed to assure compliance with NERC and applicable regional reliability corporation

[2] Reliability*First*, a new regional reliability corporation under the North American Electric Reliability Corporation (NERC), replaced three existing PJM-related reliability councils (ECAR, MAAC and MAIN) on January 1, 2006.

(ReliabilityFirst or SERC Reliability Corporation) reliability standards, as appropriate.

- SERC Reliability Corporation (SERC) Reliability Assessment
- PJM Annual Report on Operations – an assessment of the previous year's operational performance to assure that any bulk power system operational conditions which have emerged, e.g., congestion, are adequately considered going forward.
- PJM Load Serving Entity (LSE) capacity plans
- Generator and Transmission Interconnection Requests – submitted by the developers of new generating sources and new Merchant Transmission Facilities, these requests seek interconnection in the PJM Region (or seek needed enhancements as the result of increases in existing generating resources.)
- Transmission Owner and other stakeholder transmission development plans
- Interregional transmission development plans – the transmission expansion plans of those power systems adjoining PJM, and in some cases, beyond.
- Long-term Firm Transmission Service Requests
- Activities under the PJM committee structure especially, the Planning Committee (PC), the Transmission Expansion Advisory Committee (TEAC), the Subregional RTEP Committee, and local groups facilitated by PJM within the TEAC established processes (see section 1 "TEAC, Subregional RTEP Committee, and related planning activities".)
- PJM Development of Economic Transmission Enhancements based on Economic and Market Efficiency factors
- Operational performance assessments and reviews such as the aging Infrastructure Initiative – a Probabilistic Risk Assessment of equipment that poses significant risk to the Transmission System.

The cumulative effect of these drivers is analyzed through the PJM Region transmission planning process to develop a single RTEP which recommends specific transmission facility enhancements and expansion on a reliable and environmentally sensitive basis and in full consideration of economic and market efficiency analyses. See Attachment B for details of the RTEP – Scope and Procedure.

> **NOTE:** The most recent version of the PJM RTEP is available PJM Web site at http://www.pjm.com/planning/rtep-upgrades-status.aspx.

These analyses are conducted on a continual basis, reflecting specific new customer needs as they are introduced, but also readjusting as the needs of Transmission Customers and Developers change. One such RTEP baseline regional plan will be developed and approved each year.

> **NOTE:** Generation withdrawals have the potential to impact study results for any generation or merchant transmission project that doesn't have an executed ISA.
>
> Generation retirements will not affect the study results for any generation or merchant transmission project that has received an Impact Study Report (i.e., No Retool – the generator retirements are applied at the next baseline update.)
>
> Generation retirements included in interconnection project studies will be those announced as of the date a project enters the interconnection queue.

In this way, the plan continually represents a reliable means to meet the power system requirements of the various Transmission Customers and Interconnection Customers in a fully integrated fashion, at the same time preserving the rights of all parties with respect to the Transmission System. The assurance of a reliable Transmission System and the protection of the Transmission Customer/Developer rights with respect to that system coupled with the timely provision of information to stakeholders are the foundation principles of the PJM transmission planning process.

The PJM Region transmission planning process also establishes the cost responsibility for the following types of facility enhancements as defined in the PJM Tariff:

- Attachment Facilities
- Direct Assignment Facilities
- Network Upgrades (Direct and Non-direct)
- Local Upgrades
- Merchant Network Upgrades

Each RTEP encompasses a range of proposed power system enhancements: circuit breaker replacements to accommodate increased current interrupting duty cycles; new capacitors to increase reactive power support; new lines, line reconductoring and new transformers to accommodate increased power flows; and, other circuit reconfigurations to accommodate power system changes as revealed by the drivers discussed above.

Requests for interconnection of new generators or transmission facilities, while not the sole drivers of the PJM Region transmission planning process, are a key component of the RTEP. Analyzing these requests has required adoption of an approach that establishes baseline system improvements driven by known inputs, followed by separate queue-defined, cluster-based impact study analyses. Overall, PJM's RTEP process – under a FERC-approved RTO model – encompasses independent analysis, recommendation and approval to ensure that facility enhancements and cost responsibilities can be identified in a fair and non-discriminatory manner, free of any market sector's influence. All PJM market participants can be assured that the proposed RTEP was created on a level playing field.

2.3 RTEP Reliability Planning

2.3.1 Establishing a Baseline

In order to establish a reference point for the annual development of the RTEP reliability analyses a ‘baseline’ analysis of system adequacy and security is necessary. The purpose of this analysis is threefold:

- To identify areas where the system, as planned, is not in compliance with applicable NERC and the applicable regional reliability council (ReliabilityFirst or SERC) standards, Nuclear Plant Licensee requirements and PJM reliability standards including equipment replacement and/or upgrade requirements under PJM’s Aging Infrastructure Initiative. The baseline system is analyzed using the same criteria and analysis methods that are used for assessing the impact of proposed new interconnection projects. This ensures that the need for system enhancements due to baseline system requirements and those enhancements due to new projects are determined in a consistent and equitable manner.
- To develop and recommend facility enhancement plans, including cost estimates and estimated in-service dates, to bring those areas into compliance.
- To establish the baseline facilities and costs for system reliability. This forms the baseline for determining facilities and expansion costs for interconnections to the Transmission System that cause the need for facilities beyond those required for system reliability.

The system as planned to accommodate forecast demand, committed resources, and commitments for firm transmission service for a specified time frame is tested for compliance with NERC and the applicable regional reliability council (ReliabilityFirst or SERC) standards, Nuclear Plant Licensee requirements, PJM Reliability Standards and PJM design standards. Areas not in compliance with the standards are identified and enhancement plans to achieve compliance are developed.

The ‘baseline’ analysis and the resulting expansion plans serve as the base system for conducting Feasibility Studies for all proposed generation and/or merchant transmission facility interconnection projects and subsequent System Impact Studies.

2.3.2 Baseline Reliability Analysis

PJM’s most fundamental responsibility is to plan and operate a safe and reliable Transmission System that serves all long term firm transmission uses on a comparable and not unduly discriminatory basis. This responsibility is addressed by PJM RTEP reliability planning. Reliability planning is a series of detailed analyses that ensure reliability under the most stringent of the applicable NERC, PJM or local criteria. To accomplish this each year, the RTEP cycle extends and updates the transmission expansion plan with a 15 year review. This cycle entails several steps. The following sections describe each step’s assumptions, process and criteria. Attachments A through F of this manual add essential details of various aspects of the reliability planning process.

Reliability planning involves a near-term and a longer term review. The near term analysis is applicable for the current year through the current year plus 5. The longer term view is applicable for the current year plus 6 through plus 15. Each review entails multiple analysis steps subject to the specific criteria that depend on the specific facilities and the type of analysis being performed.

The analysis is initiated in December prior to each annual cycle and concludes with review by the TEAC and approval by the PJM Board about October (TEAC and the PJM Board are appraised regularly throughout the process and partial reviews and approvals of the plan may occur throughout the year.) The TEAC, Subregional RTEP and PJM Planning Committee roles in the development of the reliability portion of the RTEP are described in Schedule 6 of the PJM Operating Agreement.

2.3.3 Near-Term Reliability Review

The near-term reliability review (current year plus 5) provides reinforcement for criteria violations that are revealed by applicable contingency analysis. Limits used in the analysis are established consistent with the requirements of NERC standards FAC-010 and FAC-014. The methodology used to determine system operating limits is included in Attachment-F of this manual. System conditions revealed as near violations will be monitored and remedied as needed in the following year near-term analysis. Violations that occur in many deliverability areas or severe violations in any one area will be referred to the long term analysis for added study of possible more robust system enhancement. PJM annually conducts this detailed review of the current year plus 5. Each year of the period through the current year plus 4 (“in-close” years) has been the subject of previous years’ detailed analyses. In addition, for each of these “in-close” years, PJM updates and issues addendum to address changes as necessary throughout the year. For example planned generation modifications or changes in transmission topology can trigger restudy and the issuance of a baseline addendum. This is referred to as a “retool” study. (For example generators that drop from the Q’s cause restudy and an addendum to be issued for affected baseline analyses.) Also each year during the establishment of the assumptions for the new annual baseline analysis, current updated views of load, transmission topology, installed generation, and generation and transmission maintenance are assessed for the “in-close” range of years to validate the continued applicability of each of the “in-close” baseline analyses and resulting upgrades (including any addendum.) Adjustments in the “in-close” analyses are performed as deemed necessary by PJM. PJM, therefore, annually verifies the continued need for or modification of past recommended upgrades through its retool studies, reassessment of current conditions and any needed adjustments to analyses. All criteria thermal and voltage violations resulting from the near term analyses are produced using solved AC power flow solutions. Initial massive contingency screening may use DC power flow solution techniques.

There are seven steps in an annual near-term reliability review. They are:

- Develop a Reference System Power Flow Case
- Baseline Thermal
- Baseline Voltage
- Load Deliverability - Thermal
- Load Deliverability - Voltage

- Generation Deliverability - Thermal
- Baseline Stability

These reliability related steps are followed by a scenario analysis that ensures the robustness of the plan by looking at impacts of variations in key parameters selected by PJM. Each of these steps are described in more detail in the following material.

2.3.4 Reference System Power Flow Case

The reference power flow case and the analysis techniques comprise the full set of analysis assumptions and parameters for reliability analysis. Each case is developed from the most recent set of Eastern Reliability Assessment Group system models. PJM transmission planning revises this model as needed to incorporate all of the current system parameters and assumptions. These assumptions include current loads, installed generating capacity, transmission and generation maintenance, system topology, and firm transactions. These assumptions will be provided to and reviewed by the Subregional RTEP Committee. The subregional modeling review and modeling assumptions meeting provides the opportunity for stakeholders to review and provide input to the development of the reference power system models used to perform the reliability analyses.

The results of any locational capacity market auction(s) will be used to help determine the amount and location of generation or demand side resources to be included in the reliability modeling. Generation or demand side resources that are cleared in any locational capacity market auction will be included in the reliability modeling, and generation or demand side resources that either do not bid or do not clear in any locational capacity market auction will not be included in the reliability modeling. All such modeling described here will comport with the capacity construct provisions approved by the FERC.

Subsequent to the subregional stakeholder modeling reviews facilitated by PJM, PJM will develop the final set of reliability assumptions to be presented to TEAC for review and comment, after which PJM will finalize the reliability review reference power flow. This model is expected to be available in early January of each year to interested stakeholders, subject to applicable confidentiality and CEII requirements, to facilitate their review of the results of the reliability modeling analyses.

2.3.5 Contingency Definitions

Contingency definitions used in RTEP analysis are the same as applicable NERC TPL contingency definitions. Where the physical design of connections or breaker arrangements results in the outage of more than the faulted equipment when a fault is cleared, the additional facilities are also taken out of service in the contingency definition. For example, if a transformer is tapped off a line without a breaker, both the line and transformer are removed from service as a single contingency event.

Contingency definitions for double circuit tower line outages shall include any two adjacent (vertically or horizontally) circuits on a common structure, but shall exclude circuits that share a common structure for one mile or less. The loss of more than two circuits on a common structure constitutes a NERC extreme event.

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 category A, B and C 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 category A), all facilities shall be loaded within their normal thermal ratings. For each single contingency (NERC Category B), all facilities shall be loaded within their emergency thermal ratings. After each single contingency and allowing phase shifter, re-dispatch and topology changes to be made, post-contingency loadings of all facilities shall be within their applicable normal thermal ratings.

For the more severe NERC category C 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 category C.3 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 category A, B, and C events. Also, voltage criteria are examined for compliance. PJM examines system performance for both a voltage drop criteria (where applicable) and an absolute voltage 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 absolute voltage 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.

2.3.8 NERC Category C3 "N-1-1" Analysis

Purpose:

N-1-1 studies are conducted as part of the annual RTEP to determine if all monitored facilities can be operated:

- Within normal thermal and voltage limits after N-1 (single) contingency assuming re-dispatch and system adjustments, and
- Within the applicable emergency thermal ratings and voltage limits after an additional single contingency (N-1-1) condition.

All violations of the applicable thermal ratings are recorded and reported and tentative solutions will be developed. These study results will be presented to and reviewed with stakeholders.

Model:

Annually, the N-1-1 study is conducted on a 50/50 non-diversified summer peak case. The case building details are defined in Attachment C (C7 3.0 Step 1: Develop Base Case). Non-firm Merchant Transmission withdrawals can be removed. All BES facilities in PJM and ties to PJM will be monitored. Areas of the system that become radial post-contingency will be excluded from monitoring, with the following exceptions

- If the radial system contains greater than 300 MW of load, or
- Specific local TO Planning Criteria require that it be monitored.

Contingencies considered:

- All BES single contingencies as defined in NERC category C.3 as well as lower voltage facilities that are monitored by PJM Operations will be included in the assesment. Non-BES contingencies, defined by Transmission Owners, need to be included to check for greater than 300 MW load loss. Non-BES facilities that are included in the assessment will also have corresponding contingencies defined.

AC Solution Options in the PSS/E program:

- For the first single contingency (N-1 Condition) and to ensure the system remains within emergency thermal ratings
    - Transformer tap adjustment enabled
    - Switched shunt adjustment enabled
- After the first single contingency (N-1 Condition) and to return the system back within normal thermal ratings
    - Phase shifter adjustment enabled
    - System re-dispatched
    - Topology changes implemented
- For the second single contingency (N-1-1 Condition) – Voltage Drop Test (if applicable)

- Transformer tap adjustment disabled
- Phase shifters locked to control angle, not flow
- Switched shunt adjustment disabled except for fast switched capacitors
- Generators are set to regulate their terminal bus
- SVC’s are allowed to regulate
- Automatic shunt adjustment disabled

- For the second single contingency (N-1-1 Condition) – Thermal and Voltage Magnitude Test
    - Transformer tap adjustment enabled
    - Phase shifters locked to control angle, not flow
    - Switched shunt adjustment enabled
    - Automatic shunt adjustment enabled

PJM NERC Category C3 “N-1-1” Methodology:

Thermal Test Methodology:

The PJM NERC Category C3 “N-1-1” Analysis will test the outage of every single contingency (N-1 condition)

1. The first step of the test is to ensure that post-contingency loadings of all facilities shall be within their emergency thermal ratings immediately following the first N-1 contingency
2. The second step of the test is to ensure that post contingency loadings of all facilities shall be within their normal thermal ratings after the first N-1 contingency and subsequent re-dispatch and system adjustments. Allowable system adjustments include generation dispatch, phase shifter adjustment, system reconfiguration and load throwover.
3. The third step is to take the second N-1-1 contingency. Every second N-1-1 contingency is taken on every optimized N-1 scenario case to model the N-1-1 condition. After the second N-1-1 contingency, the thermal loading of any monitored facility that is above the applicable emergency thermal rating (long-term or short-term) is considered a reliability criteria violation and a mitigation plan will be needed.

Voltage Drop Test Methodology:

The N-1-1 Voltage Drop Test procedure follows a similar method as the thermal test method, except all monitored facilities are monitored for the emergency voltage drop limit after the second contingency (N-1-1 condition.) The calculation of voltage drop is defined in section 2.3.7.

Voltage Magnitude Test:

The N-1-1 Voltage Magnitude Test procedure follows a similar method as the thermal test method, except all monitored facilities are monitored for the emergency low limit after the second contingency (N-1-1 condition.)

Voltage Collapse:
Voltage collapse is considered to be a severe reliability violation, and consequently each N-1-1 condition that exhibits voltage collapse needs to be investigated, validated, and resolved with remedial actions, or network upgrades.

System Adjustments:
Allowable System Adjustments following the first contingency (N-1 condition):

- Application of all effective actions and emergency procedures, with the exception of load shedding
- Redispatch using only PJM generators with capacity rights during the generation redispatch process
- Application of a PJM pool-wide generation availability rate during generator re-dispatch to ensure that the re-dispatch is statistically possible
- Un-faulted facilities in multiple facility outages may be restored
- Manual system switching and re-configuration
    - Opening of transmission facilities
        - Including bus-ties
    - Closing of non-faulted transmission facilities
        - Including bus-ties
- Adjustment of Static Var Compensators (SVCs)
- Phase shifter adjustment
- Wind, solar, and other variable resources will be dispatchable up to their capacity delivery rights if they back off simulated facility loadings.
- The rest of resources can be either off line or dispatched between Pmin and (1- PJM generator average outage rate)* Pmax

Allowable System Adjustments following the second contingency (N-1-1 condition):
No manual system adjustments permitted

2.3.9 Load Deliverability Analysis

The load deliverability tests are a unique set of analyses designed to ensure that the Transmission System provides a comparable transmission function throughout the system. These tests ensure that the Transmission System is adequate to deliver each load area's requirements from the aggregate of system generation. The tests develop an "expected value" of loading after testing an extensive array of probabilistic dispatches to determine thermal limits. A deterministic dispatch method is used to create imports for the voltage criteria test. The Transmission System reliability criterion used is 1 event of failure in 25 years. This is intended to design transmission so that it is not more limiting than the generation system which is planned to a reliability criterion of 1 failure event in 10 years.

Each load areas' deliverability target transfer level to achieve the transmission reliability criterion is separately developed using a probabilistic modeling of the load and generation system. The load deliverability tests described here measure the design transfer level supported by the Transmission System for comparison to the target transfer level. Transmission upgrades are specified by PJM to achieve the target transfer level as necessary. Details of the load deliverability procedure can be found in Attachment C.

Thermal

This test examines the deliverability under the stressed conditions of a 90/10 summer load forecast. That is, a forecast that only has a 10% chance of being exceeded. The transfer limit to the load is determined for system normal and all single contingencies (NERC category A and B criteria) under ten thousand load study area dispatches with calculated probabilities of occurrence. The dispatches are developed randomly based on the availability data for each generating unit. This results in an expected value of system transfer capability that is compared to the target level to determine system adequacy. As with all thermal transmission tests applied by PJM the applicable Transmission Owner normal and emergency ratings are applied. The steady state and single contingency power flows are solved consistent with the similar solutions described for the baseline thermal analyses.

Voltage

This testing procedure is similar to the thermal load deliverability test except that voltage criteria are evaluated and that a deterministic dispatch procedure is used to increase study area imports. The voltage tests and criteria are the same as those performed for the baseline voltage analyses.

2.3.10 Generation Deliverability Analysis

The generator deliverability test for the reliability analysis ensures that, consistent with the load deliverability single contingency testing procedure, the Transmission System is capable of delivering the aggregate system generating capacity at peak load with all firm transmission service modeled. The procedure ensures sufficient transmission capability in all areas of the system to export an amount of generation capacity at least equal to the amount of certified capacity resources in each “area”. Areas, as referred to in the generation deliverability test, are unique to each study and depend on the electrical system characteristics that may limit transfer of capacity resources. For generator deliverability areas are defined with respect to each transmission element that may limit transfer of the aggregate of certified installed generating capacity. The cluster of generators with significant impacts on the potentially limiting element is the “area” for that element. The starting point power flow is the same power flow case set up for the baseline analysis. Thus the same baseline load and ratings criteria apply. The flowgates ultimately used in the light load reliability analysis are determined by running all contingencies maintained by PJM planning and monitoring all PJM market monitored facilities and all BES facilities. As already mentioned the same contingencies used for load deliverability apply and the same single contingency power flow solution techniques also apply. Details of the generation deliverability procedure can be found in Attachment C.

One additional step is applied after generation deliverability is ensured consistent with the load deliverability tests. The additional step is required by system reliability criteria that call for adequate and secure transmission during certain NERC category C common mode outages. The procedure mirrors the generator deliverability procedure with somewhat lower deliverability requirements consistent with the increased severity of the contingencies.

The details of the generator deliverability procedure including methods of creating the study dispatch can be found in Attachment C.

2.3.11 Light Load Reliability Analysis

The light load reliability analysis ensures that the Transmission System is capable of delivering the system generating capacity at light load. The 50% of 50/50 summer peak demand level was chosen as being representative of an average light load condition. The system generating capability modeling assumption for this analysis is that the generation modeled reflects generation by fuel class that historically operates during the light load demand level.

The starting point power flow is the same power flow case set up for the baseline analysis, with adjustment to the model for the light load demand level, interchange, and accompanying generation dispatch. The PJM portion of the model is adjusted as well as areas surrounding PJM that impact loadings on facilities in PJM. Interchange levels for the various PJM zones will reflect a statistical average of typical previous years interchange values for off-peak hours. Load level, interchange, and generation dispatch for non-PJM areas impacting PJM facilities are based on statistical averages for previous off-peak periods. Thus the same baseline network model and criteria apply. The flowgates ultimately used in the light load reliability analysis are determined by running all contingencies maintained by PJM planning and monitoring all PJM market monitored facilities and all BES facilities. The contingencies used for light load reliability analysis will include NERC TPL category B and category C, with the exception of the C3 “N-1-1” criteria. NERC TPL Category A, normal system conditions will also be studied. All BES facilities and all non-BES facilities in the PJM real-time congestion management control facility list are monitored. The same single contingency power flow solution techniques also apply. Details of the light load reliability analysis procedure, including methods of creating the study dispatch, can be found in Attachment D.1.

2.3.12 Baseline Stability Analysis

PJM ensures generator and system stability during its interconnection studies for each new generator. In addition, PJM annually performs stability analysis for approximately one third of the existing generators on the system. Analysis is performed on the RTEP baseline stability cases. These analyses ensure the system is transiently stable and that all system oscillations display positive damping with damping ratio consistent with section G.2.2. Generator stability studies are performed for critical system conditions, which include light load and peak load for three phase faults with normal clearing plus single line to ground faults with delayed clearing. Also, specific Transmission Owner designated faults are examined for plants on their respective systems.

Finally, PJM will initiate special stability studies on an as needed basis. The trigger for such special studies commonly includes but is not limited to conditions arising from operational performance reviews or major equipment outages.

2.3.13 Long Term Reliability Review

The PJM RTEP reliability review process examines the longer term planning horizon using a current year plus 15 power flow model and a current year plus 10 power flow model. Assumptions and model development regarding this longer term view will be presented and reviewed and stakeholder input will be considered in the same process used for the near-term review. The longer term view of system reliability is subject to increased uncertainty due to the increased likelihood of changes in the analysis as time progresses. The purpose of the long term review is to anticipate system trends which may require longer lead time solutions. This enables PJM to take appropriate action when system issues may require initiation during the near term horizon in anticipation of potential violations in the longer term. System issues uncovered that are amenable to shorter lead time remedies will be addressed as they enter into the near-term horizon.

Current Year Plus 15 Analysis

The Longer term reliability review involving single and multiple contingency analyses is conducted to detect system conditions which may need a solution with a lead-time to operation exceeding five years. Two processes will be used as indicators to determine the need for contingency analysis in the longer term horizon. The first is a review of the near-term results to detect violations that occur for multiple deliverability areas or multiple or severe violations clustered in a one area of the system. This review may suggest larger projects to collectively address groups of violations. The second is a thermal analysis including double circuit towerline outages at voltages exceeding 100 kV performed on the current year plus fifteen system. All of the current year plus fifteen results produced will be reviewed to determine if any issues may require longer lead time solutions. If so such solutions will be determined and considered for inclusion in RTEP.

This evaluation of the need for longer lead time solutions considers that the NERC category C results may employ load shedding and/or curtailment of firm transactions to ease potential violations. Also this review considers that the current year plus fifteen planning horizon exceeds the required NERC planning horizon. The main effect of this extension to 15 years is to examine a load level that is significantly higher than the base forecast year-ten planning load level. This year fifteen analysis, therefore, captures the equivalent (in a 10-year horizon) of a higher load forecast plus weather sensitivity. To the extent that this long term reliability thermal review indicates marginal system conditions that may require a longer lead time solution, PJM will undertake additional longer term analyses as may be needed.

The long term deliverability analyses follow a similar pattern to the near-term load and generation deliverability analyses. The long term, however, relies solely on linear DC analysis whereas all near term violations result from analysis solutions that rely on the full AC power flow. The load deliverability case is set up for a 90/10 load level and the generation deliverability case is set up for a 50/50 load level. Generation dispatches are determined consistent with the methods for the near term analyses. The analysis for the longer term horizon evaluates all NERC category A and B single contingencies against the same normal and emergency thermal ratings criteria used for the near term (subject to any upgrades that may be applicable for the longer term.)

Reactive Analysis

In addition, the longer term review includes a current year plus 10 reactive analysis. This focuses on contingencies involving facilities above 200 kV in areas where the preceding year-15 analysis uncovered thermal violations. Areas experiencing thermal violations that also show earlier reactive deficiencies will be reviewed for possible acceleration of any longer lead time thermal solutions that were suggested by the year-15 analysis. This analysis, as necessary from year to year, will also consider long-term upgrade sensitivity to key variables such as load power factor delivered from the Transmission System or heavy transfers. If uncovered violations are insufficient to justify acceleration of upgrades and are all amenable to shorter lead-time upgrades, then the violations will continue to be monitored in future RTEP analyses.

2.3.14 Stakeholder review of and input to Reliability Planning

RTEP reliability planning, through the operation of the TEAC and Subregional RTEP Committees, provides interested parties with the opportunity to review and provide meaningful and timely input to all phases of the reliability planning analyses. This section extends the Section 1 discussion of the TEAC and Subregional RTEP Committee process specifically as it relates to reliability planning. Exhibit 1 shows the workflow and timing for the reliability planning process steps. PJM anticipates at least two Subregional RTEP Committee reliability reviews. The initial subregional meeting will present and address reliability study assumptions and parameters. The second meeting will provide the opportunity for stakeholder comment and input on criteria violations and presentations of alternative remedies to identified violations. Between the two meetings PJM will provide feedback on interim study progress sufficient to enable stakeholder preparation for the second set of subregional meetings. Additional subregional meetings will be facilitated as PJM determines is necessary for adequate input and review. The relative timing of the TEAC and subregional activities are illustrated in Exhibit 1.

<u>Subregional RTEP Committee initial assumptions meeting</u>

This meeting is expected to occur in ***December*** of each year in preparation for the upcoming annual RTEP review. Prior to the meeting PJM will post its anticipated inputs and assumptions to enable stakeholder review and preparation for the meeting. At the meeting PJM will present the assumptions for discussion and input by all interested parties. Subsequent to this meeting stakeholders will have additional opportunity to provide input to PJM in preparation for the next TEAC meeting, at which PJM will present the final reliability assumptions for TEAC review. Although the initial Subregional assumptions meeting will discuss anticipated assumptions for both the reliability and market efficiency phase of the RTEP, The final TEAC review of each will likely occur at separate TEAC meetings (see also the market efficiency discussion following.) The TEAC endorsement of final RTEP reliability assumptions is expected to occur in early ***January***.

<u>PJM development of criteria violations and stakeholder participation</u>

After the TEAC endorsement of PJM's RTEP analysis assumptions, PJM will finalize its reference system power flow which is the starting point of its series of reliability analyses. This power flow is available to stakeholders subject to applicable confidentiality and CEII requirements. PJM will perform its series of detailed RTEP reliability analyses encompassing the 15-year planning horizon. Details of the methods and procedures for the reliability analyses can be found elsewhere in this Manual 14B and its attachments. The five-year and longer time-frame criteria violations will be posted for review, evaluation and development of remedy alternatives by all interested parties. The PJM production of the reliability analysis raw results is expected to occur about ***January through July*** of each year. Posting of the results and stakeholder review and consideration of alternative remedies is expected to occur about ***February through August*** of each year. PJM will post TO and other stakeholder alternative upgrade remedies made available throughout this process. Throughout this time frame, TEAC typically has monthly or more frequent regularly scheduled meetings. PJM will periodically apprise TEAC of the progress of the violations identification and production of upgrade alternatives. Stakeholders may use these meetings to raise and discuss issues found in their reviews. Depending on the issues raised and input from stakeholders PJM may facilitate Subregional RTEP Committee meetings instead of or in addition to a scheduled TEAC meeting. These subregional meetings are intended for more focused review of subregional violations and alternative solutions.

Subregional RTEP Committee criteria violations and upgrade alternative meeting

This meeting is expected to occur, as may be necessary in various subregions, in the ***July / August*** timeframe each year. If a subregional meeting is unnecessary, the regularly scheduled TEAC meetings will provide the opportunity for that subregion’s participants open discussion of violations and upgrades. In any event, all regional and subregional projects will be appropriately presented and reviewed at a TEAC meeting. Prior to a subregional violations and upgrade meeting, PJM will post the upgrade solutions that it proposes to remedy the identified criteria violations. At this subregional meeting PJM will present the reliability upgrades of specific violations and alternative upgrades as may be appropriate. By 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.

2.4 RTEP integrates Baseline Assumptions, Reliability Upgrades and Request Evaluations

PJM’s robust energy market has attracted numerous requests from generator and transmission developers for interconnections with the Transmission System. These generator and transmission Interconnection Requests constitute a significant driver of regional transmission expansion needs. This subsection discusses this driver in the context of the RTEP preparation. Details of this process are contained in Manual 14A.

Requests for Long Term Firm Transmission Service and generator deactivations are other types of request that are evaluated and incorporated into RTEP.

Demand Response (DR) can be a load response solution to the need for transmission upgrades. DR solutions enter the PJM process in the Reliability Pricing Model (RPM) through the associated base residual and incremental auctions. The DR cleared in the auction is included in the assumptions for RTEP development and physically modeled in the baseline power flows. In this manner, load can mitigate or delay the need for RTEP upgrades.

The RTEP process baseline analyses include previously processed generators and transmission modifications as starting point assumptions. The current year RTEP evaluations performed on this baseline case are incremental to the baseline and establish a “revised” baseline for the year of the annual RTEP analysis. This revised baseline forms the starting case for the reviews of new interconnection requests. The new interconnection request analyses result in system modifications beyond RTEP upgrades that are caused by each interconnection request. New interconnection request evaluations also include a review of their effects on newly approved RTEP upgrades that are not yet committed to construction. If previously identified RTEP upgrades can be delayed because of a new interconnection request, the projects responsible for the upgrade deferrals will be credited for the benefits of the delayed need for the upgrades.

The RTEP integrates reliability upgrades, interconnection request upgrades and plan modifications and DR effects into a single process that accounts for the mutual interaction of the various market forces. In this way, transmission upgrades, interconnection requests and DR receive comparable treatment with respect to their opportunity to relieve transmission constraints.

Timing of Long-Term Firm Transmission Service Requests, and Generation and Transmission Interconnection Requests are based on the business needs of the party requesting the service. Such Requests, therefore, enter the RTEP planning process throughout the RTEP planning year. Expansion plans that result from these individual project evaluations are incorporated into the RTEP after the system impact study stage. In addition, if needed to satisfy assumed planning reserve requirements for future planning year analyses, queue generators in earlier stages of the queue process may also be included. Only the queue generators with completed signed Interconnection Service Agreements, however, are allowed to be used to alleviate constraints.

This manual contains the details regarding the RTEP reliability planning process procedures. Refer to the introductory Manual 14 for references to the details associated with other elements of RTEP including the request and RPM processes.

2.5 RTEP Cost Responsibility for Required Enhancements

The RTEP encompasses two types of enhancements: Network Reinforcements and Direct Connection Attachment Facilities. Network Reinforcements can be required in order to accommodate the interconnection of a merchant project (generation or transmission) or to eliminate a Baseline problem as a result of system changes such as load growth, known transmission owner facility additions, etc. Merchant project driven upgrades are addressed in Manual 14A. The cost responsibility for each baseline-revealed Network Reinforcement is borne by transmission owners based on the contribution to the need for the network reinforcement. Such costs are recoverable by each transmission owner through FERC-filed transmission service rates. Network reinforcements may also be proposed by PJM to mitigate unhedgeable congestion. Allocation procedures for Baseline and Market Efficiency upgrades are discussed in Attachment A.

Overall, the RTEP is best understood from the perspective of the studies that revealed the recommended Plan enhancements. To that end, the Baseline Analysis and Impact Studies identify the enhancements required to meet defined NERC and applicable regional reliability council (Reliability First or VACAR/SERC) standards, Nuclear Plant Licensee requirements and PJM reliability standards.

2.6 RTEP Market Efficiency Planning

Market efficiency analysis is performed as part of the overall PJM Regional Transmission Expansion Planning (RTEP) process to accomplish the following two objectives:

1. Determine which reliability upgrades, if any, have an economic benefit if accelerated.
2. Identify new transmission upgrades that may result in economic benefits.

PJM will perform a market efficiency analysis each year, following the availability of the appropriate updated RTEP power flow resulting from the reliability analysis process. As a result, there is a mechanism in place for regularly identifying transmission enhancements or expansions that will relieve transmission reliability violations that also have an economic impact. Constraints that have an economic impact include, but are not limited to, constraints that cause: (1) significant historical gross congestion; (2) significant historical unhedgeable congestion; (3) pro-ration of Stage 1B ARR; or (4) significant future congestion as forecast in the market efficiency analysis.

In the market efficiency analysis, PJM will compare the costs and benefits of the economic-based transmission improvements. To calculate the benefits of these potential economic-based enhancements, PJM will perform and compare market simulations with and without the proposed accelerated reliability-based enhancements or the newly proposed economic-based enhancements for selected future years within the planning horizon of the RTEP. The relative benefits and costs of the economic-based enhancement or expansion must meet the benefit/cost ratio threshold test to be included in the RTEP recommended to the PJM Board of Managers for approval (This test and its implementation is described in detail in Attachment E.) PJM will also consider potential individual plans meeting objectives 1 or 2 resulting from the analyses of the posted congestion data by all stakeholders. PJM will present all the RTEP market efficiency enhancements to the TEAC Committee for review, comment and endorsement. Subsequent to TEAC review, PJM will address the TEAC review and present the final RTEP market efficiency plan to the PJM Board, along with the advice, comments, and recommendations of the TEAC Committee, for Board approval.

2.6.1 Market Efficiency Analysis and Stakeholder Process

PJM's market efficiency analysis involves several phases. The process begins with the determination of the congestion drivers that may signal market inefficiencies. PJM will collect and publicly post relevant drivers. These metrics will be reviewed by PJM and all stakeholders to assess the system areas that are most likely candidates for market efficiency upgrades. In addition, PJM will perform market simulations to determine projections of future market congestion based on the anticipated RTEP upgraded system. This process facilitates concurrent PJM and stakeholder review of the same information considered by PJM in preparation for PJM's solicitation of stakeholder input for upgrades that may economically alleviate market inefficiencies. This solicitation of input will be to the appropriate TEAC or Subregional RTEP Committee. Following the evaluation of congestion drivers and solicitation of remedies, PJM will initiate an analysis phase which first examines the potential economic costs and benefits that may be associated with any upgrades specified during the reliability analysis. After this assessment, PJM will evaluate the economic costs and benefits of any identified new potential upgrades target specifically at economic efficiency. The following information looks at each of these phases in more detail.

2.6.2 Determination and evaluation of historical congestion drivers

All PJM metrics of historical congestion drivers will be posted monthly throughout the year, except that AAR information will be posted as specified by the AAR auction process. This information can be found at:

http://www.pjm.com/planning/rtep-development/market-efficiency.aspx

http://www.pjm.com/markets-and-operations/ftr.aspx

PJM will calculate and post gross congestion costs by constraint for each constraint causing real-time off-cost operations. Gross congestion will be calculated as the product of the constraint shadow price times the load MWs at each load bus in the affected area times the load bus dfax where the affected area is defined as any bus with a dfax of 3% or greater.

PJM will calculate and post the Unhedgeable congestion cost statistics and associated constraints. Unhedgeable congestion costs will be calculated by taking the sum of load MWs at each load bus in the affected area times the relevant load bus dfax minus the sum of economic generation MWs at each generator bus in the affected area times the relevant generator bus dfax minus the sum of FTR MWs, and multiplying the resulting MW by the constraint shadow price. Economic generation is generation which is available and on-line and which, at its current level of output, has a bid price no greater than the PJM system marginal price. Self-scheduled generation is assigned a bid price of zero in the determination of economic generation MW.

Congestion causing a pro-ration of Stage 1A ARR requests will be determined and recommended for inclusion in the RTEP with a recommended in-service date based on the 10-year Stage 1A simultaneous feasibility analysis results. This recommendation will also include a high-level analysis of the cost and economic benefits of the upgrade as additional information but such upgrades will not be subject to market efficiency cost/benefit analysis. More information on the ARR allocation auction process can be found in Manual 6 titled PJM Capacity Market.

Congestion causing pro-ration of Stage 1B ARR requests will be addressed using the “with and without” analysis and the benefit/cost ratio threshold described previously in this market efficiency material.

2.6.3 Determination of projected congestion drivers and potential remedies

PJM will provide all stakeholders with estimates of the projected congestion by performing annual hourly market simulations of future years using a commercially available market analysis software modeling tool (see assumptions and criteria material in Section 1.) This simulation will produce and PJM will post projected binding constraints, binding hours, average economic impact of binding constraints, and cumulative economic impact of binding constraints for the four RTEP market efficiency analyses (current year plus 1, current year plus 4, current year plus 7 and current year plus 12).

This analysis is expected to be completed about the ***third quarter*** of the RTEP cycle year. At this time PJM will also facilitate a TEAC or Subregional RTEP Committee meeting, as appropriate, to review congestion and solicit feedback from the stakeholders’ review of the projected congestion data as well as the historical congestion data. All stakeholders can provide input to PJM’s consideration of the congestion data and potential upgrades to be considered for market efficiency solutions to identified economic issues.

The timing of this meeting will depend, to some extent, on the complexity of the analysis, however, it is anticipated that this meeting will occur during the ***third quarter*** of each year. At this meeting, PJM will provide a summary of the analysis results and a description of any congested areas that will be analyzed using Market Efficiency analysis. PJM will also provide a high-level estimate of the transmission upgrades then being considered. At the completion of this stakeholder review, any member of the TEAC can provide additional written comments within sixty (60) days of this meeting.

Stakeholder Written Comments

These written comments will consist of three (3) sections:

- Introduction, which will describe the party submitting the comments and their reason for submitting these comments
- Summary, which will consist of no more than 3 pages summarizing the positions described in the written comments
- Discussion, which will consist of no more than 20 pages describing in detail the positions taken by the party

Parties wishing formally to submit alternative proposals of their own are encouraged to do so separately, as described further, below.

The Office of the Interconnection will have the responsibility of compiling comments from TEAC participants. All written comments will be posted to the PJM web site and provided to the PJM Board of Managers together with a PJM staff summary that will focus on conveying the following: (1) the issues; (2) the parties raising the issues; and, (3) as may be appropriate, PJM's discussion of ramifications of the issues. Communication to the Board of Managers will not include results of any voting.

2.6.4 Evaluation of cost / benefit of advancing reliability projects

PJM will perform annual market simulations and produce cost / benefit analysis of advancing reliability projects. An initial set of simulations will be conducted for each of the four years (current year plus 1, current year plus 4, current year plus 7 and current year plus 10) using the "as is" transmission network topology without modeling future RTEP upgrades. A second set of simulations will be conducted for each of the four years using the as planned RTEP upgrades. A comparison of the "as is" and "as planned" simulations will identify constraints which have caused significant historical or simulated congestion costs but for which an as-planned upgrade will eliminate or relieve the congestion costs to the point that the constraint is no longer an economic concern. A comparison of these simulations will also reveal if a particular RTEP upgrade is a candidate for acceleration or expansion. For example, if a constraint causes significant congestion in year 7 but not in year 10 then the upgrade which eliminates this congestion in the year 10 simulation may be a candidate for acceleration. The benefit of accelerating this upgrade would then be compared to the cost of acceleration as described below before recommendation for acceleration is made.

When the reliability project economic acceleration analyses have been completed, PJM will schedule a TEAC or Subregional Committee meeting, as appropriate, to review the results. The timing of this meeting will depend, to some extent, on the amount and complexity of analysis that must be performed. However, it is anticipated that this meeting will take place during the ***fourth quarter*** of each year. At this meeting PJM will provide a summary of the analysis results, including an update of the Market Efficiency analysis and a description of any recommendations for accelerating reliability projects based on economic considerations.

2.6.5 Determination and evaluation of cost / benefit of potential RTEP projects specifically targeted for economic efficiency

PJM will perform annual market simulations and produce cost / benefit analysis of projects specifically targeted for economic efficiency. The net present value of annual benefits will be calculated for the first 15 years of upgrade life and compared to the net present value of the upgrade revenue requirement for the same 15 year period.

An initial set of simulations will be conducted for each of four years (current year plus 1, current year plus 4, current year plus 7 and current year plus 10) using the as planned transmission network topology as defined by the most recent RTEP. A second set of simulations will be conducted for each of the four years using the as planned transmission network topology plus the upgrade being studied. The upgrade will be included in each of the four simulation years regardless of the actual anticipated in-service date of the upgrade. A comparison of these simulations will identify the benefit of the upgrade in each of the four years analyzed. Annual benefits within the 10-year time frame for years which were not simulated would be interpolated using these simulation results. A forecast of annual benefits for years beyond the 10-year simulation time frame would be based on an extrapolation of the market simulation results from the studied years. A higher-level annual market simulation will be made for future year 15 to validate the extrapolation results and the extrapolation of annual benefits for years beyond the 10-year simulation time frame may be adjusted accordingly. This high level simulation of future year 15 may require a less detailed model of the transmission system below the 500 kV level.

An extrapolation of the simulation results will provide a forecast of annual upgrade benefits for each of the anticipated first 15 years of upgrade life, beginning from the projects anticipated in-service date. The present value of annual benefits projected for the first 15 years of upgrade life will be compared to the present value of the upgrade revenue requirement for the same 15 year period to determine if the upgrade is cost beneficial and recommended for inclusion in the PJM RTEP. If the ratio of the present value of benefits to the present value of costs exceeds 1.25 then the upgrade is recommended for inclusion in the RTEP.

For each upgrade which is recommended for inclusion in the RTEP, PJM will provide the level of new generation or DSM per region that would eliminate the need for the transmission upgrade.

When the economic efficiency project evaluations have been completed, PJM will schedule a TEAC or Subregional Committee meeting, as appropriate, to review the results. The timing of this meeting may depend on the amount and complexity of analysis that must be performed. It is, however, anticipated that this meeting will take place ***by April*** of the calendar year that begins the subsequent RTEP planning cycle. At this meeting PJM will provide a summary of the analysis results, including an update of the Market Efficiency analysis, and a description of any recommendations for economic efficiency projects.

2.6.6 Determination of final RTEP market efficiency upgrades

PJM will perform a combined review of the accelerated reliability projects and new market efficiency projects that passed the economic screening tests to determine if there are potential upgrades with electrical similarities. This may result in new projects to replace the original projects to form a more efficient overall market solution. Stakeholders may also suggest such potential synergies. PJM will evaluate the cost / benefits of any such resulting “hybrid” projects[3]. The final list of reliability projects and market efficiency projects, including any “hybrid” projects will be presented and discussed at a ***second quarter (April)*** TEAC meeting. At this TEAC meeting PJM will review all the Market efficiency plans resulting from this cycle of market efficiency studies. Recommended projects will be taken to the PJM Board for endorsement, and will either be included in subsequent RTEP analysis if there is a “volunteer” to build the project, or a report will be filed with FERC in accordance with Schedule 6 of the PJM Operating Agreement. As part of this request for endorsement, PJM will provide the written comments submitted by the parties, and will discuss these written comments with the PJM Board.

Within the limits of confidential, market sensitive, trade secret, and proprietary information, PJM will make all of the information used to develop the Market Efficiency recommendations available to market participants to use in their own, independent analyses.

For each enhancement which is analyzed, PJM will calculate and post on its website changes in the following metrics on a zonal and system-wide basis: (i) total energy production costs (fuel costs, variable O&M costs and emissions costs); (ii) total load energy payments (zonal load MW times zonal load Locational Marginal Price); (iii) total generator revenue from energy production (generator MW times generator Locational Marginal Price); (iv) Financial Transmission Right credits (as measured using currently allocated Auction Revenue Rights plus additional Auction Revenue Rights made available by the proposed acceleration or modification of a planned reliability-based enhancement or expansion or new economic-based enhancement or expansion); (v) marginal loss surplus credit; and (vi) total capacity costs and load capacity payments under the Reliability Pricing Model construct.

For each market efficiency project proposed for RTEP, PJM will also post, as soon as practical, the following:

a. Anticipated high-level project schedule and milestone dates
b. Final commitment date after which any change to input factors or drivers will not result in transmission project deferral or cancellation.

After this TEAC meeting, any member of the TEAC can provide written comments within sixty (60) days of this meeting. These written comments will consist of three (3) sections:

- Introduction, which will describe the party submitting the comments and their reason for submitting these comments
- Summary, which will consist of no more than 3 pages summarizing the positions described in the written comments
- Discussion, which will consist of no more than 20 pages describing in detail the positions taken by the party

[3] Hybrid transmission upgrades include proposed solutions which encompass modification to reliability-based enhancements already included in RTEP that when modified would relieve one or more economic constraints. Such hybrid upgrades resolve reliability issues but are intentionally designed in a more robust manner to provide economic benefits in addition to resolving those reliability issues.

2.6.7 Submitting Alternative Proposals

Any TEAC member or other entity (consistent with PJM Operating Agreement Schedule 6 provisions), may formally submit alternative proposals for evaluation under the Market Efficiency analysis at any time, but no later than **December 31st** of each year RTEP cycle year in order to be considered in the then-current planning cycle (the RTEP market efficiency planning analysis carries over from the RTEP cycle year into the first quarter of the following RTEP planning cycle year.) These alternatives will be posted on the PJM Website. PJM will consider these alternatives, and establish the final set of proposals to be included in market efficiency analysis. The process of formally submitting proposals is not limited to transmission solutions but may also include generation solutions via PJM's established interconnection queue process; or, demand side management and load management proposals as well. Alternatively, market projects to relieve congestion can be submitted by market participants through the queue process at any time. PJM will evaluate these projects under the then current business rules contained in the PJM Tariff and Operating Agreement.

Regardless of all proposals considered – whether proposed by PJM or other parties - PJM will establish a "go/no-go" decision-point deadline (or final commitment date) after which existing RTEP transmission components will not be deferred or cancelled. This will provide certainty to developers, owners and investors.

2.6.8 Ongoing Review of Project Costs

To assure that projects selected by the PJM Board for Market Efficiency continue to be economically beneficial, both the costs and benefits of these projects will periodically be reviewed, nominally on an annual basis. Substantive changes in the costs and/or benefits of these projects will be reviewed with the TEAC at a subsequent meeting to determine if these projects continue to provide measurable economic benefit and should remain in the RTEP.

For projects with a total cost exceeding $50 million, an independent review of project costs and benefits will be performed to assure both consistency of estimating practices across PJM and that the scope of the project is consistent with the project as proposed in the Market Efficiency analysis.

2.7 Evaluation of Operational Performance Issues

As per Schedule 6, section 1.5 of the PJM Operating Agreement, PJM is required to address operational performance issues and include system enhancements, as may be appropriate, to adequately address identified problems. To fulfill this obligation, PJM Transmission Planning staff and Operations Planning staff annually review actual operating results to assess the need for transmission upgrades that would address identified issues. Typical operating areas of interest in these reviews include Transmission Loading Relief (TLR) and Post Contingency Local Load Relief Warning (PCLLRW) events.

The first operational performance issue to be addressed through the RTEP was an upgrade of the Wylie Ridge 500/345 kV transformation. The metric applied to designate Wylie Ridge an operational performance issue was the TLR metric. This same metric is applied consistently across the PJM footprint.

In addition, PJM has also developed and initiated use of a tool for Probabilistic Risk Assessment (PRA) of transmission infrastructure. PJM's 500/230 kV transformer infrastructure has been identified as particularly suited for assessment using this tool. PRA is further discussed in following sections.

2.7.1 Operational Performance Metrics

Events and metrics considered in the annual operational performance reviews are not limited to a specifically defined list and will be responsive to events and conditions that may arise. In addition, PJM stakeholders may raise operational issues to PJM's attention for consideration during the RTEP process through interactions with the Planning, TEAC or Subregional RTEP Committees.

The PJM TLR metric identifies facilities that result in over 1,000 hours or 100 occurrences of TLR level 3 or higher on an annual basis. These facilities will be evaluated through the RTEP process for system enhancement.

For PCLLRW events, PJM will review all such events after the conclusion of the peak season. The initiating facilities will be determined and the expected impacts of planned RTEP upgrades will be reviewed and the need for additional planned upgrades will be evaluated.

PRA evaluation uses an economic analysis of the cost of the investment that mitigates a risk and the dollar value of the avoided risk. The mitigation strategy cost, prime rate and payback period are used to determine if the strategy cost is less than the value of risk. Projects with lower cost than risk are candidates for the RTEP.

2.7.2 Probabilistic Risk Assessment of PJM 500/230 kV Transformers

One significant element of PJM's operational performance reviews involves a risk evaluation aimed at anticipating significant transmission loss events. PJM integrates aging infrastructure decisions into the ongoing RTEP process: analysis, plan development, stakeholder review, PJM Board approval, and implementation, over PJM's entire footprint. Thus, the aging infrastructure initiative implements a proactive, PJM-wide approach to assess the risk of transmission facility loss and to mitigate operational and market impacts of such losses.

PRA's initial implementation at PJM is a risk management tool employed to reduce the potential economic and reliability consequences of transmission system equipment losses. In collaboration with academia, vendors and member TOs, PJM integrated various input drivers into a transformer PRA initiative to manage 500/230 kV transformer risk. In the case of the 500/230 kV transformers, risk is the product of the probability of incurring a loss and the economic consequence of the loss. Probability of loss is determined based on the individual transformer unit's condition assessments and vintage history. Economic loss impact is based upon the duration of the loss and the accumulation of unhedgeable congestion costs, or the increased cost of running out of merit generation to meet load requirements after a transformer loss. If lead times for 500/.230 kV transformer units are as great as eighteen months, then outage durations can be long if adequate loss mitigation is not in place. The PRA outputs the annual risk to the PJM system of each transformer unit in terms of dollars. The annual risk dollars are then used to justify mitigating solutions such as redundant bank deployment, proactive replacement or adding spares. The deployment strategy chosen will depend on the level of risk mitigation and reliability benefit.

While initially developed for aging 500/230 kV transformers, the PRA tool is capable of assessing other equipment types and other transformer voltage classes. The PRA tool is commercially available software.

Attachment A: PJM Baseline Cost Allocation Procedures

A.1 Purpose

One of the responsibilities of PJM as an RTO is to allocate the cost responsibility for all system reinforcement projects including projects required for Customer interconnection requests, baseline transmission reliability upgrades and market efficiency upgrades. The cost allocation procedures used by PJM for baseline upgrades are described below. Manual 14A addresses request-driven upgrade cost allocation procedures.

A.2 Scope

The PJM Cost Allocation Procedures are presented in two parts: "PJM Generation and Transmission Interconnection Cost Allocation Methodologies" discusses the cost allocation methodology for projects required for generator and transmission interconnections in Manual 14A and: "Schedule 12 Cost Allocation Process for Baseline Transmission Reliability and Market Efficiency Upgrades" describes the cost allocation process for baseline transmission reliability and market efficiency upgrade project requirements.

A.3 Schedule 12 Cost Allocation Process for Baseline Transmission Reliability and Market Efficiency Upgrades

In addition to allocating the costs of interconnection projects (described above), PJM is responsible, under Schedule 6 of the Operating Agreement and Schedule 12 of the Tariff, for determining the cost allocation of all RTEP upgrades and submitting them to the PJM Board for approval. Allocation of transmission upgrades for reliability is cost-causation based. With respect to reliability, the determination of benefit is based on the elimination of a reliability criteria violation. The parties causing the violation are the parties that benefit through the elimination of the violation and the quantification of the benefit is based on the relative contribution to the violation being eliminated. Accordingly, each cost allocation calculation is based on the particular assumptions used to determine whether or not a violation exists of a particular criterion.

A.3.1 RTEP Baseline Cost Allocation

PJM's allocation of cost responsibility for RTEP reliability baseline upgrades in accordance with these provisions is based on cost causation. The market participants (typically load) that create the circumstances that would constitute a violation of reliability criteria are those that will benefit from elimination of that violation. Therefore, the quantification of the relative benefits of eliminating the violation, and thus the quantification of relative responsibility for the cost of the system upgrade(s) needed to remove the violation, is based on the relevant market participants' relative contribution to the violation to be eliminated.

The planning (modeling) assumptions associated with each reliability criterion in PJM are highly prescriptive, such that discretion cannot be applied to manipulate the determination that a violation does or does not exist. The reliability criteria and the associated modeling rules were established in this way specifically to ensure consistency of application and ability to replicate results. In this way, once it is determined that an applicable criterion has been violated, it is a simple matter to determine the extent to which load within each transmission zone contributes to that violation. That relative contribution then establishes the appropriate, proportional allocation to each zone of the costs required to remove the violation.

To the extent that a criteria violation is based on the thermal limits of a transmission facility, the cost allocation is based directly on the relative contribution of the load in each zone to the flow on that facility. For criteria violations based on voltage criteria, thermal surrogates are determined, such that the flow on a transmission facility or group of facilities best correlates to the reactive performance of the system at the point of the criteria violation. The same approach described above is then utilized to simulate incremental flows on the limiting facilities, i.e., the thermal surrogate that best correlates to the violation. Accordingly, the cost allocation for the solution to the voltage criteria violation is, again, based on the relative contribution of load in each zone to flow on the limiting facility, in these cases, the thermal surrogates.

Under this approach to cost allocation, it is entirely possible, and certainly consistent with the philosophy of assessing relative cost-causation, that the costs of upgrades that are required to mitigate criteria violations in one transmission zone may be allocated in significant part to load in other transmission zones. While many required transmission upgrades are allocated entirely to load within the same zone where the criteria violation and the related upgrade are located, the nature of large, integrated transmission systems like the PJM system is such that the needs of one area can cause or contribute to problems in other areas. The planning process identifies the most effective solutions to criteria violations without regard to the location of the load that causes such violations. Therefore, responsibility for the costs of baseline upgrades likewise must be allocated to those who cause such costs to be incurred, regardless of their physical location relative to the location of the baseline upgrade required to ensure the reliability of their service.

The basic steps for calculating the cost allocations for baseline upgrades can be summarized as follows:

<u>Generator Deliverability and NERC Category C Load Flow Violations</u>

Calculate the Distribution Factor (DFAX), where DFAX represents a measure of the effect of each zone's load on the transmission constraint that requires the mitigating upgrade, as determined by power flow analysis. The source used for the DFAX calculation is the aggregate of all PJM generation and the sink is each Transmission Owners peak zonal load.

Multiply each DFAX by each zonal load to determine the zone's MW impact on the facility that requires upgrading.

Divide MW impact for each zone by sum of all MW impacts to yield baseline cost allocation factors.

<u>Load Deliverability Violations</u>

Calculate the Distribution Factor (DFAX), where DFAX represents a measure of the effect of each zone's load on the transmission constraint that requires the mitigating upgrade, as determined by power flow analysis. The source used for the DFAX calculation is the aggregate of all generation external to the study area and the sink is the peak zonal load for each Transmission Owner within the study area.

Multiply each DFAX by each zonal load to determine the zone's MW impact on the facility that requires upgrading.

Divide MW impact for each zone by sum of all MW impacts to yield baseline cost allocation factors.

Market Efficiency Allocation

[As of the effective date of this Revision 12 of Manual 14B, the cost allocation method for transmission upgrades is currently being debated at the FERC and is yet to be determined. Neither the RPPWG nor Planning Committee are recommending or endorsing any cost allocation method, pending the outcome of the proceedings at the FERC.]

The dollar benefit in all zones with affected load is summed and the final allocation is the zonal dollar benefit divided by the total dollar benefit.

RTEP Baseline Cost Allocation Representative Example

In order to explain the derivation of baseline cost allocation factors, PJM offers the following representative example based on Upgrade # b0174, an upgrade to the Portland – Greystone 230 kV circuit.

Cost Allocation Procedure	AE	JCPL	Neptune	PSE&G	RECo
1. Calculation of Distribution Factors (DFAX), representing a measure of the impact of each zone's load on the constraint requiring the mitigating upgrade in the first place, as determined by power flow analysis.	0.27%	2.42%	3.57%	2.76%	3.02%
2. Transmission Owner Load (MW)	2995	6713	685	10760	445
3. Calculate MW Impact (MW) of each TO zone by multiplying DFAX by TO Load.	8.09	162.45	24.45	296.98	13.44
4. Total MW Impacts (MW) across zones	505.41				
5. Calculate cost allocation factors by dividing each zone's MW Impact by the Total MW Impact across all zones. (Values rounded)	1.00%	32.00%	5.00%	59.00%	3.00%

Attachment B: Regional Transmission Expansion Plan—Scope and Procedure

B.1 Purpose

The purpose of the Regional Transmission Expansion Plan (RTEP) is to develop plans which will assure reliability and meet the demands for firm transmission service in the PJM Region as described in Schedule 6 of the Operating Agreement.

B.2 Scope

As part of its ongoing responsibility, PJM Interconnection, LLC (PJM) will prepare a Regional Transmission Expansion Plan (RTEP) which shall consolidate the transmission needs of the region into a single plan. The RTEP shall reflect transmission enhancements and expansions, load and capacity forecasts, and generation additions and retirements for the ensuing five years. The RTEP shall also reflect new transmission construction and right-of-way acquisition required to support load growth in years 6 through 15.

The RTEP will:

A. Provide a 5-year plan (“near term plan”) to address needs for which a commitment to expand or enhance the transmission system must be made in the near term in order to meet scheduled in service dates.

B. PJM will develop the necessary documentation of previous year’s RTEP analyses and updates to demonstrate compliance with applicable criteria. Such documentation may include the most recent Baseline study for each year in the near-term planning horizon (current year through current year plus 5,) annual changes to each year’s baseline study assumptions for generation, transmission and load compared to the current year's assumptions for each respective study year, and retool studies to evaluate and ensure compliance with applicable standards and criteria for significant changes proposed to the system (Interconnection and New Service Requests.) The need for additional baseline retools will be considered and any needed restudy will be performed and reported.

C. Provide a 15-year plan (“long term plan”) to address new transmission construction and right-of-way acquisition. System evaluations will be performed to:

- Identify overloads 230 kV and above due to load growth for years 6 through 15. This will be completed using DC analysis only.
- Include in the RTEP any new 230 kV or 345 kV circuits identified as required to support load growth in years 6 through 8.
- Include in the RTEP any right-of-way acquisition required for any new 230 kV or 345 kV circuits identified as required to support load growth in years 9 and 10.
- Include in the RTEP any new circuits 500 kV or greater identified as required to support load growth in years 6 through 12.

- Include in the RTEP any right-of-way acquisition required for any new circuits 500 kV or greater identified as required to support load growth in years 13 through 15.

D. Include reactive planning to determine if any new transmission identified in the 15-year plan should be accelerated to mitigate identified voltage criteria violations. Additional details for the reactive planning follow:

- Development of a 10-year RTEP base case that will include Transmission Owner reactive plans.
- The long term plan voltage analysis will be performed using contingencies 345 kV and greater and monitoring substation voltages 345 kV and greater. Analysis of lower voltage systems will be completed on an exception basis only.
- Voltage analysis will be performed for areas where PJM identified thermal problems in years 6 through 15 or other areas as identified by PJM.
- Based on the results of the voltage analysis, PJM will recommend appropriate modifications to the RTEP through the Transmission Expansion Advisory Committee.

E. Provide an assessment based on maintaining the PJM region's reliability in an economic manner.

F. Avoid any unnecessary duplication of facilities.

G. Avoid the imposition of unreasonable costs on any Interconnected Transmission Owner (ITO) or any user of transmission facilities.

H. Take into account the legal and contractual rights and obligations of the Interconnected Transmission Owners.

I. Provide, if appropriate, alternative means for meeting transmission needs in the PJM Region.

J. Provide for coordination with existing transmission systems and with appropriate interregional and local expansion plans.

K. Include a designation of the Interconnected Transmission Owner or Owners or other entity that will own a transmission facility and how all reasonably incurred costs are to be recovered.

L. Identify local system limitations discovered in analyzing the Transmission System.

M. Include Scenario Planning evaluations beginning in mid-2006. Scenario Planning examines the long-term impacts on the reliability of the PJM system from uncertainty with respect to certain assumptions implicit in the development of the RTEP. PJM will examine the effects of uncertainty with respect to selected variables such as economic growth effect on the Load Forecast, Circulating transmission flow effects on system deliverability and generation scaling sensitivities.

N. Include Probabilistic Risk Assessment (PRA) of Aging Transmission System Infrastructure beginning in 4Q, 2006. PRA is employed to mitigate transformer risk on the bulk power system. The consequences of a failure, both reliability and economic impacts, are then considered to implement, when appropriate, a proactive, PJM-wide approach to mitigate operational and market impacts to such failures.

The RTEP will not:

A. Include an evaluation of Transmission Owner transmission expansion or enhancement plans for local area load supply, which are not needed for reliability, market efficiency or operational effectiveness of the Transmission System and do not otherwise negatively impact the Transmission System. These Transmission Owner projects (Supplemental Projects) will be identified in the RTEP for information purposes and tracked for possible future impact implications.

B. Include any upgrades based solely on scaling up of generation to solve load flow studies for years 6 through 15.

B.3 Procedure

I. Solicit input and coordinate with Transmission Expansion Advisory Committee (TEAC) and, as appropriate, TEAC's Subregional RTEP Committee.

   A. Present the preliminary results of the most recent, applicable NERC regional reliability council (Reliability*First* and SERC) Reliability Assessments and the most recent PJM Regional Transmission Expansion Plan (RTEP).

   B. Present a summary of the transmission expansion or enhancement needs that will be addressed in the RTEP.

   C. Provide periodic updates to the TEAC on status of the RTEP.

   D. Solicit input on future transmission needs and requirements from those who will not be contacted directly as listed below.

   E. Schedule and facilitate Subregional RTEP committee reviews as may be needed to foster the goal of a transparent and participatory planning process.

II. Identify known Transmission System expansion or enhancement needs from the following plans and analysis results:

   A. Most recent, applicable Reliability Assessments (Reliability*First* and SERC) – (on PJM website)

   B. Most recent PJM Annual Report on Operations – (on PJM website)

   C. PJM Load Serving Entity (LSE) capacity plans

   D. Generator and Transmission Interconnection requests

   E. Transmission Owner transmission plans

   F. Interregional transmission plans.

   G. Firm Transmission Service Requests

   H. PJM Transmission Expansion Advisory Committee (TEAC) and Subregional RTEP Committee input

   I. PJM Development of Economic Transmission Enhancements

III. PJM will consider the RTEP impacts of each Generation Interconnection Customer ("GIC") and/or Transmission Interconnection Customer that is currently engaged in discussion with PJM concerning plans for siting generating and/or transmission facilities.

Typical items to be included are as follows:

A. GIC and/or Merchant Transmission Facilities developer project status, schedule, and milestones.

B. PJM will review the status of studies currently being performed or scheduled to be performed by PJM for the GIC and/or Merchant Transmission Facilities developer.

IV. GIC and/or Merchant Transmission Facilities developer plans will be included in the RTEP based on the following criteria:

A. Developer must be presently engaged in discussion with PJM concerning their plans for siting generating and/or transmission facilities and actively pursuing those plans. Interconnection Studies in response to requests for Generator and/or Transmission Interconnections will be conducted in accordance with the following scope:

- Identify transmission enhancements required to meet reliability requirements over the next 5 years.
- No studies will be conducted beyond 5 years for interconnection projects.
- "But-for" costs will be applicable toward all system upgrades identified in the RTEP Baseline.

B. GIC and/or Merchant Transmission Facilities developer plans will be treated equal to LSE plans submitted via EIA 411 in that they will be explicitly modeled and explicitly included in the RTEP report.

C. GIC and/or Merchant Transmission Facilities developer plans, which have not been released publicly, will be masked to the greatest extent possible to preserve the confidentiality of the developer's identity and specific site location(s).

D. GIC and/or Merchant Transmission Facilities developer plans, which were developed as a result of a PJM feasibility study or are being developed in conjunction with a PJM feasibility study being performed concurrent with the RTEP process, will be evaluated explicitly during the RTEP.

E. GIC and/or Merchant Transmission Facilities developer plans which have not undergone a PJM feasibility study or are not actively being developed as a result of an agreement executed with PJM to perform a feasibility study concurrent with the RTEP process, will only be considered to the extent that the GIC generator installation or Merchant Transmission Facilities developer facility may affect the sensitivity of transmission enhancement or expansion alternatives which are being evaluated.

V. PJM will exchange information and data with each Transmission Owner (TO) for the purpose of developing RTEP assumptions in preparation for the Subregional RTEP Committee assumptions meeting. Typical items to be included are as follows:

A. TOs will verify their transmission and capacity plans.

B. TOs and PJM will discuss the status, impact, and schedule of relevant studies in which they are mutually engaged in performing.

C. TOs will provide information concerning the contractual rights and obligations which PJM must consider per the RTEP protocol as listed in Schedule 6 of the PJM Operating Agreement.

D. TOs will provide PJM with any information related to concerns, operating procedures, or special conditions for each of the TO's systems that PJM should consider related to the analysis to be performed for the RTEP.

E. TOs will discuss the accuracy of PJM's load flow representation for each of the TO's systems including the impact of using the present representation for each of the TO's underlying systems.

F. TOs will identify system needs which are currently not identified by published transmission plans but could be included for consideration during the RTEP analysis.

G. TOs will provide the names, addresses, telephone numbers, FAX number, and email address for personnel identified to interact with PJM on matters dealing with the RTEP process.

H. TOs will provide a confidentiality statement regarding all information released to the TO by PJM during the course of the RTEP process.

I. TOs will provide information on new loads or changing loads that will impact the transmission plan.

VI. PJM will include available information from neighboring TOs / Regional Transmission Operators, gained in the course of interregional planning activities, related to plans in other regions which may impact the PJM RTEP.

VII. RTEP Analysis General Assumptions:

A. PJM System Models will be drawn from the PJM and applicable regional reliability council (Reliability*First* and SERC) central planning database which includes transmission plans consistent with the most recent FERC 715 Report and most recent Regional EIA-411 Reports.

B. LSE capacity models are to be based on the most recent Regional EIA-411 Reports.

C. GIC capacity plans will be modeled as described in Procedures III and IV.

D. When the PJM load in the RTEP model exceeds the sum of the available in-service generation plus generation with an executed ISA, PJM will model new generation to accommodate additional load growth by including queued generation that has received an Impact Study.

E. PJM Load Forecasts are to be based on the most recent LAS Report.

F. Power Flow models for world load, capacity, and topology will be based on the most recent Eastern Reliability Assessment Group (ERAG) power flow base cases.

G. Generation outage rates will be based on the most recent generator unavailability data available to PJM. Estimates, based on historical outage rates for similar in-service units, will be used for all generating units in the neighboring regions and for all future PJM units.

H. Firm sales to, and firm purchases from, regions external to PJM will be modeled consistent with the ERAG base interchange schedule.

I. Only PJM's share of generation will be modeled to serve PJM load. Generation located within PJM, but not committed to PJM, will be accounted for in the interchange schedule.

J. The Reliability Principles and Standards as shown on Attachment D to this Manual 14B, "PJM Reliability Planning Criteria."

K. Stability analysis and short circuit studies will also be performed.

L. All PJM Transmission System facilities 100 kV and greater, and all tie lines to neighboring systems will be monitored.

M. Contingency analysis will include all facilities operated by PJM.

N. The published line and transformer thermal ratings at ambient temperatures of 50°F (10°C) winter and 95°F (35°C) summer will be used for all facilities.

O. The voltage limits applied for planning purposes will be the same as applied in PJM Operations.

P. PS/ConEd PAR Flows: Model a 1000MW import at Waldwick and 1000MW Export at Goethals and Farragut with Ramapo PARS controlling 920 MW to NYPP. Except, for load deliverability testing, the export to ConEd at Goethals and Farragut may be decreased to 600 MW to represent a 400 MW emergency PJM purchase from NY for the capacity deficiency conditions being modeled. Likewise, the Ramapo setting is changed to 1000 MW into New Jersey.

Q. Assumptions used for the economic analysis and comparison of alternatives will be included in the report.

R. Planning and Markets will, annually based on historical data, develop a circulation model to be applied to the 5 year RTEP base case. This assumption will be reviewed with the PJM Planning Committee prior to implementation.

VIII. Evaluate Transmission enhancement and expansion alternatives and develop a coordinated Regional Transmission Expansion Plan.

A. Develop solution alternatives for regional and subregional transmission needs.

B. Evaluate solutions on a regional basis and optimize solutions to address needs on a coordinated regional basis in a single plan.

C. Test the single regional plan for reliability, economy, flexibility, and operational performance based on forecasts for future years.

IX. RTEP Deliverables

A. A 5-year plan, which includes recommended regional transmission enhancements, including alternatives if applicable, that address the transmission needs for which commitments need to be made in the near term in order to meet scheduled in-service dates.

B. The 5-year plan will include planning level cost estimates and construction schedules.

C. The 5-year plan will specify the level of budget commitments which must be made in order to meet scheduled in-service dates. The commitment may include facility engineering and design, siting and permitting of facilities, or arrangements to construct transmission enhancements or expansions.

D. The 15-year plan will identify new transmission construction and right-of-way acquisition requirements to support load growth.

B.4 Scenario Planning Procedure

Beginning in mid-2006, PJM will include scenario planning evaluations as part of the RTEP process. Scenario planning examines the long-term impacts on the reliability of the PJM system due to uncertainty with respect to certain assumptions implicit in the development of the RTEP. PJM will examine the effects of uncertainty with respect to selected variables such as economic growth effect on the load forecast, circulating transmission flow effects on system deliverability and generation sensitivities. In the course of the RTEP planning cycle scenario planning will evaluate Transmission System requirements, as may be necessary to ensure the robustness of the RTEP. The following sensitivities will be considered:

I. Load forecast for economic growth

The current 90/10 load values only account for weather uncertainty and do not consider economic growth deviations. An economic growth sensitivity may consider the effects of high economic growth factors and higher than forecast loads to determine the impact on RTEP baseline upgrades identified for years 6 through 10 for:

- Eastern PJM Mid-Atlantic Region (PSE&G, JCP&L, PECO, Delmarva, AE and RECO).
- Southwestern PJM Mid-Atlantic Region (PEPCO and BG&E).
- Western PJM Mid-Atlantic Region (MetEd, PPL, UGI and Penelec).
- PJM Western Region (ComEd, AEP, Dayton, Duquesne and AP).
- PJM Southern Region (Dominion).

System upgrades identified as required in years 6 through 10 may be advanced if the initiating overload occurs in an earlier year due to the high economic growth factor scenario.

II. Circulation

Circulation assumptions included in the RTEP baseline analysis will be reviewed for appropriate sensitivities.

III. Generation sensitivities

When the PJM load in the RTEP model exceeds the sum of the available in-service generation plus generation with an executed ISA, PJM will model new generation to accommodate additional load growth by including queued generation that has received an Impact Study. This newly added generation could affect the load deliverability results either by advancing or mitigating limits. Generation sensitivities may be examined as appropriate to add information regarding the impacts of any such generators with less certain in-service dates. In addition, in areas that are experiencing load deliverability issues, sensitivities to the mitigating effects of new local generation may also be quantified.

PJM will analyze the results of any generation sensitivities for consideration of adjustments to any new transmission or ROW acquisition previously identified in the RTEP for years 6 through 15.

IV. Additional Information

For any overloads that resulted in transmission or ROW acquisition in years 6 through 15, PJM will provide the level of new generation or DSM per region that would eliminate the need for the transmission or ROW acquisition.

Attachment C: PJM Deliverability Testing Methods

C.1 Introduction

Schedule 10 of the PJM Reliability Assurance Agreement states that Capacity Resources must be deliverable, consistent with a loss of load expectation as specified by the Reliability Principles and Standards, to the total system load, including portion(s) of the system in the PJM Control Area that may have a capacity deficiency at any time. Certification of deliverability means that the physical capability of the transmission network has been tested by the Office of the Interconnection and found to provide service consistent with the assessment of transfer capability internal to PJM as set forth in the PJM Tariff and, for Capacity Resources owned or contracted for by a Load Serving Entity, that the Load Serving Entity has obtained Network Transmission Service or Firm Point-to-Point Transmission Service to have capacity delivered on a firm basis under specified terms and conditions .

PJM determines the Capacity Requirement for the entire PJM footprint to achieve this reliability objective assuming sufficient network transfer capability will exist. The energy from generating facilities that are ultimately committed to meet this capacity requirement must be deliverable to wherever they are needed within PJM in a capacity emergency. Therefore, there must be sufficient transmission network transfer capability within PJM. PJM determines sufficiency of network transfer capability through a series of Deliverability tests.

It is important to point out that deliverability ensures that the PJM Transmission System is adequate for delivery of energy from the aggregate of capacity resources to the aggregate of PJM load. Additionally, the generator deliverability test determines whether a generator qualifies for the status of a "certified" capacity resource with respect to the installed capacity obligations imposed under the Reliability Assurance Agreement. It does not guarantee any rights to specific generators to deliver energy to specific loads within PJM. Nor does it guarantee any rights to generators to produce energy during any particular set of operational circumstances. Deliverability ensures that the Transmission System within PJM can be operated within applicable Reliability Criteria and, ensures within those criteria that regional load will receive energy, with no guarantee as to price, from the aggregate of capacity resources available to PJM.

Failure of the deliverability test for a new capacity resource will result in denial of full capacity rights for the generator until such generator deliverability deficiencies are corrected. Failure of load deliverability tests will result in the initiation of appropriate mitigation actions including securing additional capacity resources, reduction of peak load and/or an enhancement to the Transmission System to increase the load area’s ability to import power.

C.2 Deliverability Methodologies

To maintain reliability in a competitive capacity market, capacity resources must contribute to the deliverability of energy within PJM in two ways. First, within an area experiencing a localized capacity emergency, or deficiency, energy must be deliverable from the aggregate of the available capacity resources to load. Second, capacity resources within a given electrical area must, in aggregate, be able to be exported to other areas of PJM. PJM has developed testing methodologies to verify compliance with each of these deliverability requirements.

C.3 Overview of Deliverability to Load

The first of these tests, the delivery of energy from the aggregate of available capacity resources in one PJM electrical area and adjacent non-PJM areas (support from external areas may be considered to meet deliverability to the extent such support may be reasonably expected) to another PJM electrical area experiencing a capacity deficiency, is the more common deliverability test that has been utilized within PJM for some time. It is often discussed in the context of demonstrating the "deliverability to the load" as opposed to the "deliverability of individual generation resources". This ensures that, within accepted probabilities, energy can be delivered to each PJM load area from the aggregate of capacity resources available to PJM (regardless of ownership). These tests address reliability only and do not address the economic performance of the system.

For the adequacy of generating capacity of the entire PJM footprint, the acceptable loss of load expectation (LOLE) is based on load exceeding available capacity, on average, during only one occurrence in ten years (1/10). This concept of deliverability coincides with the assumptions inherent in the determination of the PJM Installed Reserve Margin (IRM), i.e. the total amount of installed capacity necessary to be at the disposal of the PJM operator to ensure delivery of energy to load consistent with an LOLE of 1/10. The determination of the IRM is based on the assumption that the delivery of energy from the aggregate of available capacity resources to load within the PJM footprint will not be limited by transmission capability. This assumption depends on the existence of a balance between the distribution of generation throughout PJM and the strength of the Transmission System to deliver energy to portions of PJM experiencing capacity deficiencies.

The specific procedures utilized to test deliverability from the load perspective involve the calculation of Capacity Emergency Transfer Objectives (CETO) and Capacity Emergency Transfer Limits (CETL) for the various electrical areas of PJM. A CETO value represents the amount of energy that a given area must be able to import in order to remain within an LOLE of 1 event in 25 years (1/25) when that area is experiencing a localized capacity emergency. The LOLE calculation takes into account all generation within the study area including that which may not be a PJM capacity resource. The CETL represents the actual ability of the Transmission System to support deliveries of energy to an electrical area experiencing such a capacity emergency. Providing that the CETL for a given area exceeds the CETO for that area, the test is passed and, on a probabilistic level, the area will be able to import sufficient energy during emergencies. The Transmission System is tested at a LOLE of 1/25 so that the transmission risk does not appreciably diminish the overall target of a 1/10 LOLE for PJM.

To test the assumptions used in the development of the PJM Installed Reserve Margin, electrically cohesive load areas must first be defined. The historical implementation of this test based these areas on Transmission Owner service territories and larger geographical zones comprised of a number of those service territories. Current study areas include the definition of smaller areas, within service territory boundaries. These areas, known as Locational deliverability Areas (LDAs) were defined based on the impact of generators, potentially within the area and on the contingencies known to limit operations in the area. Similar techniques may be used to form future new areas to establish incentives for infrastructure that promotes reliability.

PJM will analyze the need for the addition of an LDA if either of the following criteria is met:

- RTEP Market Efficiency Analysis

Constrained facilities will be identified utilizing the market efficiency analysis. Facility constraints that are not resolved by an existing approved RTEP upgrade are identified for further consideration. PJM may propose a new LDA when annual market efficiency analysis identifies persistent congestion on a 500 kV or above facility or interface for multiple years beyond the next BRA.

- RTEP Long Term Planning

Future constrained facilities or clusters of facilities are identified utilizing the long term planning analysis. Potential facilities are screened using thresholds that are utilized in the RTEP long-term planning studies. This analysis is updated annually based on approved RTEP upgrades. 500 kV and above facilities that advance more than three years between RTEP cycles are identified for further consideration. If the driver for a 500 kV facility advancing more than three years is linked to a specific event (e.g. significant generation retirement), it may require further analysis.

Once a facility has been identified utilizing the above methods, distribution factor analysis is utilized to determine the specific busses included in the analyzed LDA. The model used to determine the load bus distribution factors would include all approved RTEP upgrades. A distribution factor cutoff is established based on one of the existing LDA's, and is dependent upon an analysis of the specific system topology and the identified constrained facilitiy(s).

These procedures are consistent with the changing nature of load responsibility under wholesale and retail access and provide a wider range of information about the performance of the Transmission System as electrical areas of different sizes are evaluated. The sequence of evaluating areas of differing size involves nesting small sub-areas into larger areas and finally areas into larger geographical areas of PJM to help identify the interrelationships between local and large geographical area deliverability problems.

After an area is defined, two generation patterns must be established. The first represents the capacity resource deficiency within the area. Based on the calculated CETO for the area, sufficient resources must be removed from service to create a need to import energy into the area. As the magnitude of the deficiency is adjusted, single contingency analysis is used to establish the CETL value. The second generation pattern required represents the dispatch of the remainder of PJM and surrounding non-PJM areas, comprised of a much larger number of generators not experiencing any emergency conditions. The larger area in PJM is modeled as experiencing only normal levels of unit outages simulated through a uniform reduction of all on-line generation. The reduction is based on an average Equivalent Forced Outage Rate (EFORd) as that term is defined by NERC standards (http://www.nerc.com/page.php?cid=4|43|47) for PJM capacity resources.

Thermal studies to determine potential overload conditions are evaluated using a probabilistic approach whereby up to 10,000 different generation outage scenarios within the study area are simulated to determine an expected value for the various facility loading levels under test at the CETO. Voltage analysis uses a combination of discrete generator outages and scaled generator output under test at the CETO.

C.4 PJM Load Deliverability Procedure—Capacity Emergency Transfer Objective (CETO)

The Capacity Emergency Transfer Objective (CETO) analysis determines a target MW import value for a test area that ensures sufficient transmission capability to access available external capacity reserves. The import value determined is a measure of the transmission capability required by the test area so that the area does not experience a modeled, transmission induced loss of load event more frequently, on average, than 1 in 25 years. This test ensures comparability of transmission service to all areas within the PJM Region.

The CETO for each sub-area in PJM is determined separately using PJM's reliability software to perform a single area reliability study for each load area. The system models are based on the latest RTEP load and capacity data available at the time of the study. Only the load and capacity within the study area are modeled while the capacity supply from outside the study area is assumed unlimited. The transmission system is not modeled. The CETO is the import capability value that is necessary for the study area to achieve the CETO reliability standard. The CETO reliability standard is one event in 25 years.

More detail is available by referring to PJM Manual 20 – Resource Adequacy Analysis at http://www.pjm.com/documents/manuals.aspx

C.5 PJM Load Deliverability Procedure—Capacity Emergency Transfer Limit (CETL)

1.0 Introduction

PJM specifies a reliability objective regarding each study area's ability to import needed and available capacity assistance. The purpose of performing a Capacity Emergency Transfer Objective/Limit Study (CETO/CETL) also known as a Load Deliverability study is to verify that this objective is met. Load Deliverability analysis is therefore one of the tests applied to validate the deliverability of PJM capacity resources to PJM load. Load Deliverability analysis is performed for a study area. At present, load deliverability study areas consist of individual zones, sub-zones and the geographical combinations of zones. Eighteen zones and sub-zones have thus far been identified. The zones correspond to the present power flow areas of the PJM operating companies. Five global study areas which are geographical combinations of power flow zones have thus far been identified.

2.0 Study Objectives

The goal of a PJM Load Deliverability study is to establish the amount of emergency power that can be reliably transferred to the study area from the remainder of PJM and the areas adjacent to PJM in the event of a generation deficiency within the study area (the study area's CETL). This transfer limit, in combination with its corresponding CETO, is then used to determine if the import capability required to meet the reliability objective is sufficient. An indicator of the amount of reserve transfer capacity (if any) available is also provided.

3.0 General Procedures and Assumptions

3.1 Independent Study Area Generation Capacity Deficiency

For the purposes of analysis, each tested study area within the PJM control area is assumed to be experiencing a generation deficiency independently. Thus, the remainder of PJM and adjacent non-PJM areas are operating normally and are assumed to be able to supply the study area with emergency power up to the limit of their available reserves. Load in all other areas beyond the area under test will be modeled at 50/50 load level reduced by forecast energy efficiency. The amount of reserves considered available from any adjacent non-PJM area may be changed to reflect historical data. Generally the procedure first tests the limit based on PJM reserves. The resource supply is opened to areas external to PJM as necessary, based on a reasonable expectation of such external support.

3.2 Consistency with PJM Emergency Operations Procedures

In all cases, the study area CETL analysis should reflect actual PJM emergency operations procedures designed to make as much power available to the deficient study area as possible under the prevailing system conditions. This should include (but is not limited to):

- The operation of any available PJM generation regardless of system economics.
- The activation of any PJM Load Management (LM) schemes that may serve to unload limiting facilities to the extent that it does not reduce the load in the area under test below expected 50/50 load reduced by forecast energy efficiency levels.
- The modification of any transfers modeled in the base case.
- The adjustment of any Phase Angle Regulators (PARs) which PJM or PJM member companies control (within existing agreements for emergency operation).
- The activation of any approved PJM or PJM member company operating procedure (procedure descriptions are available in Manual 3.)
- Re-dispatch of capacity resources in PJM are allowed internal to the study area to relieve an overload provided that the CETO is increased by the amount of generation re-dispatch required to eliminate the internal overload.

3.3 Study Area Definitions—Zonal and Global

A study area may consist of a single PJM transmission owner's transmission system (230 kV and below for the Mid-Atlantic system) with its connected load and generation. In this case, the study area is referred to as a **Zonal** study area. A study area may also consist of a geographical combination of various transmission systems (with all connected load and generation) sharing common bulk facilities for importing power. For this combination type of study area, a **Global** CETL analysis will be performed in which all load and generation in the area will be modeled internal to the study area. Assessment of both Global and Zonal Load Deliverability analyses will identify the most restrictive emergency import margins with respect to reliability criteria and deliverability of capacity resources.

PJM Global CETL Study Areas

Eastern Mid-Atlantic Area – Comprises all load and generation connected 500 kV and lower in PECO, PSE&G, JCP&L, Delmarva, AE, and RECO.

Southern Mid-Atlantic Area – Comprises all load and generation connected 500 kV and lower in BG&E and PEPCO.

Western Mid-Atlantic Area – Comprises all load and generation connected 500 kV and lower in Penelec, Met-Ed and PP&L.

Mid-Atlantic Region – Comprises all load and generation connected 500 kV and lower in Penelec, Met-Ed, PP&L, BG&E, PEPCO, PECO, PSE&G, JCP&L, Delmarva, AE and RECO.

Western Region – Comprises all load and generation connected 765 kV and lower in ComEd, ATSI, AEP, Dayton, DEOK, Duquesne and AP. Note that CPP is within the ATSI transmission Zone.

PJM Zonal CETL Study Areas

Penelec – All load and generation connected at 230 kV and below.

AP – All load and generation connected at 500 kV and below.

ATSI – All load and generation connected at 345kV and below.

DEOK – All load and generation connected at 345kV and below.

Met-Ed - All load and generation connected at 230 kV and below.

PP&L - All load and generation connected at 230 kV and below.

BG&E - All load and generation connected at 230 kV and below.

PEPCO - All load and generation connected at 230 kV and below.

JCP&L - All load and generation connected at 230 kV and below.

PECO - All load and generation connected at 230 kV and below.

AE - All load and generation connected at 230 kV and below.

PSE&G - All load and generation connected at 230 kV and below.

Delmarva - All load and generation connected at 230 kV and below.

ComEd - All load and generation connected at 765 kV and below.

AEP - All load and generation connected at 765 kV and below.

Dayton - All load and generation connected at 345 kV and below.

Duquesne - All load and generation connected at 345 kV and below.

Dominion – All load and generation connected at 500 kV and below.

Delmarva South - All load and generation connected at 230 kV and below as defined in Figure E-1.

PSE&G North - All load and generation connected at 230 kV and below as defined in Figure E-2.

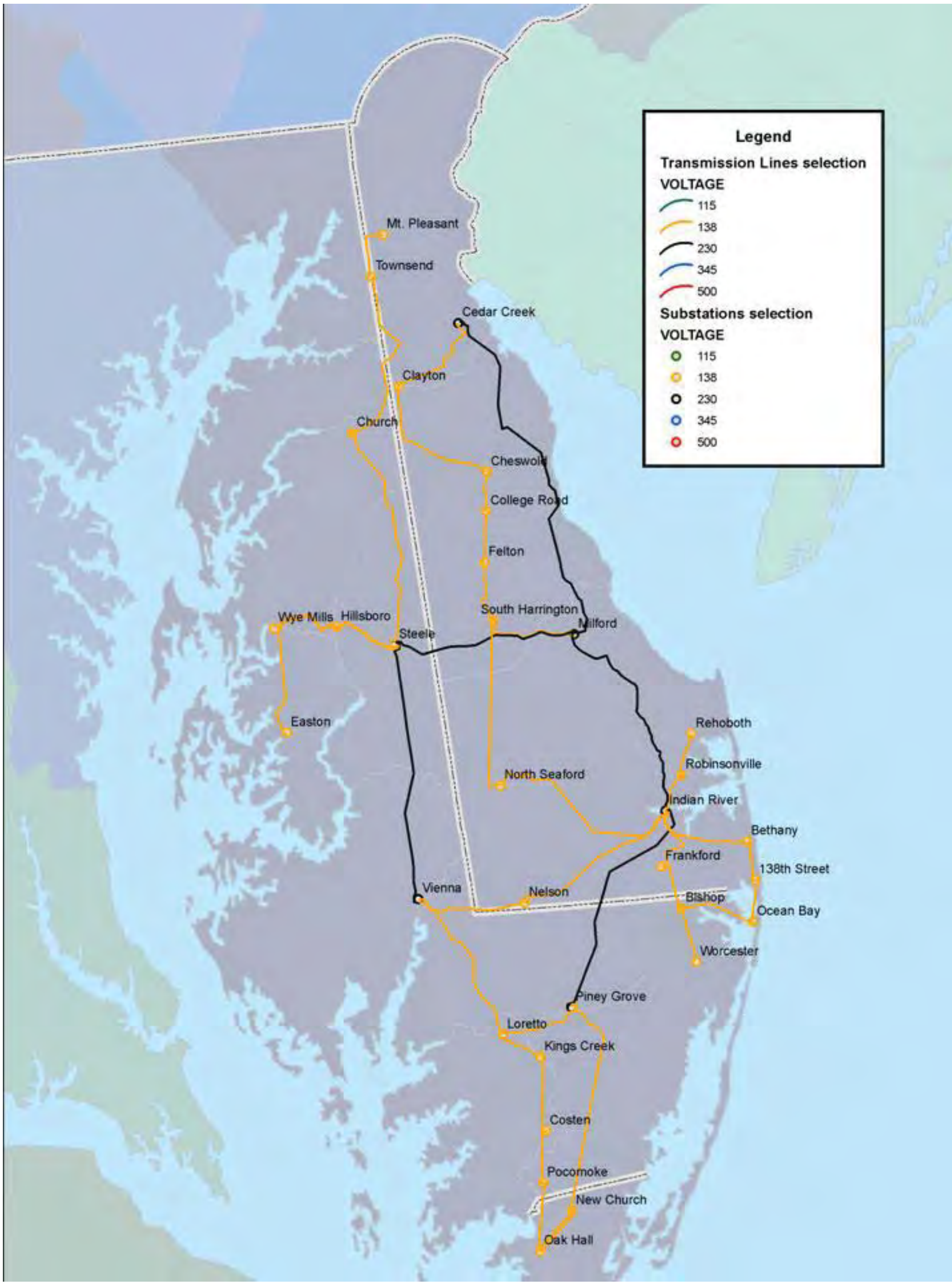


Figure E-1 (Delmarva South)

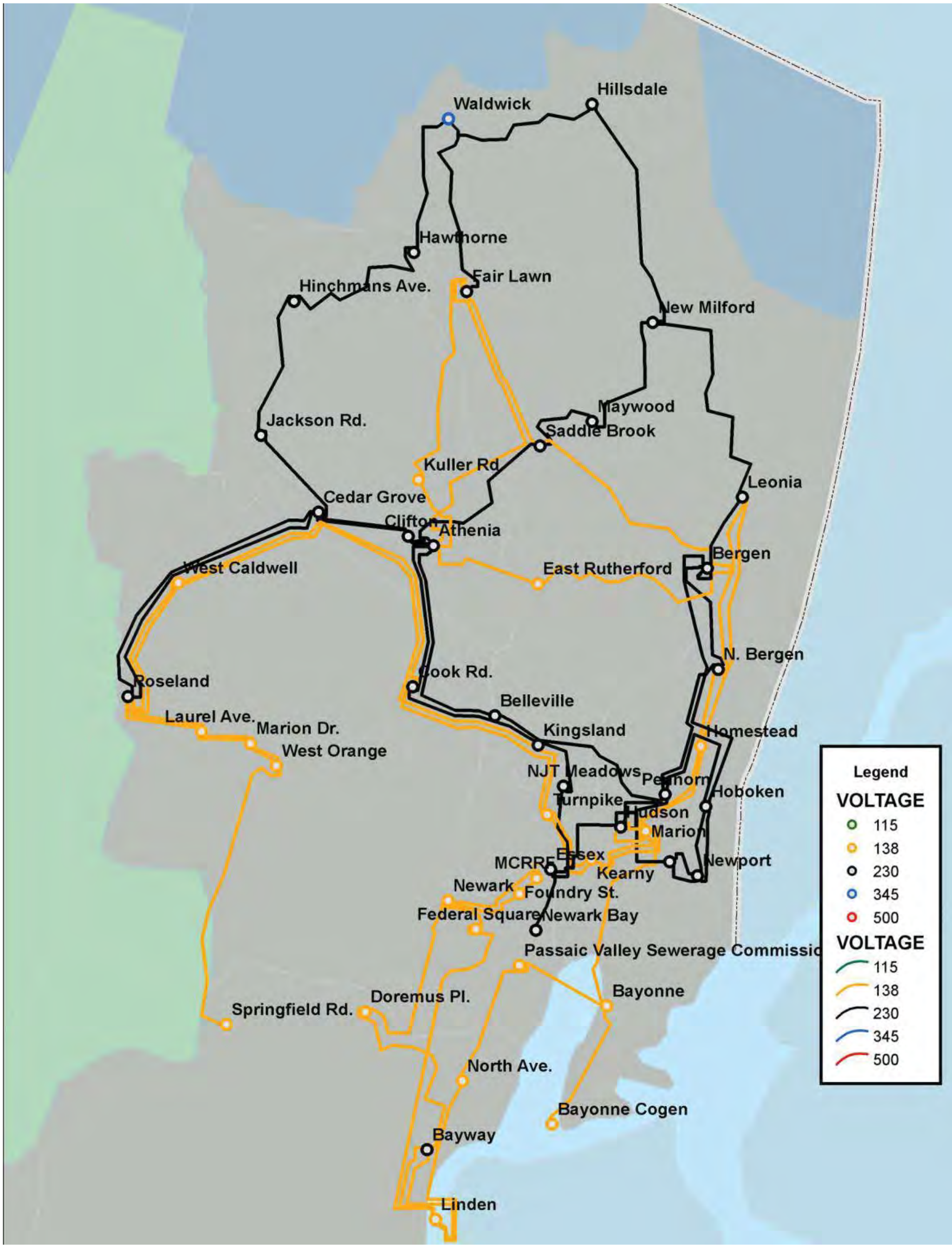


Figure E-2 (PSE&G North)

4.0 Base Case Development

Two separate base case models are developed as may be necessary; a PJM summer peak case to study summer-peaking study areas and a PJM winter peak case to study winter-peaking study areas (The need for a winter case is assessed annually. Currently the only PJM winter peaking area has summer and winter peaks sufficiently close to enable the analysis on only a summer peak case). The RTEP load flow case nearest to the study time period should be selected and modified as required (modeling the projected load, generation, and transmission system configuration for the target study period).

To calculate plausible generator outage scenarios, a file containing the installed MW capacity and the Generator Unavailability Subcommittee (GUS) five-year planning equivalent forced outage rate demand (EFORd) for every PJM capacity resource will be developed. Related data is available at http://www.nerc.com/page.php?cid=4|43|47.

4.1 Study Area Capacity Deficiency Assumptions

The study area being evaluated is assumed to be experiencing the generation deficiency due to a combination of higher-than-expected load demand (a 90/10 load forecast) and greater-than-expected generator unavailability. The 90/10 load forecast level is modeled by using the value of the 90/10load contained in the latest LAS report along with generator outage scenario(s) that would lead to a generation deficiency which cause a transmission limitation.

4.2 Study Area CETL Base Case Modeling Summary

- Behind the Meter and energy only generation should be modeled at the average historic MW output during the previous year’s 10 highest load hours for the study area each hour being selected from a different day.
- No study areas will be defined less than a peak load of 1500 MW.
- Generator reactive output will be reduced in proportion to the MW scaling reduction for any generation that is modeled below the rated capability.
- The 90/10 load adder is assumed to be at 0.8 power factor.
- Normal and emergency ratings included in the power flow will be those applied in Operations (at 35°C).
- PAR setting should be 1000 MW to NJ at Ramapo, 1000 MW to NJ at Waldwick, and 1000 MW into ConEd at Goethals and Farragut. PARs located within PJM may be operated as needed subject to the appropriate agreements (if any) and PJM Operating Company practices. Except as follows.
- PAR settings during subsequent contingency analysis can decrease the 1000 MW delivery to ConEd at Goethals and Farragut to as low as 600 MW delivery as required to enhance deliverability to the eastern study areas.
- The forecast 90/10 MW load for the area under test will be reduced by the available energy efficiency and DR (both in MW).The greater of the 90/10 MW load in the area under test reduced by the total amount of energy

efficiency and DR or the 50/50 load reduced by forecast energy efficiency, will be used as the MW load in the area being tested.

- If the 50/50 load reduced by energy efficiency is used to model the load in the test area, the forecast 90/10 MW load reduced by the amount of energy efficiency and DR needs to be adjusted by a MW adder to reach the level of 50/50 MW load minus the energy efficiency. The MVAR load associated with the 50/50 load minus the energy efficiency also needs to be increased by an amount equal to the difference between the MVAR associated with the 90/10 load adder at an 80% power factor and at the power factor in the 50/50 load forecast. The MVAR adder is to account for the assumption that the incremental MW (90/10 load adder) between the 90/10 and 50/50 load forecast is at an 80% power factor.

  Note that the above assumes that the 90/10 forecast contains only a MW value. If the 90/10 forecast contains both a MW and a MVAR value, the power factor of this forecast 90/10 load needs to be used for the adjustment instead of the 80% power factor.

4.3 Procedure for Determining Load Deliverability Facility List

The following procedures outline the process for determining which facilities will be monitored for the PJM Load Deliverability test. The first procedure provides the details for internal PJM facilities and the second procedure concentrates on external PJM facilities.

Internal PJM Load Deliverability Facility List

1. PJM monitors all transmission facilities for its load deliverability test and screens criteria violations for upgrades that pass a transfer distribution factor (TDF) cutoff test and are on PJM's monitored facility list (Lists of PJM monitored lines and substations are available at http://www.pjm.com/markets-and-operations/transmission-service/transmission-facilities.aspx.) PJM performs load deliverability for its entire region by individually studying each study area listed in § 3.3. A different subset of the Transmission Facilities is the focus for each study area.
2. The following defines the TDF cutoff for PJM facilities that will be included in the separate Load Deliverability test for each study area. If a 100 kV and up facility is excluded from all load deliverability analyses based on its unresponsiveness to load supply, that facility may be addressed in generator deliverability or it becomes subject to reliability screening under the standard NERC TPL 001-004 criteria[4].

   All non-radial facilities 345 kV or greater will be included regardless of OTDF.

[4] Any 100 kV and above facility that is not subject to upgrade screening in the load deliverability analysis will be evaluated in a subsequent screening that evaluates the NERC TPL-001 through 004 criteria in the 50/50 peak load scenario. All facilities failing these standard NERC criteria will be identified for upgrade.

All facilities with an external OTDF (an “external OTDF” is based on a source point external to the study area and a sink point internal to the study area) greater than 10% will be included regardless of voltage class.

All facilities with an external OTDF between 5% and 10% will be included unless both PJM and the TO agree that the facility should not be subject to the load deliverability test.

All facilities with an external OTDF less than 5% will not be included unless the PJM and TO agree that the facility should be subject to the load deliverability test.

3. The Load Deliverability Facility List can be modified prior to each baseline analysis but cannot be changed between baseline studies.
4. All PJM monitored facilities will be included when determining any generation re-dispatch or PAR movements required for the base case development. However, only the facilities on the Load Deliverability Facility List will require system upgrade if overloaded for this load deliverability test.
5. The substations to be included for voltage analysis will be developed based on the Load Deliverability Facility List.
6. Additional substations to be included for voltage analysis as agreed to by PJM and the TO.

External PJM Load Deliverability Facility List

For study areas electrically close to PJM, PJM conducts joint coordinated interregional studies on a periodic basis that examines and addresses deliverability issues between PJM and adjacent external systems.

4.4 Dispatch for PJM Areas Not in Capacity Emergency

PJM generators should be dispatched as per existing RTEP base case procedures (see also “Deliverability of Generation”). To simulate the average forced outage rate for generation in PJM, a uniform de-rate of all generation is done.

4.4.1 Dispatch for non-PJM Areas Not in Capacity Emergency

One of the base principles for the load deliverability test is that the study area is the only area that is in a capacity emergency. All adjacent external areas to PJM are assumed to be at a peak load but in a non-emergency condition. Increasing available generation (respecting Pmax) simulates exports from these areas to the study area.

The locations of generation increases and corresponding MW import level to the study area is typically optimized to provide the highest available imports to any given study area. The import amounts from each external area can be based on strength of ties or historical imports when the study area was capacity deficient. The amount of reserves considered available from any external system may be changed from the optimized scenario to reflect historical import data or to minimize constraints at the discretion of the engineer conducting the study.

4.5 Dispatch for Load Deliverability Study Area

4.5.1 Procedure to Determine Dispatch for Voltage Analysis

1. Derate all generators in the zone by their EFORd.
2. Rank generators by EFORd^(1/PMAX).
3. To model discrete generator outages, select generators in rank order until the next selected generator would exceed 105% of the target generator outage value.
4. Multiple generators at the same substation may be outaged unless the outaged MW to installed MW ratio is greater than 60%. (For example, if a station had 3-100 MW units, 1 unit would be outaged since 100 MW/300 MW = 33% but two units would not be outaged since 200 MW/300 MW = 66%)
5. Any remaining MW outages required to meet the target generator outage value will be obtained through a uniform scale of all on-line generation's MWs and MVARs in the study area.
6. The Transmission Owner(s) may request analysis of a different outage pattern. If this outage pattern results in more severe reliability problems it will be used in place of the original outage pattern only if both the Transmission Owner and PJM accept the new outage pattern.

4.5.2 Procedure to Determine Dispatch for The Mean Dispatch Case

1. All generators in the study area are sampled until 10,000 generation outage scenarios are found where the amount of generation selected is within +/- 2% of the amount needed to meet the target generator outage value required to model the import objective.
2. The 10,000 generation outage scenarios are determined by using a Monte Carlo simulation and randomly assigning a value between 1 and 0 to each generator in the study area. If the value is greater than the generator forced outage rate, then that generator is turned on. If the value is less than the generator forced outage rate, then that generator is turned off. There is no limit to the number of units that can be simultaneously outaged at a station.
3. Determine the average MW output of each generator in the study area by using its dispatched values in the 10,000 generator outage scenarios. These average MW output values for each generator are referred to as the Mean Dispatch.
4. The reactive capability of each unit is reduced by the ratio of each unit's average MW output from the preceding step to the unit's maximum MW output.
5. Create a base case modeling the average MW output of each generator determined in step 5 above. This case is referred to as the mean dispatch case. It models a generation outage scenario based on the average MW for each unit from the 10,000 generation outage scenarios determined in step 5 above. This case is used by the entities to study potential

reinforcements required to resolve any overloaded flowgates. In addition, since the case models an average generation outage scenario and therefore average losses for those outage scenarios, it is the best case to use when determining the impact on flowgates of the various discrete generation outage scenarios applied for the median loading.

6. Perform an AC contingency analysis on the mean dispatch case to obtain the percent loading for each flowgate. This percent loading is referred to as the reference loading.
7. Flowgates that have a reference loading greater than or equal to 90% of the appropriate (i.e., normal or emergency) rating (at 35°C) in the mean dispatch case are tested further as defined below.
8. To determine the discrete generation outage scenarios, all generators in the study area are sampled until 10,000 generation outage scenarios are found where the amount of generation selected is within +/- 2% of the amount needed to meet the target generator outage value required to model the import objective. (This process is described in steps 7 and 8 above).
9. The flowgate loading for each discrete generation outage scenario is determined as follows:
    a. For each generator in the study area, a distribution factor is established for each flowgate using the generator in the study area as the sink point and all generators external to the study area, being used to model the transfer as the source points.
    b. The impact on the flowgate due to the change in generation is determined for each generator by determining the change in MW output in the generation outage scenario from the output modeled in the mean dispatch case. The change in MW value is then multiplied by the distribution factor of each flowgate to determine the +/- impact on the flowgate.
    c. The AC MVA loading from the mean dispatch case is incremented or decremented by this MW result.
    d. This results in 10,000 percentage loadings being established for each flowgate (i.e., one flowgate percent loading for each of the generation outage scenarios studied).
10. If any overloads exist, any of the system adjustments noted in section 3.2 can be implemented and the procedure in section 4.5.2 is repeated.
11. Any overloads that still remain will require mitigation in order for the study area CETL to exceed the CETO.

4.6 Study Results

1. Five % points are selected (30-70% in 10% increments) to quantify the probability of a given % loading for each flowgate.
2. For example, a 90% flowgate loading in the column of the first point, 30%, means that in 3,000 of the 10,000 discrete generation outage scenarios

the line loading was below 90%. Likewise, a 90% flowgate loading in the column of the third point, 50%, means that in 5,000 of the 10,000 discrete generation outage scenarios the line loading was below 90%. This third point is the median flowgate loading.

3. Select 50% probability point such that any circuits with loadings exceeding their applicable rating for more than 50% of the dispatch scenarios will require upgrade.

4.7 CETL Determination

After steps 4.5.1 and 4.5.2 are completed and any required system upgrades are identified to eliminate any voltage problems or overloads, the study area CETL can be determined.

CETL for Voltage Problems

To determine the CETL for voltage problems, the imports into the study area will be increased in 50 MW increments starting from the dispatched base case identified in section 4.5.1. The import change will be modeled by increasing external generation and uniformly decreasing internal study area generation.

CETL for Thermal Problems

To determine the CETL for thermal problems, the transfer distribution factor on each of the flowgates will be calculated by using a source of generation external to the study area and a sink of generation internal to the study area. The transfer distribution factor multiplied by the increased imports will indicate which overload will limit the study area imports from a thermal perspective.

CETL for Study Area

The lower of the CETL identified for the voltage problems and the thermal problems will be used as the study area CETL.

5.0 Transitional Rules

This Load Deliverability Procedure will be applied for all future load deliverability analysis for planning years 2008 and beyond. Any existing projects identified through the RTEP for installation prior to June 2008 and approved by the PJM Board will remain requirements as identified in previous analysis.

C.6 Deliverability of Generation

The second deliverability test, the ability of an electrical area to export capacity resources to the remainder of PJM has historically been applied in situations where problems were expected to occur. Consistent with the move from IOU service territories to electrical areas, this test is applied to ensure that capacity is not "bottled" from a reliability perspective. This would require that each electrical area be able to export its capacity, at a minimum, during periods of peak load. Export capabilities at lower load levels would be based more on economic decisions and would not reflect on deliverability criteria and therefore the "certification" of resources as deliverable capacity.

Deliverability, from the perspective of individual generator resources, ensures that, under normal system conditions, if capacity resources are available and called on, their ability to provide energy to the system at peak load will not be limited by the dispatch of other certified capacity resources. This test does not guarantee that a given resource will be chosen to produce energy at any given system load condition. Rather, its purpose is to demonstrate that the installed capacity in any electrical area can be run simultaneously, at peak load, and that the excess energy above load in that electrical area can be exported to the remainder of PJM, subject to the same single contingency testing used when examining deliverability from the load perspective. In short, the test ensures that bottled capacity conditions will not exist at peak load, limiting the availability and usefulness of certified capacity resources to system operators. In actual operating conditions, energy-only resources may displace capacity resources in the economic dispatch that serves load. This test would demonstrate that a magnitude of resources equal to or greater than the installed capacity in any given electrical area could simultaneously deliver energy to the remainder of PJM. Therefore, these tests do not require the calculation of the equivalent of export CETO and CETL values.

The electrical Regions from which generation must be deliverable, range from individual buses to the entire regional generation under study. The premise of the test is that all capacity within the Region is required; hence the remainder of the system is experiencing a significant reduction in available capacity. However, since localized capacity deficiencies reductions are tested when evaluating deliverability from the load perspective, the dispatch pattern in the remainder of the system is modeled based on a uniformly distributed outage pattern.

C.7 Generator Deliverability Procedure

1.0 Introduction

To maintain reliability in a competitive capacity market, resources must contribute to the deliverability of the Control Area in two ways. First, energy must be deliverable, from the aggregate of resources available to the Control Area, to load in portions of the applicable PJM region experiencing a localized capacity emergency, or deficiency. PJM utilizes the CETO / CETL procedure to study this “deliverability of load”. Second, capacity resources within a given electrical area must, in aggregate, be able to be exported to other areas of PJM that are experiencing a capacity emergency. PJM utilizes a Generator Deliverability procedure to study the “deliverability of individual generation resources”. This document provides the procedure for Generator Deliverability.

2.0 Study Objectives

The goal of the PJM Generator Deliverability study is to determine if the aggregate of generators in a given area can be reliably transferred to the remainder of PJM. Any generators requesting interconnection to PJM must be “deliverable” in order to be a PJM installed capacity resource.

3.0 General Procedures and Assumptions

Step 1: Develop Base case

The RTEP base case is developed for a reference year 5 years in the future. All RTEP identified system upgrades and Supplemental RTEP Projects are included in the system model. Load is modeled at a non-diversified forecasted 50/50 summer peak load level reduced by energy efficiency as per the latest load forecast. All approved firm interchange is included with roll-over rights. Generation and Merchant Transmission projects that have proceeded at least through the execution of the Facility Study Agreement stage of the interconnection process are considered in the model along with any associated network upgrades. The starting point dispatch is developed as explained in the next step. PJM uses a uniform reduction of generation in place of discrete forced outages for this test due to the significant bias any one specific outage pattern can have on the final overload results.

Step 2: Establish initial RTEP dispatch for unit under study

Place all in-service capacity resources (those that have procured capacity delivery rights) on-line at a generation value equal to their installed capacity x (1 – PJM average EEFORd). Wind units with capacity delivery rights are derated to their granted capacity rights (either 13% beginning with the “U” queue or 20% for prior queues) representing the combined effects of wind variation and outage characteristics. The target generation value is the projected load + losses + firm interchange. (See addendum 1 for treatment of transmission withdrawal and injection rights). If all in-service capacity resources de-rated by the PJM EEFORd are greater than the target generation value, then all in-service capacity resources should be uniformly reduced to meet the target generation value. If all in-service capacity resources de-rated by the PJM EEFORd is less than the target generation value, then place all capacity resources with an executed Interconnection Service Agreement (ISA) on-line at a generation value equal to the installed capacity x (1 – PJM average EEFORd). If all in-service and ISA capacity resources de-rated by the PJM EEFORd are greater than the target generation value, then all these resources should be uniformly reduced to meet the target generation value. If all in-service and ISA capacity resources de-rated by the PJM EEFORd is less than the target generation value, then place all capacity resources with an executed Facility Study Agreement on-line at a generation value equal to the installed capacity x (1 – PJM average EEFORd). If all in-service, ISA and Facility Study capacity resources de-rated by the PJM EEFORd are greater than the target generation value, then all these resources should be uniformly reduced to meet the target generation value.

All resource requests in the study queue ahead of the unit under study are set at 0 MW but available to be turned on. The resource request under study is also set at 0 MW but available to be turned on. Resource requests queued after the unit under study are not modeled. The loading on each transmission line that results from this dispatch and the application of a contingency is the base loading of the facility. (See Addendum 2 for treatment of Common Mode Outage Procedures).

Step 3: Determine potential overloads

PJM uses a linear (DC) power flow program to analyze each facility for which PJM is responsible to determine whether any contingencies can overload the facility (including comprehensive analysis of single, towerline, bus, and stuck breaker contingencies). These results are utilized to determine which flowgates will be used in the generator deliverability analysis,i.e., the program examines each PJM flowgate (contingency / monitored element pair) on the entire PJM footprint. The procedure below explains conceptually how the program works; following the procedure below would yield the same results as the program. The procedure uses a load flow set up according to step 2.

Determine the distribution factor for each generator on each flowgate. The distribution factor for a particular generator is referenced to the PJM online generation. For each flowgate, multiply the distribution factor of each generator by the offline portion of the generator to obtain the MW impact the generator would have on a particular flowgate if it were ramped from its output in the initial load flow to its full output. This result will be referred to the ramping impact of a particular generator on a particular flowgate. For all flowgates determine the cumulative ramping impact of generators with greater than a 1% distribution factor. The total amount of ramped generation is capped to limit the number of potential overloads to a reasonable number of the worst impacts. A typical cap for the total ramping is 10,000 MW but the actual value can vary to establish a reasonable scope for the potential overloads. For each flowgate, add the cumulative ramping impact to the initial DC loading. If the resulting DC loading is greater than the flowgate rating, then this flowgate is a potential overload.

Step 4: Determine 80/20 DC loading

The number of generators having greater than a 1% distribution factor in Step 2 is often large enough that having them all simultaneously outputting their full installed capacity would be extremely improbable. As a result, in this step the number of generators contributing to the cumulative ramping impact on a flowgate is further restricted in the following manner.

Units modeled in the power flow with greater than a 5% distribution factor (or 10% distribution factor for flowgates whose monitored element's highest terminal voltage level is equal to or greater than 500 kV) that contribute to the cumulative ramping impact are ranked according to their distribution factor on a potentially overloaded flowgate. The availability (1 – EEFORd) of the unit with the highest distribution factor is then multiplied by the availability of the unit with the second highest distribution factor and so on until the expected availability of the selected units is as close to but not less than 20%. This resulting "80/20" cumulative ramping impact is then added to the initial DC loading on the flowgate. This resulting loading is the 80/20 DC loading and the generators chosen to contribute to the cumulative ramping impact are the 80/20 generators.

Step 5: Determine Facility Loading Adder

This Step 5 addresses off-line generators which are not included in the 80/20 list. Existing generators that do not have capacity delivery rights and active queued generators that are not yet in commercial operation (or do not yet have a signed ISA) are offline but available to be turned on. The ramping impact of this set of generators determines the Facility Loading Adder. First, for their ramping impact to be considered, off-line generators must pass the impact threshold of at least a 5% DFAX (10% for flowgates with monitored elements having the highest terminal voltage 500 kV and above) on a flowgate or with an impact (DFAX times a generator's full energy output rating) greater than 5% of the flowgate's rating.

The ramping impact of offline generators is determined according to their classification as: (1) existing generators that do not have capacity delivery rights and active queued generators with signed ISA's, or (2) active queued generators without signed ISA's. Category (1) generators are allowed to aggravate or backoff overloaded flowgates. Category (2) generators are considered only if they aggravate overloaded flowgates (active queued generators without signed ISAs are not allowed to backoff overloads.)

For each potential flowgate, an approximated CETO will be calculated by finding a receiving end area. The receiving end area will include:

- Load buses with a positive impact on flowgate loading
- Generators with negative impact on flowgate loading

The estimated CETO will be calculated using the following function:

Estimated CETO = 1.08 * (Bus Loads + Losses - Diversity – Demand Response) – (1 – 1 * Avg. EEFORD) * ICAP + Largest Unit

Each receiving end area will be assigned a portion of the PJM Capacity Benefit Margin (CBM) based the receiving end area's share of the PJM load. CBM will be used to offset generators that contribute to the Facility Loading Adder when the import level for a receiving end area becomes greater than:

(receiving end area estimated CETO - receiving end area CBM allocation)

To ensure that new generators within small clusters of the electrically closest generation to a flowgate will not be offset by the delivery cap, an exception to the CBM offset will be made. Generators which contribute to the Facility Loading Adder and have distribution factors that fall outside of two standard deviations of the mean of all PJM generator distribution factors will be available to contribute to the Facility Loading Adder. The amount of generation change from the initial load flow due to changes in 80/20 and Facility Loading Adder generation shall not be any more than the online installed capacity exclusive of the 80/20 generators × PJM average EEFord. This rule is enforced by curtailing generators that contribute to the Facility Loading Adder. In order to always maintain a critical system condition for this deliverability test, the 80/20 or 50/50 generation, as applicable, will not be curtailed to enforce this rule.

The ramping impact of active queued generators without signed ISA's considers the commercial probability of queued generators at the feasibility and impact study stage of the interconnection process. For generators at the feasibility study stage of the interconnection process, the output of the generator is multiplied by the historic commercial probability of a generator at the feasibility study stage of the interconnection process. For generators at the impact study stage of the interconnection process, the output of the generator is multiplied by the historic commercial probability of a generator at the impact study stage of the interconnection process. To be conservative, these values are then multiplied by 150% to determine the ramping impact of generation at the feasibility study and impact study stage of the interconnection process. The entire requested capacity of queued generation is used to determine the ramping impact of generation that has signed a facility study agreement.

The summation of 85% (100% for a Merchant Transmission project) of the ramping impact on a flowgate of each off-line resource that meets the above conditions is calculated. The resulting impact defines the Facility Loading Adder. The Facility Loading Adder is added to the base loading and the 80/20 DC loading to obtain the final DC loading on the facility.

Step 6: Determine Final Flowgate Loading

If a flowgate has a final DC loading less than 90% of its rating, it is not considered to be overloaded and is not tested further. If a flowgate has a final DC loading greater than or equal to 90% of its rating, the 80/20 generators are ramped up to their installed capacity in the load flow from step 2 and all remaining PJM generators are uniformly ramped down such that the PJM firm interchange is maintained. The resulting flowgate loading is the 80/20 AC loading.

The Facility Loading Adder can sometimes have a significant impact on the results of a deliverability study. However, ramping up the units associated with the adder in the load flow will typically create too much localized generation and a localized capacity emergency condition elsewhere when the rest of PJM is proportionally displaced to maintain the firm interchange. Therefore, to account for the effect of these units on the facility in question, the Facility Loading Adder, as determined in Step 5, is added to the 80/20 AC loading to result in the Final Flowgate Loading. This Facility Loading Adder accounts for the ramping impact of those offline resource requests that are both electrically close to a flowgate and did not participate as an 80/20 generator without actually turning them on. If the cumulative ramping impact of these offline resource requests has a beneficial effect on the flowgate, then the loading of the flowgate will be decreased to account for this beneficial effect. Similarly, the flowgate loading will be increased if these offline resource requests will further add to the overload.

In summary, the 80/20 generators will define the study area *for a particular flowgate* by determining which units to ramp up. All remaining online units are proportionally displaced to some level below their installed capacity x (1 – PJM average EEFORd) to maintain the firm PJM interchange.

Addendum 1: Modeling Transmission Withdrawal Rights (TWRs) and Transmission Injection Rights (TIRs)

Firm TWRs and TIRs may be associated with a controllable merchant transmission request, i.e. HVDC, which interconnects PJM to another system. If the transmission request has an executed ISA associated with it, the firm rights are modeled at their full amount. When the firm rights are modeled, the initial dispatch in step 2 will need to be modified to support these rights. If the transmission request does not have an executed ISA and is queued ahead of the project under study or is the project under study the following rules apply; for TWRs the sign of the distribution factor is changed for the purpose of deciding whether to model the right. The right is modeled at its full amount if a generator with its distribution factor would be in the 80/20 list. The right is treated as a Facility Loading Adder using the rules of Step 5.

Addendum 2: Common Mode Outage Procedure

In addition to single contingencies, PJM planning criteria requires that the PJM system withstand certain common mode outages. These outages include line faults coupled with a stuck breaker, double circuit towerline outages, faulted circuit breakers and bus faults. PJM uses a procedure very similar to the generator deliverability procedure to study common mode outages. The list below highlights the other details of the common mode outage procedure that differ from the generator deliverability procedure.

In addition to the modeling of capacity resource requests, all existing energy resources and energy resource requests queued ahead of the unit under study are set at 0 MW but available to be turned on. The energy resource request under study is also set at 0 MW but available to be turned on. Energy resource requests queued after the unit under study are not modeled.

A 50/50 DC loading is used instead of an 80/20 DC loading, i.e., the expected availability of the selected units is close to but not less than 50%.

For all voltage levels, a 10% distribution factor is used instead of a 5% distribution factor to select the 50/50 generators.

Attachment D: PJM Reliability Planning Criteria

The PJM Reliability Planning Criteria consist of multiple standards and applicable planning principles that include PJM planning procedures, NERC Planning Standards, NERC Regional Council planning criteria, and the individual Transmission Owner FERC filed planning criteria. PJM applies all applicable planning criteria when identifying reliability problems and determining the need for system upgrades on the PJM system. Details of specific criteria applicable to the various stages of reliability planning are discussed along with the corresponding discussion of each procedure found elsewhere in this manual.

I. The PJM Transmission Owners are required to follow NERC and Regional Planning Standards and criteria as well as the Transmission Owner FERC filed criteria. References to the various planning standards and criteria can be found at: PJM - NERC and Regional Compliance and http://www.pjm.com/planning/planning-criteria.aspx.

- Reliability*First* Approved Standards will be applied for all Reliability*First Bulk Electric System facilities*.
- SERC Reliability Criteria will be applied to all SERC networked transmission systems rated 100 kV and higher.
- Transmission Owner standards filed in their FERC 715 filings will be applied to all facilities included in the PJM Open Access Transmission Tariff facility list. Also, interconnections to Transmission Owner facilities are subject to owner standards found at: http://www.pjm.com/planning/design-engineering.aspx (these are technical interconnection requirements and do not factor into near-term and long-term planning analyses.

PJM maintains a list (http://www.pjm.com/markets-and-operations/transmission-service/transmission-facilities.aspx) of all PJM Open Access Transmission Tariff facilities along with which facilities are included in the PJM real-time congestion management control facility list. Both facility lists are referenced in the PJM Reliability Planning Criteria.

II. The PJM Generator Deliverability Procedure and Load Deliverability Procedure will be applied to all facilities in the PJM real-time congestion management control facility list.

III. Facilities included in the PJM real-time congestion management control facility list but not included in the applicable regional council planning criteria as defined in section I above will be evaluated against the following criteria. For all tests, PJM will not accept a planned loss of load of more than 300 MW. Attachment D-1 contains a description of the various load loss types referred to in this document. This criterion is in addition to, not in place of, each Transmission Owners Planning Criteria as reported in the FERC 715 filing.

1. The loss of any single transmission line, cable, generator, or transformer may not result in any monitored facility exceeding the applicable emergency rating or applicable voltage limit. (The applicable emergency rating and voltage limits will be as defined in PJM Operations.) The single contingency test will be applied as per the RTEP Generator Deliverability Procedure. (See Attachment C of this PJM Manual 14B.)

- The RTEP base case which includes a 5-year horizon system representation and non-diversified forecasted 50/50 summer peak load will be used for this analysis.
- System load will be represented at an area or zone wide minimum power factor of 0.97 lagging as measured at the transmission / distribution interface point.
- The 300 MW load limit referenced above does not include load that is immediately restored via automatic switching to adjacent substations.
- Automatic or supervisory switching as proposed by the Transmission Owner to sectionalize the system for single contingency events must receive acceptance by PJM Operations.
- During normal conditions with all facilities initially in-service, no uncontrolled load loss or load loss due to automatic schemes is allowed for a single contingency event. Consequential load loss is allowed.

2. After the occurrence of the transmission line, cable, generator or transformer outage, the system must be capable of re-adjustment such that no facility exceeds the maximum continuous rating or voltage limits as defined in PJM Operations.
3. During maintenance of any single transmission line, cable, generator, transformer, bus or circuit breaker, the loss of a transmission line, cable, generator, or transformer may not result in any monitored facility exceeding the applicable emergency rating or voltage limit (The applicable emergency rating and voltage limits will be as defined in PJM Operations.) However, for practical purposes, PJM Planning will only include a specific bus or circuit breaker maintenance condition in all future analysis if PJM Operations experiences operational problems as a result of the bus or circuit breaker maintenance condition.
    - Pre-contingency generation redispatch will be considered acceptable for mitigation of a potential overload or voltage limit.
    - This test will be applied at 70% of the diversified forecasted 50/50 summer peak load, as modeled in the RTEP base case, unless the Transmission Owner provides information to PJM Operations demonstrating sufficient maintenance windows at a lower load level.
    - No cascading or uncontrolled load loss is allowed under any circumstance.
    - Consequential load loss is allowed.
4. After occurrence of the maintenance outage and the subsequent facility outage as defined in the previous test #3, the system must be capable of re-adjustment such that no facility exceeds the maximum continuous rating or voltage limits as defined in PJM Operations.

IV. The PJM Light Load Reliability Analysis Procedure will be applied to all facilities in the PJM real-time congestion management control facility list.

Attachment D-1: Load Loss Definitions

Uncontrolled Load Loss – Uncontrolled load loss would require operator interaction to prevent system cascading or to return the system to applicable ratings or voltage limits. Manual load dump as defined in PJM Operations would be included in this category. The PJM Reliability Planning Criteria does not allow for the system design to permit Uncontrolled Load Loss for any contingencies that are studied.

Examples:

- Voltage collapse
- A facility overload without automatic schemes to drop load and with no available generation to re-dispatch pre-contingency.

Consequential Load Loss – Consequential load loss occurs due to the design of the system but does not include automatic schemes designed to drop load under various conditions.

Examples:

- A transformer serving radial load that taps a networked circuit.
- Load that is served from a radial circuit.

Controlled Load Loss due to Automatic Schemes – Controlled load loss occurs due to the operation of automatic schemes that are designed to drop load under specific maintenance conditions.

Planned Load Loss = Consequential load loss + Controlled load loss due to automatic schemes.

The 300 MW total load loss limit is based, in part, on a Federal reporting requirement for major system incidents on electric power systems (refer to Electric Power System Emergency Report - Form EIA-417R).

Attachment D-2: PJM Reliability Planning Criteria Methods

D-2.1 Light Load Reliability Analysis

The light load reliability analysis tests the ability of an electrical area to export generation resources to the remainder of PJM during light load conditions. The export generation is selected by using the historical mix of generation that operates at the light load level. This test is applied to ensure that generation capability, including renewable generation capability that typically operates at light load such as wind, pumped hydro, or other emerging storage technologies are not "bottled" from a reliability perspective.

The light load reliability analysis, from the perspective of individual generator resources, ensures that, under light load system conditions, their ability to provide energy to the system has a probability of not being limited by the typical dispatch of other generation resources that operate at that demand level, including resources in neighboring systems. The Generator Deliverability Test and Common Mode Outage procedure have a similar objective at the summer peak forecast load. While deliverability under all possible system conditions is not in the purview of the RTEP, analyzing the system performance under this wide range of forecasted demand levels improves overall deliverability of generating resources. Consideration will be given to the capacity factor by fuel class during this period, as described in Table 1. This test does not guarantee that a given resource will be able to deliver energy at the light load condition. Rather, the purpose is to demonstrate that typical light load generating capabilities in any electrical area can be run simultaneously, at light load, and that the excess energy above demand in that electrical area can be exported to the remainder of PJM. In short, the test ensures that bottled capability conditions will not exist at light load, limiting the availability and usefulness of a range of resources available to system operators, including renewable resources. In actual non-emergency operating conditions, the economic dispatch serves load.

D-2.2 Light Load Reliability Analysis Procedure

1.0 Introduction

To maintain reliability and operational flexibility during the light load period, resources within a given electrical area must, in aggregate, be able to be exported to other areas of PJM. PJM utilizes a Light Load Reliability Analysis procedure to study the system performance during typical light load conditions. This document provides the procedure for Light Load Reliability Analysis.

2.0 Study Objectives

The goal of the PJM Light Load Reliability Analysis study is to determine if the aggregate of generators in a given area can be reliably transferred to the remainder of PJM during light load conditions. Generators requesting interconnection to PJM must pass this test in order to become a PJM capacity or energy resource.

3.0 General Procedures and Assumptions

Step 1: Develop Base case

The RTEP base case is developed for a reference year 5 years in the future. All RTEP identified system upgrades and Supplemental RTEP Projects are included in the system model. PJM load is modeled at 50% of a non-diversified forecasted 50/50 summer peak load level reduced by energy efficiency as per the latest load forecast. System Interchanges will be determined by PJM through the use of data, including statistical averages based on historical data for off-peak load periods for typical previous years. Generation and Merchant Transmission projects that have proceeded at least through the execution of the Facility Study Agreement stage of the interconnection process are considered in the model along with any associated network upgrades. The starting point dispatch is developed as explained in the next step. PJM uses a combination of uniform reduction of coal powered generation and discrete outages for this test.

Step 2: Establish initial RTEP dispatch for unit under study

Existing PJM Resources: Place all in-service nuclear resources on-line at a generation value equal to their installed capacity. Wind units are derated in the initial dispatch to 40% of their nameplate capability. Coal units are initially derated consistent with Table 1. Queued Units in the PJM queue that have an ISA will be placed on-line consistent with Table 1. The target generation value for each Transmission Owner (TO) zone in the model is the projected load + losses + historical interchange for the light load period, as calculated by PJM. If necessary, coal resources in each TO zone are then uniformly de-rated or increased from the initial dispatch until the target generation value is met.

Existing MISO Resources: Model all existing wind generation in the MISO area online at a 100% capacity factor. Sink all MISO generation uniformly to maintain the target interchange. MISO generation dispatch utilized to serve MISO load will reflect a typical yearly statistical average for off-peak periods for interchange between MISO West, Central, and East.

Queued Resources in PJM and neighboring systems: Model all non-ISA queued generation offline. Model all ISA queued generation online. If selected by the test procedure, queued MISO wind resources will have the potential to be dispatched to 100% capacity factor. Similarly, if selected by the test procedure, queued PJM wind resources will have the potential to be dispatched to 80%.

For queued interconnection studies, all queued resources in the study queue ahead of the unit under study are set at 0 MW but available to be turned on per the Generator Deliverability procedure and Common Mode Outage test procedure. The resource request under study is also set at 0 MW but available to be turned on. Resource requests queued after the unit under study are not modeled. The loading on each transmission line that results from this dispatch and the application of a contingency is the base loading of the facility. (See Addendum 2 for treatment of Common Mode Outage Procedures).

Table 1 – Light Load Base Case

Network Model	Current year + 5 base case
Load Model	Light Load (50% of 50/50 summer peak)
Capacity Factor for Base Generation Dispatch for PJM Resources (Online in Base Case)	Nuclear – 100% Coal >= 500 MW – 60% Coal < 500 MW – 45% Oil – 0% Natural Gas – 0% Wind – 40% All other resources – 0% Pumped Storage – full pump
Capacity Factor for Base Generation Dispatch for MISO Resources (Online in Base Case)	Wind – 100%
Interchange Values	Historical values
Contingencies	NERC Category A, B, C (except C3)
Monitored Facilities	All PJM market monitored facilities

Step 3: Determine potential overloads

The method to determine potential overloads is similar to the methods used for the generator deliverability test. Also, the Common Mode Outage procedure is applied to include the effects NERC Category C events such as bus faults, faulted breakers, and double circuit towerline outages.

Step 4: Determine 80/20 DC loading

This portion of the test is the generator deliverability procedure except only wind generation is considered with a maximum ramping from the base dispatch of 40% to 80% of nameplate capability.

Step 5: Determine Facility Loading Adder

This portion of the test is the generator deliverability procedure except only wind generation is considered with a maximum ramping from the base dispatch of 40% to 80% of nameplate capability.

Step 6: Determine Final Flowgate Loading

This portion of the test is the generator deliverability procedure except only wind generation is considered with a maximum ramping from the base dispatch of 40% to 80% of nameplate capability.

Attachment E: Market Efficiency Analysis Economic Benefit / Cost Ratio Threshold Test

PJM uses a Benefit/Cost Ratio test to determine whether an economic-based enhancement or expansion will be included in the RTEP. Specifically, to be included in the RTEP recommended to the PJM Board of Managers for approval, the relative benefits and costs of the economic-based enhancement or expansion must meet a Benefit/Cost Ratio Threshold of at least 1.25:1. The Benefit/Cost Ratio is calculated by dividing the present value of the total annual benefit for each of the first fifteen years of the life of the enhancement or expansion by the present value of the total annual cost for each of the first fifteen years of the life of the enhancement or expansion. Assumptions for determining the present value of the benefits and costs (e.g. discount rate and annual revenue requirement) will be among the assumptions that are approved by the PJM Board each year to be used in the economic planning process.

The Benefit/Cost Ratio is expressed as follows:

Benefit/Cost Ratio = [Present value of the Total Annual Enhancement Benefit for each of the first 15 years of the life of the enhancement or expansion] ÷ [Present value of the Total Enhancement Cost for each of the first 15 years of the life of the enhancement or expansion]

The purpose of a Benefit/Cost Ratio Threshold is to hedge against the uncertainty of estimating benefits in the future and to provide a degree of assurance that a project with a 15-year net benefit near zero will not be approved. At the same time the threshold is not so restrictive as to unreasonably limit the economic-based enhancements or expansions that would be eligible for inclusion in the RTEP.

E.1 Total Annual Enhancement Benefit

The benefit component of the Benefit/Cost Ratio (Total Annual Enhancement Benefit) is the sum of two metrics: the “Energy Market Benefit” and the “Reliability Pricing Model (RPM) Benefit.” By including these two metrics, the benefits to customers from reductions in both energy prices and capacity prices as a result of an economic-based enhancement or expansion will be taken into account in the formulaic analysis. These two metrics in turn each consist of two elements -- the change in production cost and the change in load payment, which are weighted seventy percent and thirty percent respectively. This comprehensive test captures customers’ benefits in the energy markets and the capacity markets that may correspond to responsibilities related to obtaining reasonably priced energy as well adequate capacity.

a. Energy Market Benefit

The energy-market benefit analysis is conducted using an energy market simulation tool that models the hourly least-cost, security-constrained commitment and dispatch of generation over a future annual period. A detailed generation, load, and transmission system model is used as input into the simulation tool in order to mimic the hourly commitment and dispatch of generation to meet load, while recognizing constraints imposed on the economic commitment and dispatch of generation by the physical limitations of the transmission system. Benefits of potential economic-based enhancements, PJM will perform and compare market simulations with and without the proposed enhancement for selected future years within the planning horizon of the RTEP. A comparison of these simulations will identify the annual economic impact of the enhancement for each of the future study years. An extrapolation of these results provides a projection of annual benefits for each of the first fifteen years of the life of the enhancement.

The Energy Market Benefit component of the Benefit/Cost Ratio is expressed as:

Energy Market Benefit = [.70] * [Change in Total Energy Production Cost] + [.30] * [Change in Load Energy Payment]

The Change in Total Energy Production Cost is the difference in estimated total annual fuel costs, variable O&M costs, and emissions costs of the dispatched resources in the PJM Region without and with the enhancement or expansion.

The Change in Load Energy Payment is the difference between the annual sum of the hourly estimated zonal load megawatts for each PJM transmission zone multiplied by the hourly estimated zonal Locational Marginal Price for each PJM transmission zone without and with the economic-based enhancement or expansion. In determining the Change in Load Energy Payments for projects, the costs of which will be assigned cost responsibility on a regional basis (e.g. above 500 kV facilities), the Load Energy Payment in all PJM transmission zone will be considered whether there is an increase or decrease in the Load Energy Payment in the transmission zone. However, for projects, the cost of which will be allocated using a flow-based or distribution factor methodology (e.g. below 500 kV facilities), only the Load Energy Payment in the PJM transmission zones that show a decrease will be considered in determining the Change in Load Energy Payments.

b. Reliability Pricing Model Benefit

Reliability pricing benefit analysis is conducted using the Reliability Pricing Model software. The Reliability Pricing Model Benefit component of the Benefit/Cost Ratio evaluates the benefits of a proposed economic-based enhancement or expansion that will be realized in the capacity market and is expressed as:

Reliability Pricing Benefit = [.70] * [Change in Total System Capacity Cost] + [.30] * [Change in Load Capacity Payment]

The Change in Total System Capacity Cost is the difference between the sum of the megawatts that are estimated to be cleared in the Base Residual Auction under PJM's Reliability Pricing Model capacity construct times the prices that are estimated to be contained in the offers for each such cleared megawatt (times the number of days in the study year) without and with the economic-based enhancement or expansion.

The Change in Load Capacity Payment is the sum of the estimated zonal load megawatts in each PJM transmission zone times the estimated Final Zonal Capacity Prices (payments paid by load in each transmission zone) for capacity under the Reliability Pricing Model construct (times the number of days in the study year) without and with the economic-based enhancement or expansion. The Change in Load Capacity Payment will be evaluated in the same manner as the Change in Energy Load Payment. Like for the Change in Energy Load Payment, in determining the Change in Load Capacity Payment for projects the costs of which will be assigned cost responsibility on a regional basis (e.g. above 500 kV facilities), the Load Capacity Payment in each and every PJM transmission zone will be considered; for projects, the cost of which will be allocated using a flow-based or distribution factor methodology (e.g. below 500 kV facilities), only the Load Capacity Payments in the PJM transmission zones that show a decrease will be considered in determining the Change in Load Capacity Payment.

E.2 Total Annual Enhancement Cost

The annual cost of the enhancement is the revenue requirement of the enhancement. The enhancement's annual revenue requirement is an assumption that is developed by PJM and presented to the TEAC for discussion and review. As stated earlier, the benefits and costs will be considered over the same time period (for each of the first fifteen years of the life of the expansion).

Attachment F: Determination of System Operating Limits used for planning the Bulk Electric System

This document describes the process and measures used by PJM to develop System Operating Limits (SOLs) used for the planning horizon. The method described in this attachment is applicable to all Bulk Electric System (BES) facilities.

Definitions:

A System Operating Limit (SOL) is defined as:

The value (such as MW, MVAr, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within applicable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Thermal Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
- Transient Stability Ratings or Limits (Applicable pre- and post-Contingency Stability Limits)
- Voltage Stability Ratings or Limits (Applicable pre- and post-Contingency Voltage Stability)
- System Voltage Ratings or Limits (Applicable pre- and post-Contingency Voltage Limits)

PJM's Planning analyses are designed to ensure all applicable PJM, NERC, regional and Transmission Owner criteria are enforced. This is accomplished through exhaustive application of established PJM facility ratings in the on-going system power flow and short circuit analysis. PJM ensures that its exhaustive application of facility ratings are also within system dynamic limits through system dynamic testing. This dynamic testing confirms that PJM system operating limits are not more limiting than the limits established using facility ratings.

Facility Ratings are defined by NERC as:

> The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Facility ratings determine the fundamental limits of transmission system equipment. SOLs shall not exceed the facility ratings. The facility rating is based on which ever device or component is the limiting element of the facility such as a conductor, current transformer, disconnect switch, circuit breaker, wave trap or protective relay. PJM plans its system such that no facility exceeds the limit/rating consistent with NERC Standard TPL 001 – 004. Additional information concerning SOL can be found in the Transmission Operations Manual (M-03), and Reliability Coordination Manual (M-37) located on the PJM web page at the following link:

(http://www.pjm.com/documents/manuals.aspx)

Interconnected Reliability Operating Limits are defined as:
An Interconnected Reliability Operating Limit (IROL) is defined as System Operating Limits that, if violated, could lead to instability, uncontrolled separation or Cascading Outages that adversely impact the reliability of the Bulk Electric System. In the planning horizon PJM analyses examine and reveal the violations of applicable criteria. This includes violations affecting PJM monitored facilities at all voltage levels as well as violations that may have widespread impacts affecting the Bulk Electric System, which may be eligible for designation as IROLs. PJM plans system upgrades for violations of applicable criteria, thus IROL designations are not typically required for the upgraded system in the planning horizon. PJM closely tracks the project status and milestones of all planned upgrades on a frequent and recurring basis. For baseline reliability upgrades, the project tracking is coordinated with the entity that has been designated the construction responsibility, typically the Transmission Owner. If the schedule for implementation for a planned upgrade does not meet in-service date required for system reliability in the planning or operating horizon, PJM will perform additional analysis to determine any alternative plans that need to be taken to ensure system reliability, including the establishment of an IROL. For additional information on IROLs for the operating horizon see the PJM Transmission Operation Manual (M03) and the PJM Reliability Coordination Manual (M37).

PJM's Planning methodology to determine IROL facilities simulates transfers across a facility or interface (combination of facilities), comparing thermal and voltage violations associated with a facility. The transfer scenarios used by PJM Planning are established through the application of PJM's deliverability criteria. Additional information on PJM's deliverability criteria is included in Attachment C of this manual. PJM classifies a facility as an IROL facility on the network if wide-area voltage violations occur at transfer levels that are near the Load Dump thermal limit.

As part of the development of the PJM Regional Transmission Expansion plan, SOLs which could result in system instability or uncontrolled cascading outages are identified and system reinforcements are developed. All BES facilities in PJM's footprint and ties to external systems are monitored for violation. In addition, certain selected 69kV and below facilities may also be monitored consistent with the procedures defined in the PJM Transmission Operation Manual (M-03).

SOL and IROL use in Planning

PJM plans its system based on the most restrictive System Operating Limits (such as MW, MVAr, Amperes, Frequency or Volts) of its facilities for the system configurations and contingency conditions that represent the most stringent of the applicable PJM, NERC, regional or Transmission Owner criteria over the planning horizon. The System Operating Limits used to plan the system are consistent with the limits used in Operations. Voltage limits and any exception to those limits are identified in the PJM Transmission Operation Manual (M-03).

An Interconnection Reliability Operating Limit is the value (such as MW, MVAr, Amperes, Frequency or Volts) that is derived from or is a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages. PJM Reliability Coordination Manual (M37) defines PJM's methodology for determining, monitoring, and controlling IROL facilities.

Nuclear Power Plant Generator Operators are required to transmit Nuclear Plant Interface Requirement (NPIR) to transmission entities. The transmission entities are required to include those parameters into planning and operational analysis, operate to meet those parameters, and inform the nuclear licensees when those parameters cannot be met for any reason. For details please refer to Manual M03 Section 3: http://www.pjm.com/~/media/documents/manuals/m03.ashx

PJM Planning SOL Methodology

Consistent with the requirements of NERC Standard TPL-001, in the pre-contingency state and with all facilities in service, all facilities shall be within their facility ratings and within voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as facility outages.

Following single contingencies as defined in NERC Standard TPL-002 all facilities should be within their applicable facility ratings and the system shall be transient, dynamic and voltage stable. Cascading outages or uncontrolled separation shall not occur.

Starting with all Facilities in service, the response to a single contingency as defined in NERC Reliability Standard TPL 002, may include any of the following:

Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the faulted facility. This is often referred to as consequential load loss.

System reconfiguration through manual or automatic control or protection actions.

To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and changes to the transmission system topology.

Starting with all facilities in service and following any of the multiple contingencies identified in NERC Reliability Standard TPL-003 the system shall be transient, dynamic and voltage stable and all facilities shall be within their applicable facility ratings and within applicable thermal, voltage and stability limits. Cascading Outages or uncontrolled separation shall not occur. In general, stability is not a limiting constraint in the PJM RTO. Stability limits that have been identified for certain system configurations or following multiple contingencies are identified in the PJM Transmission Operation Manual (M-03). New stability limits identified in Planning are communicated to PJM Operations and included in the Transmission Operation Manual (M-03).

In determining the response to any of the multiple contingencies, identified in NERC Reliability Standard TPL-003, in addition to the actions identified above following single contingencies, the following shall be acceptable:

For all tests, as described in Attachment D-1, consequential load loss of up to 300 MW may occur.

PJM's Reliability Planning methodology for determining SOLs utilizes multiple standards and applicable planning procedures including the PJM Reliability Planning Criteria, NERC Planning Standards (TPL 001 – TPL 004), Regional Reliability Organization criteria, and individual Transmission Owner FERC filed criteria. In all cases, PJM applies the most conservative of all applicable planning criteria when identifying reliability problems. PJM tests these criteria on a regional basis including all facilities within its footprint. All BES network elements in PJM's footprint and all transmission tie lines within PJM and to external systems are monitored for 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 category A, B, and C conditions be tested.

When appropriate PJM will identify and implement Special Protection 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/documents/~/media/documents/manuals/m03.ashx) for additional information concerning special protection 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 annual 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 special protection systems that may be indicated based on stability or short circuit testing 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 special protection system remedies may also be considered as discussed further in this Attachment and its Appendix. New Special Protection Systems, 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/documents/manuals.aspx.

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 connections of wind turbines and performance of low voltage ride through testing. In exceptional cases, PJM may add heavy load testing for other types of units when PJM determines that heavy load may be the critical load level for system stability for the limitation under review.

PJM's stability analyses ensure the dual objectives of stability of new interconnection projects and system-wide stability. PJM, each year conducts dozens of interconnection queue project stability studies. These analyses ensure newly-connecting projects and nearby changes to the system configuration maintain the stability of the project and the system. Study of these projects located throughout PJM provides a thorough, ongoing review of PJM both at the project level and system-wide. In addition, each year, PJM conducts a re-study of one third of existing PJM generation stations. This results in a three-year cycle of on-going re-study of the entire PJM system. PJM also performs additional system-wide stability analyses during the annual RTEP review. In addition, as may be required from time to time, PJM conducts stability analyses to evaluate the dynamic performance of actual or possible major future system developments. For example a proposed new backbone transmission project or prolonged unexpected backbone transmission outage in a stability sensitive area would be cause for a specifically targeted system study. Another cause could be the need to evaluate system performance resulting from major developments affecting power and energy policy.

G.2 Dynamics Procedures

This section provides a high level review of the process of setting up and performing dynamics analyses.

G.2.1 Dynamics Reference Cases

Reference power flow cases for stability analysis are created in a similar manner to that of the power flow reference cases. Additional information, however, is necessary for stability studies to simulate the combined dynamic responses of various power system components. Included in this additional information are dynamics models for generators, excitation systems, power system stabilizers, governors, loads and various other equipments. The required dynamic and other modeling information that must be supplied by generators interconnected to the PJM system is detailed in Manual 14A. A dynamic simulation links the system model or power flow information with the dynamic data or models to determine if the system and generators will remain stable for steady-state and various disturbances. The current RTEP summer peak case is used as a starting point to create new dynamics cases (light load and peak load.) For example the RTEP analysis is performed for the current year plus five (available early in each calendar year and updated for the five-year-out RTEP analyses in early fall of each calendar year). The stability case setup is for the same study year using the updated RTEP case. This updated RTEP power flow case and the associated stability case become the baseline cases for the impact study analyses (that begin in the fall of each year) that begin with the first interconnection queue of each calendar year and continue through each of the 3 subsequent annual queues.

G.2.2 Dynamics Analysis

The two dynamics cases Originate from the RTEP Power Flow Case that is created for the annual RTEP Plan analyses. The annual RTEP cycle is depicted in Manual 14B, Exhibit 1. The earliest availability for this annual RTEP reference power flow case is for the impact studies associated with the interconnection request queue that closes on January 31. For subsequent project queues that close later in the year, this reference RTEP case is updated to the most current data. The reference power flow case is reviewed and modified as necessary to correspond to the dynamics database (which includes external world dynamics data from the NERC System Dynamics Data Working Group as well as PJM data.) In addition, the case is modified to include generator step-up transformers and explicit modeling of generator station service power use along with gross generator rating. Also, because of the demands of dynamics analyses, power flow static load representations are replaced with their dynamic load model representations. PJM currently represents loads as 100% constant current real power and 100% constant impedance reactive power. In light load representations, pumped storage resources are in pumping mode.

This process is followed to develop stability setups for analysis of all PJM interconnection requests. In addition PJM's system stability analyses will use the most current available setup from this continuous development process.

Testing

After the dynamics model setup, an unperturbed dynamic simulation is run for 20 seconds. After case verification, the final, initialized set of power flows and the associated snap-shots, along with the associated dynamic run files are available to Interconnection Customers and others who have a legitimate need for the information, subject to applicable Confidentiality and Critical Energy Infrastructure Information processes (see PJM Operating Agreement §18.17 and http://www.pjm.com/documents/ferc-manuals/ceii.aspx.

Dispatch

The assumptions used for generation dispatch can be critical to the results. It is generally accepted that units operating at their highest possible power output and generating as little reactive power as necessary to maintain voltages are likely to be less stable. Normally, the units in the vicinity of the project under study will be turned on to their maximum real power output with unity power factor at the high side of the GSU's, or units' VAR output will be adjusted to hold scheduled voltages, depending on specific Transmission Owner criteria. Wind turbines are tested at light load for stability and peak load for low voltage ride through at 100% of their maximum energy value. In addition, stability test scenarios necessitated by any applicable Transmission Owner operating guides will also factor into each analysis.

Simulations to determine required upgrades (also see the Appendix to this Attachment)

Fault Criteria:

a. Fault Types: For interconnection and system stability analyses, three phase faults, single line to ground faults with stuck breaker and single line to ground faults with the communications failure cleared within zone 2 time will be examined. Each analysis will include a determination of the most critical faults to apply.

b. Clearing Times: Dynamic simulation issues are identified using estimates of actual (nominal) clearing times, including relay trip times, breaker interrupting time, fault extinguishing time, intentional delay time, and a margin for error.

c. Reclosing: Only high speed reclosing is modeled if present.

d. Fault locations: For interconnection analysis, criteria faults at power flow busses including one bus removed from the interconnection point will be examined. When clusters of generating busses are studied, the most critical faults one bus removed from new generators in the cluster will be examined. In addition, other fault locations judged critical to cluster response will be added to the scope. For system analyses, the scope will determine the most critical locations to apply criteria faults.

e. Maintenance outages: Interconnection analyses of planned line maintenance outage conditions prior to fault application are system conditions that can be anticipated and that are generally of limited duration. The least cost remedy to issues during such system conditions is to require generation to curtail output. Such analyses are, therefore, of primary interest in the operating horizon and are not generally considered to determine upgrade facilities required prior to interconnection. Nevertheless, prior to commercial operation, or prior to completion of the facilities study at the request of the Interconnection Customer, Planning will screen critical faults for issues during line maintenance. The results of the line maintenance study will be conveyed to PJM Operations, the Interconnection Customer, and affected Transmission Owners.

PJM addresses Power System Stabilizer (PSS) outages in a similar fashion. If there are existing PSS installations nearby a new interconnection or if PSS is required on the new interconnection, critical faults for the outage of these devices will be studied prior to commercial operation and the results will be conveyed to PJM Operations, the Interconnection Customer, and affected Transmission Owners.

Margins:
The margins applied by PJM are intended to be applied in impact study stability analysis that uses a project's final stability study data as further discussed below. As such, these margins account primarily for uncertainty in actual clearing times, and the final data represents the "as built" performance. With the machine modeled at net unity power factor at the high-side of the GSU (or unity power factor at the generator terminals for wind turbine installations), transient stability must be maintained for tested faults when the following margins are included:

a. Add 0.25 cycles to the nominal primary clearing time for 3 phase, normally cleared faults.

b. Add 0.25 cycles to the nominal primary clearing time for single-line-to-ground faults, plus an additional 0.5 cycles added to the nominal backup clearing time for stuck breaker (.75 cycle total clearing time margin).

c. Add 0.25 cycles to the nominal primary clearing time for single-line-to-ground faults, plus an additional 1.25 cycles to the nominal Zone 2 clearing time for failure of primary relaying (1.5 cycle total clearing time margin).

Monitoring requirements:
Rotor angle, Real power output, EFD, speed and terminal voltage of units under study are monitored. Bus Voltages in the same area are also monitored.

Acceptable Voltage Drop:
Following the disturbance, the voltages of the monitored buses maintain voltages within ±5% of the precontingency voltages

Acceptable Damping:
Following the disturbance, the oscillations of the monitored parameters display positive damping. The positive damping is determined with a damping coefficient calculation algorithm. This characterizes the degree of positive (damped) or negative (undamped) damping based on the damping trend, over the duration of the stability run, of the envelope of machine angle oscillation peaks. This trend can be observed

by drawing an envelope connecting each succeeding peak or valley of the oscillation of the monitored element. An acceptable oscillation envelope will demonstrate a positive decay within the appropriate test period (normally 10 to 15 seconds). A sustained oscillatory system response, even if slightly damped, will cause the system to be in a vulnerable state and exposed to adverse impacts for subsequent changes to the system over some prolonged time. To limit this system exposure PJM uses a 3% damping margin. Such positive damping demonstrates an acceptable response by the system, and no further analysis is required. Failure to meet the damping standard will require application of some combination of power system stabilizers, excitation system upgrade and tuning, and system upgrade.

G.3 System Impact Study and Initial Study Stability Procedures

Generating unit stability analysis is performed by PJM as a part of the System Impact Study for proposed generation interconnection to the PJM system. PJM also conducts annual system stability analysis of the PJM system in compliance with applicable NERC transmission planning criteria. PJM's standards for stability analyses satisfy NERC criteria and are the generally applicable criteria for all PJM stability analyses. In addition, Transmission Owner stability criteria may apply. Certain specific areas of PJM have been identified by PJM or Transmission Owner analysis as stability limited areas of the system. In such areas of the system, stability operating guides may apply. See PJM Manual 03 at http://www.pjm.com/documents/manuals.aspx for more information on PJM stability operating guides.

G.3.1 Stability Data Requirements

a. Submission of Project Stability Study Data

   Stability study data is included in the data required for the series of studies generally required for a System Impact Study. A System Impact Study typically includes a short circuit study, power flow study and stability study. As required by the PJM Tariff, and detailed in PJM Manual 14A, all data for the System Impact Study, including stability analysis data, must be submitted by the Interconnection Customer as part of a completed System Impact Study Agreement. System Impact Study Agreements are not complete until the required agreement is fully executed and all associated data for the complete series of studies is received. Upon PJM's acceptance of a completed System Impact Study Agreement, all associated data becomes the Interconnection Customer's final data for the System Impact Study and any subsequently necessary Facilities Study.

b. Final Stability Study Data

   Prior to beginning any of the studies generally required for a System Impact Study, PJM will accommodate modifications to submitted data unless, in PJM's judgment, such modification would adversely impact subsequently queued projects. It is the Interconnection Customer's responsibility to establish and maintain communication with the assigned PJM Project Manager to determine the latest date that specific data changes can be accommodated. Interconnection Customers are encouraged to work closely with their Project Managers to determine if any anticipated project changes can be accommodated without adversely affecting subsequent projects. After acceptance of the System Impact Study Agreement, PJM is under no obligation to accept any changes in data and may proceed through the System Impact Study, Facilities Study and the Interconnection Service Agreement processes on the basis of the final data. This final data is considered consistent with the "as built" representation of the system. As such, it should represent the actual equipment that will be installed and commissioning settings that can be achieved.

c. Changes to Stability Data After Commencement of Stability Study

This section addresses project changes that affect the stability study and often the short circuit study. Such changes typically involve the electrical, configuration and physical parameters of the generator and associated electrical equipment between the connection to the networked power system and the generator. While some configuration changes could necessitate power flow re-study, the changes that are discussed here only cause stability and possibly short circuit re-study.

After the start of the stability study PJM will complete the stability study, issue the System Impact Study report, complete any necessary Facilities Study and issue the Interconnection Service Agreement. After the start of the stability study, changes to electrical parameters that will require stability re-study, will be accommodated by PJM as resources are available and in a manner that does not negatively impact later queued projects. In addition, certain parameter changes may also require new short circuit studies. Necessary re-study caused by parameter changes may be performed by contractors. The re-study will be performed on the system model that includes all project studies completed at the time of the re-study. The scope of the re-study will determine all necessary incremental system facilities necessitated by the parameter changes.

d. Cost of Incremental Facilities Caused by Re-study

The Interconnection Customer that makes the parameter changes that cause re-study will be responsible for the costs of re-study and the cost of the incremental facilities that are specified by the re-study, including facilities that are revealed by the short circuit re-study.

G.3.2 System Impact Study Stability Scope and Process

These procedures apply to stability studies required as part of System Impact or Initial Studies. These stability studies determine the project's cost responsibility for upgrades due to interconnection stability issues. These upgrade responsibilities become part of a project's Interconnection Service Agreement (ISA.)

Stability study start dates, generally, are at least six months after the close of a queue. This allows time to complete feasibility studies and the power flow and short circuit phases of the impact study. This section outlines the process of coordination and execution of the stability study among the representatives of PJM, the Interconnection Customers and Transmission Owners.

1. PJM will develop a study scope at the beginning of each project stability analysis. This scope will include but not be limited to the following items:
   1.1. The MW Size of the project. Developers may reduce the project maximum output, based on tariff terms, from the feasibility request. Stability will study projects at their maximum outputs regardless of the project's value for capacity markets.
   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 Special Protection Systems (SPS) (for example see Manual 03) may include scenarios designed to test the proper operation of the existing guides or SPS. In such

cases, the scope may be augmented to examine and specify modified procedures or facilities that ensure the integrity of the system operation.

3. After completion of the study scope, PJM will transmit results and supporting information to the Transmission Owner. A review conference call between the Transmission Owner and PJM will be scheduled within a week of providing the results.
4. The transmission Owner will provide an estimated date for completion of its determination of system remedies for any issues identified in the stability results. Such remedies will include system impact cost estimates and the earliest feasible date to complete system modifications that accommodate the new interconnection.
5. Upon completion of the Transmission Owner review and estimates PJM will issue the final impact study report to the project developer.
6. In situations when the required system modifications or upgrades cannot be accomplished by the projected in-service date of the project, PJM will develop a scope and schedule to determine interim solutions and dates along with provided interim capability.

G.4 System Stability Studies

In addition to the system impact stability analyses of new generating interconnections, the three year cycle testing of all existing generating units interconnected to the PJM system, and certain “ad hoc” stability testing required by special circumstances that occur from time to time, PJM also conducts system stability testing of its most critical stressed system conditions during the annual Regional Transmission Expansion Plan study cycle. The RTEP stability testing examines and ensures system performance within criteria for heavy system transfer conditions. Power flow criteria are ensured on a local and system-wide basis for heavy transfers during the application of PJM’s load deliverability testing (see Manual 14B Attachment C.) These test scenarios examine emergency conditions involving extreme generating outages and loads coupled with single transmission element outages. Such circumstances are critical when the system is stressed at heavy load, rather than light load.

Based on the results of each annual RTEP cycle and previously completed stability analyses, PJM determines the load delivery limits for the case that represents the most critical conditions for PJM system stability testing. The transfers into the selected Region emanate from external PJM and non-PJM generation. Imports from external areas are based on historical levels for heavy load. An example of the type of PJM scenario that could represent the critical study condition may have local load of 65,000 MW with a transfer into the area caused by the simultaneous outage about 10,000 MW of internal area generation. This may cause a thermal limit to transfers well in excess of 6000 MW.

The transmission outage that sets the limit for transfers during the Mid-Atlantic load delivery testing is modeled for stability to ensure that the region is not stability limited. PJM also determines several more critical three-phase and single-line-to-ground fault tests to apply from a stability perspective to ensure robust, stable and adequately damped system performance. Fault testing for system stability includes the most critical Bulk Electric System lines.

G.4.1 NERC Category C3 “N-1-1” System Stability Studies

INTRODUCTION

An N-1-1 contingency pair is defined as a single line to ground (SLG) or 3-phase fault with normal clearing, manual system adjustments, followed by another SLG or 3-phase fault with normal clearing. In the NERC TPL standard, N-1-1 contingencies belong to Category C3. Manual adjustments after first (N-1) contingency are allowed to relieve any thermal or voltage violations for applicable ratings and/or to prepare for second (N-1-1) contingency.N-1-1 stability analysis is defined as a stability analysis for given N-1-1 contingency scenarios. For a given N-1-1 contingency scenario, the first (N-1) contingency is applied to a pre-disturbance base case. If the system is stable, a new operating point is computed and manual adjustments are made if necessary, and then stability is monitored following second (N-1-1) single contingency. Because of the assumed long time delay (from a stability point of view) between two single contingencies, the N-1-1 stability analysis is similar to maintenance outage study for operational guidelines.

DISPATCH

Initial base case creation for N-1-1 stability analysis follows the procedure in Attachment G, section 2.2. When an N-1 base case is created, care needs to be taken before an N-1-1 contingency is applied. First, all thermal or voltage violations in the N-1 base case should be resolved through system adjustment. Second, if available, any existing operating guidelines for the N-1 outage condition needs to be applied to the N-1 base case.

N-1-1 STABILITY ANALYSIS PROCEDURE

Considering the number of generating machines in the PJM system and the number of possible N-1-1 contingency pairs, it is very challenging to cover all of them within a reasonable lead time. In general testing all N-1-1 contingency pairs for stability is impractical and not necessary due to the fact that most contingency pairs are electrically far away from a study plant or independent from each other. It is essential to screen out critical contingency pairs which have potential stability problems without missing any potentially unstable N-1-1 contingency pairs.

Overall procedure of N-1-1 stability analysis for generating units in PJM area is as follows:

1. Selection of plants for the N-1-1 stability study
   A. The scope of annually studied plants will include the same plants included in the scope of the baseline stability study that year. Similar to the baseline stability study, one third of generators in PJM will be considered for the N-1-1 stability analysis each year resulting in each.
   B. If PJM Transmission Planning determines that the scope cannot be completed within a reasonable lead time, PJM Transmission Planning will prioritize the plants in the scope of the study and higher priority plants will be studied first.
   C. With the request of PJM Operation or Transmission Owners due to special operation need, the study for specific plants would be performed.
2. Selection of N-1-1 contingency pairs for each plant.
   A. N-1-1 contingency pairs within one bus from the high tension bus of the study plant are tested. If the number of branches connected to the high tension bus is less than three, the boundary of N-1-1 contingency pairs is extended to two buses away.
3. Conduct N-1-1 stability study

A. Assume N-1 stability results are available from the baseline stability analysis.

B. If an N-1contingency 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.

C. 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

D. Consider SPSs 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.

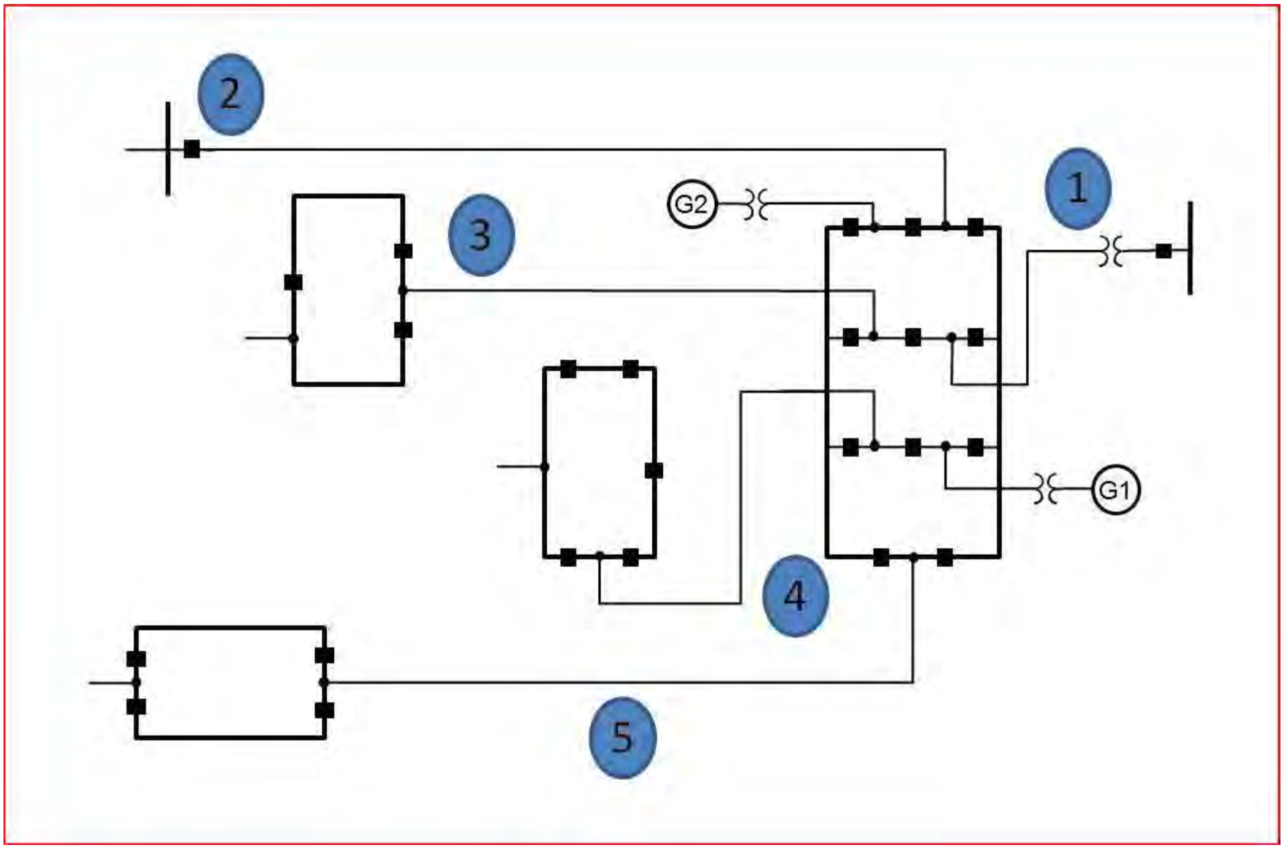


Figure 1 – Example of Five transmission lines for the N-1-1 stability study of a generic location.

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 special protection 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 interconnection requests can be found in OATT PART IV, Subpart A, PART VI, Subpart A, and OATT Attachment O Schedule H.

G.5.1 Wind Project Final Impact Study Data

Upon entering the interconnection queue, wind generators may submit approximate data for the feasibility study that represents the wind farm as a single equivalent unit. Prior to commencement of the wind farm impact study the approximate data must be replaced with detailed design data including the detailed electrical layout of the wind farm. This data is required for wind farm projects, by tariff provisions, no later than six months after the filing of the interconnection request. As described in the general discussion of System Impact and Initial Study procedures, final impact study data is generally required at the beginning of the system impact study process which often will happen to be about six months after the close of the queue. In the case of wind projects, tariff requirements ensure that the data may be supplied up to six months from the initiation of the queue request. In practice the wind farm developer, as well as all project developers, should maintain good communications with the assigned project manager to determine when PJM is scheduled to begin a specific project's stability analysis.

G.5.2 Wind Project LVRT Requirements

In addition to all facets of the standard stability study scope previously discussed, wind generators will be studied during their impact study stability analysis for compliance with the Low Voltage Ride Through Criteria (LVRT.) The LVRT criteria tests the ability to the wind farm generator to maintain operation and interconnection with the system during events that cause extremely low voltage transients as measured at the high side of the transformer that steps up the Wind Farm's voltage to the transmission system (high side of the wind farm GSU.) Peak load conditions are the most stressful for maintaining system voltage so this analysis will be conducted on a peak load power flow model (in contrast to the standard stability analysis that is conducted on an off-peak model.) Based on the results of the standard stability analysis, PJM will determine the most critical three phase faults with normal clearing and phase to ground faults with delayed clearing. The wind generator will be required to maintain its power output to the system following three phase faults cleared in up through 9 cycles (9 cycles includes any applicable margins) and that produce a voltage as low as zero at the high side of the GSU. Actual clearing times plus applicable margins will be used, which may be less than 9 cycles and high side GSU voltages may be somewhat greater than zero. Also the wind farm must maintain output to the system following the most critical phase to ground faults with delayed clearing, using actual clearing times. Applicable clearing time margins will apply to the LVRT test.

G.5.3 Wind Project Reactive Power Modeling

Stability tests will be conducted on a system model with the GSU modeled and zero generator reactive power output (unity power factor.) When power flow analysis does not model the generator step up transformer, the zero generator reactive power output is applied at the collector bus. This base case and the stability analysis will establish power factor or reactive power delivery requirements only if impact study analysis is conducted that demonstrates that the safety or reliability of the system is impacted by the lack of the requirement. System transient, oscillatory, or voltage instability during any phase of the impact study is evidence of system safety or reliability impact. For such results, the least cost remedy that considers system protection, transmission upgrades, or reactive requirements will be determined and specified.

In the event that the transient or voltage instability only affects the wind project (for example when long radial interconnection facilities cause the inability of the wind facility to remain stably interconnected), the wind project will be notified and be requested to provide project design remedies. PJM's analysis of possible remedies will be limited to specifying the size of dynamic reactive device or increased transmission interconnection capacity if such a remedies are sufficient.

G.6 Stability Analyses of Stability Sensitive Local Areas in PJM

The PJM system generally operates to limits determined by thermal and reactive criteria. In some specific instances local areas of PJM or individual plants operate to stability limitations. The PJM transmission system conditions and procedures due to localized thermal, reactive and stability considerations are outlined in PJM Manual 03.

The PJM Transmission Owners are often owners of the facilities that are subject to these procedures and carry out PJM's operating instructions ensuring safe and reliable operation consistent with these guidelines and procedures. PJM, therefore, closely coordinates review of the stability guides and procedures with the Transmission Owners and, when appropriate, Transmission Owners may conduct analysis, subject to PJM's review.

Stability guides applicable to specific plants are reviewed as part of PJM's three year cycle of generator stability analysis that ensures continued compliance with NERC criteria. Local stability guides and procedures are reviewed as necessary when interconnections or transmission changes cause the need for review. Each review is specific to the area or plants operating procedures and guides and confirms or develops modifications to the guide and system upgrades, as appropriate, to maintain reliable operation within applicable criteria.

G.7 Short Circuit

PJM performs short circuit analysis as part of the annual Regional Transmission Expansion Plan (RTEP) baseline assessment. This analysis includes a study of the entire PJM system based on its current configuration and equipment. In addition, PJM also performs the analysis on the planned system configuration using a 5-year out case. The generation and merchant transmission interconnection process (see Manual 14A) also includes short circuit analysis for each requested new interconnection project. The addition of new sources drives most breaker replacements. PJM Planning conducts short circuit analysis to ensure the high-voltage circuit breakers on the transmission system are sufficiently rated to safely interrupt fault currents. These short circuit studies are also referred to as breaker interrupting studies. Since new sources only become committed with relative assurance a few years before scheduled commercial operation and since breaker replacement lead times are only a few years, these analysis are only conducted within the 5-year planning horizon.

The short circuit analysis is performed in accordance with the following industry standards:

- ANSI/IEEE 551-2006 "IEEE Recommended Practice for Calculating Short-Circuit Currents in Industrial and Commercial Power Systems"
- ANSI/IEEE C37.04-1999 "IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers"
- ANSI/IEEE C37.010-1999 "IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis"
- 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:

- 1 year planning representation consisting of the current system plus all facilities planned to be in-service within the next year.
- Current year plus 5 planning representation using the 1 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 1 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 1 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 Special Protection 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

http://www.pjm.com/planning/rtep-development.aspx

http://www.pjm.com/planning/generation-interconnection.aspx

http://www.pjm.com/committees-and-groups/committees/teac.aspx

PJM will notify PJM System Operations and the affected Transmission Owner in the event that PJM's planning analyses indicate planning study results that violate PJM planning criteria or nuclear specific planning criteria. In addition, results of PJM Impact Studies affecting nuclear facilities are communicated to the affected Nuclear owner and operator.

PJM applies some nuclear plant study procedures that exceed *standard NERC criteria* to be consistent with certain regulatory and safety requirements specific to these facilities. Material contained in the Appendix to this Attachment G provides Nuclear Plant Interface Requirements (NPIR) regarding the nuclear specific testing procedures applied by PJM and Transmission Owner Planning.

G.9 Appendix to Manual 14B Attachment G

This appendix contains Transmission Owner specific criteria applicable to RTEP stability study analyses that may go beyond the NERC system stability performance tests routinely applied by PJM. PJM normal stability testing enforces the NERC criteria that are based on single contingencies and common-mode multiple contingencies. PJM does not permit planned load loss or interruption of firm transmission service for these events, even when such service curtailment may be permitted by the NERC standards. These contingencies are also referred to in this Attachment and Appendix as the "standard" NERC criteria and include the following events:

- System normal,
- Single phase and/or three phase fault (N-1),
- Single phase fault stuck breaker (N-2),
- Three phase fault tower (N-2), and
- Single Phase fault and communication failure (N-2).

More stringent NERC criteria that involve multi phase faults, non-common mode multiple contingencies, and higher order contingencies (also referred to as "beyond" *standard NERC criteria*) do not routinely form the basis for required PJM RTEP upgrades. Some Transmission Owner criteria, however, as detailed in this Appendix, go beyond the *standard* PJM stability screening criteria and do require remedies. These procedures, as applicable, are applied during PJM RTEP (including interconnection related) stability analyses in addition to PJM thorough testing of *standard NERC criteria* tests and system performance is verified to be stable and within criteria. The Transmission Owner specific criteria are limited to interconnections with the transmission facilities of the respective Transmission Owners.

All PJM testing applies the clearing margins and damping criteria discussed in Attachment G and more stringent criteria when the specific Transmission Owner criteria exceed these standard margins. In all cases PJM applies the criteria in a comparable and not unduly discriminatory fashion to new interconnection projects and existing generators. Violations 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, special protection systems, 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 special protection system.
- 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.9.5 PPL Specific Criteria

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

- permanent three-phase faults at a point 80% of the line impedance away from the PPL zone generating facility under consideration with delayed (Zone 2) clearing times, including reclosing, if applicable.
- Permanent three phase fault with stuck breaker or other cause of delayed clearing.
- Permanent three phase fault on one line in the substations one substation removed from the interconnection point with an over-trip of another unfaulted line in the same station. Both the over-trip and clearing of the faulted line occur in normal primary clearing time. Reclosing sequences, if applicable, will be included.
- PPL EU applies a transient synchronous stability safety margin of 7% in the export limited Northern PPL area (see PJM Manual 03 at http://www.pjm.com/documents/manuals.aspx). This implies that the net export limit based on stability will be reduced by 7% to account for a margin of error in the specified net export limit from the area.

G.9.6 Implementation of the NPIR for Planning Analysis

PJM is required to incorporate the Nuclear Plant Interface Requirements (NPIRs) into its planning processes according to the applicable NERC standards. PJM performs these planning analyses consistent with the NPIR planning requirements and its Regional Transmission

Planning requirements. PJM Manuals 14B and 39 are the two principal sources that document these requirements, among various other planning and operating process business rules. It the responsibility of the Planning engineer to monitor changes to the planning requirements contained in the NPIR source documents (kept in confidence by PJM System Operating) and Manual 39 and to update this manual to reflect changes as appropriate per the protocols of Manual 39 section 3.1.

The following material are the excerpted planning requirements and criteria contained in the NPIR's that must be incorporated into PJM Planning analyses. This material must only be changed to be consistent with the source documents.

Braidwood Station, Units 1 and 2 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected Braidwood switchyard voltages following a unit trip (Unit 1 or 2) shall be performed for various transmission system load levels and contingencies based on the study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the ComEd transmission entity on a periodic basis to support compliance with GDC 17. The results of the studies are to be provided to Exelon Nuclear by the ComEd Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the Braidwood voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the Braidwood requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for Braidwood and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following Braidwood requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:

The Braidwood Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

345kV: Normal Low (actual voltage evaluations) – 349.2kV (1.0122)

Emergency Low (contingency voltage evaluations) – 349.2kV (1.0122)

Note:

The limits above are applicable for Braidwood Units 1 and 2. It is acceptable that the Normal Low limit be conservatively adjusted upward by1kV to allow for design limitations of the transmission entity state estimators. Some state estimator designs do not allow a Normal Low limit and an Emergency Low limit to be the same value.

For the purposes of the planning studies only the Braidwood unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Stability:

Braidwood generating units 1 and 2 are to be stable for the following conditions (the following are included in PJM standard stability testing):

- A three-phase line fault with normal clearing of the line protective systems.
- A phase-to-ground fault with abnormal (delayed) clearing involving the failure of a relay or circuit breaker.
- A double line tower fault.

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if the system stability studies pertinent to the Braidwood generators, the Braidwood switchyard, or the lines connecting the Braidwood switchyard to the transmission system indicate that stability requirements contained in the PJM, NERC or ComEd Transmission Entity standards are not met.

Byron Station, Units 1 and 2 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected Byron switchyard voltages following a unit trip (Unit 1 or 2) shall be performed for various transmission system load levels and contingencies based on the study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the ComEd transmission entity on a periodic basis to support compliance with GDC 17. The results of the studies are to be provided to Exelon Nuclear by the ComEd Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the Byron voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the Byron requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for Byron and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following Byron requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:

The Byron Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

345kV: Normal Low (actual voltage evaluations) – 341.0kV (.9885 pu)

Emergency Low (contingency voltage evaluations) – 341.0kV (.9885 pu)

Notes:

The limits above are applicable for Byron Units 1 and 2. It is acceptable that the Normal Low limit be conservatively adjusted upward by .1kV to allow for design limitations of the transmission entity state estimators. Some state estimator designs do not allow a Normal Low limit and an Emergency Low limit to be the same value.

For the purposes of the planning studies only the Byron unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Stability:

Byron generating units 1 and 2 are to be stable for the following conditions (the following are included in PJM standard stability testing):

- A three-phase line fault with normal clearing of the line protective systems.
- A phase-to-ground fault with abnormal (delayed) clearing involving the failure of a relay or circuit breaker.
- A double line tower fault.

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if the system stability studies pertinent to the Byron generators, the Byron switchyard, or the lines connecting the Byron switchyard to the transmission system indicate that stability requirements contained in the PJM, NERC or ComEd Transmission Entity standards are not met.

LaSalle Station, Units 1 and 2 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected LaSalle Station switchyard voltages following a unit trip (Unit 1 or 2) shall be performed for various transmission system load levels and contingencies based on a study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the ComEd Transmission Entity on a periodic basis to support compliance with GDC 17. The results of the studies are to be provided to Exelon Nuclear by the ComEd Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the LaSalle voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the LaSalle requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for LaSalle and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following LaSalle requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:

The LaSalle Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

345 kV: Normal low (actual voltage evaluations) – 353.0 kV (1.0232 pu)

Emergency Low (contingency voltage evaluations) – 353.0 kV (1.0232 pu)

Note:

The limits above are applicable for LaSalle Units 1 and 2. It is acceptable that the Normal Low limit be conservatively adjusted upward by .1kV to allow for design limitations of the transmission entity state estimators. Some state estimator designs do not allow a Normal Low limit and an Emergency Low limit to be the same value.

For the purposes of the planning studies only the LaSalle unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Stability:

LaSalle generating units 1 and 2 are to be stable for the following conditions (the following are included in PJM standard stability testing):

- A three-phase line fault with normal clearing of the line protective systems.
- A phase-to-ground fault with normal clearing and with abnormal (delayed) clearing involving the failure of a relay or circuit breaker.
- A double line tower fault.
- A phase-to-ground fault during planned transmission line maintenance outages

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if the system stability studies pertinent to the LaSalle generators, the LaSalle switchyard, or the lines connecting the LaSalle switchyard to the transmission system indicate that stability requirements contained in the PJM, NERC or ComEd Transmission Entity standards are not met.

Quad Cities Nuclear Power Station Units 1 and 2 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected Quad Cities switchyard voltages following a unit trip (Unit 1 or 2) shall be performed for various transmission system load levels and contingencies based on the study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the ComEd Transmission Entity to support compliance with GDC 17. The results of the studies are to be provided to Exelon Nuclear by the ComEd Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the Quad Cities voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the Quad Cities requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for Quad Cities and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following Quad Cities requirements shall be utilized for the planning studies.

Voltage and Offsite Source Load Capacity Requirements:

The Quad Cities Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

345kV: Normal Low (actual voltage evaluations) – 348.2 kV (1.0093 pu)

Emergency Low (contingency voltage evaluations) – 348.2 kV (1.0093 pu)

Note:

The limits above are applicable for Quad Cities Units 1 and 2.

For the purposes of the planning studies only the Quad Cities unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Power flow and Stability Testing:

The following design requirements of the Quad Cities UFSAR are to be annually verified through the battery of transmission tests performed by PJM and ComEd. All of the Quad Cities requirements are embodied in the standard NERC, PJM and ComEd transmission criteria applied during PJM and ComEd studies related to the Regional Transmission Expansion Plan and generation interconnections. These tests ensure the Quad Cities and ComEd system are in compliance with the applicable criteria.

The transmission system is designed to withstand the sudden outage of large amounts of generating capacity. The system shall be designed to compensate for the simultaneous loss of any two generating units and maintain all transmission network flows within short term emergency limits, and all 345kV and 138kV voltages within steady state limits. This is required at all load levels up to the 50/50 load forecast. PJM testing examines the non-simultaneous outage of any two units. ComEd testing examines the most critical combination of simultaneous outages of two units.

Quad Cities Station and the transmission system is designed for stability and circuit isolation that will prevent the sudden loss of one unit at Quad Cities from causing the second unit to trip. This is confirmed by power flow and stability studies. The system shall be stable for situations involving a three phase fault on the most critical generating element with normal clearing, or a three phase fault on the most critical generating element with delayed clearing, or the loss of the most critical single facility with no fault.

Assuming one or both of the Quad Cities units are tripped when carrying full load, the high voltage lines at the station will continue to be energized from the transmission system. The transmission system shall be designed to withstand the outage of any one generator and maintain all network flows within emergency ratings (up to 50/50 load) or short term emergency ratings (up to 90/10 load).

Exelon Nuclear shall be notified by the Planning Authority (PJM) if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if the system stability studies pertinent to the Quad Cities generators, the Quad Cities switchyard, or the lines connecting the Quad Cities switchyard to the transmission system indicate that stability requirements contained in the PJM, NERC or ComEd Transmission Entity standards are not met.

Dresden Units 2 and 3 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected Dresden Station switchyard voltages following a unit trip (Unit 2 or 3) shall be performed for various transmission system load levels and contingencies based on a study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the ComEd Transmission Entity on a periodic basis to support compliance with GDC 17. The results of the studies are to be provided to Exelon Nuclear by the ComEd Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the Dresden voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the Dresden requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for Dresden and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following Dresden requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:
The Dresden Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

345 kV: Dresden Unit 2 (Blue Bus);

Normal low (actual voltage evaluations) – 332.9 kV (0.9650 pu) with Tr 86 LTC in auto, 346.2 kV (1.0035 pu) with Tr 86 LTC in manual

Emergency Low (contingency voltage evaluations) – 332.9 kV (0.9650 pu) with Tr 86 LTC in auto, 346.2 kV (1.0035 pu) with Tr 86 LTC in manual

345 kV: Dresden Unit 3 (Red Bus);

Normal low (actual voltage evaluations) – 338.8 kV (0.9821 pu) with RAT 32 LTC in auto, 345.3 kV (1.0009 pu) with RAT 32 LTC in manual

Emergency Low (contingency voltage evaluations) – 338.8 kV (0.9821 pu) with RAT 32 LTC in auto, 345.3 kV (1.0009 pu) with RAT 32 LTC in manual

Note: For the purposes of the planning studies only the Dresden unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Stability:

Dresden generating units 2 and 3 are to be stable for the following conditions (the following are included in PJM standard stability testing):

A three-phase fault on any transmission or generation element with normal clearing of the protective systems.

a. A three-phase fault on any transmission or generation element with abnormal (delayed) clearing involving the failure of a relay or circuit breaker. The fault is cleared in delayed time by back-up equipment. If the protective device which fails to operate is an independent pole operated (IPO) breaker, only one phase will be assumed to fail to clear in the primary clearing attempt which will leave only a single phase fault during the delayed clearing time. Mitigation for unstable scenarios may include generator tripping.

b. A three phase fault on any transmission or generation element accompanied by the failure of a special protection scheme to detect, clear, or properly respond to the fault. The fault is cleared in delayed time by back-up equipment, or the special protection scheme may fail to operate as designed. Mitigation for unstable scenarios may include generator tripping.

c. A three phase fault on all transmission lines installed on a multiple circuit tower. No relay or circuit breaker failure is assumed for this contingency.

d. A three phase fault on any transmission or generation element during the scheduled outage of any other transmission or generation element. No relay, circuit breaker, or special protection scheme failure is assumed for this contingency. Mitigation for unstable scenarios may include generator tripping.

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if the system stability studies pertinent to the Dresden generators, the Dresden switchyard, or the lines connecting the Dresden switchyard to the transmission system indicate that stability requirements contained in the PJM, NERC or ComEd Transmission Entity standards are not met.

Oyster Creek Unit 01 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: (FirstEnergy responsibility) Periodic analysis of the expected station switchyard voltages following a unit trip shall be performed for various transmission system load levels and contingencies to support station compliance with GDC 17. The bulk transmission system must be examined for performance during system disturbances; using normal case load flows, transient stability studies, and post-transient load flow studies. The studies are to confirm that the system performs adequately for the predicted worst case single contingency (one line or other failure) on the bulk transmission system with normal system adjustments, followed by the loss of the Oyster Creek generator. For these conditions, the studies must confirm that there was no loss of load in the system, the Oyster Creek 230kV substation is not interrupted, and a predicted minimum grid (substation) voltage is determined . Once per year any changes made to the transmission system that would affect voltage stability at Oyster Creek must be reviewed and if necessary, a new value for the minimum expected/predicted grid voltage is to be provided to Exelon Nuclear. Results of the studies are to be provided to Exelon Nuclear.

Transmission Planning studies (PJM responsibility) shall incorporate the voltage and stability requirements of the station. These studies shall include those performed for Operations and for future transmission and generation interconnection. Exelon Nuclear shall be notified if planning study results identify that the station requirements are not met by current or future system configurations, load levels, and contingencies. The following station requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:

The Oyster Creek voltage limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

	230kV Oyster Creek Switchyard Voltage
Normal Low (actual voltage evaluations)	227kV (0.9869 p.u.)
Emergency Low (contingency voltage evaluations)	223.7kV (0.9726 p.u)

Note: For the purposes of the planning studies only the Oyster Creek unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Planning assessments enforce nuclear voltage criteria at the Transmission System level, including any voltage drop criteria. Criteria are enforced on a post-contingency basis without system adjustments but allowing generation reactive supply within normal reactive limits, except as may be explicitly noted below.

Oyster Creek system normal (reference case conditions) 230 kV low voltage limit is 227 kV (.987 pu) and, under contingency conditions it is 223.7 kV (.973 pu). In addition, frequency will be monitored for all studied contingencies and verified to be maintained above 57.5 Hz.

Stability Requirements:

The system shall remain stable and perform within voltage and other applicable criteria following:

1. A 3 phase fault with primary clearing on the most critical of the 230 kV lines emanating from Oyster Creek. (standard PJM test)
2. A 3 phase fault with primary clearing on the most critical of the 34.5 kV lines emanating from Oyster Creek. (standard PJM test applied to lower voltage than PJM's standard testing)
3. A 1 phase fault on the most critical of the two 230 kV lines emanating from Oyster Creek, followed by a stuck breaker and clearing in backup clearing time. (standard PJM test)
4. The simultaneous loss of the Oyster Creek generating unit and the largest generating unit in New Jersey (Salem Unit 2) with no faults. (not part of standard testing)
5. 3 phase close-in fault on the most critical 230 kV and above lines from the station (double circuit tower outage, specifically both Manitou-Oyster Creek lines) and loss of the Oyster Creek generator (verify Oyster Creek unit trips based on out-of-step relay protection), (standard PJM test)

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met.

Three Mile Island Unit 1 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: (FirstEnergy responsibility) Periodic analysis of the expected Station switchyard voltages following a unit trip shall be performed for various transmission system load levels and contingencies to support Station compliance with GDC 17. The bulk transmission system must be examined for performance during system disturbances; using normal case load flows, transient stability studies, and post-transient load flow studies. The studies are to confirm that the system performs adequately for the predicted worst case single contingency (one line or other failure) on the bulk transmission system with normal system adjustments, followed by the loss of the TMI generator. For these conditions, the studies must confirm that there was no loss of load in the system, the TMI 230kV substation is not interrupted, and a predicted minimum grid (substation) voltage is determined. Once per year any changes made to the transmission system that would affect voltage stability at TMI must be reviewed and if necessary, a new value for the minimum expected/predicted grid voltage is to be provided to Exelon Nuclear. Results of the studies are to be provided to Exelon Nuclear.

Transmission Planning studies (PJM responsibility) shall incorporate the voltage and stability requirements of the Station. These studies shall include those performed for Operations and for future transmission and generation interconnection. Exelon Nuclear shall be notified if planning study results identify that the Station requirements are not met by current or future system configurations, load levels, and contingencies. The following Station requirements shall be utilized for the planning studies:

Voltage:

The TMI Station voltage limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

	2 Auxiliary Transformer Operation	Single Auxiliary Transformer Operation	Manual Load Tap Changer Operation
Normal Low	223 (0.9710 pu)	223 (0.9710 pu)	223 (0.9710 pu)
Emergency Low	223 (0.9710 pu)	223 (0.9710 pu)	223 (0.9710 pu)

Planning assessments enforce nuclear voltage criteria at the Transmission System level, including any voltage drop criteria. Criteria are enforced on a system normal and post-contingency basis after allowance for full system adjustments that can be available within 30 minutes following a disturbance.

Stability:

Three Mile Island generating unit stability is to be analyzed according to the applicable NERC, Regional Entities of NERC, and PJM criteria for transient stability.

Exelon Nuclear shall be notified if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if the system stability studies pertinent to the TMI generator, the TMI switchyard, or the lines connecting the TMI switchyard to the transmission system indicate that any of the stability requirements are not met.

Limerick Generating Station Units 1 and 2 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected Limerick switchyard voltages following a unit trip (Unit 1 or 2) shall be performed for various transmission system load levels and contingencies based on the study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the PECO Transmission Entity to support compliance with NRC licensing commitments for Limerick. The results of the studies are to be provided to Exelon Nuclear by the PECO Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the Limerick voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the Limerick requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for Limerick and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following Limerick requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:
The Limerick Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level are as follows:

230kV: Normal Low (actual voltage evaluations) – 225kV (.9783 p.u.)

Emergency Low (contingency voltage evaluations) – 225kV (.9783 p.u.)

Voltage drop: 2.5% (Post contingency voltage drop limit to be applied for a contingency trip of Limerick Unit 1 or Unit 2).

500kV: Normal Low (actual voltage evaluations) – 500kV (1.0 p.u.)

Emergency Low (contingency voltage evaluations) – 500kV (1.0 p.u.)

Voltage drop: 2.5% (Post contingency voltage drop limit to be applied for a contingency trip of Limerick Unit 1 or Unit 2).

69kV: Normal Low (actual voltage evaluations) – 67.5kV (.9783 p.u.)

Voltage drop: 3.4% (Post contingency voltage drop limit to be applied for a contingency trip of Limerick Unit 1 or Unit 2).

Note: The 69kV voltage limits are to be activated when notification is received from Exelon Nuclear that the Limerick 69kV source is in operation.

Note: For the purposes of the planning studies only the Limerick unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Stability Requirements:

Limerick Generating Station (LGS) Units 1 and 2 are to be stable for the following conditions:

a. A three-phase fault on any single 500 kV or 230 kV circuit terminating in the Limerick 500kV or 230kV switchyards that is cleared by primary protective equipment (standard PJM test.)

b. A three-phase fault on any single 500 kV or 230 kV circuit terminating in the Limerick 500kV or 230kV switchyards, where the most critical LGS circuit breaker fails to open and the fault is cleared at LGS by backup protective equipment. (beyond standard PJM testing.)

c. A three-phase fault on the transformer connecting the LGS 500 kV and 230 kV buses that is cleared by primary protective equipment (standard PJM test.)

d. A three-phase fault on the transformer connecting the LGS 500 kV and 230 kV buses, where the most critical circuit breaker fails to open and the fault is cleared at LGS by backup protective equipment. (beyond standard PJM testing.)

e. Simultaneous three-phase faults on both LGS to Whitpain 500 kV circuits that are cleared by primary protective equipment (beyond standard PJM testing.)

In addition, the transmission system shall remain stable for the following three cases with either one or both LGS units in service. (All the following are beyond standard PJM testing):

a. Loss of the largest generating station (i.e., loss of Peach Bottom Atomic Power Station (PBAPS) Units 2 and 3) (No faults applied).

b. Loss of the largest load (No faults applied).

c. Loss of the most critical right-of-way (i.e., four simultaneous three-phase faults on the four transmission lines on the 130-30 right-of-way):

   1. Cromby-Perkiomen (130-30) 138 kV Line
   2. Cromby-Upper Providence (220-62) 230 kV Line
   3. Limerick-Whitpain (5030) 500kV Line
   4. Limerick-Whitpain (5031) 500kV Line

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if PJM system stability studies pertinent to the Limerick generators, the Limerick switchyards, or the lines connecting the Limerick switchyards to the transmission system indicate that any of the stability requirements contained in the PJM, NERC or PECO Transmission Entity standards are not met.

Peach Bottom Station Units 2 and 3 Planning Requirements

Nuclear Plant Voltage Adequacy Studies:

Periodic analysis of the expected Peach Bottom offsite power source voltages following a unit trip (Unit 2 or 3) shall be performed for various transmission system load levels and contingencies based on a study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the PECO Transmission Entity to support compliance with NRC licensing commitments for Peach Bottom. The results of the studies are to be provided to Exelon Nuclear by the PECO Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the Peach Bottom voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the Peach Bottom requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for Peach Bottom and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following Peach Bottom requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:

The Peach Bottom Station Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level are as follows:

2SU: (Peach Bottom Tap on 220-08 line)

Normal Low (actual voltage conditions)- 225kV (.9783 p.u.)

Emergency Low (contingency voltage conditions)- 225kV (.9783 p.u.)

Voltage Drop: 1.8% (Post contingency voltage drop limit to be applied for a contingency trip of Peach Bottom Unit 2 or 3).

Maximum - 242kV (1.05 p.u.)

343SU: (Peach Bottom 230kV; Peach Bottom terminal of 220-34 line)

Normal Low (actual voltage conditions)- 225kV (.9783 p.u.)

Emergency Low (contingency voltage conditions)- 225kV (.9783 p.u.)

Voltage Drop - 2.6% (Post contingency voltage drop limit to be applied for a contingency trip of Peach Bottom Unit 2 or 3).

Maximum - 242kV (1.05 p.u.)

3SU: (13kV tertiary of Peach Bottom #1 transformer)

Normal Low (actual voltage conditions)- 13.5kV

Emergency Low (contingency voltage conditions)- 13.5kV

Voltage Drop - 2.5% (Post contingency voltage drop limit to be applied for a contingency trip of Peach Bottom Unit 2 or 3).

Maximum – 538kV (1.0760 p.u.)(on 500kV side of Peach Bottom #1 Autotransformer)

Note: The limits above are applicable for Peach Bottom Units 2 and 3.

Stability Requirements:

Stability studies shall have simulated 500 kV and 230 kV transmission line faults, the loss of each of the Peach Bottom generators, and the loss of the largest generator on the 500 kV grid. The studies must show that the transmission system is stable and there will be no cascading transmission outages for the simulated transmission line faults. The studies must show that continuous offsite power is assured for the simulated transmission system contingencies. This requirement is demonstrated by showing that offsite power sources 2SU, 343SU, and 3SU are maintained in service unless the simulated transmission system contingency is the direct supply to the offsite power source.

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if PJM system stability studies pertinent to the Peach Bottom generators, the Peach Bottom switchyards, the lines connecting the Peach Bottom switchyards to the transmission system, or the 220-08 line indicate that any of the stability requirements contained in the PJM, NERC or PECO Transmission Entity standards are not met.

Susquehanna Station units 1 & 2 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected Susquehanna switchyard voltages following a unit trip (Unit 1 or 2) shall be performed considering peak transmission system load levels with the system normal or altered by contingencies. Results of the studies are to be provided to PPL Susquehanna. To satisfy this requirement, the PJM normal course of planning studies fulfills this requirement.

Transmission Planning Studies shall incorporate the voltage and stability requirements of Susquehanna. These studies shall include those performed to evaluate future transmission and generation interconnection. PPL Susquehanna shall be notified if planning study results identify that the Susquehanna requirements are not met by current or future system configurations, load levels, and contingencies.

The Transmission Planner or Transmission Owner will perform voltage analysis using a "current year + 5" planning horizon 50-50 peak summer load flow case considering N-1, stuck breaker and tower outage contingencies on 230 kV facilities and above and a stability study (following transmission normal stability criteria along with the special stability cases identified in the FSAR (Section 8.2)). These studies are to be completed on a three year cycle by the Transmission Planner and on a two year cycle by the Transmission Owner, or sooner, if system changes dictate. The Transmission Planner or Transmission Owner will communicate the results of these studies to PPL SSES. These studies may include load flow, voltage and/or stability related work analyses.

The following Susquehanna requirements shall be utilized for the planning studies:

SSES Transformer Loading

	T-10	T-20	T-11	T-12
Normal Plant Loading	5 + J3	5 + J3	42 + J24	42 + J24
Post Unit 1 Trip Loading both Start-up transformers in-service	27.1 +J14.65	27.1 +J14.65		42 + J24
Post Unit 2 Trip Loading both Start-up transformers in-service	27.1 +J14.65	27.1 +J14.65	42 + J24	
Post Unit 1 Trip Loading T-10 Start-up transformer in-service	54.2 +J 29.3			42 + J24
Post Unit 2 Trip Loading T-10 Start-up transformer in-service	54.2 +J 29.3		42 + J24	
Post unit 1 Trip Loading T-20 Start-up transformer in-service		54.2 +J 29.3		42 + J24
Post Unit 2 Trip Loading T-20 Start-up transformer in-service		54.2 +J 29.3	42 + J24	

Monitor offsite circuits with/without one S/U transformer in service.

With **both** Start-up Transformers (T-10 & T-20) in-service

Minimum Voltage	Allowable Voltage Drop*
212kV (0.9217)	5%

With **one** Start-up Transformer (T-10 or T-20) in-service

Minimum Voltage	Allowable Voltage Drop*
216.7kV (0.9421)	2%

***Post contingency voltage drop limit to be applied for a contingency trip of Susquehanna unit 1 or unit 2.

NOTE: Voltage excursions below the Susquehanna voltage limits with durations expected to be greater than 9 seconds will result in the affected unit or units transferring from offsite power to the onsite power distribution system. Therefore, the transmission Entities shall take into consideration actions that will mitigate voltage excursions below the Susquehanna minimum voltage limits with durations greater than 9 seconds and provide notification when proposed actions cannot mitigate the voltage excursion.

Stability:

Susquehanna generating units 1 and 2 are to be stable for the following conditions:

In general, the stability requirements are that the system shall be maintained without loss of non-consequential load during and after the following types of contingencies based on the latest light load forecast prepared annually by the PJM Load Analysis Subcommittee.

Standard NERC criteria contingencies (identified as R-* cases of FSAR Table 8.2-1):

- Single contingency outage conditions
- Double circuit tower line outage or single stuck circuit breaker conditions Three phase faults with normal clearing time
- Single line to ground faults with a stuck breaker or other cause for delayed clearing

The NERC TPL Standard reliability criteria also requires an evaluation of the ability of the bulk electric system to withstand abnormal or extreme system disturbances (identified as the N-* cases of FSAR Table 8.2-1). The NERC TPL Standard reliability criteria does not require that the bulk electric system be planned and constructed to withstand these abnormal or extreme disturbances due to their low probability of occurrence. However, it is PPL SSES position to maintain stability for these FSAR Table 8.2-1 cases as well. These abnormal system disturbances are analyzed not on the basis of their likelihood of occurrence but rather as a practical means to study the system for its ability to withstand disturbances beyond those that can be reasonably expected.

A total of six (6) contingencies identified in the FSAR Table 8.2-1 are required by NERC standards. Seventeen (17) other contingencies are not required by NERC standards but analyzed to assure a high level of transmission system reliability. FSAR table 8.2-1 is attached with the list of stability cases performed for PPL Susquehanna LLC. PPL Susquehanna shall be notified if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, PPL Susquehanna shall be notified if the system stability studies indicate that any of the stability requirements contained within the attached stability summary tables is not met.

CASE	DESCRIPTION
R-1	3 phase fault at Susquehanna 500 kV on the Sunbury 500 kV line. Fault cleared in primary clearing time.
R-5	Phase-ground fault at Susquehanna 500 kV on Sunbury 500 kV line with Sunbury South 500 kV circuit breaker stuck. Clear remote terminal in primary time. Delayed clearing of Susquehanna.
R-6	3 phase fault at Susquehanna 230 kV on the Susquehanna 500/230 kV transformer. Fault cleared in primary clearing time.
R-7	3 phase fault at Montour 230 kV on Susquehanna 230 kV line. Fault cleared in normal primary clearing time.
R-13	Phase-ground fault at Susquehanna 500 kV on Susquehanna-Wescosville-Alburtis 500 kV line with Wescosville South 500 kV circuit breaker stuck. Clear remote terminal in primary time. Delayed clearing at Susquehanna.
R-18	3 phase fault at Susquehanna 230 kV on Harwood #1 & #2 Double Circuit. Fault cleared in primary clearing time.
N-2	3 phase fault at Susquehanna 500 kV on the Sunburn 500 kV line with one breaker pole stuck at Sunbury. Clear Susquehanna in primary time. Delayed clearing at remote terminal.
N-3	3 phase fault at Susquehanna 500 kV on the Susquehanna-Wescosville-Alburtis 500 kV line with one Susquehanna 500/230 kV transformer breaker pole stuck. Clear remote terminal in primary time. Delayed clearing of Susquehanna.
N-4	3 phase fault at Susquehanna 500 kV on the Sunbury 500 kV line with one Susquehanna 500/230 kV transformer breaker pole stuck. Clear remote terminal in primary time. Delayed clearing of Susquehanna.

N-8	3 phase fault at Susquehanna 230 kV on Montour line with stuck west bus breaker. Clear remote terminal in primary time, clear Susquehanna with delay (lose Stanton-Susquehanna #2 230 kV line).
N-9	3 phase fault at Susquehanna 230 kV on Jenkins line with stuck east bus breaker. Primary clearing at remote terminal. Delayed clearing at Susquehanna.
N-10	3 phase fault at Susquehanna 230 kV on the 500/230 kV transformer with stuck west bus breaker pole. Clear two poles in primary time. Primary clearing at remote terminal (Susquehanna 500 kV Switchyard). Clear stuck pole in delayed clearing time (lose Stanton-Susquehanna #2 230 kV line).
N-11	3 phase fault at Susquehanna 230 kV on Harwood #1 line with stuck tie breaker pole. Clear two poles in primary time. Clear stuck pole in delayed clearing time (lose Sunbury-Susquehanna 230 kV line).
N-12	3 phase fault at Susquehanna 230 kV on Harwood #2 line with one pole stuck on west bus breaker. Clear two poles in primary time. Clear stuck pole in delayed clearing time (lose Stanton-Susquehanna #2 230 kV line).
N-14	Susquehanna-Wescosville-Alburtis 500 kV and Susquehanna-Harwood #1 & #2 Double Circuit 230 kV crossing failure (3 phase fault on all circuits). Automatically trip Susquehanna Unit #1. Clear Susquehanna-Wescosville-Alburtis 500 kV line in primary time. Clear Susquehanna- Harwood #1 & #2 230 kV lines in primary time.
N-15	3 phase fault near E. Palmerton on all lines in E. Palmerton-Harwood R/W corridor. Clear Susquehanna-Wescosville-Alburtis 500 kV line in primary time. Primary clearing of E. Palmerton-Harwood and Harwood-Siegfried 230 kV lines.
N-16	3 phase fault near Susquehanna on both lines in Sunbury-Susquehanna R/W corridor. Clear Sunbury-Susquehanna #2 500 kV line in primary time. Primary clearing of Sunbury-Susquehanna #1 230 kV line.

N-17	3 phase fault near Susquehanna 500 kV at Sunbury 230 kV line crossing. Trip Susquehanna – Wescosville-Alburtis 500 kV, Sunbury-Susquehanna #2 500 kV, and Unit #2 in primary time. Trip Sunbury-Susquehanna #1 230 kV in primary clearing time.
N-19	3 phase fault at Columbia-Frackville 230 kV line crossing. Trip Sunbury-Susquehanna #2 500 kV line in primary time. Trip Columbia-Frackville and Sunbury-Susquehanna #1 230 kV lines in primary time.
N-20	3 phase fault on 230 kV side of Unit #1 main transformer. Trip Unit #1 main transformer. Trip Unit #1 and overtrip Unit #2 in primary time.
N-21	3 phase fault at Susquehanna 230 kV on Unit #1 generator leads with a stuck west bus breaker. Trip Unit #1 and Stanton #2 line.
N-23	Sudden loss of all lines from Susquehanna 230 kV Switchyard
N-24	3 Phase fault on Susquehanna-Jenkins 230 kV line 80% towards Jenkins with pilot relaying out. Fault cleared in Zone 2 (backup) time at Susquehanna and Zone 1 time at Jenkins.

FSAR table 8.2-1

Calvert Cliffs Units 1 and 2 (CCNPP) Planning Requirements

Nuclear Plant Voltage Adequacy Studies

At the request of CCNPP, BGE shall perform periodic analysis of expected Calvert Cliffs 500 kV Switchyard post Unit trip voltages. These studies are typically performed on an annual frequency, but could be needed on a more frequent basis. The results of these studies shall be provided to CCNPP by BGE.

Planning and Operations Transmission Studies

PJM planning and operations transmission studies shall incorporate the Calvert Cliffs 500 kV Switchyard voltage, frequency and capacity requirements in switchyard voltage section below. CCNPP shall be notified by the Planning Coordinator (PJM) if planning study results identify that the Calvert Cliffs 500 kV Switchyard requirements are not met by current or future system configurations, load levels, or contingencies. Transmission study violations based on standard PJM criteria testing will be dispositioned in accordance with the applicable PJM agreements and manuals. Resolution of study violations based on criteria that are specific to CCNPP and are beyond standard PJM criteria testing will be CCNPP responsibility. The following Calvert Cliffs 500 kV Switchyard requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements: Refer to Section 1 for the voltage and load capacity requirements.

Stability Requirements: Stability studies shall have simulated transmission line faults, the loss of each of the CCNPP main generators, and the loss of the largest generator on the 500 kV system. The studies must show that the transmission system is stable and there will be no cascading transmission outages for the simulated transmission line faults. They must also show continuity of offsite power at the Calvert Cliffs 500 kV Switchyard for the simulated transmission system contingencies by ensuring voltage limits defined in section 1.3 are not violated. CCNPP shall be notified by the Planning Authority (PJM) if the results of system stability studies identify if any of the stability requirements are not met.

Calvert Cliffs 500 kV Switchyard Voltage and CCNPP Frequency Requirements

Operating Voltage Limits for the Calvert Cliffs 500 kV Switchyard

Calvert Cliff Voltage Limits		
Plant Service Transformers (P-13000-2 & P-13000-2)	**Pre-Contingency**	**Post-Contingency**
Both xfmrs in service	500kV – 550kV	475kV – 550kV
Only one xfmr in service	520kV – 550kV	510kV – 550kV

Note: See maximum post-trip voltage drop below for loss of a CCNPP unit.

Calvert Cliffs 500 kV Switchyard Voltage Drop Limit

Maximum post-trip voltage drop (Post-contingency for a single CCNPP unit): Voltage drop of 5% of the pre-trip bus voltage with either one or both P-13000 transformers in service. The 5% post contingency voltage drop limit is to be applied at the Calvert Cliffs 500 kV Switchyard for a contingency trip of CCNPP Unit 1 or Unit 2.

Short Circuit Calculations

BGE and SMECO shall provide to CCNPP available short circuit current data at the points of interconnection, when requested for use in the CCNPP distribution system short circuit calculations.

Beaver Valley Units 1 and 2 Planning Requirements

Nuclear Station Voltage Adequacy studies: Per Service Agreement No. 1668, Schedule F, paragraph 12: "ATSI (American Transmission Systems Incorporated) will perform a probability study, at FENOC's (FirstEnergy Nuclear Operating Company) expense, by June 1 of each year to determine the frequency of grid voltage outside of values identified in this schedule. This study will include expected power flow transfers through the region that would influence grid voltages." Results of the studies are to be provided to FENOC.

Transmission Planning studies: The Transmission Planner shall incorporate the voltage and stability requirements of BVPS. These studies shall include those performed to evaluate future transmission and generation interconnection in accordance with applicable NERC and Regional Entities of NERC standards. Both FENOC (Akron) and the BVPS Design Engineering staff shall be notified if planning study results identify that the BVPS requirements are not met by current or future system configurations, load levels, and contingencies by the Transmission Planner performing the studies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for BVPS and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following BVPS requirements shall be utilized for the planning studies:

Voltages:

The voltage limit requirements are as stated below.

The Station voltage limits are as follows:

Beaver Valley Switchyard 345kV Voltage Limits

EL (Emergency Low) 341 kV (0.9850 p.u.)

NL (Normal Low) 343 kV (0.9942 p.u.)

NH (Normal High) 355 kV (1.0290 p.u.)

Beaver Valley Switchyard 138kV Voltage Limits

EL (Emergency Low) 131 kV (0.9493 p.u.)

NL (Normal Low) 136 kV (0.9855 p.u.)

NH (Normal High) 142 kV (1.0289 p.u.)

Planning assessments enforce nuclear voltage criteria at the Transmission System level, including any voltage drop criteria. Criteria are enforced on a system normal and post-contingency basis after allowance for full system adjustments that can be available within 30 minutes following a disturbance.

Frequency:

Both BVPS-1 and BVPS-2 require a stable grid frequency of 59.9 to 60.1 Hz.

Stability:

BVPS generating unit stability is to be analyzed according to the applicable NERC, and Regional Entities of NERC, criteria for transient stability. The analyzed contingencies that are evaluated against Beaver Valley's voltage requirements include:

- Loss of a significant generating unit (standard PJM testing)
- Loss of a significant transmission line (standard PJM test), or
- Loss of a Beaver Valley unit (standard PJM test)

BVPS and FENOC (Akron) shall be notified by the Transmission Planner performing the studies if the results of system stability studies identify that any of the stability requirements discussed above are not met.

Cook Unit 1 and 2 Planning Requirements

The following requirements are derived from Cook Plant Design Information Transmittal DIT-B-03036-00. The information in this DIT is to be used to perform transmission studies that support Cook Plant Operation.

This DIT looks at case reports for Mode 1 and LOCA. The purpose is to allow a comparison between plant data and the model (Mode 1) and make adjustments to the model if appropriate. These values will be transmitted to Transmission planning as input for their studies.

Depending on the preferred power line up (split = Transformer #4 and Transformer *#5;* Transformer #4 only; or Transformer *#5* only) different values for transfer must be considered. The "split" lineup will transfer the IA & I B or 2A & 2B busses to Transformer *#5* and the IC & ID or 2C & 2D busses to Transformer #4. The transfer includes the associated T-busses. These groups of loads (load groups) are called Division AB and Division CD for each unit. When the preferred power lineup is Transformer #4 only or Transformer *#5* only; then both divisions (AB and CD) will transfer to the applicable single transformer. The single transformer load group is called "Entire Plant" and consists of the Division AB and Division CD for a single unit. This DIT also looks at 69kv power requirements.

3. Design Value Determination

3.1. The values determined above are increased to allow increased use of power within the plant and for margin. The amount of the increase was determined by engineering judgement considering weld receptacles and desired margins. All power magnitudes are assumed to be at 0.8 power factor. This is reasonable since the current plant model shows power factor slightly above 0.8.

	Accident Megawatt Load		
	AB Division	**CD Division**	**Entire Plant**
Unit 1	22	22	42
Unit 2	20	24	42.5

3.2. The division power levels should be used for the normal split lineup of the switchyard when the AB division will be powered via transformer 5 and the CD division will be powered via transformer 4. The division power levels cannot be added together to represent the entire plant because the division power values are representative of different plant lineups where depending on which pumps are in service power can be shifted from one division to another. The total power levels should be used when the switchyard is lined up in either the Transformer4 only or transformer 5 only lineups.

4. 69kv System Determination

4.1. Power for the 69kv system is procedurally limited to 600 amperes at the 4kv level for each unit (Ref 4). This power would be in addition to the normal load seen on 69kv. The normal load consists of power to other buildings at the site such as the Training Center and the Visitors Center. Actual power factor is expected to be between 0.8 and 0.9. The value which results in the lowest voltage should be selected for conservatism.

4.2. Since the primary result from determining these values is the evaluation of voltage adequacy and the limitation is an absolute value for current; available power will reduce with available voltage.

4.3. The bounding case of determining minimum adequate voltage will be when system conditions are such that the minimum acceptable voltage results from applying the power allowed at that voltage via the EP (69kv source).

4.4. The lowest allowable voltage is cited in the TRM as 91%.

4.5. The power for the bounding case is 1200*0.91*4160*1.73*pf=7.86*pf (MW)

5. Conclusions for Transmission Planning Studies

5.1. The power transferred to our 34kv system will depend on the lineup of the system. The normal lineup is split so that the AB division will transfer to TR5 and the CD division will transfer to TR4. If either transformer is out of service then the entire unit will transfer to the remaining transformer (TR5 and TR4 only lineups). The following table prescribes the value to be used for transmission studies. The power factor associated with these loads is 0.80.

	Megawatt Load Transferred at Unit Trip		
	AB Division (TR5 split)	CD Division (TR4 split)	Entire Plant (TR5 or TR4 only)
Unit 1	22	22	42
Unit 2	20	24	42.5

5.2. The power that can be transferred to the 69kv system is 7.86* power factor (MW). The power factor between 0.80 and 0.90 which provides the lowest voltages should be selected.

Using the input data described above, periodic planning studies are conducted of the transmission and subtransmission networks surrounding the D. C. Cook Plant to determine worst-case offsite power voltage conditions that could credibly exist during a plant shutdown scenario, as well as minimum and maximum voltage and short circuit levels that may be experienced. These studies determine the impact of the most significant factors including transmission and subtransmission network contingencies, Cook Plant generating unit configurations, status of other generation near Cook Plant, 765 kV switched shunt reactor status, and transmission network power flows and take into account the various possible reserve auxiliary switchyard lineups. Available historic data for EHV flows and voltages is utilized in preparation of power flow models used in the studies and for independent validation of study results.

Typically, planning studies will be requested by Cook Plant personnel and performed by AEP Transmission with results provided to Cook Plant and to PJM Planning.

Voltage Requirement

TABLE 1
Maximum switchyard voltage swing requirements to reset the degraded voltage relays with the Main Generator Synchronized to the Transmission Network and the bus(s) are powered from the Unit Auxiliary Transformer(s) source:

Cook Offsite Power Source	34 kV Switchyard Source Breaker position	345 kV System Swyd Swing Limit (Value @ DGR reset.) % of 345kV				TR4 Tertiary 34.5 kV System Swyd Swing Limit (Value @ DGR reset) % of 34.5kV			
		Unit 1		Unit 2		Unit 1		Unit 2	
		Limit Note 1	**Alarm** Setpoint	**Limit** Note 1	**Alarm** Setpoint	**Limit** Note 1	**Alarm** Setpoint	**Limit** Note 1	**Alarm** Setpoint
TR5 & TR4	BD – Open BE & BC – Closed	**5.0%** Note 3	**4.5%** Note 2	**3.7%** Note 3	**3.2%** Note 2	**5.3%** Note 3	**4.8%** Note 2	**3.6%** Note 3	**3.1%** Note 2
TR5	BD & BE - Closed BC – Open	**1.1%**	**0.6%** Note 2	**0.0%**	**-0.5%** Note 2	N/A	N/A	N/A	N/A
TR4	BD & BC – Closed BE – open	N/A	N/A	N/A	N/A	**4.3%**	**3.8%** Note 2	**2.5%**	**2.0%** Note 2
The BOLDED values indicate the limits and alarm values.									

TABLE 2
Maximum switchyard voltage swing requirements to reset the degraded voltage relays with the Main Generator Synchronized to the Transmission Network and the bus(s) are powered from the Reserve Auxiliary Transformer(s) source:

Cook Offsite Power Source	34 kV Switchyard Source Breaker position	345 kV System Swyd Swing Limit (Value @ DGR reset.) % of 345kV				TR4 Tertiary 34.5 kV System Swyd Swing Limit (Value @ DGR reset) % of 34.5kV			
		Unit 1		Unit 2		Unit 1		Unit 2	
		Limit Note 1	**Alarm** Setpoint	**Limit** Note 1	**Alarm** Setpoint	**Limit** Note 1	**Alarm** Setpoint	**Limit** Note 1	**Alarm** Setpoint
TR5 & TR4	BD – Open BE & BC – Closed	**1.6%**	**1.1%** Note 2	**1.1%**	**0.6%** Note 2	**2.4%**	**1.9%** Note 2	**2.0%**	**1.5%** Note 2
TR5	BD & BE - Closed BC – Open	**1.0%**	**0.5%** Note 2	**0.7%**	**0.2%** Note 2	N/A	N/A	N/A	N/A
TR4	BD & BC – Closed BE – open	N/A	N/A	N/A	N/A	**1.5%**	**1.0%** Note 2	**1.1%**	**0.6%** Note 2
The BOLDED values indicate the limits and alarm values.									

North Anna Units 1 and 2 Planning Requirements

The Dominion System Operator must notify the station in a timely manner if any of the GDC-17 limits stated in item 1 above may potentially be impacted by the results of Operations Planning studies.

It is the responsibility of Transmission Planning to develop a long-range transmission plan which provides for orderly and timely modifications to the transmission system in order to insure an adequate, economical and reliable supply of electric power. The system must be planned, designed, and constructed to operate reliably within thermal, voltage, and stability limits. Dominion's Transmission Planning performs a wide variety of specific studies to ensure the GDC-17 requirements are met.

These include:

- Power Flow Studies
- Stability Studies

PJM and Dominion Electric Transmission Planning will design the system to meet the GDC-17 requirements. Steady state voltage limits will use the "Emergency Limit Low" and "Emergency Limit High" voltage limits of section 1. Only the following contingency scenarios will be evaluated:

Transmission Condition	Unit 1	Unit 2
All lines in	On	On
All lines in	Trip	On
All lines in	On	Trip
All lines in	Trip	Trip
Worst case N-1 contingency	On	On
Worst case N-1 contingency	Trip	On
Worst case N-1 contingency	On	Trip

PJM/Dominion Electric Transmission Planning will notify Dominion Nuclear of any NPIR criteria violations. Transmission study violations based on standard PJM/Dominion planning criteria will be handled through the normal planning processes described in the PJM agreements and manuals. Upgrades for study violations based on the more stringent Dominion Nuclear NPIR criteria will be the responsibility of the plant owner.

Voltage Limits:

The NAPS 500 kV switchyard voltage must be maintained between 505kV and 535 kV to ensure compliance with GDC-17 voltage analysis. The Dominion System Operator must notify the station in a timely manner (within 15 minutes) when one of the following conditions occurs:

- The 500 kV or 230 kV voltage or frequency limits are exceeded, and the steps taken or being taken to mitigate the exceeded limit.

Bus Name	Normal Limit Low	Emergency Limit Low
500 kV	510.0 kV (1.02 pu)	505.0 kV (1.01 pu)
230 kV	226.3 kV (0.984 pu)	224.0 kV (0.974 pu)

Bus Name	Normal Limit High	Emergency Limit High
500 kV	530.0 kV (1.06 pu)	535.0 kV (1.07 pu)
230 kV	239.2 kV (1.04 pu)	242.0 kV (1.052 pu)

Bus Name	Normal Voltage Drop	Emergency Voltage Drop
500 kV	3.5 %	3.5 %
230 kV	3.5 %	3.5 %

Bus Name	Frequency Limit Low	Frequency Limit High
500 kV	59.5 Hz	60.5 Hz
230 kV	59.5 Hz	60.5 Hz

- A contingency analysis study indicates the normal or emergency limit for the station will be exceeded if a single contingency occurs and the Transmission Operator cannot effectively mitigate the condition to avoid the violation.
- Both the Dominion and the PJM Real Time Contingency Analysis (RTCA) are not available.
- The real time telemetry between Dominion System Operator and the station is known to be out of service.
- The system conditions return to normal.

Surry Units 1 and 2 Planning Requirements

The Dominion System Operator must notify the station in a timely manner if any of the GDC-17 limits stated in item 1 above may potentially be impacted by the results of Operations Planning studies.

It is the responsibility of Transmission Planning to develop a long-range transmission plan which provides for orderly and timely modifications to the transmission system in order to insure an adequate, economical and reliable supply of electric power. The system must be planned, designed, and constructed to operate reliably within thermal, voltage, and stability limits. Dominion's Transmission Planning performs a wide variety of specific studies to ensure the GDC-17 requirements are met. These include:

- Power Flow Studies
- Stability Studies

PJM and Dominion Electric Transmission Planning will design the system to meet the GDC-17 requirements. Steady state voltage limits will use the "Emergency Limit Low" and "Emergency Limit High" voltage limits of section 1. Only the following contingency scenarios will be evaluated:

Transmission Condition	Unit 1	Unit 2
All lines in	On	On
All lines in	Trip	On
All lines in	On	Trip
All lines in	Trip	Trip
Worst case N-1 contingency	On	On
Worst case N-1 contingency	Trip	On
Worst case N-1 contingency	On	Trip

PJM/Dominion Electric Transmission Planning will notify Dominion Nuclear of any NPIR criteria violations. Transmission study violations based on standard PJM/Dominion planning criteria will be handled through the normal planning processes described in the PJM agreements and manuals. Upgrades for study violations based on the more stringent Dominion Nuclear NPIR criteria will be the responsibility of the plant owner.

Voltage Limits:

The SPS 500 kV switchyard voltage must be maintained between 505 kV and 535 kV to ensure compliance with GDC-17 voltage analysis. Similarly, the 230 kV switchyard voltage must be maintained between 220 kV and 245 kV. The Dominion System Operator must notify the station in a timely manner (within 15 minutes) when one of the following conditions occurs:

- The 500 kV or 230 kV voltage or frequency limits are exceeded, and the steps taken or being taken to mitigate the exceeded limit.

Bus Name	Normal Limit Low	Emergency Limit Low
500 kV	510.0 kV (1.02 pu)	505.0 kV (1.01 pu)
230 kV	222.3 kV (0.967 pu)	220.0 kV (0.957 pu)

Bus Name	Normal Limit High	Emergency Limit High
500 kV	530.0 kV (1.06 pu)	535.0 kV (1.07 pu)
230 kV	239.2 kV (1.04 pu)	245.0 kV (1.065 pu)

Bus Name	Normal Voltage Drop	Emergency Voltage Drop
500 kV	4.5 %	4.5 %
230 kV	6.0 %	6.0 %

Bus Name	Frequency Limit Low	Frequency Limit High
500 kV	59.67 Hz	60.33 Hz
230 kV	59.67 Hz	60.33 Hz

- A contingency analysis study indicates that the normal or emergency limit for the station will be exceeded if a single contingency occurs and the Transmission Operator cannot effectively mitigate the condition to avoid the exceeded limit.
- Both the Dominion and the PJM Real Time Contingency Analysis (RTCA) are not available.
- The real time telemetry between Dominion System Operator and the station is known to be out of service.
- The system conditions return to normal.

Hope Creek Unit Planning Requirements

Transmission Planning (PJM)

Hope Creek Generating Station, operating in the PJM controlled bulk electric system requires periodic transmission planning studies to be performed to ensure onsite power systems remain connected to the offsite power sources during grid transients or a unit trip of Hope Creek or the adjacent Salem generating units.

Periodic analysis of the expected Hope Creek switchyard voltage and voltage drop following a unit trip shall be performed for various transmission system load levels and contingencies.

Studies shall also be performed, as needed, to evaluate the effect that future proposed modifications or changes to the transmission system may have on Hope Creek offsite power source limits.

PSEG Nuclear shall be notified if any of the above planning studies identify that the Hope Creek requirements stated in Section 1 are not met by current or future configurations, load levels, and /or contingencies.

Transmission Planner organization shall provide the 500kV System Equivalent Impedances (min and max) at the Hope Creek switchyard whenever transmission planning studies are performed or as requested by the generating station.

Voltage Limits

Hope Creek Generating Station is analyzed to operate within the following voltage limits:

Emergency Low: 493 KV (0.986 p.u.)

Normal Low: 500 KV (1.000 p.u.)

High Limit: 550 KV (1.100 p.u.)

Voltage Drop Requirements

Hope Creek Generating station has been analyzed for a maximum allowable offsite voltage drop at the station following a unit trip and the worst case post trip accident loading.

2.5% Voltage Drop

Stability Requirements

Hope Creek Generating Station is operated in close proximity with the PSEG Nuclear Salem Units 1 and 2 generating stations and has been analyzed for stability for the following faults provided the station is operated per the Artificial Island Operating Guide (AIOG) A-5-500-EEE-1686:

1. Loss of Hope Creek Generator.
2. Loss of most critical Generating Unit on the Grid
3. Loss of the Most Critical Transmission Line

The Transmission Operator, Transmission Planner and PSE&G Transmission Owner are required to incorporate the requirements of the latest revision of the Artificial Island Operating Guide A-5-500-EEE-1686, into all future stability studies, and provide PSEG Nuclear with at least 24 months notice of any violations to the guide due to future system modifications which could impact generation output at Artificial Island.

Salem Units 1 & 2 Planning Requirements

Transmission Planning (PJM)

Salem Generating Station, operating in the PJM controlled bulk electric system requires periodic transmission planning studies to be performed to ensure onsite power systems remain connected to the offsite power sources during grid transients or a unit trip of Salem or the adjacent Hope Creek generating units.

Periodic analysis of the expected Salem switchyard voltage and voltage drop following a unit trip shall be performed for various transmission system load levels and contingencies.

Studies shall also be performed, as needed, to evaluate the effect that future proposed modifications or changes to the transmission system may have on Salem offsite power source limits.

PSEG Nuclear shall be notified if any of the above planning studies identify that the Salem requirements stated in Section 1 are not met by current or future configurations, load levels, and /or contingencies.

Transmission Planner organization shall provide the 500kV System Equivalent Impedances (min and max) at the Salem switchyard whenever transmission planning studies are performed or as requested by the generating station.

Voltage Limits

Salem Generating Station is analyzed to operate within the following voltage limits:
Emergency Low: 493 KV (0.986 p.u.)
Normal Low: 500 KV (1.000 p.u.)
High Limit: 550 KV (1.100 p.u.)

Voltage Drop Requirements

Salem Generating station has been analyzed for a maximum allowable offsite voltage drop at the station following a unit trip and the worst case post trip accident loading.

2.0% Voltage Drop

Stability Requirements

Salem Units 1 and 2 are located in close proximity with the PSEG Nuclear Hope Creek generating station and have been analyzed for stability for the following faults provided the station is operated per the Artificial Island Operating Guide (AIOG) A-5-500-EEE-1686:

1. Loss of One Salem Nuclear Unit
2. Loss of Largest Generating Unit on the Grid
3. Loss of the Most Critical Transmission Line

The Transmission Operator, Transmission Planner and PSE&G Transmission Owner are required to incorporate the requirements of the latest revision of the Artificial Island Operating Guide A-5-500-EEE-1686, into all future stability studies, and provide PSEG Nuclear with at least 24 months notice of any violations to the guide due to future system modifications which could impact generation output at Artificial Island

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 (R3) is for the Planning Coordinator to identify the 100 kV to 200 kV facilities that must meet Requirement 1of the standard to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System, maintain a current list of facilities determined according to the process, and provide the list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of establishment of the initial list and within 30 days of any changes to the list. The process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.

Process to determine PRC-023 Critical Facilities

As part of the development of the RTEP each year PJM staff will perform analysis to determine what facilities may be susceptible to cascading. The test will determine if the simultaneous loss of two independent[5] BES elements (without intermediate system adjustments) results in a 100 kV – 200 kV facility being loaded in excess of 115% of its emergency rating and the loss of that overloaded facility results in additional overloaded BES facilities. If there are additional overloaded BES facilities loaded in excess of their emergency rating, the 100 kV – 200 kV element that was overloaded after the initial N-1-1 will be identified as needing to meet the requirements of the standard.

[5] Note that this test methodology is beyond the current requirements of NERC Standard TPL-003 given the standard evaluates common mode failures (i.e. loss of a double circuit tower line, bus, or circuit breaker failure) that result in the loss of two or more facilities. Category C3 in Table 1 of the standard evaluates the loss of independent BES elements however system adjustments can be made following the loss of the first facility.

Attachment H: Power System Modeling Data

H.1 Power System Modeling Data

Accurate power system modeling data is a key component of quality power system analysis. PJM System Planning uses a variety of models and analytical techniques to create and maintain the simulation models used for the RTEP studies. The intended use of this Attachment is to supplement existing documentation by PJM and other entities that specify accurate modeling data requirements. PJM will continue to follow the data guidelines and standards set forth by NERC as part of the MOD standards and the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) Procedural Manual.

H.1.1 Load Flow Analysis Models

Base case creation is a collaborative process between PJM and its members. From a technical standpoint PJM follows the guidelines set forth in the ERAG MMWG Procedural Manual. In the following sections, the logistics and transfer of information between PJM and its members are detailed.

<u>Annual Updates</u>

In the fourth quarter of each year, PJM will distribute to the Transmission Owners a current year +5 summer peak network model based on the most up to date MMWG case combined with the previous year's RTEP case. This draft case will contain all upgrades identified during the previous year's RTEP cycle. Within 4 weeks of receiving the initial draft network model, Transmission Owners will provide:

- Network updates to the model that will advance the case to represent a current year + 5 base case with respect to the 1st Quarter of the following year. This update should be reviewed for correctness and compatibility with the final version of the base case under development
- Complete NERC category B and C contingency file updates that correspond to the updated network model (Include any contingencies which may not change the poweflow model, but change contingency definitions)
- Maximum credible disturbance (NERC Category D) contingencies
- Any other significant changes such as new load or block load additions
- Support, if necessary, for the development of network models for additional years and demand levels for both near term (years 1 through 5) and longer term (beyond 5 years) analyses.
- Verification that all baseline, network and supplemental upgrades are included in the updated case along with a written description of any case modifications.
- Notification of any changes to tie lines whether they are ties internal to PJM or to external companies.

Generation Owner Requirements:

- Specific information regarding generator capability per MOD 10 and MOD 12

H.1.2 Load Flow Modeling Requirements

In addition to the guidelines set forth by NERC and the ERAG MMWG procedural manual, PJM uses several specific procedures in establishing the base case so that it represents the best starting point for the annual RTEP analysis.

Generator step-up transformers

Generator models should represent the physical plant lay-out to the extent possible, explicitly modeling generator step-up transformers (GSUs) and Station Service loads (aka Auxiliary loads). This applies to units above 20 MW and connected to the BES system, consistent with BES requirements. Plants consisting of multiple units aggregating to 75 MW or more also require explicit representation of GSUs and station service loads.

Interchange

The PJM net interchange in the summer peak case is determined by the firm interchanges that are represented in the PJM OASIS system. The interchange in light load cases follows the light load criteria as defined in the Light Load Reliability Analysis in section 2.3.10 of this manual.

Generator Reactive Capability

Annually, PJM updates the model for the generator reactive capability (GCAP) of each generator based on data used by PJM Operations, which includes default limits obtained from the most up to date d-curves as well as data provided by the Generator Owners.

Interconnection Projects With Interconnection Service Agreements (ISAs)

PJM includes queue projects with a signed ISA into the base case as well as verifying the accuracy of queue projects that have not yet signed an ISA. PJM also includes the interconnection, ratings and associated upgrades for each of these projects. Transmission Owners will verify the accuracy of the points of interconnection and the associated upgrades in their zones.

Real and Reactive Load

Each TO is responsible for modeling the active (real) and reactive load profile in its zone. PJM will scale the load in each zone to the targeted values reported in the latest annual PJM load forecast report.

Real loads will be scaled uniformly in each zone to meet the PJM 50/50 load forecast less any Demand Response (DR), Energy Efficiency (EE), or Behind the Meter (BTM) generation as necessary. Real loads will also be scaled uniformly within each zone for off-peak analysis. Reactive load in each area will be scaled at a constant power factor along with the real load for peak load analysis. For off-peak analysis including light-load, PJM will provide a case to the Transmission Owners, at their discretion, for updating their zonal reactive load profile.

Any deviation from the above method of load modeling method, associated with specific test procedures such as the PJM Load Deliverability Procedure or the PJM Light Load Reliability Test Procedure will be defined specifically in other sections of this manual.

PJM will coordinate with TOs on an individual basis to ensure that non-conforming loads are properly modeled and not uniformly scaled.

Voltage Schedules

The setting of voltage schedules is crucial to the robustness of cases. PJM allows Transmission Owners to supply generator voltage schedule data. If the data is not provided PJM will use the default voltage schedules as defined in PJM Manual 03.

H.1.3 Submittal of Load Flow Data

Acceptable Data Formats

- For PSS/E users, cases should be submitted to PJM in a ".SAV" format in a PSS/E version that is readable by the current version of PSS/E that MMWG is using.
- For users of PSLF or other modeling software, cases shall be submitted to PJM in a ".RAW" format that is PSS/E compatible and is readable by the current version of PSS/E that MMWG is using.
- PJM's migration of PSS/E versions may slightly lag MMWG, in that case it is acceptable to provide updates formatted for the current version that PJM is using.
- TO's can submit data in an agreed to version if they are unable to export to the latest MMWG compatible version.

Timing

Transmission Owners must comply with the schedule dictating the timeliness of the case creation process which will be included in the initial email sent to kick off the process. This schedule will include a minimum of 4 weeks to provide updates to the case and corresponding files for the first iteration, and 2 weeks for the second iteration.

Load Flow Data Quality

- In the event that data provided by Transmission Owners does not pass all of the testing included in the MMWG data checker, PJM may request updated data.
- Transmission Owners must provide unique bus names or circuit ID's for each winding of all transformers.
- Bus numbers must be within the allocated bus number range for each company.
- Conventions used for the naming of Machine ID's vary for different TO zones. PJM will coordinate with each TO individually to align with their preferred convention.

- Certain specific modeling and naming conventions which must be followed by all TO's include:
  - High/Low Pressure units should be modeled on the same bus and designated with the corresponding machine ID "H" and "L".
  - No other machine ID should be named "H" or "L".
  - With the exception of High/Low Pressure units, multiple machines modeled on the same bus must have the same status. Offline machines should not be modeled on the same bus as machines which have a status of online.
  - Machines at the same plant with different statuses should be modeled on separate busses connected by a very low impedance line (X=.002) as defined in the MMWG manual.

H.1.4 Short Circuit Analysis Models

Short Circuit data procedures are documented in the Attachment G.7 of this manual, which references ANSI/IEEE 551. The intended use of this attachment is to supplement these procedures and outline the data requirements which PJM follows in creating the short circuit cases used for analysis.

- Short circuit models should be provided in Aspen ".olr" format, if possible.
- Each TO provided Aspen ".OLR" case should model only the TO area and its tie lines. No outside areas should be included in the submission.
- All area numbers in the TO provided cases should be consistent with MMWG designated area numbering convention. Area numbers such as 1, 2, 3, etc. are not acceptable.
- Generation owners must submit to PJM all their breaker data for breakers rated above 100 kV.
- Transmission Owners must submit an excel sheet containing explanations for outaged and out-of-service equipment that is normally in-service.

<u>Timing</u>
In the 1st quarter of each year, PJM will send the Transmission Owners an initial current year +5 impedance network model. This case is based on the most up to date PJM short circuit case combined with the previous year's RTEP case containing all upgrades, MTX projects, and generation queue projects in the Facility Studies Phase that have been identified during that RTEP cycle.

In the 4th quarter of each year, PJM will send the Transmission Owners an initial current year +1 impedance network model. This case is based on the most up to date PJM short circuit case combined with the previous year's RTEP case containing all upgrades, MTX projects, and generation queue projects in the Facility Studies Phase that have been identified during that RTEP cycle.

Transmission Owners must comply with the time schedule of the case creation process which will be included in the initial email sent to kick off the process. This schedule will include a minimum of 4 weeks to provide updates to the case and corresponding files. Once all cases and corresponding files have been submitted to PJM, a +1 case is created and analysis performed to determine overdutied breakers. TOs are then given another 4 weeks to confirm any new overdutied breakers. After the +1 year short circuit case is finalized, the +1 year case is then used to create the+5 year short circuit case for performing the short circuit studies and identifying the new system issues. The identified issues will be sent out to the Transmission Owners who will have 4 weeks to provide solutions to address these issues.

H.1.5 Stability Analysis Models

The case used for stability and dynamic studies is developed by PJM based on information from the Regional Transmission Expansion Plan (RTEP) case prepared by PJM Interconnection and the MMWG case prepared by Powertech Labs for the Eastern Interconnection Reliability Assessment Group (ERAG).

When preparing the base case for stability and dynamics, the ERAG case provides the information for the areas outside PJM while the RTEP case provides the PJM information (e.g. load forecast, network configuration). When combining the ERAG and the RTEP cases, care should be taken to preserve the ties between the PJM areas and the rest of the Eastern Interconnection.

All generator projects active in the PJM queue process that have been studied must be included in the base case for stability and dynamics. In some instances, the RTEP model for the queue project may not be detailed enough for use in stability studies. In this situation, the case must be updated to make sure that all detailed components associated with this project are included in the stability and dynamics power flow model (e.g. generator step-up transformer, loads).

In addition to updating the power flow case with the latest network information, the dynamic models must also be updated to reflect the changes introduced by the RTEP case and the stability and dynamic studies performed by PJM. In this regard, the dynamic data file from the ERAG MMWG case is updated so that the dynamic models for the generators in the PJM areas are matched against the new power flow information from the RTEP. The dynamic model for each queue generator must also be added to the dynamic data file.

The resulting power flow case, the dynamic data file and supporting files required for a complete stability and dynamics base case need also to be correlated and reviewed to determine inconsistencies as well as missing or questionable data. A base case is considered to be finished when, after the review, it compiles, links the models to the PSS/E main structure and initializes correctly. An acceptable condition for a finished base case is when simulated system dynamics, using this case, do not deviate from the initial conditions for any simulation setup with no disturbances applied to the system.

<u>Timing</u>

In the first quarter of each year, PJM will build stability cases based on the latest RTEP power flow model and the latest ERAG dynamic cases. In this period, PJM will request the Transmission Owners for load models for dynamic studies, and for other supporting data if necessary. Transmission Owners must comply with the time schedule of the stability case creation process which will be included in the initial email sent to kick off the process.

Stability and dynamics base cases:

Stability is assessed using a summer peak load and a light load condition. The summer peak stability case has the load profile of the RTEP summer peak case and corresponds to the demand expected to be served in the specific planning year. The light load stability case represents 50% of the summer peak load and is developed by scaling down the summer peak load case at the same power factor.

For simplicity, it is recommended to first build the summer peak case and then update that case to reflect the second load condition (light load). This approach provides two cases that are common in bus numbers and network information. Updates to both cases, such as addition or removal of proposed lines or queue projects would be easy to handle due to the uniformity.

After the power flow case has been finalized and revised, the dynamic data file from the dynamic data file will be updated to reflect the changes that were introduced by the addition of the PJM areas from the RTEP case and generation interconnection studies. It is important to note that the RTEP case and the ERAG case complement each other. RTEP case information is used for future generation queue projects and transmission upgrades which don't exist in the ERAG case and ERAG case consists of information of existing units.

The light load case (50% peak) is derived from the summer peak case. This approach ensures consistent bus numbers and network information in both cases, making addition or removal of proposed lines or queue projects easy to handle. After the summer peak case is completed, the PJM load is scaled down to a load representing 50% of the 50/50 load. The areas outside PJM are updated with the light load case from the corresponding ERAG MMWG case. Note that generation and shunt capacitors may be turned off or disabled in order to achieve convergence of the power flow. In addition, all pumped storage hydro units are modeled in the pumping mode with their governors and power systems stabilizers deactivated or adjusted to reflect the appropriate operating condition.

Generation/Transmission Owner Responsibilities:

- Provide necessary supporting data for stability case build upon PJM's request including but not limited to: topology information and dynamic modeling and station loads
- Provide station loads, including power factors and load representation data (CONL file) if the load representation is different from the one in the ERAG MMWG series
- Verify upgrades and generator modeling (MVA base & Topology)

If there is any discrepancy between the RTEP case and the ERAG MMWG case for existing units, PJM will follow up with the Generation owner with assistance from the TO to insure that the most current data is used.

A complete base case (summer peak or light load) must include at least:

- A power flow file: This file contains the network information and provides the initial conditions for the dynamic models.
- A dynamic data file: This file contains all the information necessary to simulate the dynamic response of the various system components.

- A gnet file: This file contains the information of those generators that do not have a dynamic model. Any generator listed in this file is considered as a negative MVA load.
- A conl file: This file indicates how loads will be modeled based on a combination of constant MVA, constant current and constant admittance. It is strongly recommended that each TO develop more accurate load representation for stability and dynamics studies

Dynamics Data Submittal Requirements and Guidelines:

The Multiregional Modeling Working Group (MMWG) provides the following topics pertaining to dynamics data submittal requirements and guidelines. This information is accessible in Appendix II of the MMWG Procedure Manual V5. A hyperlink to the manual is located at the bottom of this section.

- Power Flow Modeling Requirements
    - Bus name identifiers for synchronous condensers, Static VAr Compensators (SVCs) modeled as generators, switched shunts, relays, and HVDC terminals.
    - Step-up transformer representation requirements for both MMWG power flow cases and non-MMWG power flow cases.
    - Resistance and reactance data placements for step-up transformers represented in the power flow generator data records.
    - Xsource value representations in the power flow generator data record.
    - SVC representation requirements in power flows.
- Dynamic Modeling Requirements
    - Synchronous generator and condenser modeling / associated data requirements and exceptions.
    - Additional representation requirements and exceptions for synchronous generators and condensers modeled as described in Requirement II.1.
    - PSS/E modeling requirements for any other types of generating units and dynamic devices.
    - Exceptions to the use of standard PSS/E dynamic models.
    - Required written documentation and its submittal procedures for user-defined modeling in MMWG cases.
    - Generating unit, synchronous condenser, and other dynamic device requirements for netting.
    - Lumping conditions of similar or identical generating units at a plant.
    - Location requirements for per unit data.
    - Exception procedure for any requirements listed.

- Dynamics Data Validation Requirements
    - Dynamics data screening requirements
    - Preliminary procedures to undergo before regional data submittal to the MMWG coordinator.
    - Material required by each region to validate the dynamics model.
- Guidelines
    - Additional documentation that should be submitted with dynamics data.
    - Information pertaining to parameters for representing loads via the PTI PSS/E CONL activity that the regions should provide to the MMWG.

Location of MMWG Procedural Manual:

https://rfirst.org/reliability/easterninterconnectionreliabilityassessmentgroup/mmwg/Documents/

Revision History

Revision 20 (12/22/2011):

- Added additional detail to the NERC Category C3 “N-1-1” section
- Created NERC Category C3 “N-1-1” stability section
- Added references to DUKE Energy Ohio/Kentucky
- Added additional detail to the NERC Standard PRC-023 Transmission Relay Loadability Section
- Updated Section 2 to reflect 24 Month Planning Process
- Fixed two small typos in the alt paragraph on P55 in the C.3 Section

Revision 19 (09/15/2011):

- Added Attachment H Power System Modeling Data

Revision 18 (7/20/2011):

- Added Light Load Reliability Analysis criteria and created a new attachment D-2 to contain the criteria.
- Added description of reactive load modeling in CETL base cases.

Revision 17 (4/13/2011):

- Added references where appropriate to reflect the inclusion of the American Transmission Systems, Inc. (ATSI) and Cleveland Public Power (CPP).
- Clarified the methodology to establish an IROL in the Planning Horizon.
- Updated the short circuit methodology to include the existing process to study all BES breakers.

Revision 16 (11/18/2010):

- Added a Contingency Definitions section (10/20/2010 MRC approval)
- Added Appendix G.10 NERC Standard PRC-023 – Transmission Relay Loadability (10/20/2010 MRC approval)
- Modified PJM Critical Energy Infrastructure Information Release Guidelines (08/05/2010 MRC approval)
- Added clarifying language to Baseline Voltage Analysis test methodology (08/05/2010 MRC approval)Updated the IROL definition to align with the latest NERC IROL definition (08/05/2010 MRC approval)

Revision 15 (04/21/2010):

- Added new Attachment F describing PJM stability, short circuit and special RTEP practices and procedures. This Attachment includes the special requirements for coordination of planning for nuclear interfaces

Revision 14 (02/01/2010):

- Attachment C: Added language to specify how energy efficiency is incorporated into deliverability tests. Added additional language to specify the load level modeled in the load deliverability test for the area being tested. (1/22/10 MRC Approval)

Revision 13 (11/16/2009):

- Inserted Commercial Probability technique in Attachment C, Generator Deliverability Procedure Step 5 (10/2/08 MRC approval)
- Added Attachment F: Determination of System Operating Limits for Planning the Bulk Electric System (06/17/09 MRC approval)
- Attachment C: Cap on generation delivery adders (12/21/09 MRC approval)
- Attachment C: Added language to Overview of Deliverability to Load to clarify criteria that may trigger analysis of potential new LDAs (11/11/09 MRC approval)
- Updated hyperlinks throughout the manual
- Temperature correction and clarification to Attachment B Section VII.N.

Revision 12 (08/08/2008)

The following revisions primarily consist of additions, clarifications and reorganization to address FERC Order No. 890 requirements:

- Additions to Section 1 to update, clarify, and expand the RTEP overview.
- Combine old Sections 6 and 2 into an expanded Section 2.
- Move wind, power factor and behind the meter generation material to a reconstituted Section 6
- Include additional reliability planning process and criteria information
- Market Efficiency Process revisions (section 2 and Attachment E) plus additional editorial and consistency changes throughout including Attachments D, E, and G.
- Added Exhibit 1 edits to Intro, Sections 1, 2, related attachments
- Multiple passes of CEII revisions.
- Generation Delivery clarifications in Attachment C.
- Removed the final material in Section 2 that is related to Interconnections to Manual 14A and revised the remaining material appropriately for Manual 14B.
- Exhibit 1 update for quarterly queues
- Attachment D criteria clarifications

- Added final RPPWG comments of Nov 30, 2007 meeting, added minor clarifications, and cut material to move to the appropriate generation or transmission interconnection related portions of revised 14A and 14E as to be determined. Sections deleted from here and moved to either 14A or 14E are: (the following attachment designations are according to the previous version Manual 14B lettering)
- Moved Section 3: Generator and Transmission Interconnection Planning Process
- Generation and Transmission Interconnection Feasibility Study
- System Impact study
- Generation and Transmission Interconnection Facilities Study
- Moved Section 4: Small Resource Interconnection Process
- Moved Section 5: Interconnection Service, Construction & Other Service Agreements
- Moved Section 6: Additional Generator Requirements
- Behind The Meter Generation Projects
- Generator Power Factor Requirements
- Wind-Powered Generation Projects
- Moved Attachment A: PJM Generation and Transmission Interconnection Planning Process Flow
- Attachment B: PJM Cost Allocation Procedures
- Moved PART 1: PJM GENERATION AND TRANSMISSION INTERCONNECTION COST ALLOCATION
- Moved Attachment C : PJM Generation and Transmission Interconnection Planning Team Role Diagram
- Moved Attachment F: General Description of Facilities Study Procedure
- Moved Attachment H: Small Generator (10 MW and Below) Technical Requirements and Standard
- Moved Attachment H-1: Small Generator (above 10 MW to 20 MW) Technical Requirements and Standards
- Moved Annex 1: SCADA Requirements by Transmission Owner Region

Revision 11 (10/05/2007)

The Manual Title has been changed. The RTEP process has evolved over the past 5+ years and so has the scope of Manual 14B. The title of the manual has been changed from "Generation and Transmission Interconnection Planning" to "PJM Regional Planning Process"

Section 6 and Attachment I have been revised to reflect the implementation of the 15-year horizon component of PJM's Regional Planning Process cycle, including that for market efficiency. These changes are made in accordance with the mmm, dd 2006 FERC approval of PJM's subject Operating Agreement and Open Access Transmission Tariff (OATT) revisions.

Conforming editorial revisions have been made throughout the remainder of the document.

Revision 10 (03/01/2007)

- Attachment B: Regional Transmission Expansion Plan revised to include steps for reactive planning in the RTEP.
- Revised hyperlinks in Attachment D: PJM Reliability Planning Criteria.
- Attachment H: Small Generator (10 MW and Below) Technical Requirements and Standards replaces former attachment on Small Generators of 2 MW and less.
- Attachment H-1: Small Generator (above 10 MW to 20 MW) Technical Requirements and Standards added.
- References to PJM OATT provisions in Sections 2 and 5 are revised to indicate that they are now in the new Part VI of the OATT (along with their former Part IV locations)
- Wording in Section 2 under "Summary of RTEPProcess" and again in Attachment E is revised to reflect that generation retirements included in project studies will be those announced as of the date a project enters the project queue.
- Introduction trimmed to eliminate redundant information.
- List of PJM Manuals exhibit removed, with directions given to PJM Web site where all the manuals can be found.
- Revision History permanently moved to the end of the manual.

Revision 09 (06/07/06)

Manual sections 1 and 2 and Attachment B (Regional Transmission Expansion Plan – Scope and Procedure) are revised to include Probability Risk Analysis (PRA) of Aging Infrastructure as an input to the PJM Region transmission planning process. The timeline in Section 5 is revised to require the Transmission Owner to submit a final invoice to PJM within 120 days after project completion. Attachment B (Regional Transmission Expansion Plan – Scope and Procedure) is also revised to add guidelines for Scenario Planning. Replaced references throughout to "ECAR, MAAC and MAIN" with ReliabilityFirst, the new replacement regional reliability council as of January 1, 2006.

Revisions were made on the following pages: 8, 10, 12 through 16, 23, 24, 41, 56, 62, 63, 65, 67, 68 and 98.

Revision 08 (01/16/06)

Section 1 is revised to state that all analyses of Transmission System adequacy are conducted using the load forecast produced annually by PJM. Attachments E and G are revised to state that load is modeled in the RTEP base case used for the Generator Deliverability procedure at a “non-diversified” 50/50 summer peak load level as per the latest load forecast.

Revision 07 (01/04/06)

Section 2 is revised to add process for “Evaluation of Operational Performance Issues.” Attachment A is revised to clarify the Load Flow Cost Allocation Method and to add the Schedule 12 Cost Allocation process. Attachment C is revised to include references to Dominion and to add Addendum 2 “Common Mode Outage Procedure” to the Generator Deliverability Procedure. Attachment D is revised to include a minimum power factor for system “load”.

Revision 06 (11/21/05)

Section 2 is revised to indicate that “One RTEP baseline regional plan will be developed and approved each year” and that “Generation retirements will not affect the study results” for any project that has received an Impact Study Report. Attachment B is revised to clarify and expand the scope and procedure of the Regional Transmission Expansion Planning Process.

Revision 05 (06/23/05)

Revision includes a change in Section 6 to include reference to new Attachment E, re-writes of Attachment C (**PJM Deliverability Testing Methods**) and Attachment D (**PJM Reliability Planning Criteria**) and the addition of new Attachment E (**Economic Planning Process, Congestion Relief Evaluation**).

Revision 04 (12/17/04)

Revision includes the changes in Sections 2 and 4 necessitated for compliance with FERC Order 2003 for standardized Generator Interconnection Agreements and Procedures, re-write of Attachment F: Facilities Study Guidelines, re-write of Attachment D: PJM Reliability Planning Criteria, and the addition of Attachment H: Small Generator (2MW or less) Technical Requirements and Standards.

Revision 03 (06/08/04)

Revision includes the addition of rules for Generator Power Factor Requirements and Behind the Meter Generation in Section 2, the designation of small resources as 20 MW or less in Section 4, the addition of the Economic Planning Process in Section 6 and general updates.

Revision 02 (10/31/03)

Revision includes the addition of Wind-Powered Generator Specific Requirements to Section 2, a placeholder for the addition of the Economic Planning Process in new Section 6 (currently under development) and the addition of Attachments D (**Regional Transmission Expansion Plan – Scope and Procedure**), E (**PJM Deliverability Testing Methods**), F

(**General Description of Facilities Study Procedure**) and G (**PJM Reliability Planning Criteria)**; also, text changes throughout to conform with Nuclear Plant Licensee Final Safety Analysis Report grid requirements and with new Manual M-14E (**Merchant Transmission Specific Requirements** – also currently under development).

Revision 01 (02/26/03)

Revision includes a manual title change from PJM Manual for **Generation Interconnection Transmission Planning (M-14B)** to PJM Manual for **Generation and Transmission Interconnection Planning (M-14B)**; also, text changes throughout to conform to new Manuals M-14C and M-14D.

Revision 00 (12/18/02)

This document is the initial release of the PJM Manual for **Generation Interconnection Transmission Planning (M-14B)**.

Manual M-14, Revision 01 (03/03/01) has been restructured to create five new manuals:

M-14A: “Generation Interconnection Process Overview”

M-14B: “Generation Interconnection Transmission Planning”

M-14C: “Generation Interconnection Facility Construction”

M-14D: “Generation Operational Requirements”

M-14E: “Merchant Transmission Specific Requirements”

Working to Perfect the Flow of Energy

PJM Manual 14C

Generation and Transmission Interconnection Facility Construction

Revision: 07

Effective Date: May 23, 2012

Prepared by

Power System Coordination Department

Reliability Integration Division

PJM Manual 14C

Generation and Transmission Interconnection Facility Construction

Table of Contents

Table of Exhibits

Approval

Approval Date: 05/23/2012
Effective Date: 05/23/2012

Al Elmy, Manager

Interconnection Projects Department

Current Revision

Revision 07 (05/23/2012):

- Updated information on access to Transmission Owner's Applicable Technical Requirements and Standards.

Introduction

Welcome to the PJM Manual for Generation and Transmission Interconnection Facility Construction. In this Section you will find:

- What you can expect from the PJM Manuals in general (see "*About PJM Manuals*").
- What you can expect from this PJM Manual (see "*About This Manual*").
- How to use this manual quickly and easily (see "*Using This Manual*").

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by the PJM OI for the operation, planning, and accounting requirements of the PJM RTO and the PJM Energy Market. The manuals are grouped under the following categories:

- Transmission
- PJM Energy Market
- Generation and transmission interconnection
- Reserve
- Accounting and Billing
- PJM administrative services
- Miscellaneous

For a complete list of all PJM Manuals, go to www.pjm.com and select "Manuals" under the "Documents" pull-down menu.

About This Manual

The ***PJM Manual for Generation and Transmission Interconnection Facility Construction*** is one of the family of PJM Procedure manuals. This manual focuses on the requirements for interconnecting generating sources under PJM's Regional Transmission Expansion Planning Process.

This manual describes the various studies and agreements required to complete the transmission interconnection planning process.

This ***PJM Manual for Generation and Transmission Interconnection Facility Construction*** consists of four sections. These sections are listed in the table of contents beginning on page ii.

Intended Audience

The intended audiences for this PJM Manual for Generation and Transmission Interconnection Facility Construction are:

- Interconnection Customers' respective engineering, construction and operations staff, and consultants.

- Transmission Owners' respective engineering and construction staff and consultants.
- PJM Members.
- PJM Staff.

NOTE: The term "Interconnection Customer" is used throughout this document and is intended to refer to both Generation Interconnection Customers and Merchant Transmission Customers.

References

There are other PJM documents that provide both background and detail on other topics.

- PJM Manual for Generation and Transmission Interconnection Process Overview (M-14A)
- PJM Manual for Regional Planning Process (M14B)
- PJM Manual for Generator Operational Requirements (M14D)
- PJM Manual for Merchant Transmission Specific Requirements (M14E)

Using This Manual

We believe that explaining concepts is just as important as presenting the procedures. This philosophy is reflected in the way we organize the material in this manual. We start each section with an overview. Then, we present details, procedures or references to procedures found in other PJM manuals. .

What You Will Find In This Manual

- A table of contents that lists two levels of subheadings within each of the sections
- An approval page that lists the required approvals and a brief outline of the current revision
- Sections containing the specific guidelines, requirements, or procedures including PJM actions and PJM Member actions.
- Attachments that include additional documents, forms, or tables that support this manual.
- A section at the end detailing all previous revisions of this PJM Manual

Section 1: Interconnection Service Agreement / Interconnection Construction Service Agreement (ISA / ICSA) Implementation Phase Management

Welcome to the Interconnection Service Agreement / Interconnection Construction Service Agreement (ISA / ICSA) Implementation Phase Management section of the ***PJM Manual for Generation and Transmission Interconnection Facility Construction***.

1.1 Overview

PJM has taken steps required to more effectively coordinate a portfolio of Generation and Merchant Transmission projects. To support this effort at the individual project level, PJM's intent is to take a Project Management Model approach to the implementation of the Interconnection Service Agreement / Interconnection Construction Service Agreement (ISA / ICSA) Implementation Phase of the Generator Interconnection Projects. This section presents the Work Breakdown Structure (WBS) for the Interconnection Service Agreement / Interconnection Construction Service Agreement (ISA / ICSA) Implementation Phase along with descriptions of the various major activities and deliverables within each focus category.

1.2 ISA / ICSA Implementation Phase Work Breakdown Structure (WBS)

The complexities associated with the Interconnection Service Agreement / Interconnection Construction Service Agreement (ISA / ICSA) Implementation Phase of the Generator Interconnection Projects warrant a project management model approach, and an effective tool for managing the activities and deliverables associated with the projects is a Work Breakdown Structure (WBS). The WBS can be used as a foundation for coordination of nearly all other aspects of the projects. For example, project schedules, cost estimates, project documentation and communication formats can all be derived from the basic Work Breakdown Structure.

Exhibit 1 shows the WBS for the ISA / ICSA Implementation Phase. The major categories of focus in this phase are the Transmission Owner Facilities, Generator Facilities, and Generator Markets and Operations. The following category and sub-category descriptions are provided to explain the significance of each component of the WBS. Clearly, just about every project is different and requires a certain level of customization to the specific nuances of the project, but spelling out major activities in this manner provides a baseline from which PJM, the Transmission Owners and the Interconnection Customers can customize from there. Moreover, these major activities can also be considered as the minimum project milestone activities (where applicable) that PJM is interested in tracking through the ISA / ICSA Implementation Phase life cycle.

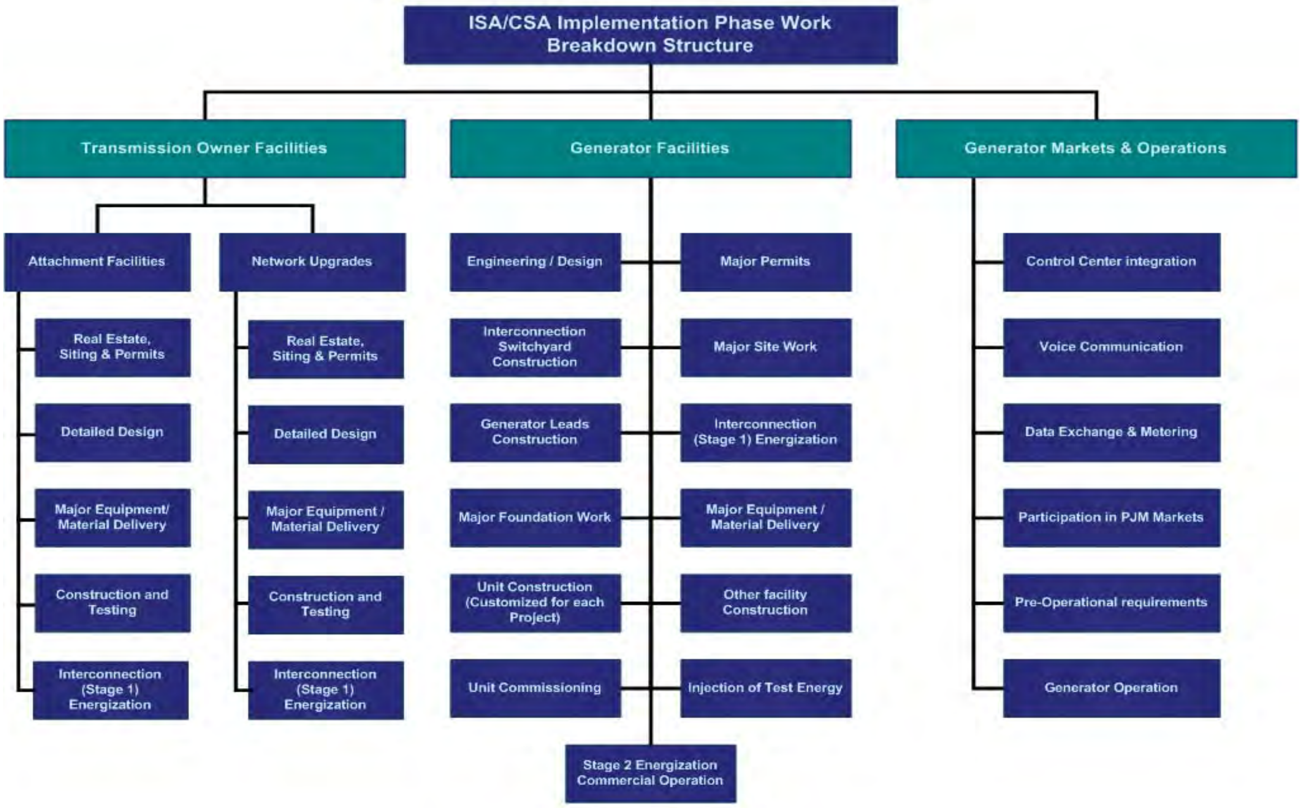


Exhibit 1: ISA/ICSA Implementation Phase Work Breakdown Structure

1.2.1 Application to Regional Transmission Expansion Plan (RTEP) Projects

PJM Manual M14C is intended to apply to the engineering and construction implementation phase for all types of RTEP projects. The project controls detailed herein are applicable to generation interconnection projects, Merchant Transmission projects, and Long Term Firm Transmission Service Requests, in addition to Baseline Upgrades and Transmission Owner Identified upgrades.

In addition, if construction of facilities is required for non-jurisdictional interconnections with executed Wholesale Market Participation Agreements (WMPAs), the same project controls outlined in this Manual M14C would apply if an ICSA is executed for applicable construction work required for these non-jurisdictional projects.

The project controls outlined in Manual M14C also apply to cases where an Interim ISA is executed and financial security is collected by PJM for the purpose of purchasing long lead time equipment, or performing engineering and construction work.

1.2.2 Large Generation Resources / Small Generation Resources

PJM Manual M14B outlines the study phase process differences between Large Generation Resources (greater than 20MW) and Small Generation Resources (20MW or less). While there are distinct differences in the paths that these types of projects take in the study process, once the projects move into the implementation phase, the same project controls outlined in this Manual M14C generally apply to both Large Generation Resources and Small Generation Resources.

1.2.3 Transmission Owner Facilities

Transmission Owner Facilities include all work related to the interconnection of the Customer Facility to the transmission grid. They include Attachment Facilities and Network Upgrades.

The work is typically performed by the respective Transmission Owners; However, as detailed in the PJM Open Access Transmission Tariff (OATT) and detailed later in this manual, an Interconnection Customer may elect to exercise the Option to Build alternative either during the ISA / CSA Execution Phase or at any reasonable time prior to 37 days after the ISA is executed. The Option to Build alternative may be pursued by the Interconnection Customer for the completion of the Attachment Facilities or the Network Upgrades, or both, depending on the circumstances.

1.2.4 Attachment Facilities

Attachment Facilities include all of the local transmission system activities required to connect the Customer Facility to the transmission system. Attachment Facilities may typically include facilities for radial connections to transmission systems such as overhead transmission line work to point(s) of interconnection, protection and controls, and metering activities required to support the Customer Facility interconnection.

The Attachment Facilities Activities are required to be completed in order for the project to achieve the milestone of Stage 1 Energization as defined by the PJM Tariff Att. P, App.2, Sect. 3.9A. This is the milestone in which the generator is interconnected with the transmission system and backfeed power is available to the Customer Facility for testing and commissioning.

- Real Estate, Siting, and Permitting – Represents milestones for siting of facilities; acquisition of critical land use, environmental, state and local permits, and acquisition of real estate/right of way.
- Detailed Design – Includes completion of Attachment Facilities engineering and detailed design activities that were not completed in the Facilities Study Phase.
- Major Material / Equipment Delivery – Activity(s) that represent the duration of the procurement, fabrication and delivery for major equipment and material associated with the Attachment Facilities.
- Construction and Testing Work – Activity(s) that represent the duration of the major construction and testing tasks related to the Attachment Facilities. This would include all pre-outage construction and testing activities; however, interim outages may be required in some cases.

- Interconnection (Stage 1) Energization – Reflects the transmission outages required for performing final connections and testing activities, and represents the milestone of completing the interconnection of the Generator Facilities to the transmission system.

1.2.5 Network Upgrades

Network Upgrades and their cost allocation methodologies are discussed in greater detail in PJM Manual M-14B, but they are defined as new or upgraded facilities required primarily to eliminate reliability criteria violations caused by proposed generation, merchant transmission or long term firm transmission service requests, but can also include certain direct connection facilities required to interconnect proposed generation projects. Network Upgrades are identified on the basis of load flow, short circuit, deliverability and stability analysis as part of the RTEP process, and can include breaker replacements or upgrades, new transformers or other substation equipment. Network Upgrades can also include construction of new transmission lines, reconductoring of transmission lines between substations, and interconnection switchyards.

The OATT defines two types of Network Upgrades for the purpose of establishing financial security requirements:

- Direct Connection Network Upgrades are Network Upgrades which only serve the Customer Interconnection facility and have no impact on the Transmission System until the final tie-in is complete.
- Non-Direct Connection Network Upgrades are parallel flow Network Upgrades that are not Direct Connection Network Upgrades.

Similarly, for jurisdictional generation interconnections to a Transmission Owner distribution system, the OATT differentiates between Direct Connection Local Upgrades and Non-Direct Connection Local Upgrades.

For any given project there may be no Network Upgrades or there may be a large number of Network Upgrades required. PJM determines the required completion dates for Network Upgrades in accordance with Interconnection Customer commercial operation milestones and with the RTEP analysis of Baseline and System Upgrades. PJM is interested in tracking each the following major activities for all Network Upgrades associated with a generation project.

- Real Estate, Siting, and Permitting – Represents milestones for siting of facilities; acquisition of critical land use, environmental, state and local permits, and acquisition of real estate/right of way.
- Detailed Design – Includes completion of Network Upgrade engineering and detailed design activities that were not completed in the Facilities Study Phase.
- Major Material / Equipment Delivery – Activity(s) that represent the duration of the procurement, fabrication and delivery for major equipment and material associated with the Network Upgrades.
- Construction and Testing Work – Activity(s) that represent the duration of the major construction and testing tasks related to the Network Upgrades. This would include

all pre-outage construction and testing activities; however, interim outages may be required in some cases.

- Network Upgrade Complete – Represents the milestone of completing the respective Network Upgrades. PJM determines the required completion dates for Network Upgrades in accordance with Interconnection Customer commercial operation milestones and the RTEP analysis of Baseline and System Upgrades.

1.2.6 Baseline Upgrades and Transmission Owner Identified Upgrades

The PJM RTEP identifies baseline reliability upgrades and Transmission Owner identified (TOI) upgrades that are defined as follows:

Baseline Upgrades are PJM upgrades primarily required to eliminate base-case reliability criteria violations but can also be driven by other factors such as economic drivers, or probabilistic spare transformer requirements.

Transmission Owner Initiated upgrades are projects originated by the Transmission Owner that are not driven by an applicable PJM criteria, and are used as inputs to the RTEP models.

PJM Power System Coordination Department tracks completion of milestones for baseline upgrades and TOIs that have been identified in the RTEP and approved by the PJM Board of Managers.

1.2.7 Customer Facilities

PJM acknowledges that there is a broad range of information related to the construction of specific generator facilities. However, the following major milestone activities are common and applicable to most Customer Facility construction projects:

- Engineering and Design – Engineering and Design activities related to the Generator Facility Construction.
- Major Permits – Represents milestones for acquisition of critical land use, air, water and operating permits.
- Major Equipment / Material Delivery – Represents milestones for the delivery of major critical path equipment and material (i.e. CTG's, STG's, major piping, etc.)
- Major Sitework – Site preparation for Customer Facility.
- Major Foundation Work – Includes all major foundation work applicable to the generator facility construction.
- Interconnection Switchyard Construction – Includes construction activities related to the interconnection switchyard, constructed by either the Interconnection Customer or the Transmission Owner.
- Generator Leads Construction – Includes the construction activities related to the generator leads from the plant switchyard to the interconnection point.
- Interconnection (Stage 1) Energization – Reflects the transmission outages required for performing final connections and testing activities, and represents the milestone

of completing the interconnection of the Customer Facilities to the transmission system.

- Unit Construction – Includes the erection of all major Customer Facility Equipment, including Combustion Turbines (1, 2, etc.), HRSGs, Steam Turbines, etc.
- Other Facility Construction – Other major critical path Customer Facility Construction activities, including piping, gas and water connections.
- Unit Commissioning – Represents the commissioning period for each unit (1, 2, etc.), from commissioning testing to first fire (injection of test energy), through final unit synchronization.
- Injection of Test Energy – Subset of Unit Commissioning, but an important milestone for PJM System Operations in the analysis and scheduling of load flows.
- Stage 2 Energization – Capacity Status Granted – Commercial Operation target milestone for each unit (1, 2, etc.).

1.2.8 Generator Markets and Operations

The Generator Markets and Operations section of the Interconnection Service Agreement / Interconnection Construction Service Agreement (ISA / ICSA) Implementation Phase WBS includes the integration of the Transmission Owner Facilities and the Customer Facility Construction with the applicable PJM internal organizations that need to be engaged in order to achieve all of the requirements prior to commercial operation of the generating facility. These requirements are reviewed in greater detail in PJM Manual M-14D, but are summarized below:

Control Center Integration

- Includes all of the required generator facility control center coordination activities, including computer systems, facilities requirements, control center communications requirements, control center staffing requirements.

Voice Communication

- Includes the integration and coordination of generating facility voice, communications and dispatch operational requirements.

Data Exchange & Metering

- Energy Management System (EMS) modeling, communication and data exchange.
- PJM Net installation process.
- SCADA requirements.
- Customer metering and communication devices.
- Revenue Metering
- Real time telemetry metering
- PJM Testing (verification of data exchange, on-line communication).

Participation in PJM Markets

- Coordination of marketing options.
- Reliability Pricing Model (RPM) integration.
- Renewable Energy Credits coordination [ie. Generator Attribute Tracking System (GATS) integration].
- Ancillary services.
- eTools set-up and implementation.
- Granting of capacity status to generating facility.

Pre-Operational Requirements

- Data exchange testing.
- Training of Interconnection Customer personnel.
- System Operations coordination
- Outage Coordination.
- Test energy injection scheduling.
- Commercial Operation.
- Coordination with PJM Dispatch.

Customer Operations

- Dispatching of generation.
- Interconnection Customer switching requirements.
- Interconnection Customer relaying requirements.
- Interconnection Customer information and reporting requirements.
- Synchronization and disconnection procedures.

1.3 ISA/ICSA Implementation Phase Team Role Clarity

The ISA / ICSA Implementation Phase Work Breakdown Structure (WBS) defines the major activities and deliverables in the ISA / ICSA Implementation Phase. PJM believes that one of the keys to effectively achieving the respective project goals and milestones is through clearly defined roles between all parties throughout the ISA / ICSA Implementation Phase.

Exhibit 2 is the Generator Interconnection Process Implementation Team Role Clarity Diagram. The focus of this manual is the ISA / ICSA Implementation Phase and the diagram is accordingly labeled M-14C (at the bottom of Exhibit 2).

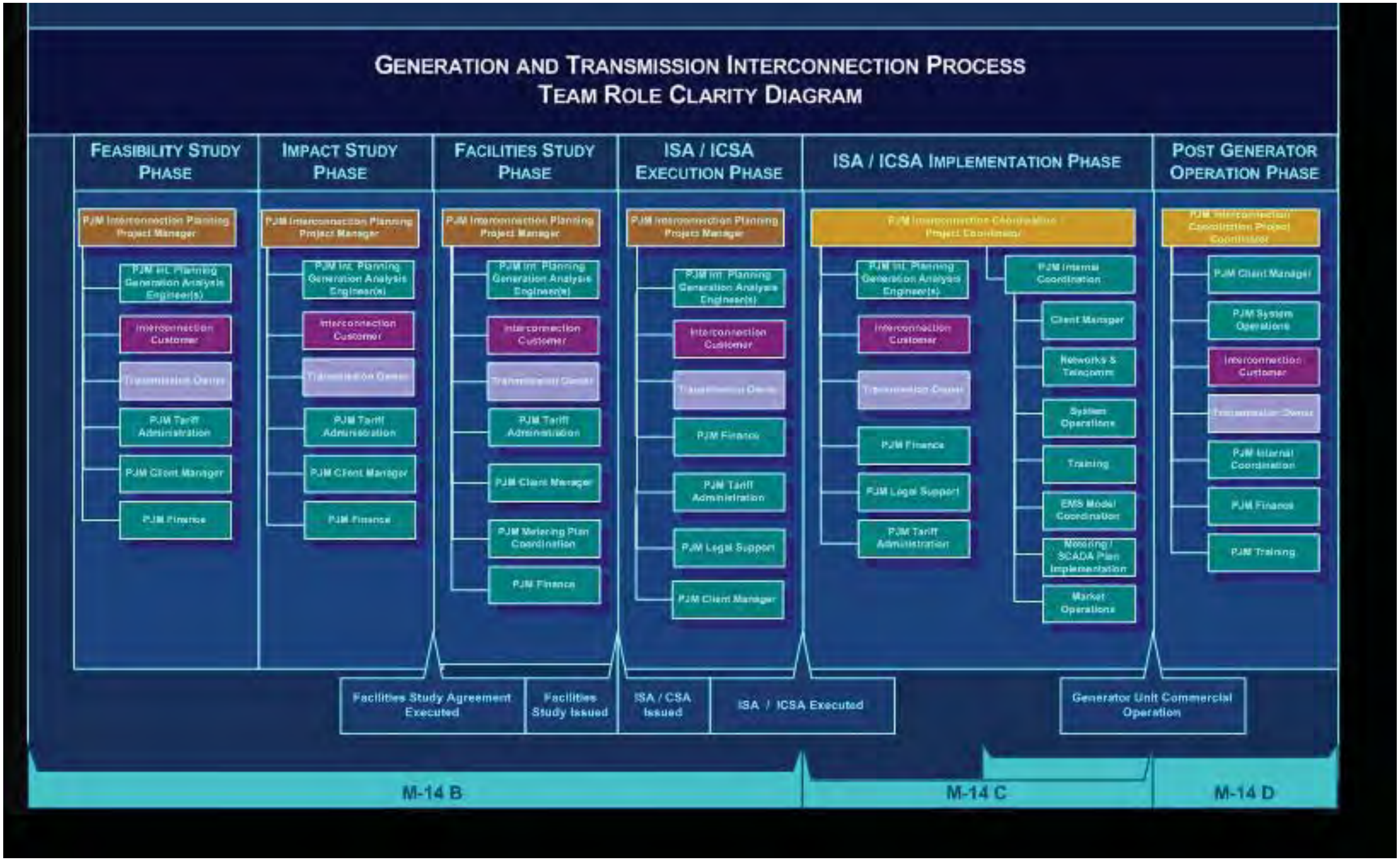


Exhibit 2: Interconnection Process Team Role Clarity Diagram

For the ISA / ICSA Implementation Phase, the PJM Interconnection Coordination Project Coordinator (IC Project Coordinator) assumes the responsibility to ensure that all of the activities, deliverables and milestones on the ISA / ICSA Implementation Phase WBS are achieved through the facilitation of all of an inter-organizational team consisting of PJM, Transmission Owner, and Interconnection Customer personnel. A critical point in the success of this role clarity model is the understanding of all team members that the PJM IC Project Coordinator is not necessarily the party actually achieving the deliverables (i.e. performing the work), but the PJM IC Project Coordinator is the project progress monitor, the coordinator of key activities, and the facilitator between the appropriate parties on the ISA / ICSA Implementation Phase team. Simply put, the PJM IC Project Coordinator serves as the single point of contact who solicits the support of the respective team members in order to effectively facilitate the resolution of issues and coordination of the activities that are critical to meeting the project milestones.

In order to manage these responsibilities across the entire PJM footprint, the PJM IC Project Coordinator also has the support of a PJM project team as detailed in Exhibit 2. Each Transmission Owner territory has been assigned a respective IC Project Coordinator for coordination of generator interconnection projects within that TO territory.

The key responsibilities that the PJM IC Project Coordinator implements with the support of the abovementioned project team are the following:

- Facilitate the resolution of scope and technical issues.
- Coordination and facilitation of project meetings; establishment of method for follow-up documentation.
- Project Controls – i.e. Project Milestone Tracking, Cost Tracking.
- Facilitation of Billing process between PJM Finance, Transmission Owners and Interconnection Customers.
- Coordination with PJM Internal Groups; Project integration required prior to Customer Facility Commercial Operation.
    - System Operations
    - PJM Net / SCADA Installation
    - EMS Modeling
    - Voice Communications
    - Member Services - Client Managers
    - Member Services - Training
    - Market Settlements
    - Real Time Telemetry / Revenue Metering
    - eTools Set-up and Implementation
- Facilitating the resolution of Contractual / Tariff Issues, project conflicts, dispute resolution.

- Performs periodic construction site reviews of Transmission Owner Facilities and Customer Facility Construction sites to assess status of construction and facilitate applicable project issues.
- Project Communication – External and PJM Internal communication.

The following is a brief description of the roles outlined on the ISA / ICSA Implementation Phase section of the Role Clarity Diagram, along with the type of key interface activities the primary parties would typically coordinate with respect to the project implementation phase. .

PJM Interconnection Planning Project Manager:

- Processes interconnection requests, and interfaces directly with the Transmission Owner and Interconnection Customer technical teams as required to issue the Feasibility, Impact and Facilities Studies as required.
- Issues appropriate agreements, and ensures that the agreements are executed within the timeframes established in the OATT (ie. study agreements, ISA/Interim ISA/ICSA/WMPA/UCSA).
- Provides direction to team on cost allocation issues and scope revisions due to RTEP Plan re-tooling if applicable.
- Issues amended Impact Studies, Facilities Studies, and ISAs/CSAs if required.
- Facilitates resolution of study phase Transmission Owner billing issues between PJM Finance, TO, and Interconnection Customer.

PJM Generation Analysis Engineer(s):

- Provides support for PJM Interconnection Planning Project Manager.

PJM Interconnection Coordination (IC) Project Coordinator:

- Provides support to the PJM team from the ISA/Interim ISA/ICSA/WMPA execution phase through commercial operation of the Customer Facility.
- Represents PJM Interconnection Coordination in project status meetings and conference calls for all applicable Transmission Owner and Customer Facility activities.
- Performs site visits as appropriate (see “Project Site Reviews” section) for TO and Customer Facility construction.
- Reviews monthly updates from the TO and Interconnection Customers for status of Baseline Upgrades, Attachment Facilities, Network Upgrades, TOIs, and Interconnection Customer facilities.
- Reviews all TO invoices, including quarterly cost reconciliations, and facilitates the resolution of any billing issues.
- Facilitates the ISA/ICSA Scope Change Process as appropriate (See “ISA/ICSA Scope Change Process” section).
- Supports the integration of RTEP projects with PJM Operations and Markets Departments through outage coordination, model coordination and coordination of Markets interfaces.

Transmission Owner:

- Interfaces regularly with PJM IC Project Coordinator on Transmission Owner Facilities Issues.
- Provides PJM IC Project Coordinator with notice of critical project status meetings and/or conference calls and includes PJM IC Project Coordinator in these meetings as required.
- Provides monthly updates on schedule and costs to PJM IC Project Coordinator for the following (see Section 2 for level of detail):
    - Baseline Upgrades
    - Attachment Facilities
    - Network Upgrades
    - Transmission Owner Identified Upgrades

Interconnection Customer:

- Provides PJM IC Project Coordinator with monthly project status reports indicating status of major milestones and highlighting any other significant project issues / concerns.
- Provides PJM IC Project Coordinator with updated contact information for Customer Facility Construction Manager and Plant Manager roles in order to support appropriate interfaces.
- Provides PJM IC Project Coordinator with notice of critical project status meetings and/or conference calls and includes PJM I IC Project Coordinator in these meetings as required.

PJM Finance:

- PJM IC Project Coordinator facilitates resolution of Interconnection Customer deposit and Letter of Credit issues with PJM Finance and Interconnection Customers.
- PJM IC Project Coordinator facilitates resolution of Transmission Owner billing issues between PJM Finance, TO, and Interconnection Customer.
- PJM IC Project Coordinator facilitates final ISA cost reconciliation between Interconnection Customer and respective TO's.

PJM Transmission & Interconnection Planning Administration:

- Provides administrative support for PJM IP Project Manager and PJM IC Project Coordinator.

PJM Legal Support:

- PJM IP Project Manager and PJM IC Project Coordinator solicit legal consulting from PJM Legal as required for contractual, tariff interpretation of dispute resolution issues.

PJM Internal Coordination (Refer to PJM Manual M-14D for details):

- Operations Planning
  - Coordination of Customer Facility naming convention issues, and system modeling, and outage planning.
- System Operations
  - Long range and detailed outage coordination related to interconnection energization, network upgrades, and Customer Facility commercial operation.
- PJM Net
  - Coordination of installation and testing activities for data link via PJM Net telecommunications or alternate PJM approved method.
- EMS Model
  - Coordination of Energy Management System (EMS) modeling, database development and testing (required minimum 6 months prior to COD).
- Member Services – Client Manager
  - PJM IC Project Coordinator works with PJM Member Services Client Manager to ensure that all commercial agreements are in place with the Interconnection Customer and all the appropriate PJM internal coordination is performed at required prior to commercial operation.
- Member Services - Training
  - PJM IC Project Coordinator works with PJM Member Services Training contact to identify specific training requirements with Interconnection Customer. Informs Interconnection Customer of available training curriculum or coordinates the need for customized training with PJM Training Department personnel.
- Market Settlements
  - Coordination of Market Settlements approval of Interconnection Customer revenue business plan, and set-up / implementation of appropriate e-Tool accounts.
- Metering & Communications
  - Coordination of Metering Plan, PJM membership, application for e-Tool accounts, definition of real time data exchange points list, agreement on commercial naming for units, and installation of revenue and real time telemetry metering at the Customer Facility.
- Capacity Adequacy
  - Coordination of the System Planning generation capacity studies with regular updates of Interconnection Customer in-service dates.

Section 2: Interconnection Coordination Project Controls

Welcome to the *Interconnection Coordination Project Controls* section of the ***PJM Manual for Generation and Transmission Interconnection Facility Construction***. In this section you will find details related to the Project Controls utilized by the ISA/ICSA Implementation Phase Team.

2.1 Overview

PJM believes that, in addition to an understanding of the ISA / ICSA Implementation Phase WBS and role clarity, another key contributing factor in the achievement of the goals of the ISA / ICSA Implementation Phase is the effective use of project controls. This section of Manual M-14C provides details about the project controls concepts and tools that PJM, in the spirit of the PJM Tariff, will use to facilitate the completion of the ISA / ICSA Implementation Phase.

The following items are reviewed in this section:

- Schedules / Milestone Tracking
- Cost Tracking
- Transmission Owner and Interconnection Customer Billing Process
- Scope Change Process
- Project Meetings
- Project Site Reviews
- Outage Coordination
- Project Communication
- Project Reporting & Documentation
- Generator As-Built Data
- Dispute Resolution
- Project Closeout

2.2 Schedules / Milestone Tracking

With a large portfolio of RTEP projects to coordinate, the accurate tracking of schedule milestones for both Transmission Owner (TO) facilities and Customer Facility construction milestones is critical for PJM to successfully coordinate not only the timely achievement of Interconnection Customer project goals, but also to effectively coordinate the entire RTEP. PJM tracks schedule milestones for TO Attachment Facilities and Network Upgrades for generation and merchant transmission projects, TO baseline upgrades and TO identified upgrades, as well as Customer Facility Construction Milestones. The RTEP is a dynamic system, and therefore PJM must rely on the support of Transmission Owners and Interconnection Customer to supply on a regular basis accurate schedule updates for PJM to integrate into the RTEP databases. The minimum schedule information required by PJM to be provided on a monthly basis from Transmission Owners and Interconnection Customer is as follows:

2.2.1 Transmission Owner Milestone Tracking:

- Attachment Facilities
  - PJM Required Completion Date
  - Current Projected Completion Date
  - Actual Completion Date
  - Current % Complete
- Network Upgrades (or Local Upgrades)
  - PJM Required Completion Date
  - Current Projected Completion Date
  - Actual Completion Date
  - Current % Complete
- Baseline Upgrades:
  - PJM Required Completion Date
  - Current Projected Completion Date
  - Actual Completion Date
  - Current % Complete
- Transmission Owner Identified Upgrades
  - PJM Required Completion Date (if applicable)
  - Current Projected Completion Date
  - Actual Completion Date
  - Current % Complete

PJM provides a standard Transmission Owner milestone update list for Transmission Owners to supply the above information:

- TO System Upgrades Milestone List
  - Provided to Transmission Owners on a regular basis for TOs to provide updates.
  - Includes a sorting by Transmission Owner from the master RTEP System Upgrade spreadsheet for all of the system upgrades related to each respective Transmission Owner.
  - Includes both Baseline Upgrades, Network Upgrades, and TO Identified Upgrades (by PJM Upgrade Number) related to Interconnection Customer Projects.
- TO Attachment Facilities

- For TO Attachment Facilities related to queued projects, PJM uses input from routine project status meetings and communications with TOs and Interconnection Customers to update the PJM database accordingly.
- PJM will apply particular focus on Stage 1 Energization (ie. backfeed power) target date, since this date is critical for integration of the projects into PJM Markets and Operations.

By setting up the Transmission Owner milestone information in this manner, PJM's intent is to provide a convenient and standardized method for Transmission Owners to provide this data on a monthly basis so that PJM can update its databases and perform any required analysis and linkage to the Generator Facility Construction Milestone information received from the Interconnection Customers. In addition, per the FERC Market Efficiency Order, PJM has established an RTEP transmission project website with updates based on milestone updates submitted by TO's. Therefore, Transmission Owners should use the following standardized guidelines for assigning percent complete information to PJM:

<u>Engineering and Planning (EP) Status</u>: 0% - 25% (includes engineering, detailed design, material procurement, resource planning)

<u>Under Construction (UC) Status</u>: 26% - 100%

26% - 90% - Construction Activities

91% - 100% - Testing and Inspection

Note: Network Upgrades related to queued projects that have been suspended are typically designated with the status: "On Hold."

2.2.2 Customer Facility Construction Milestone Tracking:

OATT Attachment P Section 3.7 requires that each constructing entity issue status reports on a monthly basis regarding the status of construction of Interconnection Facilities. PJM acknowledges that most Customer Facility Construction schedules are unique to the respective projects and there is a broad range of information that can be provided. Routine schedule milestone updates are required to be provided to PJM from Interconnection Customers in their own preferred customized format (i.e. Microsoft Project, P3, Excel spreadsheet, etc.). PJM is interested in summary level schedule updates from Interconnection Customers, but at a minimum, PJM requires the following milestone information (Start Date / Completion Date Targets with current individual summary activity % complete and overall % complete) to be provided in the Interconnection Customers' monthly updates:

- Engineering and Design
- Major Equipment / Material Delivery
- Major Sitework
- Major Foundation Work
- Interconnection Switchyard Construction
- Generator or transmission interconnection leads Construction
- Interconnection (Stage 1) Energization

- Unit Construction – Includes the erection of all major Generating Facility Equipment, including Combustion Turbines (1, 2, etc.), Steam Turbine Generators, etc.
- Other Facility Construction – Other major critical path Generating Facility Construction activities, including piping, gas and water connections.
- Unit Commissioning – Represents the commissioning period for each unit (1, 2, etc.), from commissioning testing to first fire (injection of test energy), through final unit synchronization.
- Injection of Test Energy
- Stage 2 Energization – Commercial Operation (for capacity status or energy only) target milestone for each unit (1, 2, etc.).

2.3 Cost Tracking

Tracking of current estimated costs for Transmission Owner Attachment Facilities and System Upgrade activities is also critical for PJM's facilitation of the RTEP Plan. It is important for PJM (and the Interconnection Customers) to be made aware of any major changes in the current estimated costs at completion for Attachment Facilities activities during the course of the life cycle of these activities - in a timely manner, rather than after the work is complete. It is also important for PJM to be provided with regular cost projection updates on both Baseline Upgrades and Network Upgrades related to Interconnection Customer projects for the purpose of ensuring that Interconnection Customers are informed of any significant cost overrun issues related to Network Upgrades, and also for PJM to have the most accurate cost data for use in the overall cost allocation process for the RTEP Plan and, more specifically, for Network Upgrades.

The RTEP Plan is a dynamic system, and therefore PJM must rely on the support of Transmission Owners and Interconnection Customers to supply on a regular basis accurate cost estimate projection updates for PJM to integrate into the RTEP Plan databases. The minimum cost estimate projection information required by PJM to be provided on a routine basis from Transmission Owners is as follows:

2.3.1 Transmission Owner Cost Estimate Projection Tracking:

- Baseline Upgrades:
  - Current Projected Cost at Completion
- Interconnection Customer Projects:
  - Attachment Facilities
    - Current Projected Cost at Completion
  - Network Upgrades
    - Current Projected Cost at Completion
- Transmission Owner Identified Upgrades
  - Current Projected Cost at Completion

Transmission Owners should use the same TO upgrade spreadsheets provided by PJM for schedule milestones to provide the baseline upgrade and TOI cost updates. Network upgrade cost information is included on the spreadsheets, but must be in alignment with the PJM Scope Change process for any cost revisions. Likewise, Attachment Facilities cost updates may be provided in conjunction with regular project status meetings, and should also be in alignment with the PJM Scope Change Process for revisions.

Transmission Owners should note that the cost projections provided should include Contributions in Aid of Construction (CIAC tax gross-up) amounts, only if applicable. In other words, if an Interconnection Customer has successfully pursued the Private Letter Ruling process and tax gross-up amounts are not being billed to the Interconnection Customer (via PJM) and collected, then tax gross-up amounts should not be included in these cost estimate projections. If tax gross-up amounts are being billed and collected by the Transmission Owner, then the cost estimate projections should include tax gross-up amounts. This guideline will increase the accuracy of PJM's databases since actual billing amounts will be utilized.

2.4 PJM Billing Process

Transmission Owner Billing Guidelines:

In order to establish clarity and ensure compliance with the billing requirements in FERC Order 2003, PJM has implemented a system of standardized Transmission Owner invoice forms. These TO standard invoice forms are included in this manual in Attachment A "Transmission Owner Standard Invoice Forms". It should be noted that while the focus of this manual is the ISA/ICSA phase of the interconnection process, for continuity purposes, Attachment A includes TO standard invoice forms for all phases of the interconnection process.

PJM is requiring that Transmission Owners provide billing support information on these uniform invoice forms for all the study phases and the ISA/ICSA phase to maintain accuracy within PJM Finance and also support the accounting needs of the Interconnection Customers. Continuity in Transmission Owner invoicing information will assist in the timely processing and payment of invoices, and minimize the volume of information requests related to invoices by PJM to the Transmission Owners.

The following guidelines are provided for Transmission Owner billing to PJM:

- Feasibility and Impact Study phase invoices:
  - Transmission Owners are required to provide an invoice for actual costs to perform the study work (without a detailed cost breakdown).
  - Final invoice:
    - TO is required to provide final invoice within 90 days after completion of the Feasibility Study or Impact Study work.
    - TO to mark the final invoice as "Final".
- Facilities Study phase invoicing
  - TO is required to provide an invoice to PJM on a quarterly basis for work to be performed in the next subsequent quarter. This is necessary for PJM to provide the advanced quarterly billing to the Interconnection Customer for Facilities Study work as required by Order 2003.

    - Initial invoice is required to be submitted to PJM prior to the start of work.
    - Each invoice must include the original estimated cost (from Facilities Study Agreement) current invoiced amounts, previous amounts, cumulative amounts and total estimated amounts at completion.
    - Interconnection Customer may request in writing, at the time of the execution of the Facilities Study Agreement, a quarterly cost reconciliation. (See “Quarterly Cost Reconciliation” section below for further details).
    - TOs must submit quarterly invoices to PJM by the 25th of the month prior to the quarter reflected by the billing.
    - TO billing to be based on calendar quarter:
        - For initial invoice, the invoice should include the projected costs for work to be completed during the remaining months of the current calendar quarter.
        - The second invoice for the first full calendar quarter would then be submitted to PJM prior to the beginning of the next calendar quarter.
    - Final invoice:
        - TO is required to provide final invoice within 120 days after completion of the Facilities Study work (OATT Attachment N-2).
        - TO to mark the final invoice as “Final”.
- ISA / ICSA phase invoicing:
    - TO is required to provide an invoice to PJM on a quarterly basis for work to be performed in the next subsequent quarter. This is necessary for PJM to provide the advanced quarterly billing to the Interconnection Customer for cost responsibility for work to be performed on Attachment Facilities and Network Upgrades as required by Order 2003.
    - Interconnection Customer may request, at the time of the execution of the Interconnection Study Agreement (ISA), a quarterly cost reconciliation (See “Quarterly Cost Reconciliation” section below for further details).
    - TOs are required to submit a completed form for each Attachment Facility item (Queue #) and each respective Network Upgrade (Network Upgrade #) as back-up documentation to respective Transmission Owner invoice cover sheets.
    - Initial invoice should be submitted to PJM prior to the start of work.
        - Upon execution of the ICSA (or Interim ISA), TO should evaluate and update any cash flow provided at the time of agreement execution. This cash flow can be reviewed with the project team at the construction kickoff meeting. Subsequent quarterly invoicing should follow the projected cash flow, and adjustments to the project cash flow can be made during the course of the project, if appropriate and agreed to by all parties, and documented in project status meeting documentation.
        - TO’s that do not submit invoice prior to the start of work are at risk of creating an imbalance with respect to security collected for the project.

- In order for PJM to efficiently process generator invoices by the 5th of the next month, TOs should submit quarterly invoices to PJM by the 25th of the month prior to the quarter reflected by the billing. PJM cannot guarantee that billing will be included in next generator invoicing cycle (5th business day of the next month) if invoices are not received by the above date.
- TO billing to be based on calendar quarter:
  - For initial invoice, the invoice should include the projected costs for work to be completed during the remaining months of the current calendar quarter.
  - The second invoice for the first full calendar quarter would then be submitted to PJM prior to the beginning of the next calendar quarter.
- TOs should provide a quarterly billing form each quarter during the entire duration of the construction work. If there are particular quarters where there are no projected costs, the following guidelines should apply:
  - TOs should submit a quarterly billing invoice form (PJM TO Standard Invoice Form F) only if there is a change in the "Estimated Cost at Completion" amounts (TO invoice cover sheet not required in this case).
  - If project is under suspension, a quarterly billing invoice form is not required.
- For ISA/ICSA phase invoicing, PJM requires the Transmission Owner to provide the following cost information (note: costs are TO committed costs):
  - Major Equipment / Material Costs
  - TO Labor Costs
  - Outside Services / Subcontractor Costs
  - Miscellaneous Costs (ie. easement or right-of-way fees, permits, etc.)
  - CIAC Tax Gross-up costs (if applicable)
  - The above cost breakdown information is required for current invoiced amounts, previous amounts, cumulative amounts and total estimated amounts at completion for each specific queue (Attachment Facilities) and/or Network Upgrade activity. Also required is a listing of original estimated cost per upgrade queue. The original estimated cost per upgrade / queue should be the original total, unallocated cost for that specific queue (Attachment Facilities cost) or Network Upgrade. The revised cost per upgrade / queue should be the current approved cost as reflected by any scope changes documented through the ISA/CSA Scope Change Process.
- Final invoice (ISA/ICSA phase):
  - TO is required to provide final invoice to PJM within 120 days after completion of any Attachment Facilities or Network/ Local Upgrades performed under the Interconnection Construction Service Agreement per OATT Att. P, App. 2, Sect. 9.3.
  - Acknowledging the various scenarios for the timing of completion of Attachment Facilities or Network Upgrades, completion of Interconnection

Facilities / Merchant Network Upgrades is generally considered to be in alignment with the following guidelines:

- Attachment Facilities - completion date is the date of Stage One Energization of Attachment Facilities in accordance with OATT Att. P, App. 2, Sect. 3.9.1.
- Network Upgrades – completion date is the date of Stage Two Energization of Interconnection Facilities in accordance with OATT Att. P, App. 2, Sect. 3.9.3.

➢ PJM will provide final determination of timing for sequencing of final invoice for TO facilities in cases where there are sequencing questions related to network upgrades completion with respect to Attachment Facilities completion (ie. large gaps in time)

➢ TO to mark the final invoice as "Final" (see Project Cost Reconciliation Section).

Please refer to Attachment A "Transmission Owner Standard Invoice Forms" for the complete set of Transmission Owner standard invoice forms. TOs should consult with their respective PJM IPProject Manager, or IC Project Coordinator to address any concerns about the correct form to use, components of the forms, or clarification of final invoice timing requirements.

- Adjustments to Security during Construction:
  - PJM IC Project Coordinator will make adjustments to security and balance amounts retained as appropriate through the course of construction in accordance with OATT provisions.
- Quarterly Cost Reconciliation:
  - Per the PJM OATT, an Interconnection Customer may request, at the time of the execution of the Facilities Study Agreement (FSA) or Interconnection Study Agreement (ISA), a quarterly cost reconciliation.
  - Initiation of quarterly cost reconciliation:
    - ➢ Facilities Study: Interconnection Customer provides a written request for quarterly cost reconciliation at the time of execution of the Facilities Study Agreement (OATT 206.4.1.1 and Attachment N-2).
    - ➢ ISA/ICSA phase: Interconnection Customer initiates the quarterly cost reconciliation by selecting this option as part of execution of the ISA (OATT Attachment O).
  - The quarterly cost reconciliation, if requested, would be done at a maximum frequency of one quarter in arrears (ie. the third quarterly invoice would provide the reconciliation for the first quarter).
  - Attachment A includes an example of a how the quarterly cost reconciliation cells on the TO Standard Invoice Form F could be filled out for a typical project with construction work billed on an advanced quarterly basis.

Interconnection Customer Billing / Statements:

The billing format and sequencing outlined in the previous section (Transmission Owner Billing Guidelines) enables PJM to provide the advanced quarterly billing to the Interconnection Customer for cost responsibility for work to be performed on Attachment Facilities and Network Upgrades as required by the OATT.

- Interconnection Customer Billing:
    - On the 5th business day of each month, PJM sends invoices via email only for shortfalls in accounts to Interconnection Customers for any projects that are less than 10 MW or have an active Feasibility Study, Impact Study, Facilities Study, or ISA/ICSA Implementation Phase.
    - The Interconnection Customer invoices consist of the following components:
        - Email message stating the purpose and content of the email.
        - PJM Invoice Attachment.
        - SAP Summary Report Attachment.
        - SAP Current Activity from Previous Billing Report – Line Item Report Attachment.
        - A separate email is sent for copies of Transmission Owner Invoices.
    - Per the PJM OATT, Interconnection Customer is required to pay invoiced amounts within 20 calendar days of receipt of invoice.
        - Failure by Interconnection Customer to make a timely payment of an invoice can lead to termination of the Interconnection Request. Breach, Cure, and Default procedures are outlined in OATT Att. P, App. 2, Sect. 13.
        - OATT requires that in the event an Interconnection Customer chooses to dispute all or portions of an invoice, the Generator is required to provide payment in full to PJM. PJM will hold the disputed amount in an escrow-type account until the disputed issue is resolved through the dispute resolution procedures or other means.
    - Interconnection Customer Monthly Statements:
        - On the 15th business day of each month, PJM sends a statement via email to all Interconnection Customers for projects that have either an active study phase or ISA phase.
        - The Interconnection Customer monthly statements consist of the following components:
            - Email message stating the purpose and content of the email.
            - SAP Summary Report by Phase Attachment.
            - SAP Line Item Detail Report (Project Total History) Attachment.

Project Cost Reconciliation Process

- PJM performs a cost reconciliation at the end of the ISA/ICSA phase of Interconnection Customer projects. As the middle party controlling the transfer of funds between the Interconnection Customer and the Transmission Owner, PJM assumes the lead role in the cost reconciliation process.

- Tools used by PJM to facilitate the cost reconciliation process are PJM SAP Reports, Interconnection Customer and Transmission Owner invoice logs and cost reports, and PJM-created project actual cost reconciliation summaries, which include the final cost allocation amounts for network upgrades.
- Responsibilities of the parties:
  - Transmission Owner:
    - Timely billing and cost tracking during the study phases and ISA/ICSA phase.
    - Effective Scope Change Process usage.
    - Adequate completion of TO Standard Invoice Forms.
    - Timely submission of final invoice (for each phase).
    - Submittal of reconciliation of actual costs versus invoiced costs with final invoice, using cost breakdown provided in TO Standard Invoice Form F.
  - Interconnection Customer:
    - Communication with PJM and TO on cost tracking for Attachment Facilities and Network Upgrades throughout duration of construction.
    - Support of Scope Change Process if applicable.
    - Timely payment of PJM invoices.
    - Maintain Interconnection invoice log to compare to PJM statements.
  - PJM:
    - Facilitation of billing and cost tracking issues throughout interconnection process.
    - Provide invoices as required and monthly statements to Interconnection Customer throughout interconnection process.
    - Effective follow-up with Interconnection Customers on payment of invoices within 20 days; Breach, Cure and Default procedures are outlined in OATT Att. P, App. 2, Sect. 13.
    - Effective Scope Change Process facilitation.
    - Generate project actual cost summaries as needed.
    - Reconcile and adjust Interconnection Customer and TO account balances by phase.
    - Reconcile final account balances between Interconnection Customer and Transmission Owner.
    - Facilitate completion of financial closeout documentation.

2.5 ISA / ICSA Scope Change Process

Description:

PJM has developed and implemented a scope change process to be utilized during the ISA/ICSA phase of Interconnection Customer projects. The intent of the Scope Change Process is to improve the administration of interconnection facilities construction, and to reduce the need for amendments to Interconnection Service Agreements (ISAs) and Interconnection Construction Service Agreements (ICSAs) that were previously required when significant changes in the scope, cost or schedule of interconnection facilities occurred due to circumstances that were unforeseen at the time of execution of the agreement(s). The ISA / ICSA Scope Change Process provides for a clear method of documentation of scope changes. This results in Interconnection Customers being informed about scope changes in a timelier manner, increased communication between Transmission Owners, Interconnection Customers and PJM, and fewer disputed issues at the end of projects.

The ISA / ICSA Scope Change Process was developed by PJM and its stakeholders (Interconnection Project Management Working Group) to mitigate the administrative challenges and disputes arising from changes in the project scope and/or schedule throughout the duration of detailed design and construction work for interconnection facilities (ie. Attachment Facilities or Network Upgrades).

Many of the changes that normally occur on a typical interconnection facilities project are minor and they do not have a meaningful impact on the cost or scheduled completion of work, However, if in the judgment of any party, the changes in the cost of required facilities or in the time required for their completion are sufficiently large to have a meaningful impact on the total cost or timing for completing the interconnection facilities, then the Scope Change Process is designed to be the appropriate instrument to document such changes.

The ISA / ICSA Scope Change Process is applicable only to those projects with three-party ISAs and ICSAs. In addition, the ISA / ICSA Scope Change Process only applies to previously defined impacts related to an interconnection project as defined in the ISA and ICSA. If a particular scope change results in the requirement of a new network upgrade (i.e. a new impact not previously included in PJM's interconnection studies and defined by the attachment facilities or network upgrade scope), then an amended ISA and ICSA would need to be executed, because there may be additional cost allocation responsibilities to other interconnection customers.

Thus, the scope change process is applicable to any changes that affect the already-known attachment facilities and network upgrades of an Interconnection Customer project. For example, the scope change process would apply in the case of a previously defined network upgrade that requires construction of a new segment of transmission line in the event that detailed design or initial excavations for the new transmission towers revealed unexpected subsurface conditions that required altering the foundation design, and thus the projected cost and/or schedule for completion of the tower foundations. Another typical application of the scope change process would be the case where the TO has determined that due to a six month delay in the delivery of a circuit breaker that is required to complete a breaker replacement network upgrade, the in- service date for that particular network upgrade will be significantly delayed, and the revised completion date would be reflected in the scope change form.

The ISA / ICSA Scope Change Process is designed to have the flexibility to be initiated by either the Transmission Owner, Interconnection Customer, or PJM. It is also linked to the Transmission Owner Standard Invoice Form by way of utilizing the "Estimated Cost at Completion" column to trigger the appropriate dialogue between the TO, PJM and the Interconnection Customer that may result in the scope change process being initiated.

- The following are typical situations for Interconnection Customer / Transmission Owner / PJM to initiate the ISA / ICSA Scope Change Process:
    - Transmission Owner:
        - Significant cost overrun projected during ISA/ICSA implementation phase.
        - Identification of additional scope not identified in the Facilities Study but identified later during detailed design.
        - Delay in project milestone (i.e. Backfeed power energization or completion of a Network Upgrade).
    - Interconnection Customer:
        - Delay of Commercial Operation Date (COD).
        - Significant change in project scope resulting in major change to required Transmission Owner facilities.
    - PJM:
        - Notification to Interconnection Customer about changes to network upgrade requirements due to retool analysis.
        - Notification to Interconnection Customer to modify security amount or LOC expiration date.

If an initiated scope change results in a significant cost increase, the ISA / ICSA Scope Change Process is used to identify any additional security amount required to be provided by the Interconnection Customer without having to execute an amended ISA. Likewise, if an initiated scope change results in a schedule milestone change (i.e. foundation work complete, interconnection switchyard energized, etc.), then the ISA / ICSA Scope Change Process is used to identify the revised projected completion date.

The scope change process provides for the customer's acknowledgment, though not its approval, of each scope change affecting its project. In the event an Interconnection Customer objects to a proposed change in scope, PJM, as it does with respect to other construction-related issues consistent with OATT Att. O, App. 2, Sect. 1, will facilitate discussions between the Interconnection Customer and the relevant transmission owner to ensure that the Interconnection Customer is informed of the reasons and justification for the change.

A customer's refusal to acknowledge the scope change will not, however, preclude implementation of a change that PJM finds to be appropriate and reasonable. The Interconnection Customer will remain responsible, in accordance with the PJM Tariff, for the full cost of the required upgrades. Should the Interconnection Customer continue to dispute the appropriateness of a scope change and/or any increased costs related to it, it may invoke the PJM OATT dispute resolution procedures.

Please refer to Attachment B of this manual for the ISA / ICSA Scope Change Process flow diagram and ISA / ICSA Scope Change Form.

2.6 Project Meetings

In order for PJM to more effectively coordinate the ISA/ISA implementation phase of interconnection projects, Interconnection Customers and Transmission Owners should include PJM in regular project status meetings.

PJM participation in regular project meetings provides the following benefits:

- Better collaboration between the Interconnection Customer and Transmission Owners.
- PJM can more proactively facilitate project integration with internal PJM organizations, and involve the appropriate PJM contacts at the right time.
- Elevation of PJM's awareness of project issues and status with respect to schedule milestones.
- More efficient coordination of transmission system outages.

2.7 Project Site Reviews

PJM performs site visits on Interconnection Customer projects, as well as transmission system upgrade and reliability projects that are derived from the RTEP (Regional Transmission Expansion Plan) process. The main reasons for performing these site visits are for coordination between new Interconnection Customer and the required transmission system upgrades, assisting the Interconnection Customer project in making a successful transition into PJM's operations and markets by managing the variety of tasks behind the scenes within PJM (such as metering requirements, system model building and verification, outage coordination, and operational issues), and for verification of project status relative to the Regional Plan.

PJM site reviews allow PJM to assess the status of Transmission Owner and/or Customer Facility Construction onsite. Also a better working relationship with the Site Project Manager and Plant Manager can be developed to improve the level of coordination with PJM internal organizations.

For Interconnection Customer projects, all applicable upgrades will be normally inspected during the construction and start-up phases. This includes: the generation facilities (power generation equipment), the attachment facilities (the electrical components necessary to interconnect the Customer Facility to the high-voltage system), and any network upgrades required (enhancements to the high-voltage system required as a result of the new Interconnection Customer project).

Baseline upgrades (required transmission system upgrades which are a direct result of a study finding from PJM and become part of the RTEP) will normally be inspected during the construction phase to determine schedule adherence, and possibly after energization to verify the 'as built' with the PJM system model.

Transmission Owner Identified (TOI) projects (which are projects the local transmission owner is completing for their own reason, and become part of the RTEP) will be inspected during construction or after completion. PJM will ask for a schedule update during the construction phase to ensure the project is progressing towards the completion date. Once complete, a site inspection will be performed to verify the ‘as built’ with the PJM system model.

When performing site visits, PJM will abide by all applicable safety rules including wearing of personal protective equipment such as hard hats, safety shoes, eye protection, and FR clothing (where required). In addition, a hazard awareness briefing is recommended prior to the inspection to make everyone aware of the hazards at the site and the energization status of the equipment. Special precautions and site specific items need to be discussed during this awareness briefing.

The coordination between PJM and the site is usually handled through the PJM IC Project Coordinator assigned to that area and the site’s local project / construction manager. The objective is to establish communications early in the project and obtain regular updates. These updates are necessary to ensure the coordination of other activities related to this project, such as line outages, completion of other upgrades, and other critical scheduled activities. Site visits can normally be conducted around other routine activities at the facility, such as regular status meetings, scheduling meetings, or site walkdowns.

Typical items reviewed during a Customer Facility site visit include the milestones from the Interconnection Service Agreement (ISA) and Interconnection Construction Service Agreement (ICSA). These milestones may include site work completion, equipment delivery, construction schedule and / or energization. The objective is to make sure that particular project is progressing, giving the staff at PJM enough information to be able to coordinate other on-going activities related to that project, such as network upgrades, metering enhancements, and integration into operations. Normally the site visit is accompanied by a site walkdown and review of applicable diagrams and schedules.

For baseline and TOI upgrades, normally the one-line diagram is reviewed, outage scheduling and completion dates are discussed, and a site walkdown performed during the site visit. Once again, the objective is to ensure the upgrades and schedules are meeting the PJM RTEP plan.

During the site visit, digital photos and notes may be taken. These are for internal PJM reports and database updates. The photos and notes may be used for equipment delivery verification, schedule progression, one-line diagram verification, or other appropriate milestones.

In summary, PJM may perform site visits to both Interconnection Customer projects and reliability upgrades. These site visits help PJM staff not only ensure the reliability of the transmission system by making sure upgrades are progressing and completed as required, but also help facilitate the coordination of other behind the scenes activities within PJM. Areas such as outage coordination, model updates, and integration into PJM operations are managed more completely by PJM when there is open communication and exchange of information accomplished by site visits.

2.8 Outage Coordination

The OATT requires that Transmission Owners and Interconnection Customers coordinate all transmission system outages with PJM in accordance with the PJM System Operations outage planning procedures. In addition to the detailed planning that is required by the PJM System Operations outage planning procedures, Transmission Owners and Interconnection

Customers can support PJM's long range planning of outages by supplying the PJM IC Coordinator with milestone schedule updates so that long range outage planning information can be integrated into the PJM outage planning schedules.

During the ISA / ICSA Implementation Phase, the PJM IC Coordinator will provide assistance as required in coordinating outages with PJM Operations and will facilitate the resolution of major outage related issues between PJM Operations, Interconnection Customers, and Transmission Owners. PJM outage requirements are described in detail in PJM Manual M03 (Section 4: Reportable Transmission Facility Outages / Scheduling Transmission Outage Requests).

2.9 Suspended Projects

In the event that an Interconnection Customers initiates the project suspension provisions of the OATT, the PJM IC Project Coordinator will facilitate the completion of the following activities in accordance with the OATT:

- Confirm receipt of Suspension Notification from Interconnection Customer.
- Confirm that Interconnection Customer Suspension Notification meets OATT requirements.
- Evaluate ISA Section 6 Milestones and amend as required.
- Update PJM Database (projected in-service date, network upgrade in-service date).
- Assess Impact on Network Upgrades / Baseline Upgrades. Note: projects which are suspended before ICSA is executed will be assessed on a case-by-case basis to determine if network upgrades are required to be completed.
- Facilitate Transmission Owner completion of high level assessment of known risks.
- Evaluate Transmission Owner suspension costs.
- Facilitate Billing process for Transmission Owner suspension costs (including cost reconciliation and refunding of significant TO funds that may have been already collected but will not be used as projected).
- Send 3 year Termination Letter to Interconnection Customer (with a copy also sent to the TO).

For projects that have gone through a period of suspension, and construction activities are resumed by the Interconnection Customer, the PJM IC Project Coordinator will facilitate the completion of the following activities:

- Confirm receipt of notification from Interconnection Customer that project is coming off of suspension, and confirm that notification is provided to Transmission Owner.
- Assess current impact on Network Upgrades / Baseline Upgrades.
- Facilitate Transmission Owner evaluation and confirmation of current schedule milestones and estimated costs.
- Complete Scope Change Process for revisions to Interconnection Customer ISA milestones, TO ICSA schedule, and cost impacts, as applicable.

- Update PJM database (queue projected in-service date, network upgrade required and projected in-service date).

2.10 Project Communication, Reporting and Documentation

PJM believes that another critical component to the successful achievement of Interconnection Customer and Transmission Owner project milestones for RTEP projects is an elevated level of communication between all parties. PJM facilitates this communication between parties whenever possible and necessary, however, it is incumbent on Transmission Owners and Interconnection Customers to proactively communicate issues and concerns to the other interested parties in order to create a better environment for development of more positive working relationships and the professional resolution of project issues.

The following are the main types of standard reporting and documentation that are required throughout the ISA / ICSA Implementation Phase:

2.10.1 Monthly Status Reports:

The OATT (Att. P, App. 2, Sect. 3.7) requires that each Transmission Owner and Interconnection Customer engaged in ISA / ICSA Implementation activities provide each other (and PJM) with monthly (at a minimum) status reports. PJM requests that the schedule milestone and cost estimate project information detailed in this manual be incorporated in these monthly status reports.

2.10.2 Documentation for Project Meetings:

PJM will facilitate the assignment of which party (PJM, TO, or Interconnection Customer) generates documentation from project meetings (i.e. meeting minutes and/or action items) as most appropriate for each project.

2.10.3 Notice of Completion:

The Interconnection Customer is required to notify PJM and the applicable Transmission Owner in writing upon completion of the following:

- The Customer Facility
- The Interconnection Customer interconnection facilities
- Any Transmission Owner Facilities for which the Interconnection Customer has completed through exercising the Option to Build alternative.

2.10.4 PJM Documentation Required from the Interconnection Customer prior to Synchronization:

The OATT requires that the following documentation be provided by the Interconnection Customer prior to synchronization of the Customer Facility with the transmission system:

- As-built drawings
- Pre-operation test reports
- Instruction manuals

2.11 PJM Documentation Required from the Transmission Owner prior to Synchronization:

In accordance with OATT Att. P, App. 2, Section 3.8.5, the TO is required to provide the following Notification of Inspection / Testing Results prior to synchronization of the Customer Facility with the transmission system:

> Within 10 days after satisfactory inspection and/or testing of Interconnection Facilities and/or Merchant Network Upgrades built by the Interconnection Customer (including, if applicable, inspection and/or testing after correction of defects or failures), the Interconnected Transmission Owner shall confirm in writing to the Interconnection Customer and Transmission Provider that the successfully inspected and tested facilities are acceptable for energization.
>
> Suggested wording:
>
> *By issuance of this document, the [TRANSMISSION OWNER] hereby acknowledges the pre-energization acceptance of the [NAME] Interconnection Switchyard (PJM Queue Position [XX]) built by the Interconnection Customer ([DEVELOPER]).*
>
> *PJM Queue Position [XX] for the [NAME OF FACILITY] has the requirement to provide written documentation of the completed inspection and testing for the [NAME] Interconnection Substation, pursuant to Section 3.8.5 of Attachment P, Appendix 2, Standard Construction Terms and Conditions as contained in PJM's Open Access Transmission Tariff.*
>
> *A site walkdown was conducted on [DATE] and a punch list of action items has been compiled. Unresolved punch list items still need to be resolved but do not impact energization. Pre-energization commissioning and testing has been satisfactorily performed. Follow-up energization testing will be performed after the line reconfiguration work is completed.*

2.12 Generator As-Built Data Requirements

In order to reflect as-built information in PJM's planning models, PJM System Planning requires that Interconnection Customers provide updates to generator data originally provided to PJM for the initial planning studies. This as-built data is then used in the next planning studies by PJM, so the accuracy of PJM's data is critical.

Attachment C of this manual includes the format for providing the as-built generator data. The Interconnection Customer is required to provide PJM with the requested as-built electrical modeling data (or documentation that previously submitted data is valid) within one (1) month following commercial operation of the generating unit (s). As-built generator data must be provided for each generating unit.

2.13 Dispute Resolution

For billing disputes, PJM will facilitate the dispute resolution process with the Transmission Owners and Interconnection Customer in accordance with Section OATT Att. P, App. 2, Sect. 9. All other types of disputes shall be submitted in accordance with OATT Section 12. All disputes must be initiated in writing by a disputing party to PJM, and the PJM IC Project Coordinator will confirm that the dispute initiation documentation meets OATT requirements, notify PJM Alternate Dispute Resolution Committee and PJM management, identify the appropriate OATT dispute resolution path that the disputed issue will follow, and facilitate the process between the parties.

2.14 Project Closeout

The milestone for the completion of the ISA / ICSA Implementation Phase is the point at which capacity status is granted to each Customer Facility unit (i.e. CTG1, CTG2, STG). As indicated on the Generation and Transmission Interconnection Process Role Clarity Diagram, after the capacity status milestone is achieved (per unit), the project moves into the “Post Generator Operation Phase” (see Exhibit 2).

In accordance with this process, project closeout for the purpose of PJM Manual M-14C is defined as the completion of all required deliverables related to the commercial operation of each generating unit. The PJM IC Project Coordinator then is responsible to ensure that the Generator provides all required project closeout documentation as defined in the OATT, and integration of all applicable provisions detailed in PJM Manual M14D, “Generator Operational Requirements”.

Section 3: Technical and Construction Requirements

Welcome to the *Technical and Construction Requirements* section of the ***PJM Manual for Generation and Transmission Interconnection Facility Construction***. In this section you will find an overview of both the technical requirements for generator and transmission interconnections in the PJM regions and the construction specifications for the attachment and network facilities needed to accommodate generator and/or transmission interconnections in the PJM regions.

- Description of the technical requirements and where to find the technical requirements of both PJM and the particular Interconnection Transmission Owner for generator and transmission interconnections in a specific PJM region (see "*Transmission Owner Standards – PJM website*").
- Description of the construction standards and specifications for generator attachment facilities and network facilities and where to find the construction standards for a particular Interconnection Transmission Owner to accommodate generator and/or transmission interconnections in a specific PJM region (see "*Construction Standards – PJM website*").

3.1 Transmission Owner Standards – PJM website

3.1.1 Need for Interconnection Technical Requirements

The PJM Transmission Grid provides the means for delivering the output of interconnected generators to the load centers of the PJM energy and capacity markets. As a FERC accepted Regional Transmission Organization (RTO), PJM administers the process for the interconnection of generators to the PJM Transmission Grid. To ensure that the PJM Transmission Grid is operated in a safe and reliable manner, all generator and transmission interconnections to the PJM Transmission Grid must be installed according to the established technical requirements for good utility practice.

PJM, as the Transmission Provider, will ensure that the Generation and/or Transmission Interconnection Customer has access to the applicable technical requirements of the Interconnection Transmission Owner for parallel operation of generators with the Interconnection Transmission Owner's system and other matters generally included in good utility practice. Technical requirements for generator and transmission interconnections include but are not limited to:

- Engineering design requirements and standards
- Interconnection protection requirements,
- Generator underfrequency trip settings to coordinate with automatic underfrequency load shedding schemes,
- Voltage control and reactive output requirements, and
- Data and control requirements for transmission system operation.
- Equipment specifications and suppliers
- Construction requirements and standards

- Engineering, procurement and construction process requirements and standards.

3.1.2 Application of Interconnection Technical Requirements

As specified in PJM Tariff Form of Interconnection Construction Service Agreement,, Att. P, App. 2, Sect. 2.2A, “Applicable Technical Requirements and Standards shall apply to the design, procurement, construction and installation of the Interconnection Facilities and Merchant A.C. Transmission Facilities only to the extent that the provisions thereof relate to the design, procurement, construction and/or installation of such facilities. Such provisions relating to the design, procurement, construction and/or installation of facilities shall be identified in the Interconnection Construction Service Agreement. The Interconnection Parties shall mutually agree upon, or in the absence of such agreement, Transmission Provider shall determine, which provisions of the Applicable Technical Requirements and Standards should be identified in the Interconnection Construction Service Agreement. In the event of any conflict between the provisions of the Applicable Technical Requirements and Standards that are appended to the Interconnection Construction Service Agreement and any later-modified provisions that are stated in the pertinent PJM Manual, the provisions appended to the Interconnection Construction Service Agreement shall control.”

3.1.3 Technical Requirements on PJM website (www.pjm.com)

The PJM Open Access Transmission Tariff (“OATT”) under Part I, section 1.2C establishes the requirement that “Those certain technical requirements and standards applicable to interconnections of generation and/or transmission facilities… shall be publicly available through postings on Transmission Provider’s internet website.” Accordingly, PJM makes the documents containing Applicable Technical Requirements and Standards for each Interconnection Transmission Owner (“ITO”) available through its internet website www.pjm.com under the directory titled “Design, Engineering & Construction” at http://pjm.com/planning/design-engineering/to-tech-standards.aspx.

3.2 Construction Standards – PJM website

3.2.1 Need for Construction Standards

The facilities of the PJM Transmission Grid, while operated by PJM, are comprised of the physical facilities owned by the various Interconnected Transmission Owners (“ITOs”). While the facilities of the various ITOs are operated by PJM as a fully interconnected transmission network, the physical facilities of each individual ITO are designed to the particular construction standards of that ITO. Such construction standards for a particular ITO include but are not limited to:

- transmission system voltage levels,
- spacing and clearance requirements,
- equipment design specifications,
- family of material and equipment sizes,
- fully compatible system protection schemes,
- list of Approved Contractors, and

- list of approved manufacturers and vendors of major transmission-related equipment.

While particular construction standards may vary among the various ITOs, all such standards are derived from those generally accepted industry standards developed by the American National Standards Institute (ANSI), the Institute of Electrical and Electronics Engineers, Inc. (IEEE) and the National Electric Safety Code. The ITOs have selected their various construction standards to facilitate operation, maintenance and repair or replacement of the various components utilized on their portion of the overall PJM Transmission Grid. Thus, it is essential that any additions, upgrades or other changes to the transmission facilities of any particular ITO must be designed and installed to the construction standards of that ITO. PJM, as the Transmission Provider, will ensure that any Constructing Entities authorized to perform construction activities under the “Option to Build” provisions of the PJM OATT to interconnect with the facilities of an ITO or to install or upgrade facilities within the transmission system of an ITO has access to the established construction standards of that ITO. All such construction standards shall be stated in full in an appendix to the Construction Service Agreement.

3.2.2 Application of ITO Construction Standards

The conditions applicable to an Interconnection Customer exercising its “Option to Build” are specified in Att P, App 2, section 3.2.3.8 of the PJM Tariff. Among the provisions included under the Option to Build is: “Interconnection Customer shall submit to the Interconnected Transmission Owner and Transmission Provider initial drawings, certified by a professional engineer, of the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades that Interconnection Customer arranges to build under the Option to Build. The Interconnected Transmission Owner and Transmission Provider shall review the drawings to assess the consistency of Interconnection Customer’s design of the pertinent Transmission Owner Interconnection Facilities and/or merchant Network Upgrades with Applicable Standards and the Facilities Study.”

3.2.3 Construction Standards on PJM website (www.pjm.com)

The PJM Open Access Transmission Tariff (“OATT”) under Att. P, App. 2, Sect. 3.2.3.1 states that “In the event that the Interconnected Transmission Owner and the Interconnection Customer are unable to agree upon the terms of an Interconnection Construction Service Agreement,... the Interconnection Customer shall have the right, but not the obligation (“Option to Build”), to design, procure, construct and install all or any portion of the Transmission Owner Interconnection Facilities and/or any Merchant Network Upgrades.” If a Generation and/or Transmission Interconnection Customer (“IC”) wishes to exercise the Option to Build, the IC must have ready access to the construction standards for the ITO(s) system where such facilities are to be installed. Att. P, App. 2, Sect. 3.2.3.5(a). of the OATT establishes the requirement that “Transmission Provider shall publish each Transmission Owner’s List of Approved Contractors in a PJM Manual and shall make such manual available on its internet website.” Accordingly, PJM makes the documents containing the applicable construction standards for each ITO available through its internet website www.pjm.com under the directory titled “Design, Engineering & Construction” at http://pjm.com/planning/design-engineering/to-tech-standards.aspx.

Section 4: Option to Build

Welcome to the *Option to Build* section of the ***PJM Manual for Generation and Transmission Interconnection Facility Construction***. In this section you will find an overview of the requirements related to implementation of the Option to Build provisions of the OATT.

4.1 Option to Build

The OATT allows for an Interconnection Customer to exercise the Option to Build alternative either during the ISA / ICSA Execution Phase or at any reasonable time prior to 37 days after the ISA is executed. The Option to Build alternative may be pursued by the Interconnection Customer for the completion of the Attachment Facilities or the Network Upgrades, or both, depending on the circumstances.

The OATT provisions related to timeframes for initiation of the Option to build are outlined in PJM Manual M14B. However, included in this manual is Attachment D “Option to Build Initiation Form”, which is the standard form to be used by Interconnection Customers to formally notify PJM of their intent to exercise the Option to Build.

PJM coordinates Option to Build type projects with the same project controls used for typical interconnection projects. In the event that an Interconnection Customer exercises the Option to Build, the PJM IC Project Coordinator facilitates the following activities that are unique to Option to Build projects:

Security Requirements:

- PJM to assess financial security requirements required as applicable to Interconnection Customer initiating the Option to Build.

Approved Contractors and Manufacturers:

- PJM will facilitate the process for TOs providing a List of Approved Contractors and Manufacturers as required in accordance with OATT Att. P, App. 2 Sect 3.2.3.5.
- PJM to facilitate TO review, approval/disapproval, and addition of contractor or manufacturer to List of Approved Contractors and Manufacturers if requested by Interconnection Customer.

Drawing Review:

- PJM to facilitate TO review and comment on Interconnection Customer drawings for facilities to be constructed under Option to Build within 60 days after receipt of drawings.

Inspection, Testing, and Energization:

For facilities built by the Interconnection Customer, the OATT requires that the following documentation be provided by the Interconnection Customer prior to synchronization of the Customer Facility with the transmission system:

1) Notification of Inspection / Testing Results - Within 10 days after satisfactory inspection and/or testing of Interconnection Facilities and/or Merchant Network Upgrades built by the Interconnection Customer (including, if applicable, inspection

and/or testing after correction of defects or failures), the Interconnected Transmission Owner shall confirm in writing to the Interconnection Customer and Transmission Provider that the successfully inspected and tested facilities are acceptable for energization (reference Att. P, App. 2, Section 3.8.5)

Suggested wording:

By issuance of this document, the [TRANSMISSION OWNER] hereby acknowledges the pre-energization acceptance of the [NAME] Interconnection Switchyard (PJM Queue Position [XX]) built by the Interconnection Customer ([DEVELOPER]).

PJM Queue Position [XX] for the [NAME OF FACILITY] has the requirement to provide written documentation of the completed inspection and testing for the [NAME] Interconnection Substation, pursuant to Section 3.8.5 of Attachment P, Appendix 2, Standard Construction Terms and Conditions as contained in PJM's Open Access Transmission Tariff.

A site walkdown was conducted on [DATE] and a punch list of action items has been compiled. Unresolved punch list items still need to be resolved but do not impact energization. Pre-energization commissioning and testing has been satisfactorily performed. Follow-up energization testing will be performed after the line reconfiguration work is completed.

2) Transfer of Operational Control (prior to energization) - The Interconnection Customer shall have delivered to the Interconnected Transmission Owner and Transmission Provider a written notice transferring to the Interconnected Transmission Owner and Transmission Provider operational control over any Transmission Owner Attachment Facilities that Interconnection Customer has constructed (reference Att. P, App. 2, Sections 3.9.1 and 3.9.3)

   Suggested wording:

   PJM Queue Position [XX] for the [NAME OF FACILITY] does, as required pursuant to Section 3.9.1 and 3.9.3 of Attachment P, Appendix 2, Standard Construction Terms and Conditions contained in PJM's Open Access Transmission Tariff, hereby transfer to [TRANSMISSION OWNER] operational control of the [NAME] Interconnection Switchyard as of the date written below. [DEVELOPER] has delivered prior to this written instrument of transfer, the marked-up as-built drawings of the [NAME] Interconnection Switchyard. [DEVELOPER] will ensure telemetering systems are operational and provide PJM and [TRANSMISSION OWNER] with telemetered data as specified in OATT Att. O, App. 2, Section 8.5.2 before Stage Two energization (initial synchronization of any generators).

3) Acceptance of Facilities - Within five days after determining that Interconnection Facilities and/or Merchant Network Upgrades have been successfully energized, the Interconnected Transmission Owner shall issue a written notice to the Interconnection Customer accepting the Interconnection Facilities and/or Merchant Network Upgrades built by the Interconnection Customer that were successfully energized (reference Att. P, App. 2, Section 3.10)

   Suggested wording:

   By issuance of this document, the Interconnected Transmission Owner [TRANSMISSION OWNER NAME], hereby acknowledges the acceptance of the *facilities of the [NAME] Interconnection Switching Station and Transmission Tap built by the Interconnection Customer, [DEVELOPER NAME].*

PJM requires written documentation of the acceptance of facilities constructed by the Interconnection Customer, pursuant to Section 3.10 of Attachment P, Appendix 2, Standard Construction Terms and Conditions as contained in PJM's Open Access Transmission Tariff.

These facilities were energized on [DATE] and punch list items from the site inspection of [DATE] have been resolved.

4) Transfer of Title – The Interconnection Customer shall execute all necessary documentation and shall make all necessary filings to record and perfect the Interconnected Transmission Owner's title in such facilities and in the easements and other land rights to be conveyed to the Interconnected Transmission Owner (reference Att. P, App. 2, Section 5.5).

   Suggested wording:

   RE: Transfer to [TRANSMISSION OWNER] of the [NAME OF FACILITY] (PJM Queue Position [QUEUE NUMBER])

   PJM Queue Position [QUEUE NUMBER] for the [INTERCONNECTION CUSTOMER FACILITY] does, required pursuant to Att. P, App. 2, Section 5.5 of PJM's Open Access Transmission Tariff, hereby transfer to [TRANSMISSION OWNER] the [NAME OF FACILITY] as of the date written below. [INTERCONNECTION CUSTOMER] transfer of Facilities requires a Bill of Sale to transfer and convey to [TRANSMISSION OWNER] certain items of personal property as hereinafter described.

   Facilities transferred list includes:

   - *Description*
   - *Quantity*
   - *Supplier*
   - *Catalogue Number*
   - *Item reference to Bill of Material*

Bill of Sale

This Bill of Sale, is made as of DATE ("Effective Date") by [INTERCONNECTION CUSTOMER FACILITY] to [TRANSMISSION OWNER].

Witnesseth:

Whereas, [INTERCONNECTION CUSTOMER] and [TRANSMISSION OWNER] are parties to that certain Easement Agreement ("Easement Agreement"), dated DATE, with respect to certain real property located in XXX, as described therein ("Property");

Whereas, pursuant to the terms of this Bill of Sale, [INTERCONNECTION CUSTOMER] desires to transfer and convey to [TRANSMISSION OWNER] certain items of personal property as hereinafter described.

Now, therefore, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, effective as of the Effective Date, [INTERCONNECTION CUSTOMER] does hereby Grant, Sell, Transfer, Set Over, and Deliver to [TRANSMISSION OWNER], all of the equipment, facilities, and other personal properties located at the Property, including without limitation the personal property more particularly described on the facilities transferred list attached hereto and incorporated herein by this reference ("Personal Property"), free and clear of any and all liens, security interests and encumbrances.

[INTERCONNECTION CUSTOMER] hereby represents and warrants to [TRANSMISSION OWNER], that [INTERCONNECTION CUSTOMER] is the sole lawful owner of the Personal Property; that [INTERCONNECTION CUSTOMER] has good and marketable title to the Personal Property free and clear of all liens, claims, rights, charges, or encumbrances of any nature whatsoever; and that [INTERCONNECTION CUSTOMER] has the right to transfer the Personal Property to [TRANSMISSION OWNER] as aforesaid. Notwithstanding anything herein to the contrary, [INTERCONNECTION CUSTOMER] hereby covenants and agrees for the benefit of [TRANSMISSION OWNER] that [INTERCONNECTION CUSTOMER] will, for [INTERCONNECTION CUSTOMER] and [INTERCONNECTION CUSTOMER]'s successors and assigns, warrant and forever defend, at [INTERCONNECTION CUSTOMER]'s sole cost and expense, the right, title, and interest of [TRANSMISSION OWNER] and [TRANSMISSION OWNER]'s successors and assigns in and to the Personal Property against the lawful claims and demands of all persons. The provisions of this paragraph shall apply notwithstanding any other provisions of this Bill of Sale or the Easement Agreement, and shall survive termination, cancellation, or completion of this Bill of Sale and the Easement Agreement.

This Bill of Sale shall be governed by, interpreted under and construed and enforceable in accordance with the laws of the State/Commonwealth of [STATE].

This Bill of Sale may be executed in counterparts, each of which shall be an original and all of which counterparts taken together shall constitute one and the same agreement.

In witness whereof, [INTERCONNECTION CUSTOMER] has caused this Bill of Sale to be duly executed and delivered as of the date and year first above written.
Signature of [INTERCONNECTION CUSTOMER]

Attachment A: Transmission Owner Standard Invoice Forms

Attachment A includes all PJM Transmission Owner Standard Invoice Forms for Feasibility Study, Impact Study, Facilities Study, and ISA/CSA phases. The chart below is provided to designate which forms are required to be used for each phase. Also, the correct form designation is based on agreement execution date, not queue position (i.e. Facilities Study Agreement or ISA executed prior to or after 7/8/04 effective date of FERC Order 2003).

Additional supporting details may be provided, but the attached invoice forms are designed to be used by Transmission Owners as the minimum supporting documentation for Transmission Owner invoice cover sheets.

For ISA/CSA phase invoicing, TOs would submit a completed form for each Attachment Facility item (Queue #) and each respective Network Upgrade (Network Upgrade #) as back-up documentation to respective Transmission Owner invoice cover sheets. Note that the columns marked “Present Allocation” and “Reallocation” are for PJM use only and are not to be filled in by the Transmission Owner. Invoices submitted by Transmission Owners without the appropriate back-up forms attached will be returned to the Transmission Owner unprocessed.

Interconnection Process Phase		Projects with Agreements executed after 7/8/04
Feasibility Study		D
Impact Study		D
Facilities Study		
	Attachment Facilities	E
	Network Upgrades	E
ISA / CSA Detailed Design and Construction		
	Attachment Facilities	F
	Network Upgrades	F

Exhibit 3: Transmission Owner Standard Invoice Form Designation Table

INVOICE # 　　　　　　DATE:

TRANSMISSION OWNER:

Transmission Owner to complete all shaded blocks

FEASIBILITY STUDIES

QUEUE #	NAME	INVOICE AMOUNT	WBS#
	TOTAL	$ -	

IMPACT STUDIES

QUEUE #	NAME	INVOICE AMOUNT	WBS #
	TOTAL	$ -	

INVOICE TOTAL $ -

Exhibit 4: TO Standard Invoice Form D - Feasibility Studies and Impact Studies

INVOICE # | | **DATE:**

TRANSMISSION OWNER:
Transmission Owner to complete all shaded blocks

FACILITIES STUDY * (see below)			FOR PJM USE ONLY														
			PRESENT ALLOCATION (QUEUES WITH EXECUTED ISA)							**REALLOCATION** (DUE TO ADDED QUEUES WITH EXECUTED ISA)							
Queue / Upgrade #	NAME	INVOICE AMOUNT	date	QUEUE#	% allocation	QUEUE#	% allocation	QUEUE#	% allocation	date	QUEUE#	% allocation	QUEUE#	% allocation	QUEUE#	% allocation
		$ -														
										date	QUEUE#	% allocation	QUEUE#	% allocation	QUEUE#	% allocation

(note: this cell is linked to total current invoice amount below)

Total Original Cost for Upgrade / Queue # : **$0.00**
(From Facilities Study Agreement)

FACILITIES STUDY * Support Documentation	**Total Projected Amount Next Period (Current Invoice)**	**Previous Cumulative Amount**	**Cumulative Amount Billed to Date**	**Total Upgrade Estimated Amount At Completion**	**Cost Reconciliation*** **Committed Costs through (insert date)**	**Actual Costs through (insert date)**
Transmission Owner Facilities Study Costs:	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
CIAC Tax Gross-up (if applicable)	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL	**$ -**	**$ -**	**$ -**	**$ -**	$ -	$ -

Blue shaded text cells to be used for comments to document previous reconciliation of costs in subsequent invoices

* Cost Reconciliation columns to be used if Interconnection Customer requests quarterly cost reconciliation

Exhibit 5: TO Standard Invoice Form E - Facilities Studies (Attachment Facilities and Network Upgrades)

INVOICE # ______ **DATE:** ______

TRANSMISSION OWNER: ______
Transmission Owner to complete all shaded blocks

CONSTRUCTION * (see below)			FOR PJM USE ONLY: PRESENT ALLOCATION (QUEUES WITH EXECUTED ISA)						
Queue / Upgrade #	NAME	INVOICE AMOUNT	date	QUEUE#	% allocation	QUEUE#	% allocation	QUEUE#	% allocation
		$ -							

(note: this cell is linked to total current invoice amount below)

FOR PJM USE ONLY: REALLOCATION (DUE TO ADDED QUEUES WITH EXECUTED ISA)						
date	QUEUE#	% allocation	QUEUE#	% allocation	QUEUE#	% allocation
date	QUEUE#	% allocation	QUEUE#	% allocation	QUEUE#	% allocation

Total Original Cost for Upgrade / Queue # : **$0.00**
Total Revised Cost for Upgrade / Queue # : **$0.00** (if applicable)

CONSTRUCTION * Support Documentation					Cost Reconciliation*	
	Total Projected Amount Next Period (Current Invoice)	**Previous Cumulative Amount**	**Cumulative Amount Billed to Date**	**Total Upgrade Estimated Amount At Completion**	**Committed Costs through (insert date)**	**Actual Costs through (insert date)**
Major Equipment / Material Costs	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Owner Labor Costs	$ -	$ -	$ -	$ -	$ -	$ -
Outside Services/ Subcontractor Costs	$ -	$ -	$ -	$ -	$ -	$ -
Miscellaneous Costs (provide specifics)	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL	$ -	$ -	$ -	$ -	$ -	$ -
CIAC Tax Gross-up (if applicable)	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL	$ -	$ -	$ -	$ -	$ -	$ -

Blue shaded text cells to be used for comments to document previous reconciliation of costs in subsequent invoices

* Cost Reconciliation columns to be used if Interconnection Customer requests quarterly cost reconciliation

Exhibit 6: TO Standard Invoice Form F - ISA/ICSA Detailed Design and Construction (Attachment Facilities and Network Upgrades)

Original Upgrade Cost	$340,000
Revised Upgrade Cost	$400,000

		Total Projected Amount Next Period (Current Invoice)	Previous Cumulative Amount	Cumulative Amount Billed to Date	Total Upgrade Estimated Amount At Completion	Committed Costs through (insert date)	Actual Costs through (insert date)
1st Qtr	Major Equipment / Material Costs	$70,000		$70,000	$100,000		
	Transmission Owner Labor Costs	$80,000		$80,000	$200,000		
	Outside Services/Subcontractor Costs	$40,000		$40,000	$40,000		
	Miscellaneous Costs						
	SUBTOTAL	$190,000		$190,000	$340,000		
2nd Qtr	Major Equipment / Material Costs	$20,000	$70,000	$90,000	$120,000		
	Transmission Owner Labor Costs	$90,000	$80,000	$170,000	$240,000		
	Outside Services/Subcontractor Costs		$40,000	$40,000	$40,000		
	Miscellaneous Costs						
	SUBTOTAL	$110,000	$190,000	$300,000	$400,000		
3rd Qtr	Major Equipment / Material Costs	$30,000	$90,000	$120,000	$120,000	$65,000	$50,000
	Transmission Owner Labor Costs	$50,000	$170,000	$220,000	$240,000	$77,000	$77,000
	Outside Services/Subcontractor Costs		$40,000	$40,000	$40,000	$40,000	$0
	Miscellaneous Costs						
	SUBTOTAL	$80,000	$300,000	$380,000	$400,000	$182,000	$127,000
4th Qtr	Major Equipment / Material Costs	$0	$120,000	$120,000	$120,000	$90,000	$80,000
	Transmission Owner Labor Costs	$20,000	$220,000	$240,000	$240,000	$160,000	$160,000
	Outside Services/Subcontractor Costs		$40,000	$40,000	$40,000	$40,000	$0
	Miscellaneous Costs						
	SUBTOTAL	$20,000	$380,000	$400,000	$400,000	$290,000	$240,000

Exhibit 7: Example of ISA/ICSA Phase Quarterly Cost Reconciliation

Attachment B: ISA/ICSA Scope Change Process

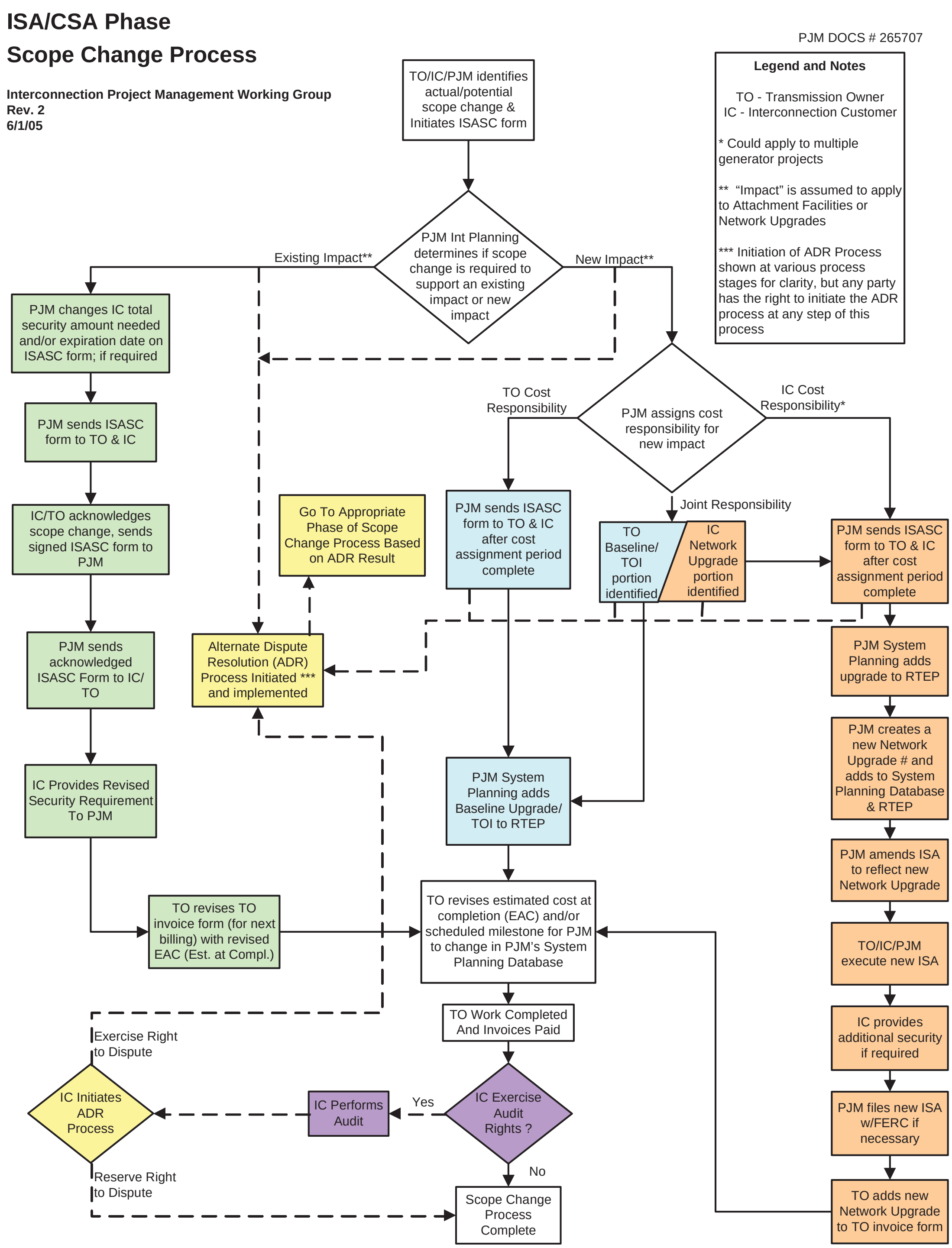


Exhibit 8: ISA/ICSA Scope Change Process Diagram

Generator and Merchant Transmission Project
ISA / CSA Phase Scope Change Form (ISASC Form)

User Guide for completing ISASC Form:
- To be filled in by Initiating Party
- To be filled in by PJM
- To be filled in by Interconnection Customer or Transmission Owner upon acknowledgement of scope change

PJM Scope Change #: ____ (Assigned by PJM)

Scope Change Initiation Date: ____ (Input by Initiating Party)

Initiating Party: ____ (TO, IC, PJM) ____ Contact Name

TO = Transmission Owner *IC = Interconnection Customer*

Scope Change Type:
- Cost ☐
- Schedule ☐
- Other ☐
- ☐ Attachment Facilities / Queue Number: ____
- ☐ Network Upgrade / Network Upgrade Number: ____

Description / Technical Justification for Scope Change (or Potential Scope Change):
(attach additional documentation if necessary)

____

Previous Approved Cost: ____ **Previous Approved Cost Date:** ____

Scope Change Impact (projected):
- Cost: ____ (projected total cost increase / decrease)
- Schedule: ____ (revised in-service date) **Orig. In-Serv Date:** ____
- Other: ____

PJM Disposition on Scope Change Type:
- Existing Impact: ☐
- New Impact: ☐

PJM Interconnection Planning Contact:
- Name: ____
- Date of PJM Disposition: ____

Additional Security Required :
Yes ☐ No ☐ Revised Total Security Amount Required (if "Yes"): ____
Revised Expiration if Security is LOC: ____

Note: PJM disposition is an acknowledgement, and does not constitute an agreement or acceptance of the scope change.

Existing Impact:

IC / TO acknowledgement of Scope Change:
(note: for network upgrades, PJM will send SC form to multiple Interconnection Customers, as required)
Queue No: ____

	Interconnection Customer:		**Transmission Owner:**
IC:	____ *(1)*	TO:	____ *(1)*
IC Contact:	____ *(2)*	TO Contact:	____ *(2)*
Date of Acknowledgement:	____ *(2)*	Date of Acknowledgement:	____ *(2)*
IC Contact Signature:	____ *(3)*	TO Contact Signature:	____ *(3)*

IC or TO Instructions:
(1) Type IC or TO Contact Company Name
(2) Type IC or TO Contact Name, and date of Acknowledgement, then email ISASC Form to PJM
(3) Print copy of ISASC Form, sign in appropriate IC or TO box, then mail original copy to PJM

Note: The purpose of signing this form is to acknowledge the existence of a potential or actual scope change. This acknowledgement does not abrogate any audit rights or dispute resolution rights after subsequent payment per PJM Tariff (OATT) requirements.

New Impact:
PJM to assign cost responsibility between IC and TO for New Impact.

- ☐ Baseline Upgrade — New Baseline Upgrade Number: ____
- ☐ Revised ISA / CSA required — New Network Upgrade Number: ____
- ☐ Joint TO / Gen cost responsibility

Exhibit 9: ISA/ICSA Scope Change Form

Attachment C: Generator As-Built Data Form

The following document contains the format for the standard PJM letter and reply form to Interconnection Customers for providing generator as-built data:

Instructions for As Built Data

Dear Generation Developer:

Data Requirements for PJM RTEPP As Built Data

You had submitted the data necessary for modeling of your Generator Project in the Impact Study phase. As part of the PJM Regional Transmission Expansion Planning Process, Impact Studies are conducted to identify transmission expansion needed to maintain system reliability with new generation injection onto the system. These studies utilize power system analysis techniques such as power flow, short circuit and dynamic simulation, which require that certain data be provided (PJM uses the PSS/E program from PTI, Inc. to perform these analyses).

PJM understands that the data you had provided for the Impact Study may have been typical data for the proposed project. However, now, as your project is completed, or is near completion, PJM requires that you provide unit specific As Built data for use in all future reliability studies. The attached forms list the data you had provided for the Impact Study. Please verify all the data, mark corrections as needed, and certify that the data is As Built and unit specific.

Attachment A: Unit Capability Data Request Form

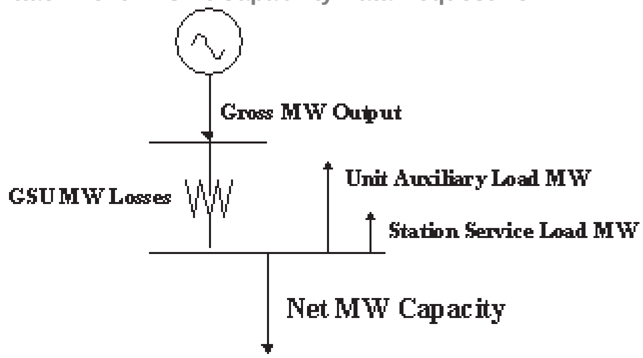
Attachment B: Unit Generator Dynamics Data Request Form

Attachment C: Unit GSU Data Request Form

In addition, if you had provided models for Excitation System, Power System Stabilizer, prime mover – governor etc., they are attached. Any changes to them are to be clearly marked, and returned. Data, in PSS/E models for any additional controls installed for excitation systems, stabilizers, turbine-governors as well as Excitation Limiters, Compensator settings, etc. has to be provided. For each piece of dynamic equipment (rotating or static) to be represented in the simulation, a model must be selected from the PSS/E dynamics library (see Appendix). The manufacturer of your equipment should be able to provide the proper model or an equivalent. In many instances, parameters for the models would be available from the vendor's commissioning studies and tests. If you cannot determine the exact PSS/E model, please forward a Control/Block Diagram for the piece of equipment in question.

Note: material changes to machine capabilities or other controls as originally submitted in the Impact Study Agreement (PJM Open Access Transmission Tariff Attachment ….) must also be formally communicated to the appropriate PJM project contact (Joe Burdis, John Fedorko, or Terry Spencer).

Attachment A: Unit Capability Data Request Form



Net MW Capacity = (Gross MW Output - GSU MW Losses* - Unit Auxiliary Load MW - Station Service Load MW)

1. Queue Letter & Position / Unit Type (CT, ST, etc.):
2. Primary Fuel Type:
3. Maximum Summer (92º F ambient air temp.) Net MW Output**:
4. Maximum Summer (92º F ambient air temp.) Gross MW Output:
5. Minimum Summer (92º F ambient air temp.) Gross MW Output:
6. Maximum Winter (30º F ambient air temp.) Gross MW Output:
7. Minimum Winter (30º F ambient air temp.) Gross MW Output:
8. Gross Reactive Power Capability at Maximum Gross MW Output - Please include Reactive Capability Curve (Leading and Lagging):
9. Individual Unit Auxiliary Load at Maximum Summer MW Output (MW/MVAR):
10. Individual Unit Auxiliary Load at Minimum Summer MW Output (MW/MVAR):
11. Individual Unit Auxiliary Load at Maximum Winter MW Output (MW/MVAR):
12. Individual Unit Auxiliary Load at Minimum Winter MW Output (MW/MVAR):
13. Station Service Load (MW/MVAR):
14. Please provide any comments on the expected capability of the unit:

- GSU losses are expected to be minimal.
  ** Your project's declared MW, as first submitted in Attachment N, and later confirmed or modified by the Impact Study Agreement, should be based on either the 92 oF Ambient Air Temperature rating of the unit(s) or, if less, the declared Capacity rating of your project.

Attachment B: Unit Generator Dynamics Data Request Form

15. Queue Letter & Position / Unit Type (CT, ST, etc.):
16. MVA Base (upon which all reactances, resistance and inertia are calculated):
17. Nominal Power Factor:
18. Terminal Voltage (kV):

Unsaturated Reactances (on MVA Base):

19. Direct Axis Synchronous Reactance, Xd(i):
20. Direct Axis Transient Reactance, X'd(i):
21. Direct Axis Sub-transient Reactance, X"d(i):
22. Quadrature Axis Synchronous Reactance, Xq(i):
23. Quadrature Axis Transient Reactance, X'q(i):
24. Quadrature Axis Sub-transient Reactance, X"q(i):
25. Stator Leakage Reactance, Xl:
26. Negative Sequence Reactance, X2(i):
27. Zero Sequence Reactance, X0:
28. Saturated Sub-transient Reactance, X"d(v) (on MVA Base):
29. Armature Resistance, Ra (on MVA Base):

Time Constants (seconds) :

30. Direct Axis Transient Open Circuit, T'do:
31. Direct Axis Sub-transient Open Circuit, T"do:
32. Quadrature Axis Transient Open Circuit, T'qo:
33. Quadrature Axis Sub-transient Open Circuit, T"qo:
34. Inertia, H (kW-sec/kVA, on KVA Base):
35. Speed Damping, D:
36. Saturation Values at Per-Unit Voltage [S(1.0), S(1.2)]:

In addition, if available please supply the following by sending via attachment to genasbuilt@pjm.com

- Exciter/Governor/Other Models and Block Diagrams
- Generator Performance Curves

- Schematic One-line Diagram showing Unit/GSU/Breakers/Interconnection
- Operating Restrictions and/or Procedures

Attachment C: Unit GSU Data Request Form

37. Queue Letter & Position / Unit Type (CT, ST, etc.):
38. Generator Step-up Transformer MVA Base:
39. Generator Step-up Transformer Impedance (R+jX, on transformer MVA Base):
40. Generator Step-up Transformer Rating (MVA):
41. Generator Step-up Transformer Low-side Voltage (kV):
42. Generator Step-up Transformer High-side Voltage (kV):
43. Generator Step-up Transformer Off-nominal Turns Ratio:
44. Generator Step-up Transformer Number of Taps and Step Size:
45. In addition, please indicate whether the GSU is shared with other units.

Appendix: Generator, Exciter, Governor, Stabilizer, Excitation Limiter and Current Compensating Models

The equipment models listed below are those available for use in PSS/E. Each model can have unique data requirements.

Generator Models
GENROE Round rotor generator model.
GENROU Round rotor generator model.
GENSAE Salient pole generator model.
GENSAL Salient pole generator model.
GENDCO Round rotor generator model with DC offset torque component.
GENCLS Classical generator model.
GENTRA Transient level generator model.
CIMTRl Induction generator model with rotor flux transients.
CIMTR3 Induction generator model with rotor flux transients.

Static Var Compensator (SVC) and Frequency Changer Models
CSVGNl SCR controlled static VAR source model.
CSVGN3 SCR controlled static VAR source model.
CSVGN4 SCR controlled static VAR source model.
CSVGN5 WSCC controlled static VAR source model.
CSVGN6 WSCC controlled static VAR source model.
FRECHG Salient pole frequency changer model.

Excitation System Models
EXDC2 1981 IEEE type DC2 excitation system model.
EXAC1 1981 IEEE type AC1 excitation system model.
EXAClA Modified type AC1 excitation system model.
EXAC2 1981 IEEE type AC2 excitation system model.
EXAC3 1981 IEEE type AC3 excitation system model.
EXAC4 1981 IEEE type AC4 excitation system model.
EXST1 1981 IEEE type ST1 excitation system model.
EXST2 1981 IEEE type ST2 excitation system model.
EXST2A Modified 1981 IEEE type ST2 excitation system model.
EXST3 1981 IEEE type ST3 excitation system model.
ESAC1A 1992 IEEE type AC1A excitation system model.
ESAC2A 1992 IEEE type AC2A excitation system model.
ESAC3A 1992 IEEE type AC3A excitation system model.
ESAC4A 1992 IEEE type AC4A excitation system model.
ESAC5A 1992 IEEE type AC5A excitation system model.
ESAC6A 1992 IEEE type AC6A excitation system model.
ESDClA 1992 IEEE type DClA excitation system model.
ESDC2A 1992 IEEE type DC2A excitation system model.
ESST1A 1992 IEEE type ST1A excitation system model.
ESST2A 1992 IEEE type ST2A excitation system model.
ESST3A 1992 IEEE type ST3A excitation system model.
EXPIC1 Proportional/integral excitation system model.
IEEETl 1968 IEEE type 1 excitation system model.
IEET1A Modified 1968 IEEE type 1 excitation system model.
IEET1B Modified 1968 IEEE type I excitation system model.
IEEET2 1968 IEEE type 2 excitation system model.
IEEET3 1968 IEEE type 3 excitation system model.
IEEET4 1968 IEEE type 4 excitation system model.
IEEET5 Modified 1968 IEEE type 4 excitation system model.
IEET5A Modified 1968 IEEE type 4 excitation system model.
IEEEXl 1979 IEEE type 1 excitation system model and 1981 IEEE type DC1 model.
IEEEX2 1979 IEEE type 2 excitation system model.
IEEEX3 1979 IEEE type 3 excitation system model.
IEEEX4 1979 IEEE type 4 excitation system model, 1981 IEEE type DC3 model and 1992 IEEE type DC3A model.

IEEX2A 1979 IEEE type 2A excitation system model.
SCRX Bus or solid fed SCR bridge excitation system model.
SEXS Simplified excitation system model.

Prime Mover and Governor Models
CRCMGV Cross compound turbine governor model.
DEGOV Woodward diesel governor model.
DEGOV1 Woodward diesel governor model.
GAST Gas turbine governor model.
GAST2A Gas turbine governor model.
GASTWD Woodward gas turbine governor model.
HYGOV Hydro turbine governor model.
IEESGO 1973 IEEE standard turbine governor model.
IEEEG1 1981 IEEE type 1 turbine governor model.
IEEEG2 1981 IEEE type 2 turbine governor model.
IEEEG3 1981 IEEE type 3 turbine governor model.
SHAF25 25 mass torsional-elastic shaft model.
TGOV1 Steam turbine governor model.
TGOV2 Steam turbine governor model with fast valving.
TGOV3 Modified IEEE type 1 turbine governor model with fast valving.
TGOV5 Modified IEEE type 1 turbine governor model with boiler controls.
WEHGOV Woodward Electric Hydro Governor Model.
WESGOV Westinghouse Digital Governor for Gas Turbine.
WPIDHY Woodward P.I.D. hydro governor model.

Power System Stabilizer Models
IEEEST 1981 IEEE power system stabilizer model.
IEE2ST Dual input signal power system stabilizer model.
PTISTl PTI microprocessor based stabilizer model.
PTIST3 PTI microprocessor based stabilizer model.
PSS2A 1992 IEEE duel input signal stabilizer model.
STAB1 Speed sensitive stabilizer model.
STAB2A ASEA power sensitive stabilizer model.
STAB3 Power sensitive stabilizer model.
STAB4 Power sensitive stabilizer model.
STBSVC WSCC supplementary signal for static VAR system.
ST2CUT Dual input signal power system stabilizer model.

Minimum Excitation Limiter Models
MNLEXl Minimum excitation limiter model.
MNLEX2 Minimum excitation limiter model.
MNLEX3 Minimum excitation limiter model.

Maximum Excitation Limiter Models
MAXEX1 Maximum excitation limiter model.
MAXEX2 Maximum excitation limiter model.

Compensating Models
COMP Voltage regulator compensating model.
COMPCC Cross compound compensating model.
IEEEVC 1981 IEEE voltage compensating model.
REMCMP Remote bus voltage signal model.

If you have any questions, please send an e-mail to genasbuilt@pjm.com.

Attachment D: Notification of Intent to Exercise Option to Build

WRITTEN NOTICE OF OPTION TO BUILD PURSUANT TO PJM TARIFF SECTION 3.2.3.1 IN APPENDIX 2 OF ATTACHMENT P IN PART VI

[INSERT DATE]

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497
Attn: Manager, Interconnection and Generation Planning

[INSERT NAME AND ADDRESS OF TRANSMISSTION OWNER]

Re: Notice of Exercise of the Option to Build Pursuant to Section 3.2.3.1 in Appendix 2 of Attachment P in Part VI of the PJM Tariff for **[INSERT NAME OF INTERCONECTION CUSTOMER AND BRIEF IDENTIFICATION OF PROJECT]**.

Pursuant to Section 3.2.3.1 in Appendix 2 of Attachment P of the PJM Tariff, **[INSERT NAME OF INTERCONECTION CUSTOMER]** hereby provides notice of **[INSERT NAME OF INTERCONECTION CUSTOMER]**'s election to exercise the Option to Build. The basis upon which **[INSERT NAME OF INTERCONECTION CUSTOMER]** is exercising this Option to Build is that [check one]:

___ **[INSERT NAME OF INTERCONECTION CUSTOMER]** has engaged in discussions with the Transmission Owner and has reached an agreement in concept with the Transmission Owner to perform portions of the scope of work under the OATT Option to Build provisions.

___ **[INSERT NAME OF INTERCONECTION CUSTOMER]** has engaged in discussions with the Transmission Owner and was unable to agree with the Transmission Owner upon the terms for an Interconnection Construction Service Agreement. The specific terms upon which **[INSERT NAME OF INTERCONECTION CUSTOMER]** and the Transmission Owner were unable to agree and which relate to Transmission Owner's design, procurement, construction and installation of the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades and the efforts undertaken by the Interconnection Customer to resolve such disagreement are as follows: **[INSERT INFORMATION]**____**[ATTACH ADDITIONAL INFORMATION IF NECESSARY]** .

Signed: ________________________________
[INSERT NAME AND TITLE OF AUTHORIZED REPRESENTATIVE WITH AUTHORITY TO SIGN ON BEHALF OF INTERCONECTION CUSTOMER]

Revision History

Revision 06 (10/07/2011):

- Updated PJM's contact information in Attachment C: Generator As Built Data form.

Revision 05 (04/01/2008)

This document is the fifth revision of the PJM Manual for Generation and Transmission Interconnection Facility Construction (M-14C). There are many editorial changes throughout this revision that reflect the current PJM organizational structure and OATT agreement naming conventions. The following is a summary of other significant content revisions in the document that reflect current PJM OATT provisions and PJM procedures:

Introduction:

Updated References section to reflect title change of Manual M14B.

Section 1:

Added "Application to Regional Transmission Expansion Plan (RTEP) section.

Added "Large Generation Resources / Small Generation Resources" section.

Updated "Transmission Owner Facilities" section.

Updated "Network Upgrades" section.

Added "Baseline Upgrades and Transmission Owner Identified Upgrades" section.

Updated "Generator Markets and Operations / Participation in PJM Markets" section.

"ISA / ICSA Implementation Phase Team Role Clarity" section – updated entire section including updates to Exhibit 2 : Interconnection Process Team Role Clarity Diagram to reflect current PJM organizational structure.

Section 2:

Updated "Schedule / Milestone Tracking" section.

Updated "Transmission Owner Milestone Tracking" section.

Updated "Customer Facility Construction Milestone Tracking" section.

Updated "Transmission Owner Cost Estimate Projection Tracking" section.

Updated "PJM Billing Process" section.

Minor edits to "ISA / ICSA Scope Change Process" section.

Minor edits to "Project Meetings" section.

Updated "Project Site Reviews" section.

Added "Suspended Projects" section.

Minor edits to "Project Communication, Reporting and Documentation" section.

Added "Documentation Required by the Transmission Owner prior to Synchronization" section.

Updated “Dispute Resolution” section.

Updated “Project Closeout” section.

Section 3:

Updated OATT references in “Construction Standards” section.

Section 4:

Deleted “Small Resource Interconnection Coordination” section in its entirety and replaced with new “Option to Build” section. Small Resource Interconnection Coordination is now addressed in the more broad “Application to Regional Transmission Expansion Plan (RTEP) section.

Attachment A:

Updated Exhibit 3: Transmission Owner Standard Invoice Form Designation Table.

Deleted TO Standard Invoice Forms A, B, and C; Revised Exhibit numbers.

Attachment D:

Added new Attachment D: Notification of Intent to Exercise Option to Build.

Revision 04 (03/03/06)

This document is the fourth revision of the PJM Manual for Generation and Transmission Interconnection Facility Construction (M-14C). The revisions include clarifications to the “PJM Billing Process” section of Section 2 to reflect changes made by the PJM OATT Housekeeping Filing effective 1/26/06. A summary of the significant revisions in the document that reflect current PJM OATT provisions and PJM procedures is as follows:

Section 2: Revisions to “PJM Billing Process” section to reflect current OATT provisions:

- Feasibility and Impact Study Phase invoicing: clarified timeframe requirement for final invoice submittal to PJM.
- Facilities Study Phase invoicing: clarified timeframe requirement for final invoice submittal to PJM, and added reference to “Quarterly Cost Reconciliation” section.
- ISA / CSA Phase invoicing: clarified timeframe requirement for final invoice submittal to PJM, and added reference to “Quarterly Cost Reconciliation” section.
- Quarterly Cost Reconciliation: Expanded section to clarify requirements for initiation of quarterly cost reconciliation by Interconnection Customer.

Revisions were made on the following pages: 27-31.

Revision 03 (12/23/05)

This document is the third revision of the PJM Manual for Generation and Transmission Interconnection Facility Construction (M-14C). There are many changes in this revision that are editorial changes to reflect the current PJM organizational structure. In addition, the following is a summary of the concept of other significant content revisions in the document that reflect current PJM OATT provisions and PJM procedures:

Introduction: Updated Exhibit 1 to include new PJM Manuals; Added note clarifying the use of the term "Interconnection Customer" throughout manual; Updated "What You Will Find in This Manual" section.

Section 1: Updated "Attachment Facilities" and "Network Upgrades" sections.

Section 1: Updated "Generator Markets and Operations" section.

Section 1: Significant revisions to "ISA/CSA Implementation Phase Team Role Clarity" section to reflect current PJM organizational structure and responsibilities, including updating Exhibit 3.

Section 2: Major revisions to "PJM Billing Process" section to reflect current OATT provisions:

- Expanded update to "Transmission Owner Billing Guidelines" that includes outline of Transmission Owner guidelines by interconnection process phase and a new "Quarterly Cost Reconciliation" section.
- Update to "Interconnection Customer Billing / Statements" section that includes current PJM Interconnection Customer billing procedures and a new "Project Cost Reconciliation Process" section.
- **Section 2:** Added new section titled "ISA / CSA Scope Change Process".
- **Section 2:** Updated "Project Site Reviews" section.
- **Section 2:** Added new "Generator As-Built Data Requirements" section.
- **Section 4:** Changed "Small Resources (10 MW or less)" to "Small Resources (20 MW or less)".
- **Attachment A:** Added new Attachment A: "Transmission Owner Standard Invoice Forms" which includes Exhibits 4-11.
- **Attachment B:** Added new Attachment B: "ISA / CSA Scope Change Process" which includes a process diagram for the ISA / CSA Scope Change Process (Exhibit 12) and the ISA/CSA Scope Change Form (Exhibit 13).
- **Attachment C:** Added new Exhibit C: "Generator As-built Data Form" which includes the standard format for Interconnection Customers to use to provide generator as-built data to PJM.

Revision 02 (04/11/04)

This document is the second revision of the PJM Manual for Generation and Transmission Interconnection Facility Construction (M-14C). The majority of changes in this revision are editorial changes to reflect the current PJM organizational structure, but the following is a summary of the concept of other significant content revisions in the document:

Cover Sheet: Changed "Transmission" Planning Department to "Interconnection" Planning.

Approval: Kenneth S. Seiler, Manager – Interconnection Planning indicated as PJM approving manager.

Section 1: Added reference to ISA phase of Merchant Transmission Projects being covered under Manual M-14C.

Exhibit 2: Added a block titled “Real Estate, Siting, & Permits” just above the “Detailed Design” block in the categories of Attachment Facilities and Network Upgrades.

Section 1: Real Estate, Siting & Permitting was added to major milestone activities for Attachment Facilities and Network Upgrades.

Section 1: Revised Network Upgrades description to include both construction of new transmission lines or reconductoring of existing lines between substations.

Exhibit 3: Updated Interconnection Process Team Role Clarity Diagram.

Section 1 & 2: Updated PJM organizational names to reflect current organizational structure (i.e. Interconnection Planning, Member Services, etc.)

Section 1 & 2: Added reference in multiple locations to “Transmission Owner Identified Upgrades” as being included in the types of upgrades covered by this manual including milestone and cost tracking.

Section 1: PJM Finance – added reference to ISA cost reconciliation.

Section 1: PJM Internal Coordination – added multiple editorial changes throughout section.

Section 2: PJM Billing Process – Divided section into “Transmission Owner Billing” and “Generator Billing / Statements”;

Exhibit 4: Updated PJM Standard Invoice Form

Section 2: Project Closeout – Revised PJM project management guidance for Post Generator Operation Phase to reflect PJM Generation Department as lead.

Revision 01 (04/11/03)

This document is the first revision of the PJM Manual for Generation and Transmission Interconnection Facility Construction (M-14C).

Manual M-14, Revision 01 (03/03/01) has been restructured to create four new manuals, with the addition of a fifth manual:

1. M-14A: “Generation and Transmission Interconnection Process Overview”
2. M-14B: “Generation and Transmission Interconnection Planning”
3. M-14C: “Generation and Transmission Interconnection Facility Construction”
4. M-14D: “Generator Operational Requirements”
5. M-14E: “Merchant Transmission Specific Requirements”

Revision 00 (02/26/03)

This document is the initial release of the PJM Manual for Generation and Transmission Interconnection Facility Construction (M-14C).

Manual M-14, Revision 01 (03/03/01) has been restructured to create four new manuals:

1. M-14A: “Generation and Transmission Interconnection Process Overview”
2. M-14B: “Generation and Transmission Interconnection Planning”
3. M-14C: “Generation and Transmission Interconnection Facility Construction”
4. M-14D: “Generator Operational Requirements”

Attachment D4

Working to Perfect the Flow of Energy

PJM Manual 14D:

Generator Operational Requirements

Revision: 20

Effective Date: July 20, 2011

Prepared by

Generation Department

PJM Manual 14D:

Generator Operational Requirements

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Approval

Approval Date: 07/20/2011

Effective Date: 07/20/2011

David Schweizer, Manager

Generation Department

Current Revision

Revision 20 (07/20/2011):

- Section 4: Data Exchange and Metering Requirements: Edits to Section 4.1.6 to delete outdated SCADA details.
- Section 6: Pre-Operational Requirements: Edits to Section 6.3.3 to update and clarify test energy requirements for new interconnecting resources.
- Section 7: Generator Operations: Added new Section 7.1.3 to address notification of automatic voltage regulator and power system stabilizer status changes to PJM Dispatch.
- Attachment C: New PJM Customer Voice / All Call Communications Request Form: Replaced form with updated version.

July 22, 2011: Corrected Revision number on page 7.

Introduction

Welcome to the ***PJM Manual for Generator Operational Requirements***. In this Introduction you will find information about PJM Manuals in general, an overview of this PJM Manual in particular, and information on how to use this manual.

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by PJM for the operation, planning, and accounting requirements of the PJM Balancing Authority and the PJM Energy Market. The manuals are grouped under the following categories:

- Transmission
- PJM Energy Market
- Generation and transmission interconnection
- Reserve
- Accounting and Billing
- PJM administrative services
- Miscellaneous

For a complete list of all PJM Manuals, go to www.pjm.com and select “Manuals” under the “Documents” pull-down menu.

About This Manual

The ***PJM Manual for Generator Operational Requirements*** is one of the PJM procedure manuals. This manual focuses on the generator markets and operations requirements for generating entities to connect to the PJM system and their responsibilities as signatories to the Operating Agreement of PJM Interconnection, L.L.C.

This manual also refers to other PJM manuals, which define in detail the telecommunication protocols, redundancy requirements, accuracy and periodicity of data, generator obligations, reporting requirements, and accounting procedures established to ensure reliable operation.

The ***PJM Manual for Generator Operational Requirements*** consists of 10 sections and 11 attachments (labeled A through K). Both the sections and the attachments are listed in the table of contents beginning on page ii.

In addition, a process flow diagram is included (Attachment G) summarizing the Generator and Markets Operations process and timelines.

Intended Audience

The intended audiences for this PJM Manual for Generator Operational Requirements are:

- Applicants to the Operating Agreement of PJM Interconnection, L.L.C.
- Generation Owners or those interested in siting and building generation in the PJM Balancing Authority.

- Operations planning staff and plant personnel for generating entities
- PJM Members
- PJM staff

References

There are other PJM documents that provide both background and detail on specific topics. These documents are the primary source for specific requirements and implementation details. This manual does not replace any of the information in those reference documents. The references for the ***PJM Manual for Generator Operational Requirements*** are:

- PJM Manual for ***Control Center and Data Exchange Requirements (M-1)***.
- PJM Manual for ***Transmission Operations*** **(M-3)**.
- PJM Manual for ***Power System Application Data*** **(M-5)**.
- PJM Manual for ***Pre-Scheduling Operations*** **(M-10)**.
- PJM Manual for ***Energy & Ancillary Services Market Operations (M-11)***.
- PJM Manual for ***Balancing Operations*** **(M-12)**.
- PJM Manual for ***Emergency Operations*** **(M-13)**.
- PJM Manual for ***Open Access Transmission Tariff Accounting*** **(M-27)**.
- PJM Manual for ***Operating Agreement Accounting*** **(M-28)**.
- PJM Manual for ***Billing*** **(M-29).**
- PJM Manual for ***Administrative Services for the PJM Interconnection Agreement (M-33).***
- PJM Manual for ***Definitions and Acronyms (M-35)***.
- PJM Manual for ***Certification and Training Requirements (M-40).***

Using This Manual

We believe that explaining concepts is just as important as presenting procedures. This philosophy is reflected in the way we organize the material in this manual. We start each section with the "big picture." Then we present details, procedures or references to procedures found in other PJM manuals.

What You Will Find In This Manual

- A table of contents that lists two levels of subheadings within each of the sections and attachments
- An approval page that lists the required approvals and a brief outline of the current revision
- Sections containing the specific guidelines, requirements, or procedures including PJM actions and PJM Member actions
- Attachments that include additional supporting documents, forms, or tables

- A section at the end detailing all previous revisions of this PJM Manual

Section 1: Generator Markets and Operations

Welcome to the Generator Markets and Operations section of the **PJM Manual for Generator Operational Requirements**. This section presents the following information:

- A summary of the Markets and Operations phase of the Generator Interconnection Process (see "*Generator Interconnection Process: Markets and Operations Phase*").
- Rules for assigning a commercial plant/unit name to new generation (see "*Generator Commercial Naming Convention*").

1.1 Generator Interconnection Process: Markets and Operations Phase

The Generator Markets and Operations phase is initiated during the Interconnection Service Agreement (ISA) and Construction Service Agreement (CSA) implementation phase of the generator interconnection process. The Interconnection Coordination (IC) Project Manager coordinates the activities of PJM Internal Coordination (Operations Planning, System Operations, CR&T, PJM*net*, EMS) and the Generation Owner to complete the Generator Markets and Operations activities during this phase. After the ISA and CSA implementation phase, PJM team leadership is transferred from the IC Project Manager to PJM Customer Relations and Training (see Attachment H for Implementation Team Role Clarity Diagram).

The table below describes PJM Generator Markets and Operations interconnection process flow and timeline (see Attachment G for PJM Markets and Operations Process Flow Diagram).

Activity	Duration		Manual Reference
	Activity	Cumulative	
Activity 1: PJM Interim Capacity Study A. System planning updates new generation project list with current generator in-service date	(1-10d) 10 days	10 days	-
Activity 2: EMS Model Update A. PJM Transmission and Interconnection Planning provides modeling information and commercial name for plant & units to System Operations B. System Operations submits Model Change requests to Engineering Support for database updates C. New database tested & installed on production EMS	(11-80d) 70 days	80 days	Section 4

Activity	Duration		Manual Reference
	Activity	Cumulative	
Activity 3: Establish Metering Plan A. PJM Client Manager sets up meeting to discuss new generation with customer • Project Schedule • Revenue and real-time options • PJM metering requirements • Business plan for unit B. Customer applies for *e*Tool Accounts based on business plan C. Confirm metering plan between Market Settlements, Operations Planning & Market Operations D. Finalize Point Exchange List	(81-100d) 20 days	100 days	Section 4
Activity 4: PJM*net* Installation A. PJM*net* Telecommunications form sent to customer B. PJM*net* form filled and returned by customer C. ARCOM Director requested by Customer (if applicable) D. Installation services & components (ARCOM directors, circuits, etc) ordered E. Delivery of installation components F. PJM*net* Installation completed	(101-190d) 90 days	190 days	Section 4
Activity 5: Metering & Communications Installation A. Customer Firewalls complete (if applicable) B. Communication paths for RTU & GMS complete C. PJM Real-Time Operations Support Department and Customer verify telemetered data accuracy.	(181–190d) 10 days	190 days	Section 4
Activity 6: Data Exchange Testing A. Begin Testing with PJM B. Verify data exchange accurate C. Communications Online	(191-200d) 10 days	200 days	Section 6
Activity 7: Confirm Voice, Communications & Dispatch Operations A. PJM Technical Architecture Department initiates installation of data communications & circuit testing B. Facilities Department installs voice communications for dispatch services	(191-200d) 10 days	200 days	Section 6
Activity 8: CR&T review Operations Requirements A. Pre-scheduling and Scheduling Requirements B. Unit Commitment C. Dispatching of Generation D. Switching Requirements E. Training and System Operator Certification F. Critical Information and Reporting Requirements G. Compliance with Synchronization and Disconnection Procedures	(191-200d) 10 days	200 days	Section 7

Activity	Duration		Manual Reference
	Activity	Cumulative	
Activity 9: PJM review of Data & Markets A. Market Settlements & operations approve unit plans and establish market accounts	(201-210d) 10 days	210 days	-
Activity 10: Capacity Status Granted A. Customer applies for Cap Mod status via eCapacity B. PJM Capacity Adequacy & Planning grant capacity status	(211-215d) 5 days	215 days	-

Exhibit 1: Generator Markets and Operations Process Flow and Timeline

1.2 Generator Commercial Naming Convention

New generation in PJM is assigned a commercial plant or unit name by PJM and the developer prior to its incorporation in the PJM model. The commercial names must be initiated at the execution of the Interconnection Service Agreement or even earlier based on the nature of the project. The following convention has been established for assigning commercial plant or unit names to new generation projects.

1. The commercial names will be assigned by PJM in collaboration with a representative from the developer, PJM Interconnection & Generation Planning, Capacity Adequacy Planning, Market Settlements and Power System Coordination Departments.
2. Where possible, the commercial names will be associated with the assigned name given by the plant owner to maintain consistency during construction and the future operation of the plant.

NOTE: The name of the developer is generally recognized as unacceptable as future projects by the same developer may cause similar confusion.

3. In the event that existing units are already named after the assigned name given by the plant owner, and it is deemed inappropriate to add additional sequential numbers to the existing units' naming convention, a local geography name (in a Township, Borough or Town designation) or PJM substation will be used based on the physical location of the generation.
4. In the event that a local geography name has already been used in another part of PJM, a local landmark will be identified and used for the PJM naming convention.
5. In any event, the generator name will be unique and differentiate itself from other names already used within the PJM system, or neighboring systems if known.
6. The assigned PJM name will be circulated by the Power System Coordination Department to Interconnection & Generation Planning, Capacity Adequacy, Member Relations, Performance Compliance and Market Settlements departments for sign off/ approval before publication to all of PJM and the customer. After the final sign off is received, the Power System Coordination Department will circulate the name, queue number, etc. to all PJM appropriate parties and the customer.

Section 2: Responsibilities of Generation Owners

Welcome to the *Responsibilities of Generation Owners* section of the ***PJM Manual for Generator Operational Requirements***. In this section you will find the following information:

- A listing of significant obligations of Generation Owners in the PJM Balancing Authority (see "*Generator Owners' Responsibilities*").

2.1 Generator Owners' Responsibilities

A Generation Owner in PJM is a Member that owns or leases with rights equivalent to ownership facilities for the generation of electric energy that are located within the PJM Balancing Authority or within the PJM West Region. Membership in PJM entails execution of the Operating Agreement and satisfactions of the data requirements, operational and market coordination, committee support and financial obligations contained within the agreement.

The responsibilities for a Generator Owner within PJM that are defined below are required to maintain the safe and reliable operation of the PJM Interconnection. The generator owner under PJM's direction takes all actions possible to maintain PJM Interconnection reliability. The responsibilities identified below are consistent with the NERC Functional Model for interconnected system operation.

This list is a collection of significant operational responsibilities and obligations of a Generator owner that are included in the PJM OA, PJM RAA, PJM West RAA and the PJM Procedure manuals. It is not intended to be an all-inclusive list of every responsibility and obligation of a Generator owner.

A Generator Owner:

- Is subject to applicable code of conduct and other applicable confidentiality agreements. (PJM OA Sect. 1.7.4a)
- Takes action to maintain local reliability and public safety. (PJM OA Sect. 1.7.4a)
- Operates generation system facilities under the direction of PJM. (PJM OA Sect. 1.7.4f)
- Operates generation facilities in accordance with all federal and state regulations and PJM procedures. (PJM OA Sect. 1.7.4f , PJM RAA Schedule 2.B.2)
- Maintains generation facilities in accordance with good utility practice and PJM standards. (PJM OA Sect. 1.7.4g, PJM RAA Schedule 2.B.2)
- Establishes capability of its generation facilities and provides this information to PJM and the Local Control Center (LCC) if the facilities are designated PJM capacity resources. (PJM Manual M-21 Section 1)
- Provides annual baseline and real time updates of fuel limited generating units to PJM during emergency conditions. (PJM Manual M-13 Section 5)
- Complies with the data information and metering requirements established by PJM. (PJM Manual M-14D Section 4, PJM West RAA Schedule 8.1)

- Maintains assigned voltage schedules and responds promptly to specific requests and directions of the PJM dispatcher or the LCC dispatcher in event of low/high voltage situations. (PJM Manual M-12 Section 5 Voltage Control)
- Follows directions from the LCC for switching interconnection points.
- Helps maintain a reliable transmission system by providing reactive capability curve information to PJM as soon as the information is available. (PJM Manual M-03 Section 3 Generating Unit Reactive Capability)
- Complies with procedures called for by PJM or the LCC in event of operating limit violations and other emergency conditions. (PJM Manual M-13)
- Provides real-time operations information to PJM in compliance with PJM procedures. (PJM Manual M-14D Section 4, PJM RAA Schedule 2.B.3)
- Provides information about planned, maintenance and unplanned outages of generation facilities to PJM. (Manual M-10 Section 2, PJM West RAA Schedule 8.3)
- Supplies engineering data for generating unit models to PJM. (PJM Manual M-05 Section 1)
- Develops, documents, and communicates operator guidance, as necessary. (PJM Manual 14 Section 4 Training)
- Plans and coordinates generation outages.
- Works with PJM to mitigate identified reliability concerns for planned generation outages. (Manual M-10 Section 2)
- Large generating plant owners with market operations centers (MOCs) must maintain continuous staffing and meet all of the communication and information system requirements defined by PJM. (PJM Manual M-01, PJM OA Sect. 1.7.5, PJM RAA Schedule 2.B.3)
- Personnel Requirements (PJM Manual M-01 Section 2 Control Center Staffing) - Generation system operators shall:
- Be competent and experienced in the routine and abnormal operation of generators within interconnected systems.
- Be accountable to take any action required to maintain the safe and reliable operation of the generation facility.
- Have thorough knowledge of PJM procedures and their application.
- Have a working knowledge of NERC and MAAC guides and how they coordinate with PJM manuals.
- Have an understanding of routine protection schemes for PJM generation facilities.
- Have knowledge of how to evaluate desired system response to actual system response.
- Have knowledge of and be able to evaluate and take action on equipment problems in generation facilities.
- Have knowledge of the general philosophy of system restoration and the philosophy and procedures of their company as well as that of the pool.

- Have initial and continuing training that addresses the required knowledge and competencies and their application in system operations.
- Have current PJM Generation System Operator Certification
- Plant Personnel should have a working knowledge of switching and tagging procedures for the generation facility
- Develops, documents, and maintains switching and tagging procedures (OSHA 29 CFR Part 1910.269).
- Is accountable for directing station forces in generation system switching activities
- Follows up on significant system events with an investigative process to analyze, document and report on operating abnormalities. (PJM Manual M-13)
- Generator owners providing black start services will follow procedure outlined by PJM (PJM Manual M-10 Section 2, PJM Manual M-12 Section 4, PJM Manual M-27 Section 10)

Section 3: Control Center Requirements

Welcome to the *Control Center Requirements* section of the ***PJM Manual for Generator Operational Requirements***. In this section you will find the following information:

- A description of the generation control center categories within PJM (see "*PJM Control Center Categories for Generating Entities*").
- A summary of control center requirements for generation owners (see "*Control Center Requirements for Generating Entities*").
- Voice communication requirements for generation owners (see "*Voice Communication Requirements for Generating Entities*").

This section presents a summarized version of the requirements for control centers established by generating entities for reliable operation in the PJM Balancing Authority. For more details, please refer to the ***PJM Manual for Control Center and Data Exchange Requirements***.

3.1 PJM Control Center Categories for Generating Entities

PJM Members may be involved with transmission operations, generation operations, load service operations, and/or PJM Energy Market participation. For each of these operations, a different control center category has been designated.

For generation operations, the control center category is the Market Operations Center (MOC), which is established by participating generating entities to facilitate their responsibilities regarding the security of the PJM Balancing Authority.

For each of the services listed, data is exchanged between the MOC, PJM and one or more of the other PJM member control center categories – Local Control Centers (LCCs), Load Service Centers (LSCs), and Marketing Centers, corresponding to Regional Transmission Owners, Load Serving Entities and Marketers.

- Generation Scheduling Services
- EMS Services
- Historical EMS Data Services
- Energy Transaction Services
- Long-term Planning Services
- PJM Administration Services

3.2 Control Center Requirements for Generating Entities

This section discusses the control center requirements for the PJM generating entities, which are similar to those of other PJM members. For efficient and reliable participation in the PJM Balancing Authority, the following requirements for the members' control center computer systems, communications, facilities, and staffing have been established.

3.2.1 Computer System Requirements

The generation owner's MOC serves as the primary operating link to the PJM control center and includes computer system hardware and software that supports their responsibilities under the Agreement. The list below summarizes the computer system requirements for all PJM member control center categories including the MOC.

The control center is required to:

- Achieve a 99.95% availability level for its computer hardware and software
- Prepare and implement a backup and archiving plan
- Follow PJM computer system security procedures
- Follow PJM system maintenance procedures
- Ensure expansion capability of its computer system

3.2.2 Communications Requirements

Telecommunications (voice and data) circuits, which must be reliable and secure, should be tested regularly and/or monitored online, with special attention given to emergency channels.

3.2.3 Facilities Requirements

The MOC facility considerations include the physical space housing operations staff and, if appropriate, a computer room, communications room, and power supply area. The specific implementation of control center facilities considerations should be appropriate for the nature of the computer systems and communications equipment installed. The following list summarizes the facilities requirements for a generation owner.

The control center is required to:

- Provide an environment suitable for its equipment and personnel
- Ensure a stable and secure supply of AC power for its equipment
- Restrict access to its work area to avoid distractions
- Establish a protocol for information flow to control room personnel
- Install smoke and fire detection and protection equipment
- Comply with PJM backup procedures

3.2.4 Control Center Staffing Requirements

MOCs should be staffed 24 hours a day, 7 days a week, with 99.9% availability of personnel who are trained for all normal and emergency situations that are anticipated. Training courses for operations, technical staff and maintenance personnel should be conducted. The PJM Customer Relations and Training Department can provide assistance, as required, for training related to PJM operations.

As of March 1, 2003, PJM requires all generation and transmission operators who operate on PJM systems to undergo the PJM Certification examination. Further details are provided in PJM Certification and Training Requirements (Manual 40) and Section 6 of this manual.

For details on MOC control room operator staffing levels and operational guidelines as well as staffing guidelines in the event of loss of an EMS, please refer to the PJM Manual for ***Control Center and Data Exchange Requirements***.

3.3 Voice Communication Requirements for Generating Entities

This section summarizes the PJM requirements for primary voice and facsimile communications and alternate voice communications for control centers including the MOCs established by generating entities.

3.3.1 Dispatch Voice and Facsimile Communications

The dispatch voice system provides high-priority voice communications between PJM and various PJM Members. The dispatch voice system hardware consists of the All Call system, Ring Down circuits, and manual dial circuits. Equipment at PJM includes an IPC Tradenet and BT digital switch and a Nortel Meridian PBX. Access and interfacing to the communications service providers is configured so that either switch can operate in stand-alone mode, but economy and performance are optimized when they are operating together.

Communications via facsimile machines is another redundant means of exchanging information between PJM operations, accounting, and planning personnel and all categories of PJM Members.

3.3.2 Alternative Voice Communications

The dispatch voice system (All Call, Ring Down, and manual dial PBX) is designed to provide voice communications during normal circumstances. Should the PJM primary All Call System, Ring Down, Manual Dial, and Facsimile Communication fail, the following systems provide alternative communication capabilities in the event the normal system is not effective for some reason:

- Business Voice System
- Cellular Telephones
- Satellite Telephones

Section 4: Data Exchange and Metering Requirements

Welcome to the *Data Exchange and Metering Requirements* section of the PJM Manual for ***Generator Operational Requirements***. In this section you will find the following information:

- Description of computer system data exchange methodology and requirements. (See "*Computer System Data Exchange*").
- Rules pertaining to generator metering. (See "*Data Exchange and Metering Requirements*").

4.1 Computer System Data Exchange

4.1.1 PJM*net* Communications System

PJM*net* is the primary wide-area network for communicating Control Center voice and data to and from PJM. PJM*net* will support:

- Inter-Control Center Communications Protocol (ICCP) data links to Control Centers.
- SCADA links to plants via remote terminal units (RTUs) using Distributed Network Protocol (DNP3.0 Implementation Level 2). In the event that the participant(s) cannot handle TCP/IP transport for the DNP implementation, an ARCOM director can be used to facilitate this connection.
- Generator All-Call to Control Centers.

PJM*net* is a dual-redundant Frame Relay network that connects member Control Centers and plants to PJM’s primary and emergency backup Control Centers. Private voice and data permanent virtual circuits (PVCs) are provided to link to PJM's primary and emergency backup Control Centers. The number of physical interfaces and their capacity will be determined by the impact of your facilities on overall PJM Operations.

For installation of PJM*net*, new generator participants are required to complete and return the PJM*net* Telecommunications Request Form (*see* Attachment B) which will be sent to them.

4.1.2 Energy Management System (EMS)

Information is exchanged between the PJM Interconnection L.L.C. (PJM) EMS computers and the EMS systems of PJM Members. Please note that the following description of EMS-to-EMS Data Communications is based on Member company systems that support both Generation and Transmission functions; a Generation Control Center or a Transmission Control Center would need to support the appropriate subset of these functions. The system primarily supports real-time functions such as PJM Balancing Authority network monitoring, generation control, and security analysis.

4.1.3 PJM EMS Communication Protocols

All new Control Center to Control Center links will be implemented using the Inter-control Center Communications Protocol (ICCP) standard. ICCP is a comprehensive, international standard for real-time data exchange within the electric power utility industry. It is intended to support inter-utility, real-time data exchange critical to the operation of interconnected systems.

A detailed description of the format and content of the ICCP Conformance Blocks (as adapted to PJM needs) may be found in the PJM document *ICCP Network Interface Control Document (NICD)*, dated March 27, 2000.

Request this document from PJM Customer Relations. Other documents that may be supplied to PJM Member-applicants include documents describing data types and message structures as well as supplying detailed information on network protocol and line discipline.

4.1.4 EMS Data Exchange

EMS data is exchanged between each Member's system and the PJM EMS computer system, on one of several fixed cycles, as well as on demand, by exception, and interactively.

- The EMS data sent cyclically from PJM Members to the PJM includes:
    - Data needed for the PJM control programs
    - Data needed for monitoring generation
    - Data needed for monitoring transmission
    - Data needed for monitoring interchange
- The EMS data sent cyclically from the existing PJM EMS to each PJM Member's EMS includes:
    - System control data
    - Generation and transmission information required for monitoring and security analysis programs
    - Area Regulation data

Cyclic data exchanged at the fast scan rate (two seconds) is used to develop the PJM Area Control Error (ACE) and associated individual PJM Member Area Regulation megawatt values. Cyclic data exchanged at a slower scan rate (ten seconds) is used to develop dispatch control values, security monitoring, and data tracking.

Cyclic data sent hourly from PJM Members defines the accumulated energy values. PJM Members are responsible for the accuracy of the data they send to PJM. A maximum of 1% overall inaccuracy in the repeatability of data from transducers or potential transformers/current transformers is allowed for instantaneous monitored values (real time data).

Further information may be found in Section 5 of the PJM Manual for Control Center and Data Exchange Requirements.

Hourly MWh readings data must be the same values that are recorded in the history registers of the revenue meters at the metered locations. Billing data has a higher overall accuracy requirement than real time data. Regular calibration of PJM Member metering is necessary to keep the data as accurate as possible. Further information may be found in Section 4 of the PJM Manual for Control Center and Data Exchange Requirements.

Data exchanged either by exception, on demand, or interactively between PJM Member's and the PJM's EMS systems include:

1. Breaker, disconnect, and line status changes, with associated data quality code information.
2. Hourly MWh values for tie-lines and generators.
3. Alarm messages in text and data format.
4. Pre-formatted reports in text and data format.

The following exhibit summarizes the data requirements and exchange rates for the cyclic data exchanged between PJM EMS and PJM Members' EMS systems.

Data	Exchange Rates
From PJM Members to PJM	
Data needed for PJM Control Programs (AGC tie-line MW, Locally Sampled Frequencies)	Fast Scan Rate (2 seconds)
Data needed for monitoring generation (Generation MW Telemetry)	Slow Scan Rate (10 seconds)
Data needed for monitoring transmission (Line/Transformer Flows, Voltages)	Slow Scan Rate (10 seconds)
Accumulated Energy Values	Hourly Exchange Rate
Breaker, disconnect, and line status changes	By Exception (on event)
From PJM EMS to PJM Member's EMS	
AGC Regulation Signals	Fast Scan Rate (2 seconds)
AGC Individual Unit MW Set Points	Slow Scan Rate (10 seconds)
Dispatch control values	Slow Scan Rate (10 seconds)
Generation MW Telemetry	Slow Scan Rate (10 seconds)
Line/Transformer Flows and Bus Voltages	Slow Scan Rate (10 seconds)

Exhibit 2: Summary of EMS Data Requirements and Exchange Rates

Each PJM Member is responsible for determining data-quality indicators for all data transmitted to PJM. Both failed individual values and any value calculated using a failed point must be flagged. When a point fails for an extended period, a manual update of the point's value is necessary once every thirty minutes to keep the data as accurate as possible.

4.1.5 EMS Model

New generators of more than 10 MW or any new capacity resource intending to set real-time LMP must be explicitly modeled in the PJM EMS network model. The EMS network model is updated twice in a year, during the months of April and November. For a new generator to be included in an EMS model update, all technical modeling information must be submitted to PJM before the following deadlines:

Target In-Service Date	EMS Model Update Date	Info Submitted Before
May 1 to November 30	April	February 15
Dec 1 to April 30 (next year)	November	September 15

Exhibit 3: Deadlines for Modeling Data to Be Submitted

4.1.6 SCADA—Supervisory Control and Data Acquisition

The PJM SCADA system allows PJM to communicate directly with individual generators or smaller Control Centers. The system uses computer, database and digital communications technology to implement the use of common standards in an open environment, independent of any particular vendor or proprietary protocols system.

The PJM SCADA system is designed to allow transfer of both generation and revenue data via one system. A data concentrator (e.g. Remote Terminal Unit, Generator Control System, etc.) is located at the Member's site, and, after collecting data from the industrial metering equipment, communicates with PJM's SCADA system using either DNP 3.0, Level 2 (Distributed Network Protocol) or ICCP (Inter-Control Center Protocol).

The system allows real-time bi-directional transfer of analog and digital data into the system database for storage and real-time transfer to the EMS system.

Information can also be sent from the EMS system through the SCADA system via ICCP and/or DNP 3.0 to the customer, allowing for Automatic Generation Control (AGC), analog set point, device control, and other functions.

<u>Real-Time Customer Connection</u>

All customers connecting to PJM in real-time must be able to support a minimum data model or connection to PJM will not be allowed.

All data items, regardless of type, are collected and disseminated at the same 2-second rate. Instantaneous MW and MVAR information is collected on the same data scan as Integrated MWh and MVARh. The MWh and MVARh quantities represent the integrated energies of the previous hour. This configuration minimizes the number of data scan types and simplifies the definition of the customer information in the SCADA database.

Components of the real time information will be periodically collected and stored temporarily in the SCADA/EMS internal database. This allows the hourly revenue information to be extracted from the instantaneous data stream for eventual transmission to the PJM Market Settlement System.

<u>Non-Real-Time Customer Connection</u>

This mode of non-real-time data transfer is necessary to support customers that request connection to PJM for revenue information transfer, but do not meet PJM's minimum requirements for instantaneous data transfer.

All customers connecting to PJM in a non-real-time mode must be able to support a minimum data model or connection to PJM will not be allowed.

Physical connection to the customer will be accomplished prior to data transfer, and depending on the transport, disconnection may take place immediately after data transfer is complete.

A refresh of the instantaneous information from this class of customer may be initiated by the PJM SCADA every 5 to 15 minutes.

Sample Configurations

The wide variety and unknown quantity of possible Members dictates that the system cannot be locked into a fixed configuration. Member size and type of installation (new or existing) determine the installation configuration and possible features.

Some of the possible configurations are shown below. All metering installations below accommodate one or more metering points. Please note that the following table is a guideline only. Specifics of the installation may dictate an alternate configuration.

	Metering Installation				
Generator Size	**IED**	**Data Model**	**Configuration**	**Monitoring Period**	**Protocol**
Very Small (<10 MW)	Data Concentrator	All data types available OR Collect MWh and MVARh only	Dedicated TCP/IP with encryption gateway over secure internet.	2 Second Periodic	DNP 3.0
Small (10–100 MW)	Data Concentrator	All data types available	Dedicated TCP/IP with encryption gateway over secure internet.	2 Second Periodic	DNP 3.0
Medium (>100–500 MW)	Data Concentrator	All data types available	Dedicated TCP/IP with single router to redundant frame relay networks.	2 Second Periodic	DNP 3.0 or ICCP
Large >500 MW)	Data Concentrator, SCADA, EMS or GMS	All data types available	Dedicated TCP/IP with dual routers to redundant frame relay networks–Single Local Area Network	2 Second Periodic	DNP 3.0 or ICCP

Exhibit 4: Guidelines for Metering Installations

The table below shows the types of equipment necessary for exchanging data with PJM.

Situation	Real-Time & Billing Metering	Operational Changes Sent via	Generator Bidding
Minimum Changes/Minimum Cost	Via Host Utility; MWh entered in **eMeter** for PJM billing.	Host Utility.	Via Host Utility
<10 MW injection to grid or unit runs infrequently.	RTU at plant, single DNP network connection with encryption gateway.	Internet, through **eMKT**	Internet, through **eMKT**
>10 MW and <100MW injection to grid; unit runs continuously.	RTU at plant, single DNP network connection with encryption gateway.	Internet, through **eMKT**	Internet, through **eMKT**
>100 MW and <500MW injection to grid; unit runs continuously.	RTU at plant, redundant network connection, single router.	Internet, through **eMKT**	Internet, through **eMKT**
>500 MW injection to grid; unit runs continuously	RTU at plant or ICCP via SCADA system, redundant ICCP or DNP network connection, dual routers.	Internet, through **eMKT**	Internet, through **eMKT**
Control Center for Multiple Units	Install metering and use SCADA System; redundant ICCP network connection to PJM, dual routers.	Internet, through **eMKT**	Internet, through **eMKT** and **PJM*net***

Exhibit 5: Equipment Types for Data Exchange with PJM

The following exhibit displays a typical multi-unit metering and data flow configuration.

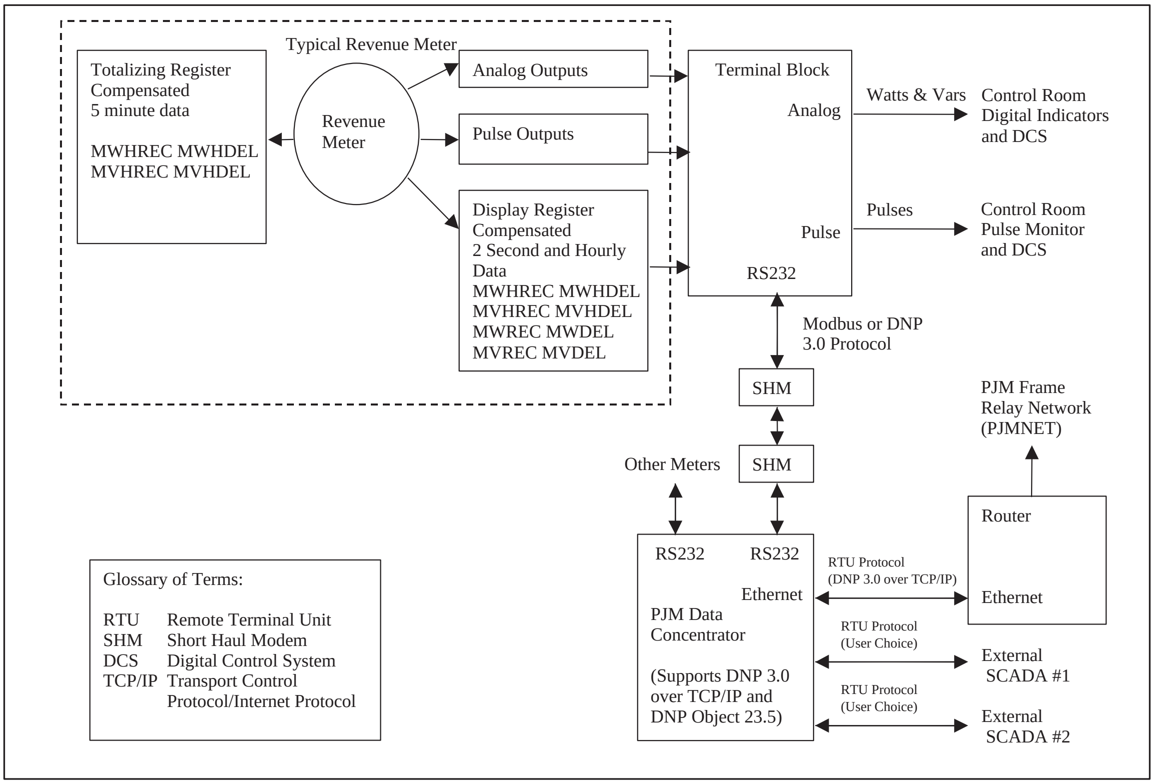


Exhibit 6: Typical Multi-Unit Metering and Data Flow Configuration

The following exhibit shows PJM precision requirements for real-time and revenue metering information.

Real Time Instantaneous Data Sent To PJM	
Frequency	1/1000th of HZ (i.e. 60.001 Hz)
Voltage	1/10th of kV (i.e. 69.1 kV)
Real Power MW	1 MW integer (i.e. 52 MW) required, but PJM will accept greater precision if available
Reactive Power MVAR	1 MVAR integer (i.e. 42 MVAR) required, but PJM will accept greater precision if available
Regulation Capability MW	1 MW integer (i.e. 10 MW)
Real Time Instantaneous Data Sent From PJM	
Lambda cost signal	1/10th of $/MWh (i.e. 23.1 $/MWh)
Regulation Signal (AR)	1 MW integer, + or – (i.e. 10 MW)
Revenue Data Sent To PJM	
MWh Delivered and Received	1/1000th of MWh (i.e. 20.001 MWh)
MVARh Delivered and Received	1/1000th of MVARh (i.e. 15.002 MVARh)

Exhibit 7: PJM Real-Time and Revenue Data Precision Requirements

4.2 Data Management and Metering Requirements

4.2.1 Data Management and Security

Each Generator shall supply the necessary planning and operating data required to accurately model, schedule, and monitor the PJM system. Specific data requirements for power system applications, production cost and reliability assessment are located in the PJM Manual for Data Management. This data must include, but is not limited to:

- Expected unit operations and desired market service/segment.
- Stability study data.
- Step-up transformer data (impedance and tap setting).
- Relay settings and generator protection package.
- Generator operating curves and associated test data (reactive/saturation).
- Special operating restrictions (including environmental).
- Identification of equipment ownership and maintenance responsibilities.
- Test data for metering calibration, backup communications, and relays.
- Any other data required to certify a generator as eligible to participate in a specific market segment or service.

The Generator shall also provide telemetered data via DNP 3 protocol to the Supervisory Control and Data Acquisition (SCADA) system or via ICCP to the PJM Energy Control System computer. Computer systems and metering shall be consistent with PJM practices, and compatible with PJM computer and communication systems.

Examples of this required data include: MW, MVAR, MWh, voltage, and equipment status (i.e., open/close). The data is to be provided in accordance with standards contained with the ***PJM Manuals for Control Center and Data Exchange Requirements, Pre-Scheduling Operations, Energy & Ancillary Services Market Operations,*** and ***Balancing Operations***. PJM may require the ability to disconnect the facility from the PJM system via the Local Control Center's SCADA system.

It is required that data be sent to PJM automatically. In the event that the data is not automatically received by PJM, the generator operator shall call PJM with the required data at intervals specified by PJM. The generator operator must correct any problems associated with the failure of data-transmission equipment within a reasonable time.

The Generator and Local Control Center shall promptly exchange all information relating to all conditions which affect (or could affect) the operations of any facility reporting data.

The Generator shall communicate the outage of any data communication equipment connecting the facility to the PJM system in accordance with the following requirements:

- Each facility will be assigned to one of the PJM Local Control Centers as its primary contact, unless arrangements are made to communicate information directly to PJM. The assignment is based upon the voltage level of the connection to the Transmission System and the geographic location of the facility.

- All planned and maintenance outages of data communications equipment requiring the involvement of PJM personnel must be requested by the Generator. All information must be in a format defined by PJM.
- Advance notification of planned and maintenance outages must meet the requirements defined in the PJM Manual for Pre-Scheduling Operations.

Additional specific data requirements are defined in other sections of this manual. All records must be retained in accordance with NERC, FERC and PJM data retention requirements. All back-up voice and data communication plans and test procedures must be documented and provided to PJM.

4.2.2 Metering Plan

In order to establish a metering plan for new generation, a PJM Client manager is assigned. A kick-off meeting between the client manager and the generation owner will be held to discuss the following issues:

- Project schedule including testing/commercial dates
- Options for providing real-time and revenue data
- Business plan for the unit(s) - The new participant is required to apply for the necessary eTool accounts based on the individual business plan.
- PJM metering requirements - To satisfy these requirements, all generators connecting to the PJM system are required to install and operate metering and related equipment capable of recording and transmitting all voice and data communications. Specific data metering requirements depend on the size and business plan of the generator connecting to the PJM system.
- All generators that participate in the PJM market as a capacity resource must provide instantaneous power and reactive power flow (real-time telemetered) data, regardless of MW size.
    - Distributed generators modeled at less than 10MW must provide instantaneous power data at the BES injection point within 10% of hourly MWh revenue accumulated data
- Generators that **<u>are not</u>** participating as capacity resources must provide instantaneous real power and reactive power flow data only if:
    - They are 10 MW or larger, or
    - They are greater than 1 MW and connected at a bus operating at 34 kV and above
- Very small generators (less than 10 MWs) may not be required to supply real-time telemetered information. PJM will evaluate requests not to supply real-time telemetry. Evaluation will consider network security and market requirements. Generators that are not required to supply real-time (two-second scan) metering will not be eligible to set real-time LMP. Revenue-related information is necessary for very small units. This information can be obtained from the local utility or manually read by the customer and supplied to PJM. If desired, a direct connection to PJM can be established.

- Generators that are required to supply real-time and revenue information can supply this through the local utility's connection to PJM, or if desired, via a direct connection from the generator to PJM. Real-time information will be collected at a two-second data rate, and revenue information will be collected hourly. The revenue information represents the accumulated energy for the previous hour.

The required revenue information is necessary to satisfy the needs of PJM's Market Settlements program. The real-time information is required for PJM's Energy Management Applications (State Estimator, Security Analysis, etc.).

4.2.3 Metering for Individual Generators

PJM does not require generator owners to directly connect to PJM, but leaves this as an option if it enhances the owner's ability to participate in PJM markets and functions. A generation owner has a number of options with respect to information acquisition and transmission.

At the most basic level, a generator owner can negotiate data transmission to and from PJM through the local utility or transmission facilities owner. This allows the generator owner the flexibility to use already proven and acceptable methods of data transfer to minimize initial start-up costs and procedures, while meeting all of the current requirements for providing data to PJM. This basic communication can be supplemented with the use of the Internet-based eSchedules and eData, further expanding the data transfer capabilities between the customer and PJM without a direct connection to PJM.

A generator owner may decide that direct connection to PJM makes the best business sense, so facilities have been provided to make that connection as simple and cost effective as possible. The generator owner that decides to connect directly to PJM will be required to meet requirements determined by the net MW produced and the markets in which the generator owner decides to participate.

Additionally, information about PJM's operational status and other types of non market-sensitive data can be directly communicated through these same facilities. This type of communication is not required but is provided by PJM as a value-added service to enhance participation in PJM markets.

PJM’s data requirements are described in two categories: real-time information and non real-time information. Either or both of these types of data can be directly communicated to PJM depending on the customer requirements and operating agreement with the local utility.

<u>Real-Time Data</u>

Real-time or instantaneous information is defined as data required by PJM that determines system security and stability as well as congestion and LMP. The minimum data model for real-time data transmission requires:

- Instantaneous Net (+/-) MW for each unit, measured on the low-side of generator step-up transformer
- Instantaneous Net (+/-) MVAR for each unit, measured on the low-side of generator step-up transformer

- Distributed generators modeled at less than 10MW must provide Instantaneous Net (+/-) MW and MVAR at aggregation point (BES injection point) based on an agreed upon algorithm.

Additional transmitted data may include bus voltages, circuit breaker status, and other data.

Account Metering

Non-real-time or revenue information is needed by PJM's applications and systems that determine Grid Accounting and Energy Interchange. The minimum data-model for revenue data transmission requires:

- Hourly Compensated MWh delivered for each unit.
- Hourly Compensated MWh received for each unit.
- Hourly Compensated MVARh delivered for each unit (not currently required).
- Hourly Compensated MVARh received for each unit (not currently required).

Note: The MVARh revenue information will be considered a requirement in the event that PJM implements a Reactive Power Market.

Additional information on PJM Metering requirements may be found in Sections 4 and 5 of the ***PJM Manual for Control Center and Data Exchange Requirements***.

Data Communications Systems and Requirements

Data communications systems and requirements are dependent on the type of facilities connected to PJM, category of generator(s) based on Net MW, and market participation. The Generator owner with facilities directly connected to PJM must, at a minimum, provide PJM with the contact name and voice phone number of person or persons responsible for the continuous operation of that equipment.

Additionally, the Generator owner with multiple connected facilities may have to provide centralized contact and control information to minimize confusion and downtime resulting from equipment failure. Additional data or control room functionality may be necessary and will be determined on a per-generator basis.

For questions about Data and Metering Requirements, contact PJM's Customer Relations at 610-666-8980.

Section 5: Participation in PJM Markets

Welcome to the *Participation in PJM Markets* section of the ***PJM Manual for Generator Operational Requirements***. In this section you will find the following information:

- Description of marketing options available to Generator Owners (see "*Marketing Options*").
- Description of required/mandatory services (see "*Ancillary Services*").
- Description of PJM marketing tools that are currently available (see "*Marketing Tools*").
- Description of the PJM two-settlement system (see "*Description of the Two-Settlement System*").
- Role of Generation in the PJM pre-scheduling and scheduling processes (see "*Pre-Scheduling and Scheduling*").
- Description of the resource commitment process (see "*Resource Commitment*").

5.1 Marketing Options

There are several marketing options available to generator owners in the PJM Interconnection L.L.C. (PJM) Balancing Authority, but not every generating unit qualifies to participate in every PJM market. The marketing options available to generation owners depend on the physical characteristics of the unit(s) as well as the business philosophy of each owner. Additional information on all of the PJM markets may be found at the heading "PJM Markets" on the PJM Web site.

5.1.1 PJM Wholesale Energy Market

The PJM wholesale energy market includes both day-ahead and real-time markets.

- In the day-ahead market, Locational Marginal Prices (LMPs) are calculated for each hour of the next operating day based on generation offers, demand bids, and bilateral transaction schedules submitted in advance. The next-day schedule is developed using least-cost, security-constrained resource commitment and security-constrained economic dispatch programs.
- During the operating day, hourly clearing prices are determined by the actual system operations security-constrained economic dispatch.

By entering the day-ahead market, participants may commit to energy prices and transmission congestion charges in advance of real-time dispatch. Additionally, a participant may submit price-sensitive demand bids, increment offers, decrement bids or may inform PJM of the maximum congestion charges it is willing to pay.

PJM receives bids and offers for next-day energy until 1200 (noon); LMPs are posted at 1600 each day, along with hourly schedules. The Balancing market re-bidding period opens at 1600 and continues until 1800. Throughout the operating day, PJM continually re-evaluates individual generation schedules and sends updates as required. Settlements take place in each market; the settlements in the Balancing Market take into account any variations from the scheduling planned in the Day-Ahead Market.

Please refer to the heading *"Description of the Two- Settlement System"* later in this section.

5.1.2 Regulation Market

The PJM Regulation Market provides PJM participants with a market-based system for purchase and sale of the Regulation ancillary service. Generation owners submit resource-specific offers to provide Regulation, and PJM utilizes these offers together with forecasted LMPs and generation schedules produced by the Unit Dispatch system to calculate an hourly Regulation Market Clearing Price (RMCP). This clearing price is then used to determine the credits awarded to providers and charges allocated to purchasers of the Regulation service.

- To be eligible to participate in the Regulation Market, the resource must meet these criteria:
- Generation resources must have a governor capable of AGC control.
- Resource must be able to receive an AGC signal.
- Resource must demonstrate minimum performance standards, as set forth in the PJM Manuals.
- New Resources must pass an initial performance test (minimum 75% compliance required). PJM will rely on owner's data for initial qualification. Resources qualified as of June 1, 2000 are grandfathered.
- Resource must exhibit satisfactory performance on dynamic evaluations.
- Resource MW output must be telemetered to the PJM control center in a manner determined to be acceptable to PJM.

Generators may choose to participate in the PJM Regulation Market. Qualification for this program requires each participating resource to achieve specified performance standards and to be equipped with Automatic Generation Control (AGC).

Generators submit their availability and price on a day-ahead basis; prices for Regulation are capped at $100 per MWh. Compensation for Regulation is based on the Regulation Market clearing price, which includes the Regulation bid plus any lost-opportunity cost from the energy markets. For more details on regulating unit eligibility and the regulation market business rules, please refer to the ***PJM Manuals for Pre-scheduling Operations*** and ***Energy & Ancillary Services Market Operations***.

5.1.3 Synchronized Reserve Market

The PJM Synchronized Reserve Market provides PJM participants with a market-based system for purchase and sale of the Synchronized Reserve ancillary service. Generation owners submit unit-specific offers to provide Synchronized Reserve, and PJM utilizes these offers together with forecasted LMPs and generation schedules produced by the Unit Dispatch system to calculate an hourly Synchronized Reserve Market Clearing Price (SRMCP). This clearing price is then used to determine the credits awarded to providers and charges allocated to purchasers of the Synchronized Reserve service. For more details, please refer to the ***PJM Manual for Energy & Ancillary Services Market Operations***.

5.1.4 Capacity Credit Market

Owners of generation serving as a PJM Capacity Resource may submit bids to the PJM Daily Capacity Credit Market or the longer-term Capacity Credit Market. On a daily basis, any excess capacity is required to be bid into the Capacity Credit Market.

Bids are submitted using the eCapacity tool. Through eCapacity, generators may create bilateral capacity transactions or submit capacity modifications to increase or decrease the installed capacity rating of a unit. Load Serving Entities may enter Active Load Management modifications and view peak load and obligation data.

5.2 Ancillary Services

The following ancillary services are provided by PJM in coordination with the generating entities and are required/mandatory services, calculated after-the-fact in the billing process.

5.2.1 Reactive Supply and Voltage Control from Generating Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities under the control of the Balancing Authority operator are operated to produce or absorb reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources must be provided for each transaction on the Transmission Provider's transmission facilities.

The amount of reactive supply and voltage that must be supplied with respect to the Transmission Customers transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider. The charges for such service are shown in Schedule 2 of the Open Access Transmission Tariff. Also, new generators have the option of filing with FERC to receive a revenue stream for their reactive output.

After consultation with the Generator Owner regarding necessary step-up transformer tap changes, PJM will provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. The Generation Owner shall provide notification to PJM when the changes have been implemented. Generation Owners shall update reactive curves (D-curves) via eDart to ensure PJM and TO EMS Security Analysis results are accurate.

5.2.2 Regulation and Frequency Response Service

Regulation and Frequency Response service provides the continuous balancing of resources (generation and interchange) with load and maintains the Interconnection frequency at sixty cycles per second (60 Hz). Within PJM, Regulation and Frequency Response service is accomplished through the Regulation Market, which is described in this section under *“Marketing Options.”*

5.3 Marketing Tools

Additional information on all PJM Marketing tools can be found on the PJM home page at PJM Tools.

5.3.1 eMKT

This is the Market User Interface for participating in the PJM Wholesale Energy Markets, specifically the Day-Ahead Market, the PJM Regulation Market, and the PJM Synchronized Reserve Market. Users may submit resource-specific generation offers with operating details, fixed or price-sensitive demand bids, as well as bilateral transactions and financial increment and decrement bids. The PJM eMKT interface also enables viewing public and private day-ahead results and managing portfolios. New users should submit information under User Registration from the Market User Interface.

5.3.2 Markets Database

The PJM Markets database, a subsection of the eMKT tool, contains generator information including owner, plant, operating limits, and resource availability details. This data allows PJM to reliably pre-schedule, schedule and dispatch generation within the PJM Balancing Authority.

Generators may initially submit cost-based or price-based bids to PJM. Cost-based bids are subject to the rules approved by the PJM Board. Cost-based bidders are allowed to submit start-up and no-load costs daily but may be audited for accuracy.

Price-based bids are not subject to audit, but start-up and no-load costs can only be bid in biannually. All generators must also have a cost-capped bid on file. After a price-based bid has been submitted, the generation owner no longer has the option to return to cost-based bidding for that unit.

5.3.3 PJM eSchedules

This tool is used by Generation Owners in PJM to submit their internal PJM energy schedule data. All PJM internal transactions, including load and generation interchange adjustment modeling and implicit internal spot market schedules, are handled through the PJM eSchedules system. New users who are PJM Members may register to use eCapacity and eSchedules by submitting the User Registration form from the login screen.

5.3.4 PJM eCapacity

This electronic tool enables a competitive installed-capacity market and fulfills the data reporting requirements for generation owners with granted capacity status. Users of eCapacity can view peak loads and obligations in any zone, shop for PJM installed capacity, and create bilateral transactions to buy or sell unit-specific or capacity credits. New users may register to use eCapacity by submitting the User Registration form from the login screen.

5.3.5 eDART

The Dispatcher Application and Reporting Tool (DART) provides communication with PJM for generation operators regarding unit outage requests, updates to reactive capability curves (D-curves) and AVR status.

When fully implemented, operators will also use this tool to submit data for Supplemental Status Reports (SSRs), Restoration Drill Data, Instantaneous Reserve Checks (IRCs), and Morning Status Reports. Additional applications may be integrated in eDART in the future. User registration is available from the PJM Web site.

5.3.6 eGADS

The Generator Availability Data System (GADS) enables the operators of generation units to submit performance data into PJM records for determination of unit availability. Units are tracked on a rolling twelve-month basis for demand equivalent forced outages (EFORd) to determine their unforced capacity. Operators are required to submit data monthly using the eGADS interface. New plant operators should contact PJM for user set-up.

5.4 Description of the Two-Settlement System

5.4.1 Market Participants

Market Sellers

Market participants owning PJM-designated Capacity Resources must submit offers into the Day-Ahead Market unless the resource(s) is unavailable due to outage. If a Capacity Resource is not scheduled in the Day-Ahead Market, the Market Seller may revise its offer and submit bids into the Real-Time Market or may self-schedule.

A self-scheduled generator must submit hourly MW schedules and may submit a price at which they would reduce output (decrement bid).

An offer of generation must not exceed the $1000/MWh price cap. An offer from a Capacity Resource remains in effect until specifically superseded by another offer. A resource may submit offer data for up to seven days in the future.

If the notification time, start-up time or time-to-reach-minimum of a Capacity Resource exceeds 24 hours, the Market Seller must submit binding offers for the next seven days. Market Sellers offering combined-cycle units must make available either the schedule for the combustion turbines (CTs) or the schedule for the combined-cycle unit.

PJM

PJM receives, analyzes and posts data via the Market User Interface. To maintain reliable operation, PJM may perform supplemental resource commitments after the day-ahead schedule is posted. Additionally, as a result of analysis, PJM may limit its dependence on combustion turbines to provide reserves. These limits are based on past performance of the resources.

Data posted by PJM includes:

- Total hourly MW quantities as specified in demand bids
- Forecasts of total hourly demand for the next four days and peak demand for the subsequent three days.
- Hourly LMP values for the next operating day at the completion of the day-ahead scheduling process.

- The schedule of demand, supply and bilateral transactions for private viewing by market participants.

5.4.2 The Day-Ahead Market

The Day-Ahead Market allows participants to purchase and sell energy at binding day-ahead prices. It also allows transmission customers to schedule bilateral transactions at binding day-ahead congestion charges. These congestion charges are based on the differences in Locational Marginal Prices (LMPs) between the transaction source and the sink.

Load Serving Entities (LSEs) will submit hourly demand schedules, including any price-sensitive demand, for the amount of demand that they wish to lock in at day-ahead prices. Any generator that is a PJM-designated capacity resource must submit a bid schedule into the day-ahead market unless it is self-scheduled or unavailable due to outage.

Other generators have the option to bid into the day-ahead market. Transmission customers may submit fixed or dispatchable bilateral transaction schedules into the day-ahead market and may specify whether they are willing to pay congestion charges or wish to be curtailed if congestion occurs in the day-schedule.

All spot purchases and sales in the day-ahead market are settled at the day-ahead prices. After the daily quote period closes, PJM will calculate the day-ahead schedule based on the bids, offers and schedules submitted using scheduling programs that perform least-cost, security-constrained resource commitment and dispatch for each hour of the next operating day. The day-ahead scheduling process will incorporate PJM reliability requirements and reserve obligations into the analysis. The resulting hourly schedules and LMPs represent binding financial commitments to the Market Participants. Financial transmission rights (FTRs) are accounted for at the day-ahead LMP values.

<u>Timelines</u>

The day-ahead scheduling/bidding timeline for the two-settlement system consists of the following time frames:

- 1200: Day-Ahead Market bid period closes. All bids must be submitted to PJM. At 1200, PJM runs the two-settlement software to determine the hourly commitment schedules and the LMPs for the day-ahead market. This is the first resource commitment run, to determine the resource commitment profile satisfying fixed demand, price-sensitive demand bids, and operating reserve objectives. This commitment analysis also includes external bilateral transaction schedules and external resource offers into the PJM Day-Ahead Market.
- 1600: Based on the first resource commitment, PJM posts the day-ahead hourly schedules and LMPs on the Web-based Market User Interface (MUI) for the two-settlement system. PJM also makes these results available in downloadable files, via the MUI or a dedicated communication link.
- 1600-1800: PJM opens the Balancing Market offer period. During this time, Market Participants submit revised offers for resources not selected in the first commitment.
- 1800: The Balancing Market offer period closes. PJM performs a second resource commitment, which includes the updated offers, updated resource availability information, updated PJM load forecast information and load forecast deviation.

- 1800: Operating Day. PJM may perform additional resource commitment runs, based on updated PJM load forecasts and updated resource availability information. PJM sends out individual generation schedule updates to specific generation owners.

5.4.3 The Real-Time Balancing Market

The Balancing Market is based on real-time operations. It provides financial incentives for generators to follow the real-time economic dispatch instructions issued by PJM.

Generators designated as PJM Capacity Resources that are available but not selected in the day-ahead scheduling may alter their bids for use in the balancing market. If not altered, the original bids remain in effect for the Balancing Market.

Balancing prices are calculated on the actual system operating conditions as described by the PJM state estimator. LSEs will pay balancing prices for any demand that exceeds their day-ahead scheduled quantities. The LSEs will also receive revenue for demand deviations below their scheduled quantities.

Generators are paid balancing prices for any generation that exceeds their day-ahead scheduled quantities and will pay for generation deviations below their scheduled quantities. Transmission customers pay congestion charges for bilateral transaction quantity deviations from day-ahead schedules. All spot purchases and sales in the balancing market are settled at the balancing prices.

5.4.4 Grid Accounting

There are several services within the Interchange Energy Market for which PJM calculates charges and credits that are allocated among the PJM Members. (Detailed explanations may be found in the ***PJM Manual for Operating Agreement Accounting***.)

PJM provides accounting for these services:

- Spot Market Energy—Energy bought or sold by PJM Members through the PJM Energy Market.
- Regulation—The capability of a specific resource with appropriate telecommunications, control, and response capability to increase or decrease its output in response to a regulating control signal (see ***PJM Manual for Balancing Operations***).
- Operating Reserves—The amounts of generating Capacity scheduled to be available for specified periods of an Operating Day to ensure reliable operation.
- Synchronized Reserve—Capability of a specific synchronized generating or demand resource that can be provided within ten (10) minutes (see ***PJM Manual for Energy & Ancillary Services Market Operations***).
- Transmission Congestion—The increased cost of energy delivered when the Transmission System is operating under constrained conditions.
- Transmission Losses—Energy requirements in excess of load requirements due to the energy consumed by the electrical impedance characteristics of the Transmission System.

- Emergency Energy—Energy bought from or sold to other Balancing Authorities by PJM due to emergencies either within the PJM Balancing Authority or within the other Balancing Authorities.
- Metering Reconciliation—Metering errors and corrections that are reconciled at the end of each month by a meter error correction charge adjustment.
- Unscheduled Transmission Service—Service that PJM Members can provide to or receive from the New York ISO and are credited or charged according to the Operating Agreement.
- Ramapo PAR Facilities—Carrying charges collected from PJM RTOs paid to the New York ISO for the Phase Angle Regulators (PARs) at Ramapo and charged according to the Operating Agreement.
- Capacity Credit Market—Capacity credits bought or sold through the PJM daily and monthly capacity credit markets.

These services are applicable to the different types of market participation, as shown in the following table. Each service is further broken down in the billing statement (see the ***PJM Manual for Billing***).

	Market Buyers	**Market Sellers**	**Transmission Customers**
Spot Market Energy	X	X	
Regulation	X	X	
Synchronized Reserve Market	X	X	
Operating Reserves	X	X	
Transmission Congestion			X
Transmission Losses			X
Emergency Energy	X	X	
Meter Reconciliation	X	X	
Unscheduled Transmission Service	X	X	
Capacity Credit Market	X	X	

Exhibit 8: Applicable Services as defined by Market Participation

PJM Energy Market accounting is designed to operate on a balanced basis. That is, the total amount of the charges equals the total amount of credits; there are no residual funds. With certain exceptions, each of the individual services also operates on a balanced basis. Charges and credits for a particular service (such as regulation) offset each other exactly. In certain cases, excess charges or credits in one service category are used to offset charges and credits for another service.

Accounting Input Data

At the end of each operating hour, PJM collects information regarding actual operations during the hour. This information is recorded either by the PJM System Operators or by automated systems. The market accounting processes use this information as input data. Other accounting input data is provided from various systems and databases. This information includes data describing PJM Members' installed generating resources, scheduling information for PJM Members' transactions, and Transmission System parameters, such as loss factors determined annually by PJM system planning staff.

5.5 Pre-Scheduling and Scheduling

One of the principal purposes of the PJM pre-scheduling activities is to establish and maintain a database containing current generator information. Now named the Markets Database, it was previously known as the Unit Commitment Database (UCDB). The name changed with the introduction of the two-settlement system. The database contains resource-specific information including company, plant, operating limits, resource availability, etc., and is used during pre-scheduling, scheduling and dispatching. This data allows PJM to schedule generation resulting in the lowest overall production cost while maintaining the reliability of the PJM Balancing Authority.

Each Generator must advise PJM on a daily basis of its generation schedule and/or bid price for the following day. Generators must abide by these schedules unless approval for deviation is secured from PJM or unless equipment problems beyond the Generator's control prevent operation at the specified schedule.

Specific details concerning the data requirements and deadlines for the pre-scheduling and scheduling processes are contained in the ***PJM Manuals for Pre-Scheduling Operations*** and ***Energy & Ancillary Services Market Operations***.

5.6 Unit Commitment

5.6.1 Process

The resource commitment process includes the Markets Database (formerly the Unit Commitment Database or UCDB) and the functions of HydroScheduler and the Dispatch Management Tool (DMT). The Markets Database is a large database containing information on each resource that operates as part of the PJM Interchange Energy Market.

The Resource Scheduling and Commitment (RSC) programs provide an optimized economic commitment schedule for thermal generating units and are the primary tool used to determine commitment of resources that have operating constraints requiring multiple-day operation.

The Hydro Calculator computes hourly reservoir elevations and hydro plant generation from input river flows and hydro plant discharges.

The DMT runs in the corporate computer system and performs accounting and operations functions with respect to combustion turbines. Additional information on the PJM resource commitment process may be found in the following manuals:

- PJM Manual for Pre-Scheduling Operations
- PJM Manual for Energy & Ancillary Services Market Operations
- PJM Manual for Billing

5.6.2 Data Requirements

The two-settlement technical software develops the Day-Ahead Market results based on minimizing production cost to meet the demand bids and decrement bids. The results incorporate PJM Balancing Authority security constraints and reliability requirements necessary for reliable operation.

Two-Settlement Technical Software

The PJM Two-Settlement Technical Software is a set of computer programs performing security-constrained resource commitment and economic dispatch for the Day-Ahead Market. The individual programs are:

1. Resource Scheduling and Commitment (RSC)—Performs security-constrained resource commitment based on generation offers, demand bids, increment offers, decrement bids and transaction schedules submitted by participants and based on PJM Balancing Authority reliability requirements. RSC will enforce physical resource-specific constraints that are specified in the generation offer data and generic transmission constraints that are entered by the Market Operator.
2. Scheduling, Pricing and Dispatch (SPD)—Performs security-constrained economic dispatch using the commitment profile produced by RSC. SPD calculates hourly unit generation MW levels and LMPs for all load and generation buses for each hour of the next operating day.
3. Study Network Analysis (STNET)—Creates a powerflow model for each hour of the next operating day based on the scheduled network topology, the generation and demand MW profile produced by SPD and the scheduled Tie Flow with adjacent Balancing Authorities. STNET performs AC contingency analysis using the contingency list from PJM EMS and creates generic constraints based on any violations that are detected.

After the close of the generation re-bidding period at 1800, the RSC is the primary tool used to determine any change in steam unit commitment status. Commitment changes are based on minimizing the additional startup costs and costs to operate steam units at economic minimum, as well as providing sufficient operating reserves to satisfy the PJM Load Forecast.

The purpose of this second phase of resource commitment is to ensure that PJM has scheduled enough generation in advance to meet the PJM Load Forecast for the next operating day and for the subsequent six days. CT units are included in the scheduling process and are scheduled in the Day-Ahead Market. However, the decisions concerning actual operation of pool-scheduled CT units during the operating day are not made until the current operating hour in real-time dispatch.

Section 6: Pre-Operational Requirements

Welcome to the *Pre-Operational Requirements* section of the ***PJM Manual for Generator Operational Requirements***. In this section you will find the following information:

- Description of data exchange testing procedures (see "*Data Exchange Testing*").
- Description of required training procedures (see "*Training and System Operator Certification*").
- Pre-operational requirements of Generation for coordination with dispatch (see "*Coordination with Dispatch*").

6.1 Data Exchange Testing

6.1.1 Introduction

PJM interfaces with a wide range of different customer systems. Procedures for verifying that these systems are ready to go into production operation vary by type of system, its functionality, the number of data points, etc. For purposes of illustration, test requirements for a Generation Management System (GMS) are provided here. A GMS is typically the most comprehensive system used for generator interconnection, and therefore, has the most comprehensive testing requirements.

By definition, a GMS provides a centralized control center interfacing via remote terminal units to numerous generating locations. This data is then sent to PJM via the Inter-control Center Communication Protocol (ICCP) link.

6.1.2 Test Requirements for New Generator Management Systems (GMS)

In general, PJM is responsible for testing data connections between a Member company's GMS hardware and PJM's computers. PJM generally does not test communication between a Member's remote terminal units (RTUs) and the Member's GMS computers. When using a new GMS system, the Member Company should test input of all RTU information/data into their GMS before involving PJM.

Communication testing by PJM uses the TEST System, which tests the communication of information from the Member's GMS database into the PJM database. If changing from the previous GMS to the new one, testing will be enhanced if all of the data available in the existing GMS is simultaneously available to the new GMS. Where possible, testing of any new GMS should be done from the company's parallel test system connected to the PJM TEST system.

PJM does not require that any RTU be connected to the Member's GMS during testing with PJM's TEST system. The Member Company may have as many RTUs connected to their (new) GMS as they wish while testing with PJM's TEST system. Testing with PJM's TEST shall not reduce the availability of accurate telemetry to PJM's Operational EMS.

The Member Company must comply with these PJM naming and telemetry conventions (if applicable to the installation):

- Transmission line MW and MVAR
- Transformer MW and MVAR

- Generating unit MW and MVAR
- Station kV
- Frequency
- Transformer taps

In addition, the Member Company must support transmission of breaker/disconnect status. Testing should include several scheduled/intentional communication re-starts initiated by both PJM and the testing company.

After the Member Company has successfully completed testing with PJM's TEST System, PJM will schedule the test of the company's new GMS with all telemetry available. The test should comply with the following criteria:

- Real-time metering via ICCP datalink connection must be in place before testing in order to maintain reliability of the PJM Balancing Authority.
- The Member Company must make known when its test period is starting.
- During this time, the Member Company shall maintain the old GMS in such a state that it can be restored in total within one hour upon demand by the PJM Supervising Dispatcher if the new GMS is not performing to the Dispatcher's satisfaction.

Link-up time for ICCP Links: The link shall be 99.5% operational or higher. PJM shall qualitatively judge whether or not the data is acceptable.

Error Rate Determination for ICCP Links: The error rate is taken from the console log on the communications server. The time between each clui_down and clui_up messages shall be used to determine the down time. The total uptime shall be determined by the time between the first clui_up messages and the last clui_down message.

6.1.3 Communications Considerations

For companies using the TASE.2 (ICCP) protocol, the following specific items should be considered:

- The requirements for communication with PJM over TASE.2 are detailed in two documents: the ***PJM ICCP NICD*** and the ***PJM ICCP Communications Workbook***, which can be obtained from your PJM Project Manager.
- The ICCP association form must be received by PJM for PJM to properly configure the link before any testing can start.
- Before testing with PJM's TEST system, it is desirable for the Member Company's vendor to communicate with the PJM DEV system over a dial-up modem.
- Since TASE.2 runs over TCP/IP and, at PJM both the Real Time EMS and TEST systems are connected, the Member company and PJM must take special precautions to prevent the Member company test GMS from communicating directly to the PJM Real-Time EMS system.

6.1.4 Offline Test

- Both companies will bring the data link up between the Member Company and PJM and verify that all sessions Conformance Blocks (for ICCP) are up.

- Both companies will compare values between the Member company and PJM such as:
  1. Line and transformer flows: All 500 kV, 345 kV, selected 230 kV and tie lines (MW and MVAR),
  2. Generator values
  3. Testing Company Totals
  4. Frequency
  5. Lambda - Cost Signal - verify unit response to cost signal
  6. Regulation (dump plots)
  7. Breaker status
  8. Voltages
  9. Transformer taps
  10. Capacitor VARs
  11. Reactors
  12. Reactive Transfer Limits
  13. Transfer values
  14. Pond levels, integrated values
  15. Loss factors
- Both companies will check the points in the various reporting cycles to see that they are updating at the proper scan rate.
- PJM will have the Member company tel-fail several lines, including facilities at different voltage levels. Companies will compare values, singly and several at once, adjacent and separated in the PTID list. Both companies check for the appropriate flag set in the status code section of the Value Table for the corresponding PTID.
- PJM will have the Member Company restore tel-fails and compare values.
- PJM will have the Member company tel-fail breaker status out-of-service for selected breakers and then restore, checking status each time.
- PJM will have the Member company change a transformer tap and verify.
- PJM will bring up PJM GMS displays and check values on:
  1. bar charts (Member company’s generation)
  2. voltages
  3. world map
  4. associated portion of transmission system
- PJM will change scheduled frequency (e.g., 59.98 Hz). Member Company will verify the change.
- PJM will change the system cost. Member Company will verify the change.

- PJM will suspend regulation. Member Company will verify they are receiving a zero regulation signal.
- PJM will unsuspend regulation. Member Company will verify they are receiving the regulation signal the PJM is dispatching.
- PJM will cause the ACE signal to go from a lower to a raised position. Member Company should verify both the correct value and direction.
- PJM will send any one Emergency Procedure (using EPIS display) and comment in the Comments Section. Member Company will verify the Emergency Procedures Message, comment and dispatch time.

6.1.5 Online Test

The Online Test involves the connection of the Member Company's new GMS system to the PJM's RT EMS system. The communications should be accurate and reliable. All systems will be closely watched by the test director over a period of time. During this test, repeat as many steps as possible from the Offline Test above when the new link is brought on line.

6.1.6 Dispatcher Testing Procedure and Computer-to-Computer Testing

Verify Key Control Items on PJM's Displays:

1. PJM will request the Member Company to tel-fail a value for one of their transmission facilities.
2. Check for the appropriate flag on the left side of the PJM Null display and in the status code section of the TAFLA display.
3. PJM will change scheduled frequency (e.g. 59.98 Hz) and verify that the Member Company received the change. PJM will return the frequency signal to normal.

Verify Network Applications

PJM will verify that the State Estimator Application operates properly with the member's equipment included in the PJM Network Model. Specifics of this verification will be based on the overall impact of the member's equipment on the PJM system.

Verify Accounting Data

After confirming connectivity to the customer's metering equipment, PJM will verify the validity and accuracy of individual test data being transmitted. Test data will also be made available from SCADA to Markets Settlements to verify that it is being accurately transmitted.

The generation owner must designate the applicable network model bus(es) at which each revenue meter is to be priced. Once accounting data is successfully being stored in the Market Settlements Database, the generation owner and the Market Settlements staff will compare the accounting data being sent from the generator to the data being received by the PJM settlements system to confirm that it is being transferred accurately.

Verify Real-Time Operational Scheduling

After confirming connectivity, use the Unit Hourly Update page (in eMKT) with the current date to simulate a change in a unit's operational status. PJM will verify that the change was received.

6.2 Training and System Operator Certification

6.2.1 Training

Training of system operators and other operating personnel is essential to promoting reliable operation of the system. Formal PJM sponsored training programs for system operators and others are available on a regularly scheduled basis. Standard PJM system operator training courses include: Initial Training Program (ITP - basic concepts and PJM operating procedures, 4 weeks), Generation MOC Orientation (MOC – generation dispatch procedures, 5 days), and the annual PJM System Operator Seminar (Seminar – updates and refreshers on PJM procedures, 4 days, done 6 times or more yearly).

Key topics in PJM System Operator Training include: normal and emergency operating procedures, data reporting requirements, and other specific procedures for generation and transmission system operators. Other PJM courses for operating personnel are delivered on an “as needed” basis. All PJM training courses are posted on the PJM Web site and available to all PJM members.

6.2.2 PJM System Operator Certification

PJM has instituted a System Operator Certification Program to promote the reliability of the PJM systems. The Certification Program went into effect as of March 1, 2003. The PJM certification program is required of all generation and transmission system operators who operate on the PJM systems are in direct communication with PJM system operators located at any PJM Control Center, and perform daily operations-related functions at the direction of PJM system operators during normal, emergency and/or system restoration states. PJM system operators must also be PJM certified.

System Operators who were operating on the PJM systems on March 1, 2003 had until February 28, 2005 to become PJM Certified. System Operators who begin operating on the PJM systems after March 1, 2003 are allowed two years to become PJM Certified.

PJM System Operator Certification and Training Requirements are documented in PJM Manual 40, entitled Certification and Training Requirements.

Certification Examinations

There are two PJM Certification Exams: one for Generation System Operators and the other for Transmission System Operators. Details are as follows:

System Operators who participate in the real-time operations of the PJM system by dispatching generation resources and performing other generation-related real-time duties of a Market Operation Center (MOC), PJM or PJM West system operator are required to complete and pass the PJM Generation Examination.

System Operators who participate in the real-time operations of the PJM transmission systems and perform other transmission-related real-time duties of a Local Control Center

(LCC), PJM or PJM West system operator are required to complete and pass the PJM Transmission Examination.

For further information go to: http://www.pjm.com/training/certification/sys-op-cert.aspx.

6.3 Coordination with Dispatch

6.3.1 Operation

Every Generator interconnected with and synchronized to the transmission system must at all times coordinate operation with PJM and the Local Control Center, providing all necessary and requested information and equipment status, to assure that the electrical system can be operated in a safe and reliable manner.

This coordination includes, but is not limited to:

1. Supplying generator net-MW and MVAR output.
2. Supplying frequency and voltage levels.
3. Scheduling the operation and outages of facilities including providing advanced notification.
4. Coordinating the synchronization and disconnection of the unit with the PJM or local system operator.
5. Providing data required to operate the system and to conduct system studies.
6. Providing documented start-up and shutdown procedures including ramp-up and ramp-down times.
7. Following PJM-directed plant operation during emergency and restoration conditions.
8. Following PJM-directed operation during transmission-constrained conditions.

   Note: for Distributed generators modeled at less than 10MW PJM requires the generators to be able to follow PJM direction via SCADA or an agreed upon alternative method.

6.3.2 Communication

To ensure reliable operations and responsiveness, Generators must be properly staffed to support a 7-day, 24-hour contact for communications. Data must be sent to PJM automatically. In the event that the data is temporarily not received by PJM, the Generator Operator must call PJM with the operating data at intervals specified by PJM. The Generator Operator shall correct any problems associated with the failure of equipment within a reasonable time.

The Generator and Local Control Center shall promptly exchange all information relating to all conditions which affect (or could affect) the operations of any facility reporting data.

The Generator shall communicate the outage of any electrical equipment connecting the facility to the PJM system in accordance with these requirements:

1. Each facility will be assigned to one of the PJM Local Control Centers as its primary contact, unless arrangements are made to communicate this information directly to

PJM. This assignment is based upon the voltage level of the connection to the Transmission System and the geographic location of the facility.

2. All planned and maintenance outages of electrical equipment requiring involvement of PJM personnel must be requested by the Generator. The appropriate information must be in a format defined by PJM.

6.3.3 Test Energy

Test energy is energy generated for a predetermined period by a new resource interconnecting with the PJM Balancing Authority for the first time. The test energy period starts with Stage Two energization (initial synchronization of generator to the transmission system per ICSA). Depending on the size and nature of the generating unit(s), this period may be a matter of hours or days.

Providers of test energy are not required to participate in the Day-Ahead (DA) energy market. Test energy compensation can be obtained at Real-Time (RT) Locational Marginal Price (LMP).

Market participation & compensation can only occur if proper metering and modeling are completed as specified in other parts of this manual and the eMeter account is active.

Day-Ahead energy market participation is optional to mitigate RT deviations from DA position.

Before providing interconnected test energy, Generators must:

1. Have in place an executed Interconnection Service Agreement with PJM.
2. Have in place an executed Interconnection Agreement with Transmission Owner if required by the Transmission Owner.
3. Provide PJM with an accurate Test Schedule, including times and output of unit.
4. Provide notification to PJM Dispatch Operations 30 minutes prior to a change-in-state of each generating unit.
5. Provide the PJM Dispatch Operations and the Market Settlements department accurate information as to when unit will be available for commercial use and in which markets it intends to do business.

If metering is not in place and verified via test, then an eSchedule internal bilateral transaction may be used to support any agreement between the generator owner and the transmission owner. This is an option PJM provides to the parties involved but is not a requirement.

Upon completion of the test period and when the generator is determined to be available for commercial operation, each unit is subject to other voice and data test requirements which are discussed in other sections of this manual.

6.3.4 Other Requirements

The Generator Owner shall develop operating principles and procedures for its facility, coordinated with PJM requirements and provide the necessary training and certification for appropriate employees. Generators must provide for the necessary communication of information between the Generator and PJM. This information includes:

1. A copy of the Generator's switching procedures
2. Generator data for each generating unit, unit step-up transformer and auxiliary transformer.

Each Generator shall develop operating practices and procedures, coordinated with PJM, for normal and emergency operation and assistance in remedial action. These practices and procedures must incorporate the applicable standards and requirements contained in the PJM Manuals and the NERC Planning and Operating Standards.

Conditions may be encountered on the PJM system, which require participation in remedial action. These include, but are not limited to: actual or contingency flow or voltage-limit violations, violation of synchronous stability limits, low or high frequency, voltage reductions, system blackouts, and maximum and minimum generation conditions.

Each Generator shall immediately notify PJM of any condition that inhibits operating in a reliable manner or in a manner previously agreed upon. Such conditions include, but are not limited to the availability of fuel, inability to operate due to labor restrictions, equipment, environmental, or weather-related problems.

To ensure that all PJM personnel responsible for the design and operation of the PJM system are familiar with equipment configurations, capabilities, and operating parameters, PJM may request, and the Generator shall provide in a timely manner, detailed information about the type, nature, and operating characteristics of the facility and all related equipment.

The Generator must keep and maintain accurate and complete records for Generator interconnection facilities. These records must contain information regarding the operation and maintenance of all equipment and must be consistent with good industry practice. The data in these records must be sufficient for PJM to comply with applicable regulatory requirements. The Generator must make these records available to PJM for inspection and copying as PJM may request.

Section 7: Generator Operations

Welcome to the *Generator Operations* section of the ***PJM Manual for Generator Operational Requirements***. In this section you will find the following information:

- Description of the dispatching process (see "*Dispatching of Generation*").
- Switching requirements for all equipment a Generator Resource owns, operates or controls (see "*Switching Requirements*").
- Generator information and reporting requirements (see" *Critical Information and Reporting Requirements*").
- Requirements and procedures for Generator synchronization and disconnect (see "*Synchronization and Disconnection Procedures*").

7.1 Dispatching of Generation

7.1.1 Generator Real-Power Control

The Generator must deliver the electric energy generated by the facility to PJM at the point(s) of interconnection in the form of 3 phase, 60-Hertz alternating current at the nominal system voltage at the point of interconnection.

Generators and their protective systems (relaying, V/Hz, etc.), larger than 20 MW, must be capable of operating at a frequency of 57.5 Hz for 5 seconds or longer, or 58.0 Hz for 30 seconds or longer, to coordinate with system preservation under-frequency load shedding. Additionally, generators and their protective systems must be capable of operation at over-frequency up to 62 Hz for a limited duration.

At no time shall the operation of the generating facility, including the associated generators or any of their auxiliary devices, result in an electrical output in which harmonic distortion exceeds the recommended limits contained in IEEE Standard 519, which defines voltage waveform and harmonic content.

The generator shall operate on unrestricted governor control to assist in maintaining interconnection frequency, except for the period immediately before being removed from service and immediately after being placed in service. Governor outages during periods of operations must be kept to a minimum and must be immediately reported to PJM. When a generator governor is not available, the unit output should not fluctuate from pre-scheduled output unless otherwise directed.

System conditions permitting, Generators must respond immediately to a PJM request directing a change in generation output and must proceed at a rate which is within 2% of the generator's stated ramp-rate, until the prescribed output is reached.

7.1.2 Voltage and Reactive Control

General

All Generators must install and have available generator field-excitation regulators. The reactive output of the generator must be regulated in the manner specified by PJM and/or the Local Control Center. An outage of any unit generator voltage regulator, supplementary excitation control, or power system stabilizers must be communicated to PJM though eDart as far in advance as possible. The Generator Owner must submit these outages.

Voltage control may involve maintaining a predetermined voltage schedule or a reactive generation level. Under normal operations, the Generator shall operate the facility with automatic voltage-regulation equipment in service at all times, except for outages of the regulator for maintenance or equipment failure.

Over-voltage and under-voltage protection systems must be capable of allowing abnormal system operations within PJM post-contingency operating limits. Momentary voltage fluctuations are permitted provided they neither disturb service provided by PJM or the Generator on their respective systems nor hinder PJM from maintaining proper voltage conditions on its system.

PJM has no criterion that exempts generators from compliance with the requirement to:

1. Maintain a voltage or Reactive Power schedule.
2. Comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage).

When notified of the loss of an automatic voltage regulator control, PJM shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.

During an emergency, the Generator must participate in a voltage reduction declared by PJM and operate the facility at the voltage level requested by the Local Control Center. Unless PJM requests a manual adjustment, the Generator must maintain the facility's automatic voltage regulator(s) in service during an Emergency.

The Generator must notify PJM and the Local Control Center with as much lead-time as possible prior to performing all voltage regulator maintenance. In addition, the Generator shall notify the Local Control Center at least 30 minutes prior to removing or returning the voltage regulator to service. In the event that automatic voltage regulating devices are out-of-service, the Generator shall provide manual voltage regulation to maintain the prescribed voltage schedule or reactive power schedule.

Operations

The Generator, at the option of PJM, shall operate the facility either:

1. According to a predefined voltage schedule provided by PJM (or)
2. According to a reactive power schedule provided by PJM and consistent with the facility's generation capability and the PJM electrical system.

Either schedule must recognize transmission/distribution equipment limits and must be coordinated with the Local Control Center.

When operating to a pre-determined voltage or reactive schedule, the generator reactive output must not violate appropriate pre/post contingency voltage limits.

Additionally, when maintaining a voltage schedule, the generator shall be operated with automatic generator field-excitation regulators in service and must maintain voltage within acceptable bandwidth of the prescribed schedule.

When PJM determines that system conditions warrant a change, the Generator may be requested to deviate from the predetermined voltage or reactive power schedule. PJM may direct a facility to operate in lead, lag, or unity power factor as long as the direction is within the unit's capability.

7.1.3 Notification to PJM for Reactive Power Resource Status during Unit Start-up

Generators may elect to operate their AVR in manual mode when synchronized and producing MW's during startup until minimum load is achieved (or during shutdown as applicable) in order to ensure overall unit stability (or based upon other physical equipment limitations). For those units that register as a Generator Operator in accordance with the NERC Statement of Compliance Registry Criteria, notification to PJM dispatch is required if the AVR is out-of-service during start-up and upon any change in AVR status or capability. The notification to PJM dispatch must be either verbally and via eDart (plus verbal notification to TO), or via telemetered status. Additionally, Generation Owners must notify PJM dispatch, in the same manner, of any change in PSS status, or any other reactive power resource under Generator Operator control.

7.1.4 Generator Operation under Constrained System Conditions

Under normal conditions, each Generator limits its generating output to the value specified in the pre-scheduling information for that hour or to the value directed by the PJM control signal. However, when the system is constrained, PJM may direct the Generator to deviate from these values any time reliability principles and standards are violated.

Where practical, PJM will direct all non-cost measures to be implemented prior to requesting Generators to redispatch. Specific details concerning operation of the transmission system under constrained conditions can be found in the ***PJM Manual for Transmission Operations***.

7.1.5 Generator Operation under Emergency Operating Conditions

Each Generator must limit its generating output to the value specified by its pre-scheduling information for that hour or to the value directed by PJM. PJM has the authority to direct deviation from the pre-scheduled values any time applicable reliability principles and standards are violated.

In order to maintain system reliability during emergency operations, it is critical that Generators respond to directives from PJM. Typical directives are outlined in the PJM Manual for ***Emergency Operations***. Note that these directives may require a Generator to provide additional operational data required by PJM for supplementary system analysis.

In general, a Member's responsibilities during emergency operation include:

- Taking other actions, as requested or directed by PJM, to manage, alleviate, or end an emergency.
- Cooperating with each other and PJM to carry out the emergency procedures and to implement requests and instructions received from PJM for the purpose of managing, alleviating, or ending an emergency.
- Providing notification and other information to governmental agencies as appropriate.

- Collecting, storing, and providing data and other information to PJM to facilitate preparation of reports required by governmental or industry agencies as a result of an Emergency.
- Cooperating and coordinating with PJM and other PJM Members in the restoration of all or parts of the Bulk Electric System in the PJM Balancing Authority.

Additionally, a PJM Generation Owner controlling the output of a Capacity Resource must take or arrange for any or all of the following actions, when directed by PJM, to manage, alleviate or end an emergency:

- Reporting the operating status and fuel situation.
- Canceling testing and maintenance.
- Reducing non-critical plant load.
- Directing personnel to unattended generation sites.
- Starting (including black-start) and loading generation, as directed.
- Reducing output to emergency minimum generation.
- Shutting down generation.
- Interrupting sales for delivery to loads outside the PJM Balancing Authority.
- Selling energy to other Balancing Authorities as requested during emergency conditions in other Balancing Authorities.
- Maintaining records of emergency actions taken and the results achieved.

During an emergency (as determined/declared by the Local Control Center or by PJM) the Generator shall respond as promptly as possible to all directives from the Local Control Center and PJM. These directives may relate to actual or contingency thermal overload of electrical circuits or actual or contingency high/low voltage conditions.

The Local Control Center may also direct the Generator to:

- Increase or decrease the facility energy and/or reactive output
- Connect or disconnect the facility from the PJM electrical system, and/or
- Deviate from the prescribed voltage or reactive schedules.

If safety or system reliability conditions warrant, the Local Control Center may isolate the facility from the PJM electrical system without prior notice to the Generator or upon such notice as is possible under the circumstances. The Local Control Center shall advise the Generator as soon as possible of any forced outages of the PJM electrical system that affect the facility's operations.

The Generator and PJM shall maintain communications and contact during all PJM or Local Control Center emergency operations. When the Local Control Center has determined that the emergency conditions have been alleviated, the Center shall inform the Generator and allow the facility to return to normal operations.

To safely restore the Transmission System following the outage of any facility, the facility isolated from the PJM electrical system shall be allowed to reconnect only under the direction of the Local Control Center or PJM. In all cases, the facility shall be made ready to return to service and provide energy to the PJM system as soon as possible.

Criteria for determining certain emergency conditions are reviewed in the following tables.

Capacity Shortage Procedures			
Condition	**Alert**	**Warning**	**Initiation**
Maximum Emergency Generation Alert	Requested in Operating Plan on prior day.		When demand is greater than highest normal bid.
Primary Reserve	Reserve is less than primary requirement.	Reserve is less than primary requirement but greater than spinning reserve.	
Load Management Curtailment			When generation is not available to meet forecast demand.
Voltage Reduction	Estimated reserve is less than forecast spinning reserve requirement.	Synchronized reserve less than spinning requirement.	When load relief is needed to maintain tie schedules or relieve transmission constraints.
Voluntary Customer Load Curtailment	Forecasted reserve indicates a probable need for this action.		When earlier procedures have not produced needed load relief.
Radio / TV Appeal			When earlier procedures have not produced needed load relief.
Manual Load Dump		Reserves are less than largest contingency.	When earlier procedures have not produced needed load relief.

Exhibit 9: Criteria for Determining Capacity Shortage Emergency Conditions

Light Load Procedures			
Condition	**Alert**	**Warning**	**Initiation**
Minimum Generation Alert	To provide alert that system conditions may require the use of emergency procedures		When expected generation levels are within 1000 MW of normal minimum generation limits
Compile report of Emergency Reducible Generation (ERG)			Prior to Light Load Period
Reduce all units to normal minimum generation			During the Light Load Period
Minimum Generation Emergency Declaration		To notify members further generation reductions are needed to meet the minimum load during the valley period.	At determination of PJM dispatcher
Minimum Generation Event	.	PJM declares event and requests percentage of ERG as needed (stepped process) to maintain system control	When utilization of ERG is necessary to match the decreasing load
Cancellation			Takes place in reverse order of implementation as PJM load begins to exceed generation and actions taken are no longer necessary

Exhibit 10: Criteria for Determining Light Load Emergency Conditions

7.1.6 Black Start

The LCC must have and maintain the capability and authority to conduct black starts with all generators in the PJM Balancing Authority that are within their respective zones. Voice communication (LCC-to-plant) tolerant of major power system failures is the minimum requirement to achieve black start. Private communication systems on un-interruptible power supplies (UPS) and radio systems are examples of this type of system. The current satellite-phone voice communication from PJM to the LCCs meets the minimum requirements for PJM-to-LCC communication. The current PJM approach of communicating directly through the satellite (avoiding the ground station) is designed to be tolerant of major power system failures. Black Start units operators shall not permit their fuel inventory for Critical Black Start CTs to fall below 10 hours – if it falls below this level, unit operators shall notify PJM and place the unit in Max Emergency.

Specific details concerning procedures that the PJM OI follows to ensure, monitor, and perform accounting for Black Start Service can be found in the ***PJM Manuals for Pre-***

Scheduling Operations, ***Balancing Operations***, and ***Open Access Transmission Tariff Accounting***.

7.2 Switching Requirements

A Generator is responsible for switching all equipment it owns, operates, or controls. A trained person must be available within a maximum of two hour's notice for the purposes of performing switching. Specified devices isolating the facility from the Transmission System shall be switched by the Generator or the Local Control Center (according to the configuration and contract) whenever requested by PJM. These devices must be locked if applicable and tagged to provide adequate safety.

The Generator's switching procedures shall at all times be followed precisely by the Generator and be closely coordinated between the Generator and the Local Control Center. Either party (Generator or LCC) must provide a written copy of in-effect switching procedures to the other party upon request.

If requested by the Generator, specified Local Control Center devices shall be operated and tagged by the Local Control Center according to the Local Control Center's switching and tagging practices and safety rules. Local Control Center switching and tagging practices and safety rules shall apply to all situations involving the Local Control Center and any Generator personnel involved with Local Control Center switching and tagging.

7.3 Critical Information and Reporting Requirements

PJM is responsible for coordinating and approving requests for necessary outages of generation and transmission facilities. This assures the reliable operation of the PJM Balancing Authority. PJM maintains records of outages and outage requests for these facilities.

The procedure begins when a designated resource owner and/or an entity acting on their behalf submits an outage request via eDART. The outage request is recorded electronically and can be accepted or rejected by the PJM Dispatcher. Refer to the PJM Manual for ***Pre-Scheduling Operations*** for information on the outage request procedure and request tracking via eDART.

It is important to emphasize that PJM does not schedule or determine when outages should take place. PJM only accepts or rejects the requests for outages submitted by Members. It is the responsibility of each Generator to determine its own best schedule of outages.

Outage requests are honored by PJM on a first come-first served basis. Requests are rejected only when they affect the reliability of the PJM Balancing Authority.

7.3.1 Planned Outage

The Generator shall provide PJM with written notice of its intent at least thirty days prior to performing planned maintenance of the facility, including turbine, generator, and boiler overhauls or inspections, testing, nuclear refueling, etc.

When feasible, the Generator shall provide PJM with written notice of its intent at least thirty days prior to testing protective apparatus associated with generator interconnection facilities, including circuit breakers, relays and auxiliary equipment. PJM personnel or designated Local Control Center personnel may observe such testing.

The Generator shall notify PJM and the Local Control Center of its intent to remove electrical equipment from service by 10:00 a.m., three working days prior to the planned maintenance outage begins.

An additional notification to PJM and the Local Control Center is required 30 minutes before the planned outage begins.

The Local Control Center may request the Generator to delay or reschedule the planned maintenance outage if system-reliability conditions warrant.

To the extent practical, PJM will provide to the Generator advance notice of PJM's intention to perform planned maintenance on reportable PJM facilities that may affect the Generator's operations.

7.3.2 Maintenance Outage

A maintenance outage is an outage that may be deferred beyond the next weekend but requires that the Capacity Resource be removed from service before the next planned outage. Characteristically, these outages may occur throughout the year, have flexible start dates, are much shorter than planned outages, and have a predetermined duration established at the start of the outage.

7.3.3 Unplanned Outage

The Generator may not remove any equipment from service without prior notification to PJM and/or the Local Control Center (LCC) except in the case where equipment must be disconnected from the system without PJM approval to prevent injury to personnel or damage to equipment.

However, if the Generator has any advanced knowledge of an unplanned outage, the Generator shall notify the LCC with as much lead-time as practical. For reliability reasons, the Generator shall notify the LCC as soon as reasonably possible of the following:

- The starting time of the unplanned outage.
- The energy reduction resulting (or expected to result) from the unplanned outage.
- The estimated time the equipment incurring the unplanned outage is expected to return to service.
- The time the Generator equipment is actually returned to service.
- The reason for the outage.

The Generator must submit a record of the events and circumstances giving rise to the unplanned or forced outage to PJM as soon as reasonably possible. The Generator must also notify PJM of any unusual operating conditions which may result in the reduction of output or tripping of multiple generators offline.

In addition, the Generator must notify PJM of any system conditions, whether a result of equipment failure or mandated restrictions (plant, governmental, etc.), which may result in potential generation reduction or controlled shutdown of any generator.

Additional details regarding Planned, Maintenance, and Unplanned outages can be found in the ***PJM Manual for Pre-Scheduling Operations***.

7.3.4 Generating Unit Reactive Capability Reporting

Generating Unit Reactive Power is a primary method of providing voltage support on the PJM system. A lack of deliverable Generating Unit Reactive Power, which is relied upon to be available based on reported Reactive Capability, can result in PJM system reliability problems including voltage collapse. Whereas, proper reporting can result in controlled measures, such as generation adjustment in lieu of unanticipated load shedding to address inadequate Reactive Power Reserves.

Generating Unit Reactive Capability is a measurement of the reactive power able to be delivered by a generating unit to the transmission system. It is defined by the MW versus MVAR points of a generator capability curve. To help maintain a reliable transmission system, each Generation Owner/Operator must provide capability curve information to PJM via eDART as soon as the information is available. The Local Control Center for the Transmission Zone where the unit is located will be automatically notified via eDART, as well as any other Local Control Centers with eDART authority to receive automatic notification for the unit. For real-time changes, each Generation Owner should also notify PJM and the respective LCC via phone. "Continuous Unit Reactive Capability Curve" data must be provided as follows via eDART:

- *Continuous Unit Reactive Capability Curve (required to provide)* - data that provides the realistic usable reactive output that a generating unit is capable of delivering to the PJM Interconnection and sustaining over the steady state operating range of the unit.

The PJM EMS Real-Time and Study Network Applications, Seasonal PJM Operating Studies, and PJM Planning Studies use Continuous Unit Reactive Capability Curves for actual pre-contingency steady-state analysis and for simulated post-contingency security analysis.

The Generator Operator shall notify PJM as soon as practical, but within 30 minutes of any temporal unit performance issues, including reactive capability derates or status or capability change on any generator Reactive Power resource, such as the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability and a status or capability change on any other Reactive Power resources under the Generator Operator’s control and the expected duration of the change in status or capability.

The Generating Unit Reactive Capability determination should reflect planned unit modifications and real-time limitations caused by system voltages, unit transformer tap position setting, temperature, operating conditions and restrictions, station auxiliary equipment, generator terminal bus voltage limitations, and auxiliary bus voltages limitations. There may be different limiting conditions for either leading or lagging reactive capability.

Planned modifications (tap changer adjustment, GSU replacements, turbine modification, etc) that impact generator reactive capability should be communicated to the impacted TO and PJM as far in advance as possible but no later than the return of the unit from the planned maintenance or scheduled adjustment. Changes should be communicated via eDart.

To ensure accuracy of generator reactive capabilities that may result from planned unit modifications, a critical input to PJM and Transmission Owner security analysis packages, PJM requires that each Generation Owner/Operator review and confirm their unit reactive capability data via eDART on a bi-annual basis. PJM and the Transmission Owners should then verify accuracy of unit reactive capabilities modeled in their respective EMS systems. The bi-annual review periods are defined as follows:

- Pre-Summer Review: From April 1 through April 30, Generator Owners should review their unit reactive capabilities in eDART. From May 1 through May 31, PJM and Transmission Owners should review and update EMS reactive capabilities based on the updated data in eDART.
- Pre-Winter Review: From October 1 through October 31, Generator Owners should review their unit reactive capabilities in eDART. From November 1 through November 30, PJM and Transmission Owners should review and update EMS reactive capabilities based on the updated data in eDART.

See Attachment D for a detailed description of the PJM Generating Unit Reactive Capability Curve Specification and an explanation of the PJM Reactive Capability Reporting Procedures.

A reactive test shall be performed as soon as practical following any planned upgrades which impact a unit’s reactive capability. Estimated or calculated data reactive capability data (D-Curve) must be provided as an interim measure until a reactive test can be performed.

Effective February 1st, 2005, PJM requires periodic verification of reactive capability via real-time testing. See Attachment E for a detailed description of the PJM requirements for Generator Reactive Capability Testing. In addition, see Attachment F for detailed procedures on scheduling and conducting reactive tests.

7.3.5 Fuel Limitation Reporting

Background and Intent

PJM needs data concerning unit fuel reserves for it to reliably operate the PJM Balancing Authority and its associated markets. This is especially true during periods of severe weather and/or times when there are external fuel constraints (i.e., coal strike, oil embargo). During PJM's last capacity driven load dump situation (Winter Freeze, 1994) the fuels data provided by PJM's members reduced the severity and duration of actual load curtailments.

It is the intent of this procedure to require all capacity resources to report fuel data so that in severe situations, PJM can continue to make the calls that are in the best interest of all its members. In contrast with past procedures, where PJM could have used this data to restrict the output of various generators based upon their fuel limitations without financial compensation, PJM will now use the information to assist the market in providing solutions to emergency situations.

PJM's authority to require all capacity resource owners to provide these reliability based reports is found in the PJM Operating Agreement (11.3 Member Responsibilities; 11.3.1 General; 1.10 Emergency, line ii) and in the "good utility practices" of NERC Policy 6 (Section B, Emergency Operations, Guides 1 and 2.2).

Seasonal Reporting

Prior to going into the winter season, PJM will notify and request from all members with capacity resources, by unit report of fuel information. Additionally this information may be requested at other intervals as deemed necessary such as a fuel crisis (i.e., embargo, strike) or forecasted period of severe cold weather.

An electronic spreadsheet will be sent to participants indicating required data (see Sample Fuel Baseline Data exhibit below). The required data will include information such as each unit's:

- available primary fuel
- available secondary fuel
- projected fuel inventory (in terms of MWh)
- typical fuel inventory (in terms of MWh)
- average amounts of fuel per delivery
- delivery frequency
- amount of firm gas schedules

While some of this data may represent broad projections, it will assist in providing a baseline that can be compared to data submitted in the real-time reporting process to assist in determining the severity of specific emergency conditions.

Fuel Baseline Data DATE: 1/30/01

Company	Plant Name	Unit Type	Winter (kW)	Primary Fuel		Alternate Fuel		Primary Fuel Availability (MW-Hours)	Primary Average Fuel Availability (MW-Hours)	Alternate Fuel Availability (MW-Hours)	Alternate Average Fuel Availability (MW-Hours)	Gas Schedules (% of Firm)	Average Delivery Amount	Delivery Frequency	Comments
				Fuel Type	Transport Method	Fuel Type	Transport Method								
Company A	Unit 1	GT	7,000	NG	PL	KER	TK	1200	1400	670	470	37%	35	3/DAY	
Company A	Unit 2	ST	10,000	FO6	RR			2000	1800				60	5/DAY	

Exhibit 11: Sample Data (Fuel Baseline)

Real-Time Reporting

When PJM receives a severe cold weather forecast or foresees a potential fuel crisis (i.e. embargo, strike), real-time updates of fuel limited units will be requested of members via Part G of the Supplementary Status Report (see *Attachment A* of ***PJM Manual for Emergency Operations***). This data will also be reported in other situations when a Supplementary Status Reports is requested, such as Capacity Shortage emergencies.

A unit is considered fuel limited when it is not capable at running at its maximum capacity for the next 72 hours. If a unit has an alternate fuel which would allow it to run at its maximum capacity for more than 72 hours, it does not need to be reported. However, if switching fuels involves a shut down and introduces the risk of the unit not being able to re-start after the switch, the unit should be reported if its primary fuel supply would produce less than 72 hours of runtime at maximum capacity. Besides fuel, the limitation of other resources, such as water, may also restrict the amount of time a unit will be able to operate. If a unit has less than 72 hours of run time at maximum capacity due to any resource limitation, it along with any fuel limited units should be reported in Part G, "Resource Limited Units," of the Supplementary Status Report (see Attachment C of ***PJM Manual for Emergency Operations***). The following information should be included:

- Unit Name—The name of the unit(s) (units with shared resource supplies should be listed together) that are considered resource limited.
- Fuel type
- Maximum Capacity—The current maximum capacity of the unit(s).
- Emergency Minimum—If a unit cannot cycle due to uncertainty of starting up again, Emergency Minimum must be included with a note in the Comments section.
- Current Energy—Current MW output.
- Total Burn Hours Remaining —Total burn hours remaining with unit at max capacity.
- Comments—If a unit is limited for a resource other the fuel, this should be noted in this column as well as any other pertinent information on the unit.

In addition to unit information submitted to PJM via Part G of the SSR, members should also monitor fuel inventories for the following minimum levels:

- CTs or Diesels—Less than or equal to 16 hours at maximum capacity
- Steam—Less than or equal to 32 hours at maximum capacity

In the event the above levels are reached, generation owners must immediately report this to the PJM Scheduling Coordinator (610) 666-8809.

PJM's Use for Fuels Data

PJM uses the fuel data in conjunction with the other data reported in the SSR to evaluate system conditions. Reports such as the PJM System Status Report (see Attachment C of the ***PJM Manual for Emergency Operations***) are compiled. Some portions of the reports are posted electronically via the internet or faxed to members so all members can assess the severity of the impending weather and available generation capacity. Additionally reports derived from this information are used to lead strategy discussions among SOS members about the criticality of the situation and to determine the timing of various emergency procedures that may be used.

An invitation may also be posted to other members to attend a PJM SOS conference call to discuss the meaning of this data and how it may result in various emergency procedures.

At no time in any of these communications or discussions will individual units or company's data be distributed or divulged. PJM will treat this information with the greatest degree of confidentiality. Discussions on individual units or company's fuel status will only occur between PJM and the generation owners who provided the data. During group discussions, PJM will only discuss what possible emergency actions are foreseen or what aggregate fuel crisis exists.

Unit specific Fuel Limitation Information is considered proprietary and confidential, and will not be distributed amongst participants. Only aggregate information will be discussed for the sole purpose of developing reliable operating strategies during projected capacity deficient conditions.

Operation of Fuel Limited Units

PJM requests companies that have units classified as fuel or resource limited units to bid these units in the Max Emergency category. This will serve to preserve these resources for the times when they are needed most. If a unit bid into PJM has resources of less than 32 hours (at maximum capacity) for a steam unit or 16 hours (at maximum capacity) for a CT or Diesel, and PJM has issued a Cold or Hot Weather Alert, then the unit must be bid in the Max Emergency category.

PJM will continue to schedule system generation based upon the Two Pass methodology and generator owner's individual bids. If PJM has particular concerns over units deemed critical to current or future system conditions, then PJM will initiate individual communications with the members responsible for those units.

If PJM asks a unit to operate differently then what was accepted in the day-ahead market (in order to conserve the unit's current fuel), then this unit would be paid its lost opportunity cost for the accepted hours that it was not run. (Reference Operating Agreement, section 3.2.3, (e), (f)).

7.4 Synchronization and Disconnection Procedures

The Generator must obtain prior approval from PJM when synchronizing the facility to, or disconnecting the facility from, the PJM electrical system. In addition, the Local Control Center must be notified when synchronizing or disconnecting from the Transmission Owner’s system. The only exception is when equipment must be disconnected from the system without PJM approval to prevent injury to personnel or damage to equipment. If the disconnection occurs without prior PJM approval, the Generator shall immediately notify the Local Control Center as to the cause, energy reduction, and the expected return time.

The Generator must keep the LCC and PJM dispatchers informed at all times of the facility's availability or any change in status. Additional requirements appear in the PJM Manuals for Pre-Scheduling Operations, Energy & Ancillary Services Market Operations, Balancing Operations, and Control Center and Data Exchange Requirements.

The facility shall normally be operated with all of the Generator's protective relays (primary or back-up) in service whenever the facility is connected to, or operating in parallel with, the PJM electric system. The facility may operate for a limited time to perform maintenance with one set of redundant relaying in service. PJM and the Local Control Center shall be notified of such occurrences.

Section 8: Wind Farms Requirements

Welcome to the Wind Farms Requirements section of the ***PJM Manual for Generator Operational Requirements***. In this section you will find the following information:

- Description of Wind Farms data requirements.
- Description of PJM Wind Power Forecasting service.

8.1 Computer System Data Exchange

The PJM SCADA system allows PJM to communicate directly with individual generators or smaller Control Centers. A data concentrator (e.g. Remote Terminal Unit, Generator Control System, etc.) is located at the Member's site, and, after collecting data from the industrial metering equipment, communicates with PJM's SCADA system using either DNP 3.0, Level 2 (Distributed Network Protocol) or ICCP (Inter-Control Center Protocol) consistent with PJM Control Center Requirements Manual (M01).

Every Generator interconnected with and synchronized to the transmission system must at all times coordinate operation with PJM and the Local Control Center, providing all necessary and requested information and equipment status, to assure that the electrical system can be operated in a safe and reliable manner. Attachment L defines coordination models that are considered acceptable PJM Wind Farm Communication Models.

This coordination includes, but is not limited to:

- Supplying low side generator net-MW and MVAR output.
- Supplying meteorological data (wind speed, wind direction, temperature, pressure and humidity). Wind speed and direction required.
- Scheduling the operation and outages of facilities including providing advanced notification.
- Coordinating the synchronization and disconnection of the Wind Farm with PJM and Transmission Owner.
- Providing data required to operate the system and to conduct system studies.
- Providing documented start-up and shutdown procedures including ramp-up and ramp-down times.
- Following PJM-directed plant operation during emergency and restoration conditions.
- Following PJM-directed operation during transmission-constrained conditions.

All data items, regardless of type, are collected and disseminated at a frequency of 10 seconds or less.

Each PJM Member is responsible for determining data-quality indicators for all data transmitted to PJM. Both failed individual values and any value calculated using a failed point must be flagged. When a point fails for an extended period, a manual update of the point's value may be necessary to keep the data as accurate as possible. The Generator shall communicate the outage of any data communication equipment connecting the facility to PJM Dispatch.

8.2 Wind Farm Data Requirement for Wind Power Forecasting

PJM Wind Power Forecaster has been selected through competitive process between several National and International Vendor's. It has been determined through the learning process that the Wind Power Forecaster requires several data points from the wind farms to accurately forecast the wind power. The following are the data requirements for wind farms:

8.2.1 Initial Data Requirements

The Wind Farms are required to provide the following data points for each turbine as part of their initial set up so they can be properly modeled within the Wind Power Forecasting Tool.

- General Turbine Information
    - Class of turbine
    - Capacity of turbine
    - Power Generation Threshold Rates (i.e. minimum / maximum wind speed)
- Manufacture Power Curves of individual wind turbines
- Geographic location (longitude and latitude) of wind farm site or each turbine if available.
- Hub height of wind power facility
- Aggregate Historic data (measured MW output, outage information, and wind speed at hub height) for existing facilities that connect to PJM Transmission or bid into the PJM market.
- Ambient Temperature Operating Limits and information regarding installation of "cold weather packages" to increase thermal limit capabilities during extreme cold weather conditions.

Note: Aggregate Reactive Capability Curve (D-Curve) required ensuring accuracy of Security Analysis Results.

8.2.2 Aggregate Real Time Output

The Wind Farms are required to provide the real time aggregate Wind Farm MW output along with other data points. This output should be telemetered at low-side net and high side-net of the Wind Farm.

8.2.3 Real Time Meteorological Tower (or mutually agreed upon alternative source)

The Wind Power Forecasting accuracy is highly dependent on the availability of the real time meteorological tower data for tuning the forecaster model. Each wind farm must install at least one meteorological tower (or wind speed and direction from selected turbines' anemometer and wind vane) in the farm and provide real time meteorological data to PJM though ICCP or DNP 3.0, Level 2 link. Depending upon the topology and the accuracy of the Wind Power Forecast, PJM may request addition of more meteorological towers at a Wind Farm site.

The height of the meteorological tower should be same or close to the hub height of the wind turbine. The generation owner should calibrate and check the accuracy of the met tower every year as per standard.

The meteorological data shall include the following parameters:

Parameter	Units	
Wind Speed	meters/second	Required
Wind Direction	Degree from True North	Required
Temperature	Fahrenheit	Preferred
Pressure	Hectopascals	Preferred
Humidity	percent	Accepted

8.2.4 Generator Outage Reporting (Aggregate Turbine availability)

PJM is responsible for coordinating and approving requests for outages of generation and transmission facilities, as necessary, for the reliable operation of the PJM RTO. PJM maintains records of outages and outage requests for these facilities.

The electronic Dispatcher Application and Reporting Tool (eDART) provides communication with PJM for generation operators regarding unit outage requests, updates to reactive capability curves (D-curves), and AVR statuses. Additional applications may be integrated in eDART in the future. User registration is available from the PJM Web site.

In eDart, a Wind Farm is modeled as a single unit with a capability equal to the sum of all turbines at full output. Wind Farm aggregate turbine outage/derate information is required to validate and enhance the accuracy of the Wind Power Forecast. Generation Owners should not provide outage tickets related to wind speed since specific turbine parameters will be modeled within the forecast tool.

See the PJM Manual for Pre-Scheduling Operations (Manual 10) Section 2 Outage Reporting for the generation outages reporting.

Note: Due to the impact of planned/unplanned turbine outages on wind power forecast accuracy, wind resources shall report any outage of one megawatt or more with duration of one hour or longer. Outages shall be submitted on aggregate plant capacity by outage type.

8.2.5 Grid Capacity Limit (Constraints or Economic Curtailments)

PJM is responsible for capturing congestion and economic curtailment directives and providing the data as inputs into the Wind Power Forecasting Tool.

8.2.6 Wind Power Forecast

PJM will collect the wind turbine/farm locations' real-time aggregate power output and meteorological data from the Wind Farms. The data will then be sent to the Wind Power Forecaster along with Wind Farm curtailment/outage information. All data shared with the Wind Power Forecast vendor is treated as confidential. The Wind Power Forecaster will collect all of the data from PJM and other outside sources, such as global and regional weather forecasts, and after processing the data will send PJM the Wind Power Forecast and all associated data for the individual or aggregate Wind Farms as designated by PJM.

PJM does four different types of forecasts for each individual or aggregate Wind Farm. All the examples consider the current time to be T.

1. Short Term Forecast (T + 6): Update Wind Power Forecast with a frequency of every ten minutes and forecast interval of five minutes for the next six hours (6) for the individual or aggregate Wind Farms as designated by PJM.
2. Medium Term Forecast ((T + 6) + 42): Update Wind Power Forecast with a frequency and interval of every hour for the next forty two hours (42) for the individual or aggregate Wind Farms as designated by PJM.
3. Long Term Forecast (((T + 6) + 42) + 120): Update Wind Power Forecast with a frequency and interval of every hour for the next one hundred twenty hours (120) for the individual or aggregate Wind Farms as designated by PJM.
4. Ramp Forecast: (T + 6): Update Wind Power Ramp Forecast with a frequency of every ten minutes and forecast interval of five minutes for the next six hours (6) for the individual or aggregate Wind Farms as designated by PJM.

8.3 Forecast Data Usage

8.3.1 Real-time Reliability Assessment

PJM will use the Short-Term Wind Power Forecast to evaluate current day congestion and to ensure that sufficient generation resources are available to respond to real-time or projected fluctuations in Wind Power Output.

8.3.2 Day-ahead Reliability Assessment

PJM will use the Medium-Term Wind Power Forecast to predict day-ahead congestion and mitigating strategies and to ensure that sufficient generation resources are scheduled within PJM to meet forecast load, transaction schedules and PJM reserve requirements. PJM may choose to use the updated version of the day-ahead Wind Power Forecast provided by the forecaster after 1700 hours and before 1800 hours.

The Long-Term Wind Power Forecast may be used to analyze weekend or long holiday conditions.

Section 9: Generator Deactivations

Welcome to the *Generator Deactivations* section of the ***PJM Manual for Generator Operational Requirements.*** In this section you will find the following information:

- Description of the PJM deactivation process (see *"Generator Deactivation Process"*).
- Methodology for compensation to Generators required to remain in service for reliability (see *"Compensation to Generators Requested to Remain in Service for Reliability"*).
- An exhibit showing the process flow diagram for generator deactivation.

9.1 Generator Deactivation Process

This section reviews the steps and timeline for the PJM generator deactivation process, and the potential results of the process. This section also reviews the methodology of compensation to generators requested to remain in service for reliability.

9.1.1 Generator Deactivation Request

Any generator owner, or designated agent, who wishes to retire a unit from PJM operations must initiate a deactivation request in writing to the PJM Power System Coordination Manager no less than 90 days in advance of the planned deactivation date. Black start resources require up to 2 years advanced notice to maintain the rolling 2-year commitment per the PJM Tariff. This notice will include, at a minimum, the following information:

- Indication of whether the unit is being retired or mothballed;
- The desired date of deactivation;
- A good faith estimate of the amount of a project investment and the time period the generator would be required to be out of service for repairs, if any, that would be required to keep the unit in or return the unit to operation.

PJM Power System Coordination Department will notify PJM Planning, PJM Markets and the PJM Market Monitoring Unit. PJM will also notify the appropriate transmission owner(s) of the request with the agreement of the generation owner or designated agent. PJM will initiate preliminary analysis of the request.

Note that only official requests to deactivate a unit are subject to the following procedures and timelines. All official requests are subject to public posting on the PJM Web site. Any requests to analyze potential retirements will be treated as unofficial requests, and the PJM deactivation process will not begin until an official public request is received.

9.1.2 Initial Analysis

PJM Planning will perform an initial analysis of the request. PJM Planning will perform standard RTEP/MAAC analysis for the affected summer peaks. PJM Planning will also identify maintenance and appropriate sensitivity analyses to be performed in addition to standard tests. PJM will review planned system reserve levels and conduct appropriate deliverability analysis. In addition, the PJM Market Monitoring Unit will analyze the effects of the proposed deactivation with regard to potential market power issues.

9.1.3 Analysis Results

The initial analysis has the following potential outcomes: (1) No reliability or market power issue identified, (2) Reliability or market power issue identified, or (3) Economic or congestion impact identified (PJM identifies potential for additional congestion due to the deactivation).

No Reliability or Market Power Issue Identified

- If no reliability or market power issue identified, the generator can retire as soon as practicable.
- Black start resources will forfeit a maximum of 1 year of revenues per existing tariff. If the unit is a black start resource, PJM will identify feasible alternative sites, and request tariff based bids to replace black start. A bid to re-power (improve) existing resource will be considered. The lowest cost replacement black start resource will be selected.

Reliability or Market Power Issue Identified

- PJM will notify the generator owner, or its designated agent, within 30 days of the deactivation request if a reliability issue has been identified. This notice will include the specific reliability impact resulting from the proposed deactivation of the unit, as well as an initial estimate of the period of time it will take to complete the Transmission upgrades necessary to alleviate reliability impact
- Within 60 days of the original deactivation request, the generator owner or designated agent, will provide PJM with an update estimate of any project cost and the period of time for which the unit would be required to be out of service for repairs, if any, that would be required to keep the unit in, or return the unit to, operation.
- Within 75 days of the original deactivation request, PJM will provide an updated estimate of the period of time it will take to complete the Transmission upgrades necessary to alleviate reliability impact
- Within 90 days of initial deactivation request, PJM will inform the generator owner, or designated agent, and post on its web site full details of the transmission upgrades that will be required in order to allow the unit to deactivate.
- Black start resources will forfeit a maximum of 1 year of revenues per existing tariff. If the unit is a black start resource, PJM will identify feasible alternative sites, and request tariff based bids to replace black start. A bid to re-power (improve) existing resource will be considered. The lowest cost replacement black start resource will be selected.

Economic or Congestion Impact Identified

- If PJM identifies an economic or congestion impact (e.g., potential for additional congestion due to the deactivation), the generator can retire as soon as practicable.
- Black start resources will forfeit a maximum of 1 year of revenues per existing tariff. If the unit is a black start resource, PJM will identify feasible alternative sites, and request tariff based bids to replace black start. A bid to re-power (improve) existing resource will be considered. The lowest cost replacement black start resource will be selected.

- Any economic impacts will be analyzed through the existing FERC approved economic planning process.

9.2 Compensation to Generators Requested to Remain in Service for Reliability

Upon receipt of notification from PJM that a generating unit will be requested to operate past its desired deactivation date, the generator owner may file with FERC for full cost recovery associated with operating the unit until it may be deactivated. The cost calculations may be reviewed with PJM prior to filing at the election of the generation owner.

In the alternative, the generator owner, or its designated agent, may choose to receive avoided cost compensation according to the Deactivation Avoidable Cost Credit in Part V of the PJM Tariff. Avoidable expenses are incremental expenses directly required for the operations of a unit proposed for deactivation. The two major components to the avoid cost formula contained in the Tariff are:

- Categories of costs that are avoidable expenses
- Limited amount for necessary investment to keep unit in operable condition

Avoidable expenses do not include variable costs recoverable under cost-based offers to sell energy in PJM Interchange Energy Market. Additional investment over and above the limited component in the avoided cost formula must be filed as a separate rate. All inquiries regarding avoidable expenses are to be directed to the PJM Market Monitor

If the generation owner, or designated agent, chooses the compensation according to the Deactivation Avoidable Cost Credit in Part V of the PJM Tariff, compensation to the generator will begin as of the day following the filing, and will be net of revenues from the PJM markets. All revenues from the PJM markets and unit-specific bilateral contracts will be net of marginal cost of service recoverable under cost-based offers to sell energy from operating capacity of the PJM Interchange Energy market, not less than zero

- A 10% adder will initially be applied to the avoidable costs, and this adder will increase in future years. Applicable adders for future years are detailed and defined in Part V of the PJM Tariff.

Costs (avoidable cost rate minus net revenues) will be allocated as an additional transmission charge to the zone(s) for which the Transmission Owner(s) will be assigned the cost of the transmission upgrade.

If a generation owner, or designated agent, chooses to file for full cost of service with FERC, PJM begins crediting the generator the amount approved by FERC, on the timeline ordered by FERC as part of the approval. PJM also allocates the costs associated with these credits according to FERC order.

The following exhibit displays the generation deactivation process flow.

Generation Deactivation Process Flow

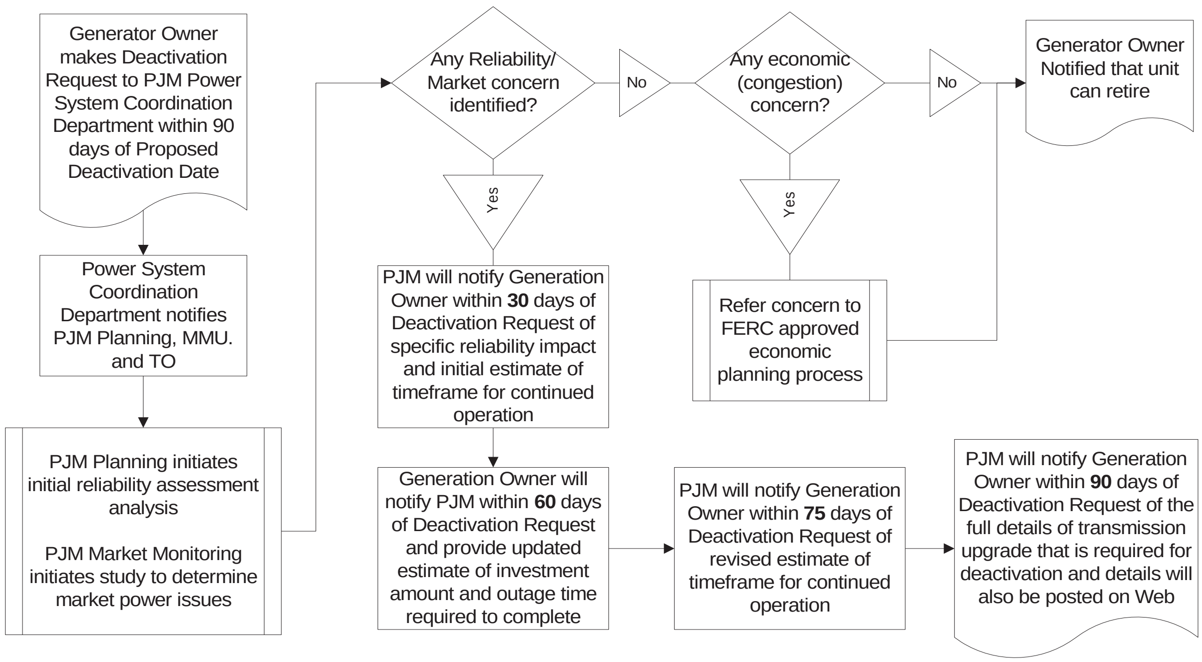


Exhibit 12: Generation Deactivation Process Flow

Section 10: Black Start Replacement Process

Welcome to the *Black Start Replacement Process* section of the ***PJM Manual for Generator Operational Requirements.*** In this section you will find the following information:

- Description of the PJM black start replacement process.
- Process flow diagram for black start replacement.
- Description of cost-based components for black start replacement bids (see *"Cost-Based Components for Black Start Replacement"*).

10.1 Black Start Replacement Process

The following business process is defined for replacement of critical black start units in PJM when a Black Start Generator Owner (GO) that terminates its commitment to provide black start service. Portions of this Black Start Replacement Process may also be initiated to request new black start resources due to any of the following events:

- The Transmission Owner identifies new or changed black start needs as a result of a review of its restoration plan.
- The Transmission Owner (TO) exercises its right to terminate the two-year commitment to a black start resource by providing notice of termination one year before the date the commitment period ends, in accordance with Schedule 6A of the PJM OATT.
- PJM terminates a Black Start Unit's designation as critical (e.g., due to reliability concerns, performance issues, or due to changes to its restoration plan) by providing two years prior notice of such termination in accordance with Schedule 6A of the PJM OATT.

10.1.1 Initial Black Start Commitment

Generators commit initially for at least two years to provide black start service from the black start service implementation date, with an annual right to terminate by each party (the generator owner and the transmission owner) with one year's notice. In the event that neither the Black Start Generator Owner (GO) nor the Transmission Owner (TO) exercises its right to terminate by providing a one year notice of termination, the commitment to provide Black Start Service automatically will be extended for an additional year to maintain a rolling two-year commitment.

In the event that a Black Start Unit fails to fulfill or chooses to deactivate or withdraw from black start service prior to its two year rolling commitment to provide Black Start Service, the Black Start Unit owner shall forfeit the received monthly Black Start Service revenues for the period of its non-performance not to exceed revenues for a maximum of one year.

10.1.2 Replacement Process Step 1

Upon receiving a request from a GO to deactivate a black start unit or otherwise withdraw from providing black start service, PJM will notify the TO.

Timeline: Within 5 business days from receipt of the termination request.

10.1.3 Replacement Process Step 2

PJM will discuss with the TO to identify feasible sites that meet the location and capability requirements for replacing the black start resource.

Timeline: Within 15 business days of receiving the termination.

10.1.4 Replacement Process Step 3

If PJM and the TO determine that there is sufficient redundancy of black start resources in the region, consistent with the minimum critical black start requirement defined in Attachment A of PJM Manual M-36 on System Restoration, such that there is no need to replace the withdrawing or deactivating black start unit in the restoration plan, PJM will initiate a final review and approval through the SOS-T committee of the TO's restoration plan and advise the TO whether such plan is adequate without a replacement black start unit.

In the event that PJM and the TO do not agree on whether there is a need to replace the withdrawing or deactivating black start unit in the restoration plan, PJM will initiate a review with SOS-T for additional technical assessment, and if after the SOS evaluation, an agreement is not yet achieved, the PJM Dispute Resolution process will be employed. Please refer to Section 5 of the ***PJM Manual for Administrative Services for the PJM Interconnection Agreement*** for more details about the PJM Dispute Resolution process.

Timeline: Within 30 calendar days of receiving the termination request.

10.1.5 Replacement Process Step 4

If PJM and the TO determine that there is a need to replace the withdrawing or deactivating black start resource, PJM will seek for replacement of the retiring black start resource using the process below.

Timeline: Within 30 calendar days of receiving the termination request.

A. After PJM and the TO determine that there is a need to replace the deactivating or withdrawing black start resource in order to meet the defined minimum critical black start zonal requirement, and also determine the location and capability requirements, PJM will post online a notification about the need for a new black start resource along with the location and capability requirements. Please refer to Attachment A of the ***PJM Manual for System Restoration*** for more details on the selection criteria for replacement black start resources. This notification will also advise that all bids submitted for the replacement black start resource must be cost-based bids consistent with Schedule 6A of the PJM OATT. Details of the required cost components for each prospective black start replacement bid are provided in the following subsection on *"Cost-Based Components for Black Start Replacement."*

B. This posting should be made within 30 calendar days of receiving a request to terminate the existing black start resource, and will mark the beginning of a "Market Window" which will last 90 calendar days from the date of the notification. The posting will also advise that PJM will be reviewing pending generator interconnection projects and other projects that are received within the Market Window.

C. PJM will review each Generation Interconnection Request pending under Part IV of the PJM Tariff at the time a Market Window is opened (as described above) and each request from Black Start Units and each Interconnection Request it receives during such Market Window, to evaluate whether the project proposed in the request could meet the black start replacement criteria for which the Market Window was established.

D. The TO will also have the option of negotiating a cost based bi-lateral contract in accordance with the existing process outlined in Schedule 6A of the PJM OATT with a generator owner for black start services. The TO may provide the alternative as one of the bids for the black start replacement that will be evaluated by PJM in step 4E pending FERC approval.

E. If PJM and the TO determines that more than one of the proposed projects within the 90 day market window meets the replacement criteria, the most cost-effective resource for the black start replacement will be chosen, provided the identified resource accepts and maintains designation as a market solution under Sections 36A or 41A of the PJM Tariff and executes the agreement(s) required thereunder. Submitted projects costs must be consistent with Schedule 6A of the PJM OATT

If no projects are received during the 90-day market window, PJM and the TO will revisit step 4A, and modify the location and capability requirements for the replacement black start resource, as well as the market window, if necessary, to allow more resources to become viable as replacements, even if sub-optimal.

If no projects are identified after the modified search criteria and market window, PJM and the TO will investigate the cause for the absence of bids, and recommend corrective action in accordance with the existing cost-based service process outlined in Schedule 6A of the PJM OATT, or address other barriers to entry identified by such investigation within the bounds of the existing tariff. In the process of this investigation, PJM will also identify limits for adjusting the cost of entry and other corrective actions within the bounds of Schedule 6A of the PJM OATT, beyond which PJM will discontinue efforts to incent a replacement black start unit.

F. After PJM and the TO have identified the most cost-effective replacement resource, PJM and the TO will coordinate with the GO for the GO's acceptance under the PJM tariff as a black start unit.

   The replacement black start unit will be compensated for provision of the black start service in accordance with the existing process outlined in the PJM OATT. Schedule 6A of the PJM tariff sets forth a formula for payments to generators for black start service and the collection of such costs from transmission customers. The annual black start service revenue requirements of each generator are determined pursuant to this formula. The Schedule 6A formula includes allocation factors for fixed and variable generation costs, which are to be used "unless another value is supported by the documentation of costs." The generator owner may choose compensation under the formulaic rate by submitting the formulaic black start costs to PJM as outlined in Section 4 of the ***PJM Manual for Balancing Operations***, or by filing for recovery of actual costs, with accompanying documentation, to the FERC.

10.1.6 Replacement Process Step 5

If it is determined that a replacement resource will not be available prior to the proposed deactivation date of the black start unit or the proposed date of withdrawal of a black start unit from providing black start service, PJM, in accordance with the PJM Deactivation procedures (see Section 8 of this manual), will use the following process.

A. PJM will identify whether there is a need to request that the generator continue to provide black start service beyond the planned deactivation date or withdrawal date of the black start unit, pending the upgrading of the transmission system in the form of replacement black start capability. Within 30 days of the GO's notification of the proposed deactivation or withdrawal of the black start unit from providing black start service, PJM will notify the GO whether there is a need for the black start unit proposed for deactivation or withdrawal to continue operating beyond its proposed deactivation date or withdrawal date.

B. In the event that such notice requests that a black start unit proposed for withdrawal from providing black start service (but which is not deactivating) continue operating, the notice shall request that such unit voluntarily fulfill its two-year rolling commitment to provide black start service.

C. In the event that the notice requests that a black start unit proposed for deactivation continue operating, the notice shall provide an estimate of the time period that the black start unit is needed to operate beyond its proposed deactivation date.

D. Within 30 calendar days of such notice by PJM, the GO shall notify PJM whether the black start unit will continue operating beyond its proposed deactivation date or withdrawal date.

E. A black start unit proposed for deactivation that operates beyond its deactivation date shall be compensated pursuant to the deactivation procedures set forth below and in Part V of the PJM Tariff.

F. A black start unit proposing to withdraw from providing black start service (but which is not deactivating) that continues providing black start service for its entire rolling two-year commitment shall receive black start service revenues pursuant to Schedule 6A of the PJM Tariff but will not be eligible for compensation pursuant to Part V of the PJM Tariff.

G. In the event that, through the market window process described above, a replacement black start resource is identified, PJM, as soon as practicable, shall notify the GO of such replacement, that its black start unit no longer will be needed for reliability, and the date the black start unit may withdraw from providing black start service or deactivate without affecting reliability..

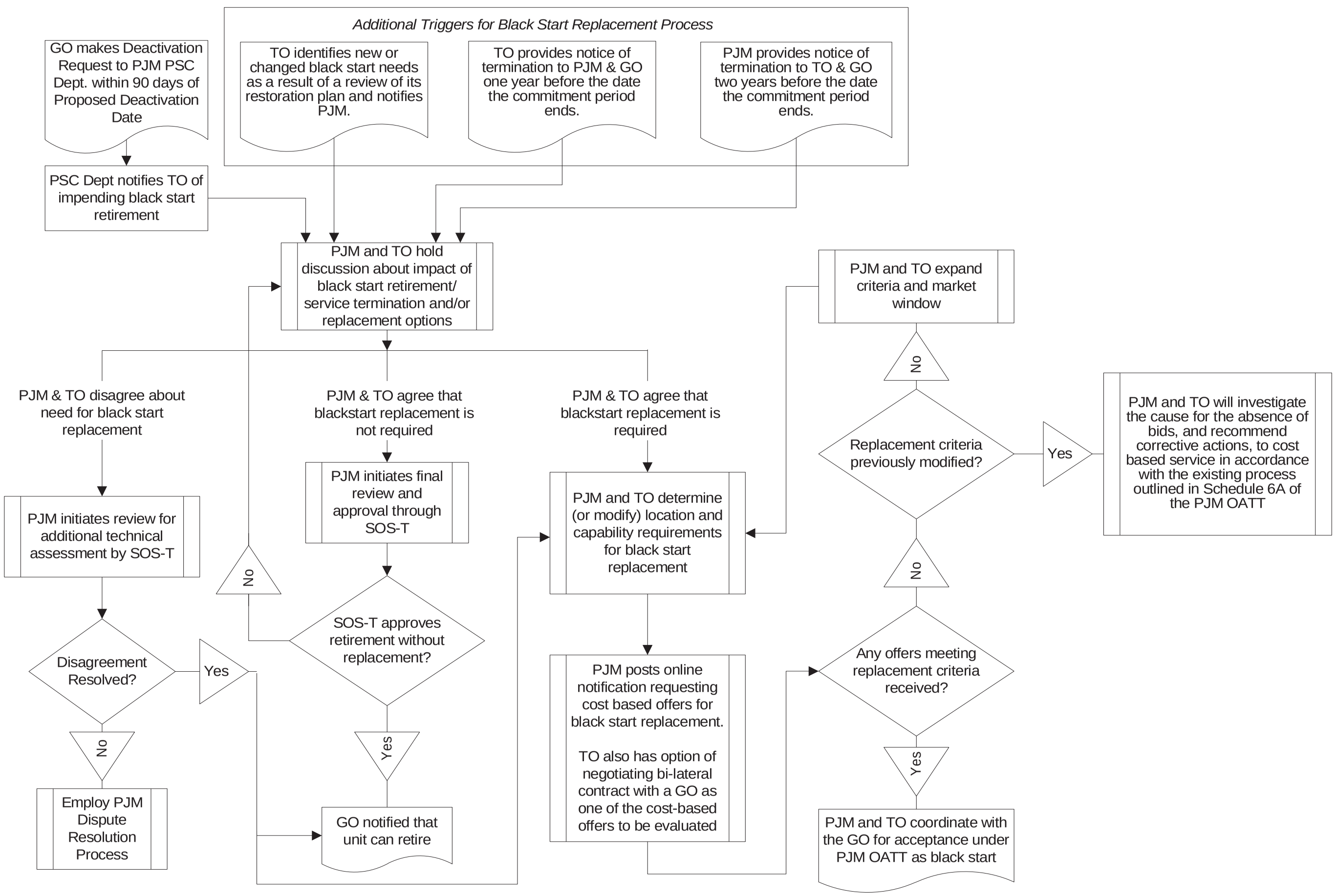


Exhibit 13: Black Start Replacement Process Flow Diagram

10.2 Cost-Based Components for Black Start Replacement

10.2.1 Capital Cost Components

The following capital cost components may be considered when documenting costs for constructing a new generator or retrofitting an existing generator for black start service capability. Submittal of actual costs with appropriate documentation to the FERC for approval is required under the existing process outlined in Schedule 6A of the PJM OATT.

- Cost of Capital strictly needed for Black Start Service Capability
- Capital Expense Categories for Black Start typically include:
- Engineering
- Construction
- Diesel Generator
- Electric Switchgear
- Air Intake Pre-heater System
- Control/Relay Modifications
- Miscellaneous Expenses
- Capital Structure
- Total Project cost of Capital for Black Start Capability with Labor
- Project Life
- Tax Life
- Depreciation Schedule (Term and Type)

10.2.2 Avoidable Cost Definition

The avoidable cost rate for providing Black Start Capability may be determined using the following formula:

Avoidable Cost Rate = Black Start Capital Cost * CRF

Where:

- Black Start Capital Cost is defined as the total cost of the capital components for constructing a new generator or retrofitting an existing generator for black start service capability as defined above.
- CRF is the annual capital recovery factor from the table below.

Age of Existing Unit (Years)	Remaining Life of Plant (Years)	Levelized CRF
1 to 5	20	0.125
6 to 10	15	0.146
`11 to 15	10	0.198
16 to 20 Plus	5	0.363

Exhibit 14: Annual Capital Recovery Factors (Culled from Draft Tariff Attachment Y on Reliability Pricing Model)

Submittal of actual avoidable costs with appropriate documentation to the FERC for approval is required under the existing process outlined in Schedule 6A of the PJM OATT.

10.2.3 Variable Cost Components

Variable costs for providing and maintaining black start capability should be documented following the revenue requirements defined in Schedule 6A of the PJM OATT, consisting of the following cost components:

- Plant Heat Rate
- Delivered Fuel Cost
- Short-term variable O&M (CDTF Based)
- Other Variable Costs strictly associated with Black Start Operations
- Long-term variable O&M and “to-go” costs strictly associated with Black Start operations

Section 11: Generator Data Confidentiality Procedures

Welcome to the Generator Data Confidentiality Procedures section of the **PJM Manual for Generator Operational Requirements.** In this section you will find the following information:

- Description of the PJM generator data confidentiality procedures.

11.1 Generator Data Confidentiality Procedures

In order for PJM to perform reliability assessment and analyses, generators are required to provide real time and scheduled outage data to PJM. While PJM has the overall reliability responsibility for the PJM RTO, local Transmission Owners have a similar responsibility to monitor and assess the reliability of their transmission systems and distribution systems. In order for the Transmission Owners to perform their local reliability functions, Transmission Owners need certain data about the generators to formulate a realistic basis for the analysis. The following Generator Data Confidentiality Procedures pertain to only real time data (real time MW, MVAR, and unit status) and scheduled outage data (start date/time, return date/time, and derate). Scheduled outage data includes both planned and maintenance outage data.

Transmission Owners require both real time and generator data to perform their reliability and planning functions. These transmission owner functions include, but are not limited to:

1. Real time EMS applications: state estimator and security analysis
2. Transmission owner's real time role
3. Transmission outage scheduling process
4. Reliability study and training

PJM may be requested to provide a Transmission Owner with generator data. The Transmission Owner's responsibilities are different for generators located inside or outside of their transmission zone. To see the list of Transmission Owner's Rights and Responsibilities for generator data outside of its zone, reference the Generator Data Confidentiality Agreement in Attachment I of this manual.

11.1.1 Generator Data within a Transmission Owner's Zone

For generator data within a Transmission Owner's zone that PJM presently receives, a Generation Owner may authorize PJM to release this information to the Transmission Owner. The Transmission Owner who seeks data initiates this process by signing a letter and sending it to the Generation owner. A template letter describing how to start this process can be found in Attachment K of this manual.

11.1.2 Generator Data outside a Transmission Owner's Zone

The Generator Data Confidentiality Procedures that follow are applicable when a Transmission Owner seeks generation data from PJM. If a Transmission Owner needs access to generator data outside of its zone, the Transmission Owner uses the following process developed by the PJM Data Confidentiality Working Group to evaluate and authorize PJM to provide all available requested data. The Transmission Owner may request PJM to provide Real-time (MW, MVAR and status) as well as future scheduled generator outage data.

11.1.3 Process to Authorize Release of Real-Time Generation Data

If the transmission owner can answer "Yes" to any of the following decision points about the real time generator data, explained in detail in Exhibit 16, then the Generator Owner will authorize the release of the data. If a Transmission Owner cannot answer "Yes" to any of the conditions, they can request an exception. All requests for exceptions must be documented in an attachment to the Generator – Data Release Matrix.

Process to Approve Real-Time Data Request
Decision Point 1: Is the Unit 2 Stations or less from the Transmission Owner's Zone?
If the unit is two stations or less from the Transmission Owner's Zone, then the request for data must be approved and the data confidentiality plan should be implemented.
Decision Point 2: Does Unit Outage affect network line flows by more than 2% line rating?
If a unit significantly changes line flows (changes by more than 2% line rating), it is important to get information on this unit's availability out to the Transmission Owner. The line rating used should be the ratings at the peak ambient temperature set. If the unit outage affects network line flows by more than 2% line rating, then the request for data must be approved and the data confidentiality plan should be implemented.
Decision Point 3: Does Unit Outage affect Transmission Owner facility more than 5% dfax?
A dfax lists the units that harm or help a facility and the percentage of harm/relief that each additional megawatt per unit brings. If an outaged unit could significantly harm or help a facility by more than 5%, it behooves the transmission owner to know the status of this unit. If the unit outage does affect the Transmission Owner facility by more than 5% dfax, then the request for data on the unit in question must be approved and the data confidentiality plan will be implemented.
Decision Point 4: Does Unit Outage affect Transmission Owner model values by 5%?
If an outaged unit could change Transmission Owner model values by 5% or more, it is necessary for the Transmission Owner to know the status of the unit in question. If the unit outage does affect the Transmission Owner model values by 5%, the request for data must be approved and the data confidentiality plan will be implemented.
Decision Point 5: Is Plant interconnected at the 230 or above kV system?
Higher kV interconnection implies that the status of the unit may impact the Transmission Owner system more, making this particular unit status important information to know. If the plant is interconnected at the 230 or above kV system, the request for data must be approved and the data confidentiality plan will be implemented.
Decision Point 6: Is Plant 500 MW or greater?
A higher MW aggregate output of the plant implies that the status of the unit may impact a Transmission Owner's system. If the plant is 500 MW or higher, the request for data must be approved and the data confidentiality plan will be implemented.

Exhibit 15: Process to Approve Real-Time Data Request – Decision Points with Definitions

11.1.4 Process to Authorize Release of Scheduled Generation Outage Data

If the transmission owner can answer "Yes" to any of the following decision points about the scheduled generation outage data, explained in detail in Exhibit 17, then the Generator Owner will authorize the release of the data. If a Transmission Owner cannot answer "Yes" to any of the conditions, they can request an exception. All requests for exceptions must be documented in an attachment to the Generator – Data Release Matrix.

Process to Approve Scheduled Outage Data Request
Decision Point 1: Is the Unit 2 Stations or less from the Transmission Owner's Zone?
If the unit is two stations or less from the Transmission Owner's Zone, then the request for data must be approved and the data confidentiality plan should be implemented.
Decision Point 2: Does Unit Outage affect Transmission Owner facility more than 5% dfax?
A dfax lists the units that harm or help a facility and the percentage of harm/relief that each additional megawatt per unit brings. If an outaged unit could significantly harm or help a facility by more than 5%, it behooves the transmission owner to know the status of this unit. If the unit outage does affect the Transmission Owner facility by more than 5% dfax, then the request for data on the unit in question must be approved and the data confidentiality plan will be implemented.

Exhibit 16: Process to Approve Scheduled Outage Data Request – Decision Points with Definitions

11.1.5 Executing a Data Confidentiality Agreement

After evaluating the applicability of the data request with the above decision points, the Transmission Owner initiates a Data Confidentiality Agreement with each Generator Owner. An officer of the Transmission Owner signs three copies of the Generator Data Confidentiality Agreement and submits them to the Manager of the PJM Power System Coordination Department. When initiating the Agreement, the PJM Generator Member Company name on record with PJM needs to be inserted into the beginning of the Agreement by the Transmission Owner. Any questions about the official Member Company name should be directed to the Manager of the PJM Power System Coordination Department. The Agreement can be found in Attachment I of this manual. (An electronic version of the Generator Data Confidentiality agreement is also available from the Manager of the PJM Power System Coordination Department.)

The agreement (all three copies) must also contain a Generator – Data Release Matrix. This Matrix lists all the generator units that a Transmission Owner requests data from a Generator Owner. Note that if the Transmission Owner wants to execute Agreements with several Generator Owners, an Agreement and accompanying Matrix must be filed for each Generator Owner. The Generator – Data Release Matrix (three copies) must be signed by the Transmission Owner's Operating Committee Member before it is sent to PJM. If a Transmission Owner does not have an Operating Committee Member, the PJM Member Committee Representative will sign the Matrix. A sample Generator – Data Release Matrix can be found in Attachment J. (An electronic version of the Generator – Data Release Matrix is also available from the Manager of the PJM Power System Coordination Department.) The Transmission Owner should train the employees that will be working with this data (certificate signers) so they understand the confidential nature of the data.

An officer at PJM signs the Agreement and the PJM OC Representative signs the Generator – Data Release Matrix. The PJM Power System Coordination Department will send all three copies of the Agreement (with Matrix included) to the appropriate Generator Owner for a signature from an officer of the company. At this time, the Operating Committee Representative (or PJM Member Representative) of the Generator Owner signs the copies of the Generator – Data Release Matrix. The Generator Owner then returns two copies of the Agreement (with Matrix included) back to the PJM Power System Coordination Department. PJM retains a copy of the executed agreement and matrix and sends a copy to the Transmission Owner for their records. After the Agreement has been executed, the Transmission Owner will be authorized to have the generator data.

If a Data Confidentiality Agreement has been executed between a Transmission Owner and Generator Owner, and the Transmission Owner wishes additional generator data, another Matrix (3 copies) should be filed requesting the new units. This Matrix should be initiated and authorized by the Transmission Owner’s Operating Committee Representative (or PJM Member Committee Representative) and sent to the Manager of the PJM Power System Coordination Department. PJM’s Operating Committee Representative will sign the Matrix and forward it to the Generator Owner’s Operating Committee Representative. The Generator Owner’s Operating Committee Representative will keep one copy of the newly executed Matrix and return the other two to the PJM Power System Coordination Department. PJM will retain one for its records and send the other back to the Transmission Owner. After the Generator Owner’s Operating Committee Representative (or PJM Member Committee Representative) returns the signed Matrix to PJM, the Transmission Owner is authorized to receive the additional generator data.

11.1.6 PJM Evaluation of Data Request

Annually, PJM will send a list to the Generator Owners stating their data that is being sent to each Transmission Owner. The Generator Owner may challenge this data release by using the dispute resolution process.

The Transmission Owner must provide the decision point under which they believe their request qualifies, and if requested, provide supporting information to PJM and the Generator Owner. If requested by a Generator Owner, PJM will evaluate the technical merits of the request using the PJM EMS model.

11.1.7 Dispute Resolution

The process for appeal is to follow the PJM Dispute Resolution Process. Further information about this process may be found in Section 5 of the ***PJM Manual for Administrative Services for the PJM Interconnection Agreement.***

Attachment A: New Generator Checklist

Operations	**Status** Date	
	Needed	**Complete**
Dispatch	☐	☐
Control	☐	☐
Plant Operation	☐	☐
Emergency Procedures	☐	☐
PJM Communications	☐	☐
Restoration	☐	☐
Loading Reserves	☐	☐
Regulation	☐	☐

Data	**Status** Date	
	Needed	**Complete**
Telemetry[1]	☐	☐
Unit Commitment[2]	☐	☐
Outages	☐	☐
Meter Error Correction	☐	☐

Market	**Status** Date	
	Needed	**Complete**
Energy Transactions	☐	☐
- Within PJM	☐	☐
- Outside of PJM	☐	☐
Capacity Transactions	☐	☐
FTRs	☐	☐
Synchronized Reserve	☐	☐
Regulation	☐	☐
Reactive*	☐	☐
Black Start	☐	☐

Exhibit 17: New Generation Checklist Page 1 of 3

[1] Real-time and integrated meter data.
[2] Daily schedule and bids, cost curves, start and no-load costs, etc.
* Anticipated Future.

Administrative	Status Date	
	Needed	Complete
Membership Application [3]	☐	☐
Interconnection Agreement	☑	☐
Firm Transmission Service [4]	☐	☐
Non-Firm Transmission Service[5]	☐	☐
Billing Contact Information Form	☑	☐
Committee Registration Forms	☑	☐
Capacity Transaction Authorization[6]	☑	☐
eCapacity Registration[7]	☑	☐
eSchedule Registration	☑	☐
eMKT Registration	☑	☐
eMTR Registration	☑	☐
eFTR Registration	☑	☐
OASIS Registration	☑	☐
eGADS Registration	☑	☐
eData Registration[8]	☑	☐
eDART Registration[9]	☑	☐

Training	Status Date	
	Needed	Complete
PJM Overview	☑	☐
eCapacity	☑	☐
eSchedules	☑	☐
eFTR, eMTR, eMKT	☑	☐
OASIS	☑	☐
eGADS, eDART, eFuel, Generator Outage Reporting	☑	☐
Unit Commitment	☑	☐
LMP	☑	☐
Operations	☑	☐
Dispatcher	☑	☐
Communications	☑	☐
Emergency Procedures	☑	☐
Market Settlements	☑	☐

Exhibit 18: New Generation Checklist Page 2 of 3

[3] Membership Application – http://www.pjm.com/
[4] Firm Transmission Service Application – http://www.pjm.com/services/downloads/trans.DOC
[5] Non-Firm Transmission Service Application – http://www.pjm.com/services/downloads/trans.DOC
[6] Capacity Transaction Authorization Form – http://www.pjm.com/custchoice/cccheck/inscap.pdf
[7] eCapacity/eSchedules Registration – http://www.pjm.com/forms/eschedules_user_registration.html
[8] eData Registration – http://edata.pjm.com/
[9] eDART Registration – http://www.pjm.com/edart/edart_index.html

Systems/Communications	**Short Term** Date	
	Needed	**Complete**
Communications	☐	☐
Telemetry		
ICCP EMS Links	☐	☐
Metering Links	☐	☐
PJM*net*		
Frame Relay	☐	☐
ISDN Backup	☐	☐
POTS line for router	☐	☐
Routers	☐	☐
IGN Network		
Frame	☐	☐
Routers	☐	☐
Other devices (TBD)	☐	☐
Voice		
Generator ALL CALL	☐	☐
POTS	☐	☐
Systems/Applications		
EMS		
System Changes	☐	☐
Modeling	☐	☐
PJM Testing	☐	☐
Integration Testing	☐	☐
Unit Commitment (eMKT)		
System Changes	☐	☐
Permission to view existing data	☐	☐
Testing	☐	☐
Regulation Logger		
System Changes	☐	☐
Testing	☐	☐
Two-Settlement (eMKT)		
System Changes	☐	☐
Testing	☐	☐

Exhibit 19: New Generation Checklist Page 3 of 3

Attachment B: New PJM*net* Customer Implementation Voice/Data Communications Template

PJMnet

New PJMnet Customer Implementation Voice/Data Communications

Objective

The completion of this document will provide PJM with the information necessary to configure and install the required voice and data communications necessary for you, our new customer, to communicate with PJM. PJM will assume total responsibility for the coordination efforts required to acquire and implement the appropriate telecommunications circuits.

Customer Information

PJM Member Name:	______________________________
Customer Business Name:	______________________________
Customer Business Address:	______________________________
	______________________________
Customer Business Contact:	______________________________
Telephone Number:	______________________________
Fax Number:	______________________________
email Address:	______________________________
Customer Technical Representative:	______________________________
Customer Technical Representative email:	______________________________
Customer Technical Representative Fax Number:	______________________________
Total Number of MW at Site/for which site is responsible:	______________________________
Site Access Hours:	______________________________
Site Access Requirements:	______________________________

Site Circuit Information

Desired hardware install by date: ______________________________

Desired circuit fully operational date: ______________________________

Area code and exchange telephone number where circuit is to be terminated:

Location Name: ______________________________

Street: ______________________________

City: ____________________ State: ________ Zip Code: _________

Site Point of Contact: ______________________________

Site Point of Contact Telephone Number ______________________________

Site Point of Contact email ______________________________

Site Point of Contact Fax Number ______________________________

Circuit Termination: ______________________________

Floor/Room Number/Name: ______________________________

Telephone Number (within 5 feet of router) ______________________________

For the purposes of remote router support POTS lines need to be installed for each router.

Number Assigned: ______________________________

Number Assigned: ______________________________

Site Circuit Termination Design:	YES	NO
Diverse Telecommunications Entrance Facilities into Site	☐	☐
Telecommunication carrier demarcation location different from install location	☐	☐
Termination capacity currently exists	☐	☐

Demarcation Extension to be performed by: ☐ None ☐ Telco ☐Site Staff

Circuit Configuration (provided by PJM)

Physical Address DS1 Port Speed CIR

☐ PVC to PJM Primary Control Center ☐ PVC to PJM Emergency Backup Control Center

Circuit Notes:

PJM Supplied Hardware Information

☐ Very Large (A) ☐ Large (B) ☐ Medium (C) ☐ Small (D)

Communication Protocol: ☐ ICCP ☐ DNP ☐ EMS ☐ SCADA

PJMnet Router Type:

ARCOM devices required (DNP implementations only) ☐ Yes ☐ No

Hardware Notes:

Note for electrical facilities that have a major impact on PJM operations: PJM requires the computer hardware and software at each control center should achieve a long-term 99.95% availability level for those critical functions directly affecting the successful operation of PJM. Redundant hardware configurations with either automatic or rapid manual failover schemes are generally necessary to achieve 99.95% availability. In addition, reliable AC power source(s) and communications are also necessary. Members should keep this requirement in mind when designing these systems.

Customer Site Environment Information

Site Power Configuration (diversity/redundancy):	YES	NO
Separate Equipment Breakers	☐	☐
Separate Electrical Panels for Equipment	☐	☐
Uninterruptible Power Supply	☐	☐
120v/60 Hz AC Power Available	☐	☐

If no AC power is available, please describe available power:

Voice Modules

PJM*net* will provide a voice-over IP (VOIP) output from each router for future voice communication with PJM. PJM will be using a conventional dial plan for the PJM*net* VOIP circuits (will match the corresponding public switched network phone number).

What type of facility will you have connected to the router? ☐ PBX ☐ Standard Phone

☐ Trader Turret System

If a PBX Connection, please specify port type: ☐ FXS ☐ FXO ☐ E&M

Note: An FXO connection to the router is preferred because any standard phone can be connected to the router in case of a PBX failure.

Hardware Notes:

Date Site Survey Completed: ________________________________

Network Information

Network Address: ____________ Subnet Mask: ____________________

IP Address for PJM Router: ________________________________

Will this network be protected by a firewall? ☐ Yes ☐ No

Will the firewall be providing Network Address Translation (NAT)? ☐ Yes ☐ No

Will the firewall be in service during router installation? ☐ Yes ☐ No

Please provide a contact for the firewall administrator

Name:_______________________ Phone: ___________________________

Can IP 10.134. be used by PJM? ☐ Yes ☐ No

If yes, supply a 10.34.xx address that will be used as a loop back address. -10.34.

Please list what devices (RTU, Meter< FEP, etc.), device type (DNP, ICCP) IP Address will be monitored:

Device Name/Type	Communications Protocol	IP Address

Attachment C: New PJM Customer Voice/All Call Communications Request Form

Objective

This document will provide PJM with the information necessary to implement voice (two-way) and All Call (one-way) communications, which are essential for operation of the PJM grid.

Customer Information

PJM Member Name: ____________________________
Customer Contact
Name: _________________________________
Street: _________________________________
City, State, Zip code: _______________________________
Telephone: ____________________________
Email Address: __________________________
Customer Type: (check the one that applies)
Generation Transmission Dispatch Center Demand Side Response
PJM Transmission Zone(s) of Operation _____________________

Site Information

Total Number of MW at Site for which site is responsible: ____________
Desired date of operation: __________________
Location where the phone call is received
Location name: ___________________________________
Street: ____
City, State, Zip code: _______________________________

Two Way Voice Communication Information

Primary **dedicated** phone number for PJM Dispatch Operations to call:
____
Secondary **dedicated** phone number for PJM Dispatch Operations to call:
____

PJM All Call Information

(PJM requires a Primary phone number dedicated solely to PJM for operation and emergency communications. All Call may not terminate in voice mail, ACD or answering systems)
Primary number: ________________________
Secondary Number: _____________________ Cellular: YES NO
(May be shared lines or cellular numbers, indicate if cellular)
Tertiary Number: ________________________ Cellular: YES NO
(May be shared lines, indicate if cellular)

Approval

Please provide your PJM Contact's name: _____________________________
Contact Will Lebus (610-666-4782) or Jay Stauffer (610-666-2272) for technical assistance or questions in completing this form.

Attachment D: PJM Generating Unit Reactive Capability Curve Specification and Reporting Procedures

The purpose of this attachment is to provide further explanation of the PJM Generating Unit Reactive Capability Curve Specification and Reporting Procedures that are discussed in this manual Section 7: *Generator Operations*.

Specifications

Listed below are the specifications for the Continuous Generating Unit Reactive Capability Curve (required by PJM).

1. The following data for each point on the curve must be specified:
   A. In general, the “Unit Net MW Output” provided to the system, as measured at the low-side of the unit step-up transformer, excluding any station service load fed of the unit terminal bus, consistent with the PJM EMS model.
   B. The leading or lagging “Unit Minimum Net MVAR Limit” at the specified “Unit Net MW Output”, consistent with the PJM EMS model.
   C. The leading or lagging “Unit Maximum Net MVAR Limit” at the specified “Unit Net MW Output”, consistent with the PJM EMS model.
2. The “Unit Minimum and Maximum Net MVAR Limits” must indicate the realistic, usable capability that is sustainable during continuous long-term unit operation. This sustainable continuous capability is based on actual operating experience (or testing) and takes into consideration any normal unit or plant restrictions at 95 degrees Fahrenheit ambient or above. Therefore, the reactive capability derived results in the proven sustainable reactive capability, rather than merely reflecting the design limits of the unit.
3. A sufficient number of curve points must be provided to accurately model the full operating range and capability of the unit as described above.

Data Requirements

1. A minimum of two curve points must be provided.
2. A maximum of eight curve points may be provided.
3. The “Unit Maximum Net MVAR Limit” must be greater than (or equal to) the “Unit Minimum Net MVAR Limit” for each curve point.
4. The “Unit Minimum Net MVAR Limit” may be equal for any number of adjacent curve points.
5. The “Unit Maximum Net MVAR Limit” may be equal for any number of adjacent curve points.
6. The “Unit Net MW Output” must be increasing from the first to the last point.
7. Company can either test or apply the best engineering judgment to construct D-curve at min load points.

Data Format

Data should be provided to PJM in the format shown in the exhibit below via eDART.

(Note that if a unit's current default curve in eDART has less than eight points, a revised curve with more points can be entered in the eDART "Description" field):

	MW	Minimum MVAR	Maximum MVAR
Point 1			
Point 2			
Point 3			
Point 4			
Point 5			
Point 6			
Point 7			
Point 8			

Exhibit 20: PJM Unit Reactive Capability Curve Data Format

PJM Unit Reactive Capability Curve Reporting Process for Permanent Changes

1. Each Generation Owner/Operator must continually provide accurate permanent capability curve changes to PJM via eDART as soon as the information is available. The "New Default" field should be checked in eDART.
2. Once the accuracy of the submitted reactive capability curve is verified, PJM will permanently update the PJM Unit Reactive Capability Curves in use by PJM Operating/Planning Studies and PJM EMS Network Applications programs.

Real-Time PJM Unit Reactive Capability Reporting Process for Temporary Changes

1. Whenever a PJM unit's reactive capability is limited or reduced (or is planned to be limited or reduced) for any reason, the generator's owner/operator must immediately enter a temporary ticket via eDART. For real-time changes, the generator's owner/operator should also notify the PJM Power Dispatcher (PD) and respective LCC by phone.
2. Whenever a PJM unit's Automatic Voltage Regulation (AVR) status is off (or is planned to be off), the generator's owner/operator must immediately enter a ticket via eDART. For real-time changes, the generator's owner/operator should also notify the PJM Power Dispatcher (PD) and the respective LCC by phone.
3. The PJM PD will receive the ticket and either temporarily update the unit's reactive capability curve in use by the PJM EMS Network Applications, or will temporarily set the unit's AVR status in use by the PJM EMS Network Applications to "OFF" for the specified time period.

4. The generator's owner/operator must immediately modify the eDART ticket and notify the PJM PD and respective LCC by phone whenever the unit's normal reactive capability or AVR is restored (or is anticipated to be restored).
5. The PJM PD will either restore the unit's normal reactive capability curve in use by the PJM EMS Network Applications, or will set the unit's AVR status in use by the PJM EMS Network Applications to "ON". The PJM PD will then close the unit reactive ticket.

PJM Reactive Reserve Check (RRC)

1. Upon the request of PJM, all Transmission Owner LCC's will provide a Reactive Reserve Check (RRC) report to PJM. PJM dispatch generally requests a RRC during capacity deficient conditions or when a Heavy Load Voltage Schedule Warning is implemented, and periodically on Sundays for testing purposes.
2. This report, filled out in eDart RRC form, will include the following information within the Transmission Owner's zone:
   A. Unit MVAR Reserve (The sum of the differences between the present operating points, leading or lagging, and the lagging MVAR capability of all synchronized units.)
   B. Lagging MVAR Reserve (The sum of the lagging MVAR capability of all online condensers and Static VAR Compensators (SVCs).)
   C. Transmission Capacitor/Reactor MVAR Reserve (The sum of the nameplate MVAR values of capacitors that are capable of being energized or reactors that can be removed from service.)

Note: The first two items require open dialogue between the Transmission Owner and the Generation Owners within the Transmission Owner's footprint.

3. PJM will make the report available to LCC's.

PJM Reactive Reserve Check (RRC)			
Transmission Owner	Unit MVAR Reserve	Lagging MVAR Reserve	Transmission Capacitor/ Reactor Reserve
PJM TOTAL			

Exhibit 21: PJM Reactive Reserve Check (RRC)

PJM Actions:

1. PJM dispatcher requests LCCs to provide Reactive Reserve Check Data for the entire PJM CA or on a Control Zone basis, as necessary. An eDart RRC report ID will be via all-call.
2. PJM dispatcher takes a snapshot of reactive reserves from the PJM EMS system for comparison purposes.
3. PJM dispatcher works with LCC to resolve/rationalize reported differences in reactive reserves. PJM and TO maintain reserve data on a per Unit basis within dispatch control room in order to resolve data discrepancies.
4. PJM dispatcher / LCC / MOC modify reactive curves as appropriate to ensure accurate Security Analysis results.

PJM Member Actions:

1. Transmission / Generation dispatchers review reactive capability curves.
2. Generation Dispatchers update eDART Reactive Capability Curve to reflect changes and indicate if temporary or new default.
3. Transmission Dispatcher review eDART for any changes to reactive capability curves and update LCC EMS.
4. Transmission Dispatchers poll MOC's or specific plant regarding changes to reactive capability curves.
5. Transmission Dispatcher maintains reserve data on a per unit basis, within the control room, in order to resolve data discrepancy issues between MOC, plant, and/or PJM.
6. PJM MOCs remain on heightened awareness and notify TO/PJM regarding unit performance issues and update eDART as appropriate.
7. Transmission Dispatchers enter data in eDart via the RRC Form.

Attachment E: PJM Generator Reactive Capability Testing

Objective

The objective of reactive capability testing for generators is to improve the transmission system reliability by accurately determining generator reactive capability on a regular basis. Also, this testing could identify any conditions which are limiting the reactive capability of generating units in PJM. PJM encourages testing to be coordinated between PJM, the Generator Owner, and the local Transmission Owner to ensure that the impact on system operations is minimized. Testing is intended to demonstrate reactive capability for those conditions where reactive reserves would be required.

PJM will evaluate the Generator Reactive Capability Testing requirements contained within this document and may expand testing to various MW output levels if experience indicates it is beneficial to do so.

General Requirements

1. Units with a nominal capacity greater than 70 MW and black start units will be required to perform a reactive capability test.
2. All other units with capacity less than 70 MW and non-black start units will verify the reactive capability reported in the PJM e-DART system on a periodic basis consistent with PJM Manual 14D.
3. Generation Owners are required to test 20% of the number of their eligible assets annually, totaling 100% of their eligible assets over a 5-year period. More frequent testing may be done if the Generator Owner so chooses.
4. The PJM generator reactive capability testing period will begin on May 1 and continue through September 30. This testing cycle will repeat on an annual basis, ensuring that all designated units are tested at least once in a five year cycle.
5. Generator reactive capability testing will take place Monday thru Friday, between 0900 and 1100 hours, Eastern Time.
6. The Generator Owner will determine the best time to conduct these tests. This test may be conducted in conjunction with other testing (including the Net Demonstrated Capability testing), provided all other requirements of this test are met. All equipment will be tested with all auxiliary equipment needed for normal operation in service.
7. As an alternative, data collected during routine operation of the unit is acceptable, provided all test requirements are met.
8. The tests required are functional and do not require special instrumentation. They are designed to demonstrate that the ratings can be obtained for the time periods required under normal operating conditions for the equipment being tested.
9. Projected system conditions must permit the unit to operate at full capacity without adversely impacting system operations.
10. PJM will consider other test periods on a case by case basis, so long as proposed testing periods do not adversely impact system operations.

Testing Requirements for both Units Larger than 70 MW and Black Start Units

1. The over-excited (lagging) and under-excited (leading) reactive capability outputs (MVAR) is required to be tested at or near demonstrated capability (i.e. a single MW point test).
2. A steady active and reactive power output will be maintained during the test.
3. Exception Criteria: Lagging/Leading tests are required depending on unit type. All exceptions must be documented and reviewed by PJM and Transmission Owners. Test requirements are as follows:

Unit Type	Required Testing	Exception Criteria
Nuclear	Lagging Test	Documented Exception to Lagging based on impact to System Reliability
Black Start Near-term Steam	Lagging Test Leading Test	Not Applicable
All Other	Lagging Test 0 MVAR Test	Documented Exception to Lagging test based on impact to System Reliability
Note: Near-term Steam units are defined as steam units with a hot start plus (+) notification time of less than 8 hours. The list of units is maintained by PJM and located in Transmission Owners Restoration Plan.		

4. The reactive capability curve and minimum excitation limiter settings for each machine will be used to determine the expected reactive capability. If a machine has been tested previously, the expected reactive capability for a new test should reflect the reactive capability that was demonstrated.
5. Units are to be tested while maintaining the voltage within normal operating limits on the system bus (pre- and post-contingency voltage limits). This requirement may require a departure from scheduled voltage during the test, provided no adverse effect on the validity of test results can be demonstrated. The Generator Owner will need to coordinate between its designated LCC, PJM, and other units in order to allow the unit being tested to demonstrate its maximum reactive capability while maintaining system voltages within acceptable limits.
6. All reasonable measures shall be taken to ensure the results from the reactive capability test are based upon actual operating conditions. If it is not possible to maintain the system voltage within operating limits, for non-black start unit leading capability tests, then it is acceptable to calculate the non-black start unit leading

reactive capability quantities. Calculated test results will not be acceptable on an on-going basis. Black start units and Near-term Steam units are required to test both leading and lagging reactive capability.

7. For hydrogen-cooled generators, the hydrogen pressure should be raised to the normal operation pressure. If the hydrogen pressure cannot be raised, then the reason for this condition should be documented and the appropriate reactive capability curve should be used.

8. The over-excited reactive capability test should be conducted for a minimum of one hour. Data for the under-excited reactive capability test may be recorded as soon as a limit is encountered.

9. When the maximum sustained over-excited and under-excited reactive output during the test is achieved, the MW and MVAr outputs at the generator terminals (low side gross), auxiliaries, the generator step-up transformer (GSU) primary (low side net, after auxiliaries), and the GSU secondary (high side net) should be recorded.

   If metering is unavailable, it may be necessary to calculate some of these quantities. A note should be provided in the “Remarks” section of “Lagging and Leading/Zero Form R” for points which are calculated.

   PJM will evaluate the reported values as compared to the average values consistent with requirements. The average values will serve as the basis for modifying the default reactive curves within eDart.

10. During the test, the scheduled and actual voltages at the system bus and the generator terminals should also be recorded. In addition, the nameplate GSU impedance, MVA rating, primary and secondary voltage ratings and available tap settings, and the existing GSU tap setting should be provided.

11. The reasons for any limit to unit reactive capability during the test should also be specified (for example, reactive capability curve limit, minimum excitation limiter settings, field current limitation, generator voltage, auxiliary bus voltage, system voltage limits, generator vibration, generator temperatures, hydrogen pressure restriction, shorted rotor turns, etc.) in the remarks section.

Notification and Reporting Requirements

If non-cost operations (the adjustment of generator MVAR output or the movement of PAR or LTC transformer taps) or off-cost operations are required to accommodate the test, PJM will communicate these requests directly to the appropriate LCCs and MOCs.

MOC Actions:

- Proposed testing dates/times should be communicated via eDart to the PJM Dispatch, PJM Reliability Engineer and LCC no later than noon 3 business days prior to the test, ensuring testing impacts are incorporated into day-ahead studies. PJM and LCCs will consider shorter notification times and try to accommodate reactive testing while ensuring that operating limits are not violated.

- The test notification will be submitted using a “MVAR Test” Ticket in which the test duration should be provided, as well as any additional relevant information for the test within the description field.

- Prior to the test scheduling, the MOC (Generation Owner) shall confirm with PJM Reliability Engineer that MW and MVAR data is being provided to PJM via ICCP. If issues are identified, they are required to be resolved before proceeding with the test scheduling of the unit
- Any scheduled or unscheduled maintenance work on the unit scheduled for testing must be complete and all eDART tickets cleared prior to contacting PJM for the purpose of initiating the study process.
- The MOC will contact PJM Reliability Engineer at least three hours prior to the start of the scheduled testing in order to initiate the real-time study process.
- Real-time testing should be coordinated with LCC and PJM Transmission dispatchers. At least 30 minutes notice should be provided to allow PJM and LCC operators to adjust the system to ensure testing does not result in voltage limit violations.
- The MOC will coordinate any required transmission mitigation steps to resolve internal plant limitations with PJM Reliability Engineer.
- If testing must be canceled or rescheduled, the MOC will inform PJM Reliability Engineer as soon as possible.
- The MOC will coordinate the implementation of their portion of the exit strategy with PJM, if required.
- Generator Owner shall submit complete PJM Leading and/or Lagging Test Form R to reactivetesting@pjm.com within 30 calendar days after completion of the testing.
- The MOC will coordinate all actions with PJM dispatch.

LCC Actions:

- The appropriate LCCs will conduct studies in accordance with established company procedure in order to determine the effect of scheduled testing on their systems.
- LCC should contact PJM Reliability Engineer with any possible concerns regarding the scheduled testing.
- LCC support staff will ensure that the LCC operators are aware of scheduled reactive capability tests and communicate the pre-studied mitigating action plan.
- Prior to studying the test, the LCC will verify, with the PJM Reliability Engineer and the generating station, the expected MW and MVAR output levels of the unit during testing, and ensure that the AVR is in service.
- The LCC will contact the PJM Reliability Engineer no later than two hours and 15 minutes prior to the scheduled test start time in order to discuss the results of their studies and the mitigating steps required, if any.
- The LCC will discuss, coordinate, and implement any actions necessary as required by mitigation strategies with PJM prior to the start of testing.
- The LCC will communicate MVAR output step changes to the testing unit in coordination with PJM. In general, MVAR step changes should be no greater than 100 MVAR increments.

- If testing must be canceled or rescheduled, the LCC will inform PJM Reliability Engineer as soon as possible.
- The LCC will coordinate the implementation of their portion of the exit strategy with PJM, if required.
- The LCC will coordinate all actions through PJM Reliability Engineer.

PJM Actions:

- All testing requests will be reviewed by PJM Reliability Engineers and Power Directors to ensure that there is no conflict between the testing and any planned transmission outage. PJM will give the MOC a suggestion for a more appropriate date and time to conduct the test, if necessary.
- PJM Reliability Engineer shall verify the accuracy of the telemetry data with the generation owners prior to commencing the test. If issues are identified, they are required to be resolved before proceeding with the test scheduling of the unit
- PJM Reliability Engineer and Power Director will review and approve the test in accordance with the established PJM procedure.
- PJM Reliability Engineer will ensure that PJM dispatch is aware of scheduled reactive capability tests and communicate the pre-studied mitigating action plan via the PJM Transmission Log.
- Once the PJM Reliability Engineer is contacted by the MOC, they will contact the LCCs of all regions concerned in order to initiate the transmission operator's study process. They will verify the expected unit output levels with the LCC and ensure that the AVR is in service.
- PJM Reliability Engineer will re-evaluate the pre-studied mitigating action plan prior to test commencement and communicate any necessary adjustments to the impacted parties.
- PJM Reliability Engineer and/or Dispatch will discuss possible mitigation strategies with the appropriate LCCs.
- PJM Reliability Engineer will contact the MOC no later than two hours prior to scheduled testing to inform them whether mitigation steps will be required.
- PJM Reliability Engineer will coordinate with the appropriate MOCs and LCCs in order to implement the selected mitigation strategy.
- PJM Reliability Engineer will coordinate with the LCC in making MVAR output step changes with the testing unit.
- If the testing must be cancelled or rescheduled, PJM Reliability Engineer will contact the MOC and LCCs as soon as possible.
- PJM Reliability Engineer will coordinate the implementation of the exit strategy with the MOC and LCCs, if required.
- PJM Reliability Engineer will coordinate all actions and communications between the MOC and LCCs.

Test Cancellation

PJM dispatch and/or the impacted parties may cancel the generator reactive capability testing for the following reasons:

- Internal planning issues.
- Emergency procedures.
- Inability to control actual or post-contingency voltage issues created by scheduled testing.
- Any operating issues created on LCC equipment not monitored by PJM.

Cancellation of the generator reactive capability test will be communicated to all impacted parties.

PJM will document all cancellations and terminations including the party responsible and the reason for the cancellation or termination.

Voltage Schedules

Adjustments may need to be made to local voltage schedules in order to accommodate the scheduled testing. These adjustments will be considered and studied on a case by case basis.

Note: Deviate from voltage schedule to demonstrate reactive capability while monitoring impacts to limits using SA packages.

PJM will discuss the changes with the appropriate LCC and if the recommendation does not cause a violation of a defined limitation, the LCC should implement the PJM request.

PJM will retain its control of the reactive facilities, such as transmission capacitors, LTCs, and generator MVAR output.

If internal plant or LCC limits restrict the request, PJM dispatch will study the limitations and recommend changes to plant facilities if appropriate.

If the recommended changes cannot be implemented due to equipment or facility limitations, other options will be considered, including test cancellation or rescheduling.

Exit Strategy

Risk

PJM will not allow scheduled generator reactive capability testing to place the system in an unacceptable state. However, there is always the possibility of equipment failure resulting in unplanned situational constraints that would require immediate remedial action.

Requirements

The following are steps that will be considered and agreed upon prior to allowing the scheduled generator reactive capability testing;

Each scheduled test will be studied and approved on a case by case basis.

All required mitigation steps will be agreed to and coordinated with all concerned parties, to include PJM Reliability Engineer, the responsible MOC, and the appropriate LCCs, prior to the scheduled testing.

Parameters

PJM will NOT allow operation over any applicable post-contingency STE or LTE ratings.

PJM will NOT allow operation over any applicable pre-contingency normal rating.

In the event of a facility rating discrepancy between PJM and the LCC that cannot be resolved, PJM will default to the most conservative limit.

In the event that the testing results in an unexpected thermal or voltage violation, standard mitigation steps will be taken to return the facilities in violation back to normal limits within fifteen minutes.

The mitigation steps taken will not cause limit violations on any other company's equipment or facilities.

Post-Test Evaluation

PJM will provide feedback on a periodic basis to generation owners on the status of their reactive capability test results. PJM will also provide the results of generation reactive capability tests to the appropriate LCC operator.

PJM will analyze the reactive capability test results in the same calendar year in which the reactive capability test was performed for the unit.

PJM Staff will conduct periodic audits of generator reactive capability test results and will provide summary report information to the PJM System Operations Subcommittee and the PJM Operations Committee on a periodic basis.

Test Evaluation

PJM will evaluate each unit's reactive capability test results against its stated reactive capability limits modeled within the PJM EMS. This evaluation will determine which units performed over, under, or within 5% of their stated limits, as well as what follow-up steps are necessary to ensure that the correct information is modeled within the PJM EMS.

Units Testing Within 5% of Stated Limits

Units with test results within 5% of their stated limits will be considered as having fully demonstrated their stated reactive capability.

PJM will notify the MOC that their units achieved their reactive capability, and no further action will be required.

Units Testing Over 5% of Stated Limits

Units with test results over 5% of their stated limits will be considered as having fully demonstrated their stated reactive capability.

PJM will notify the MOC that their units exceeded their stated reactive capability and will propose that they increase the reactive capability modeled within the PJM EMS by entering New-Default eDART MVAR ticket.

Units Testing Below 5% of Stated Limits

Units with test results under 5% of their stated limits will not be considered as having demonstrated their stated reactive capability.

PJM will determine which units not demonstrated due to either internal or external operational limitations based on reasons documented within the submitted test results.

For units that claimed external operational limitations,

A. PJM will perform further analysis to confirm external limitations and possible remedial measures in the event of future attempts by the MOC to demonstrate the unit's reactive capability.

B. If an external limitation is confirmed, PJM will provide confirmation to the MOC that their units performed below their stated reactive capability due to external limitations and will not require any further action.

C. If no external limitation is confirmed, PJM will require that the MOC either permanently reduces the reactive capability modeled within the PJM EMS by entering a "New Default" eDART MVAR ticket or retest to demonstrates the stated capability of the unit.

D. If the MOC chooses to retest the unit, PJM will require that a temporary eDART MVAR ticket be submitted that will remain active until the unit demonstrates the original stated capability.

For units that claimed internal operational limitations,

A. PJM will notify the MOC that their units performed below their stated reactive capability

B. PJM will require that the MOC either permanently reduces the reactive capability modeled within the PJM EMS by entering a "New Default" eDART MVAR ticket or retest to demonstrates the stated capability of the unit.

C. If the MOC chooses to retest the unit, PJM will require that a temporary eDART MVAR ticket be submitted that will remain active until the unit demonstrates the original stated capability.

Glossary

Scheduled Voltage—The voltage level normally maintained at the system bus during peak load conditions.

Gross Reactive Capability—The maximum sustained overexcited and under-excited reactive output, which generating equipment is expected to produce under normal operating conditions.

Net Reactive Capability at the GSU Primary—The maximum sustained overexcited and under-excited reactive output exclusive of auxiliary usage expected to produce under normal operating conditions.

Net Reactive Capability to the System—The maximum sustained overexcited and under-excited reactive output exclusive of auxiliary usage and GSU reactive power losses expected to produce under normal operating conditions.

GSU (Generator Step-Up Transformer)—An Inductive stationary device that transfers electrical energy from generator voltage to a higher transmission voltage.

Lagging Form R

Net Demonstrated Lagging Reactive Capability Test Data

eDart Ticket # ______________________

Company ______________________ Reported By ______________________

Plant ______________________ Unit ______________________

Date of Test ______________________ Time of Test: Begin / End __________ / __________

Ambient Temperature, F ______________________ Ambient Relative Humidity ______________________

Normal Hydrogen Pressure, PSIG ______________________ Actual Hydrogen Pressure, PSIG ______________________

Blackstart: ☐ Yes ☐ No Near-Term Steam: ☐ Yes ☐ No ☐ N/A

Time of Measurement	Instantaneous Gross Gen.		Instantaneous Aux. Power		Net Gen.@ GSU Low-Side		Net Gen.@ GSU High-Side	
	MW ☐	MVAr ☐	MW ☐	MVAr ☐	MW ☐	MVAr ☐	MW ☐	MVAr ☐
Start of Test								
15 min								
30 min								
45 min								
End of Test								
Average of Test**								
Stated Capability								

* Please check boxes for telemetered data ** Average of all test data

	Phase 1	Phase 2	Phase 3
Generator Bus Voltages	______ kV	______ kV	______ kV
Auxiliary Bus Voltages	______ kV	______ kV	______ kV
System Bus Voltages	______ kV	______ kV	______ kV

Generator Voltage Schedule ______________ kV Generator Voltage PT Ratio ______________

System Voltage Schedule ______________ kV System Voltage PT Ratio ______________

GSU Nameplate Data

Tap Setting: ______________ kV Impedance: ______________ % Capability: ______________ MVA

Remarks: (Plant Limitations)

Remarks: (System Limitations)

Remarks: (Other Limitations)

Leading / Zero Form R

Net Demonstrated Leading / Zero Reactive Capability Test Data

(leading / zero form may not be necessary, depending on unit type)

eDart Ticket # ______________________ Leading: ☐ Zero: ☐

Company ______________________ Reported By ______________________

Plant ______________________ Unit ______________________

Date of Test ______________________ Time of Test: Begin / End __________ / __________

Ambient Temperature, F ______________________ Ambient Relative Humidity ______________________

Normal Hydrogen Pressure, PSIG ______________________ Actual Hydrogen Pressure, PSIG ______________________

Blackstart: ☐ Yes ☐ No Near-Term Steam: ☐ Yes ☐ No ☐ N/A

Readings are to be recorded as soon as leading / zero limit is encountered

Time of Measurement	Instantaneous Gross Gen.		Instantaneous Aux. Power		Net Gen.@ GSU Low-Side		Net Gen.@ GSU High-Side	
	MW ☐	MVAr ☐	MW ☐	MVAr ☐	MW ☐	MVAr ☐	MW ☐	MVAr ☐
Instantaneous								
Average of Test**								
Stated Capability								

* Please check boxes for telemetered data ** Average of all test data

	Phase 1	Phase 2	Phase 3
Generator Bus Voltages	__________ kV	__________ kV	__________ kV
Auxiliary Bus Voltages	__________ kV	__________ kV	__________ kV
System Bus Voltages	__________ kV	__________ kV	__________ kV

Generator Voltage Schedule __________ kV Generator Voltage PT Ratio __________

System Voltage Schedule __________ kV System Voltage PT Ratio __________

GSU Nameplate Data

Tap Setting: __________ kV Impedance: __________ % Capability: __________ MVA

Remarks: (Plant Limitations)

Remarks: (System Limitations)

Remarks: (Other Limitations)

Attachment F: Generator Reactive Capability Test Study Process

Objective

The objective purpose of this attachment is to demonstrate the process which the PJM Reliability Engineers will use to study the feasibility of generator reactive capability test.

Study Process – Example

All generator reactive capability testing will be studied by PJM prior to the scheduled testing date, in accordance with the established PJM procedures.

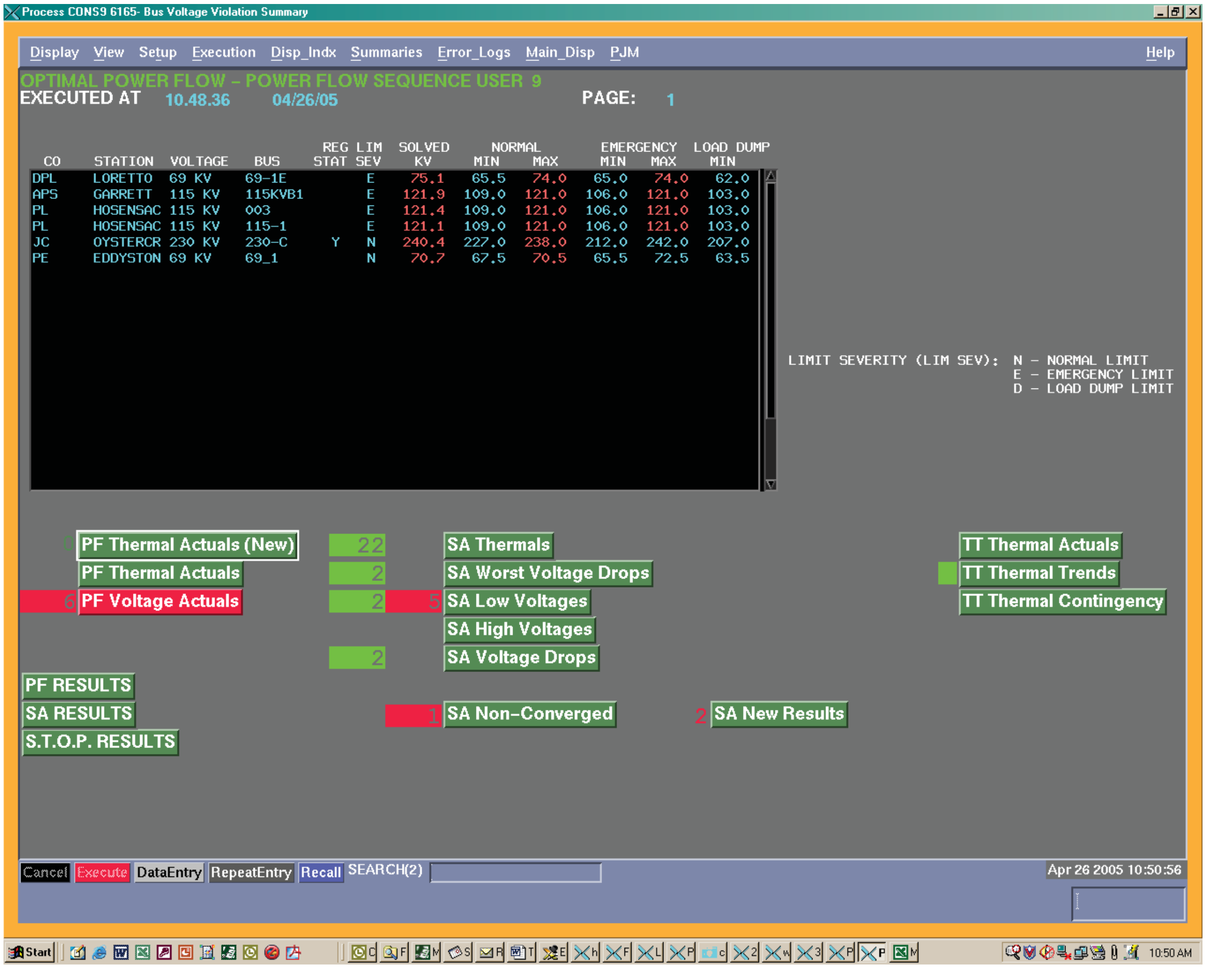
Each test will also be studied in real-time, prior to the start of the test, in order to verify that there will be no adverse effect on system operations. If it is determined that the testing will cause an actual or post-contingency violation that cannot be mitigated, the testing will be rescheduled.

Purpose:

- The purpose of this example is to demonstrate the process which the PJM Reliability Engineers will use in studying the effects of scheduled generator reactive capability testing, using a large nuclear unit on the PJM 500kv system. This process will be used for day(s)-ahead and real-time studies. This particular example was done using a real-time SE snapshot.
- The purpose of the study is to identify any potential problems caused by the unit's reactive capability testing, and to determine the steps required in mitigating those problems. Any unit reactive capability testing that poses a threat to system reliability or results in off-cost operations will be canceled.

Scenario:

- The case used in this study was a State Estimator case from April 18, 2005, shortly after 0800 hrs. The PJM RTO system load at that time was approximately 66107 MW. There were no post-contingency thermal problems at the time, and the only voltage issues were some post-contingency low voltages in the COMED system and a few marginally high voltage actuals scattered across the system.
- The next exhibit is a screenshot from the PJM EMS showing system voltage actuals prior to testing.



CO	STATION	VOLTAGE	BUS	REG STAT	LIM SEV	SOLVED KV	NORMAL MIN	NORMAL MAX	EMERGENCY MIN	EMERGENCY MAX	LOAD DUMP MIN
DPL	LORETTO	69 KV	69-1E		E	75.1	65.5	74.0	65.0	74.0	62.0
APS	GARRETT	115 KV	115KVB1		E	121.9	109.0	121.0	106.0	121.0	103.0
PL	HOSENSAC	115 KV	003		E	121.4	109.0	121.0	106.0	121.0	103.0
PL	HOSENSAC	115 KV	115-1		E	121.1	109.0	121.0	106.0	121.0	103.0
JC	OYSTERCR	230 KV	230-C	Y	N	240.4	227.0	238.0	212.0	242.0	207.0
PE	EDDYSTON	69 KV	69_1		N	70.7	67.5	70.5	65.5	72.5	63.5

Exhibit 22: Voltage Actuals Prior to Test

- The PJM Reliability Engineers will initiate his study by taking a ‘snapshot’ of the real-time system. This ‘snapshot’ will need to be adjusted to reflect anticipated changes to system conditions prior to the scheduled test time.
- In order to correctly model the unit for testing, the PJM Reliability Engineer will need to go to the ‘Gen. KV/MVAR Parameter Changes’ display and adjust the ‘DES. MVAR’, ‘MVAR MIN’ and ‘MVAR MAX’ to match the maximum rated MVAR output of the unit at the appropriate MW level. This number should match the number verified with the LCC.
- In order to properly recognize mitigation strategies once the MVAR output level has been adjusted, the PJM Reliability Engineer will need to limit the response of the reactive resources in the appropriate transmission zones. This will cause the study case to assume the following:
    - LTC transformers are locked.
    - Phase angle regulators hold a fixed angle.

- Switched capacitors are locked.
- Generators will not control local voltage.
- Load is modeled at constant MW and MVAR.

- This process is the same as when doing an open-ended voltage study. An example display is shown in the exhibit below.

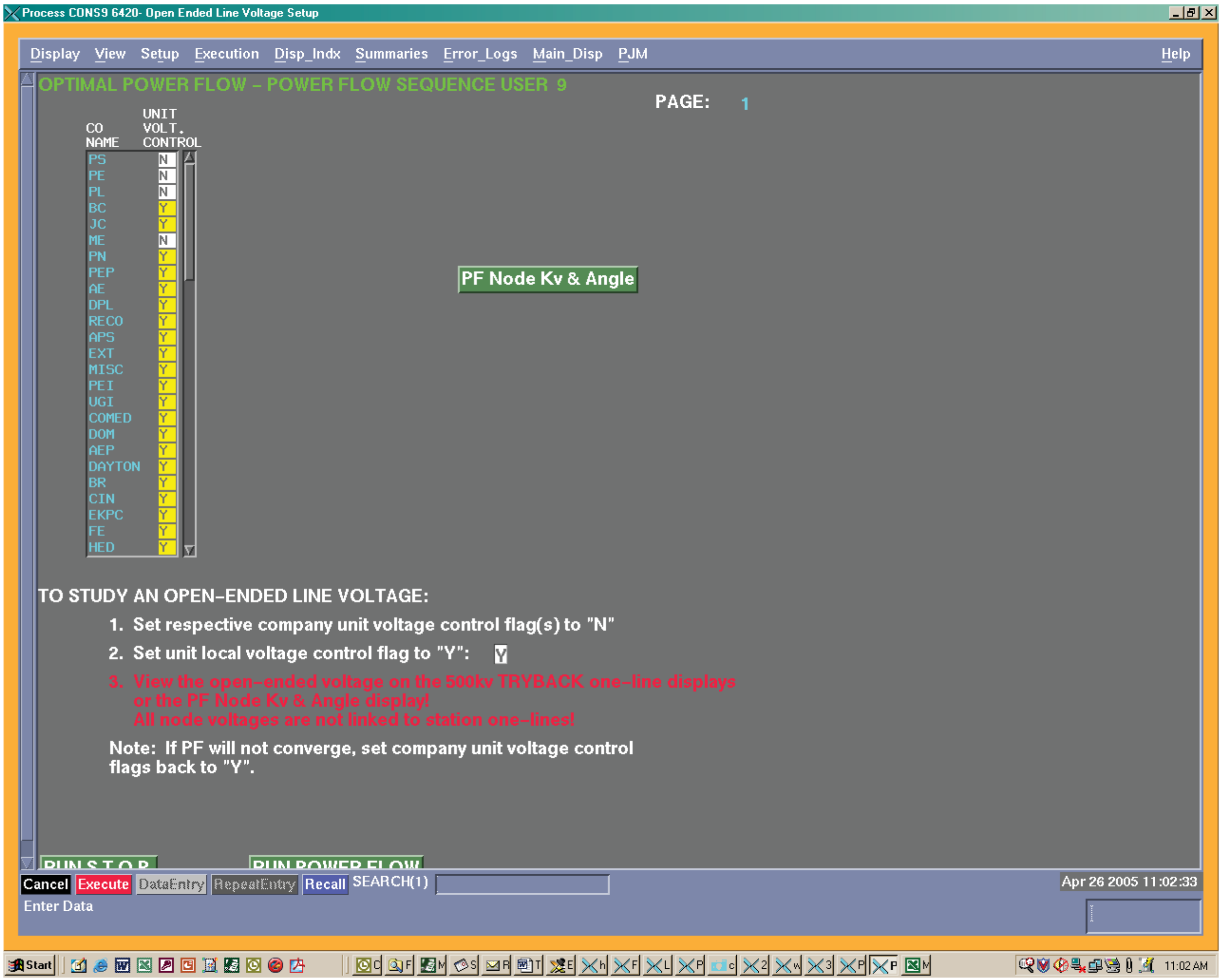


Exhibit 23: Open-Ended Line Voltage Setup Display

- Run power-flow and advanced applications. Once the advanced applications have run, the PJM Reliability Engineer will analyze the results. Example results of voltage actuals, prior to implementing mitigating actions, are shown in the next screenshot.

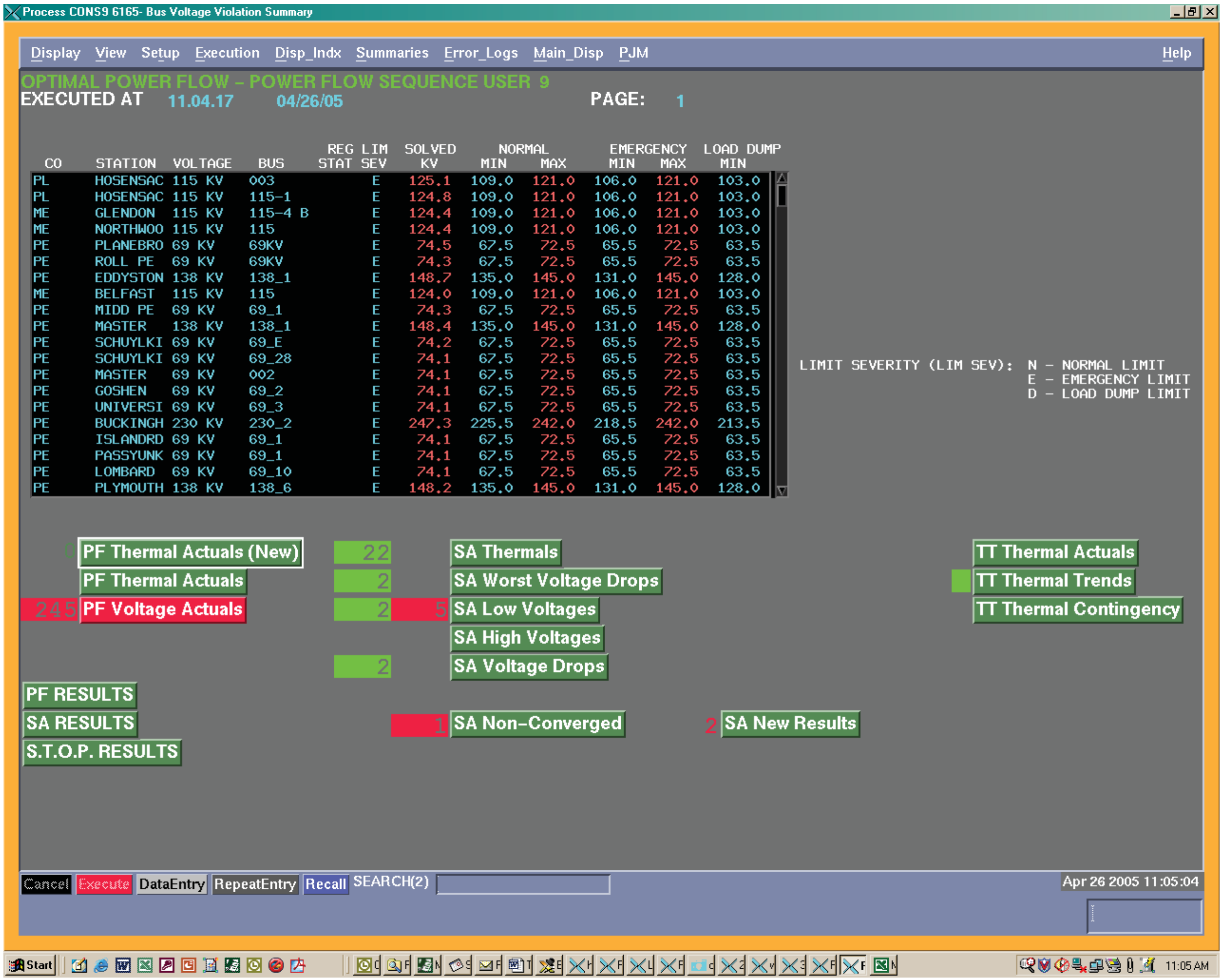


Exhibit 24: Voltage Actuals Prior to Mitigation Steps

- The PJM Reliability Engineer will then determine if the mitigating strategy identified in the day(s)-ahead studies are applicable based on projected system conditions. The PJM Reliability Engineer will finalize a set of recommended mitigation steps to take in order to accommodate the testing, and communicate this strategy with the affected LCC and MOC. The LCC and MOC may raise any concerns or additional issues at that time. Mitigation strategies include adjustments to capacitors, reactors, LTC, or surrounding unit MVAR outputs.
- Once the PJM Reliability Engineer and the LCC have developed and confirmed a set of mitigation steps, PJM will contact the MOC and inform them that mitigation steps must be taken prior to allowing the unit to test. The PJM Reliability Engineer must contact the MOC at least two hours prior to the start of testing.
- The PJM Reliability Engineer and the LCC will take the appropriate actions prior to the unit testing. In this example, 500 kv capacitors at or near the nuclear station were removed from service.

- The resultant voltage actuals, after the mitigation steps, are shown in the next screenshot.

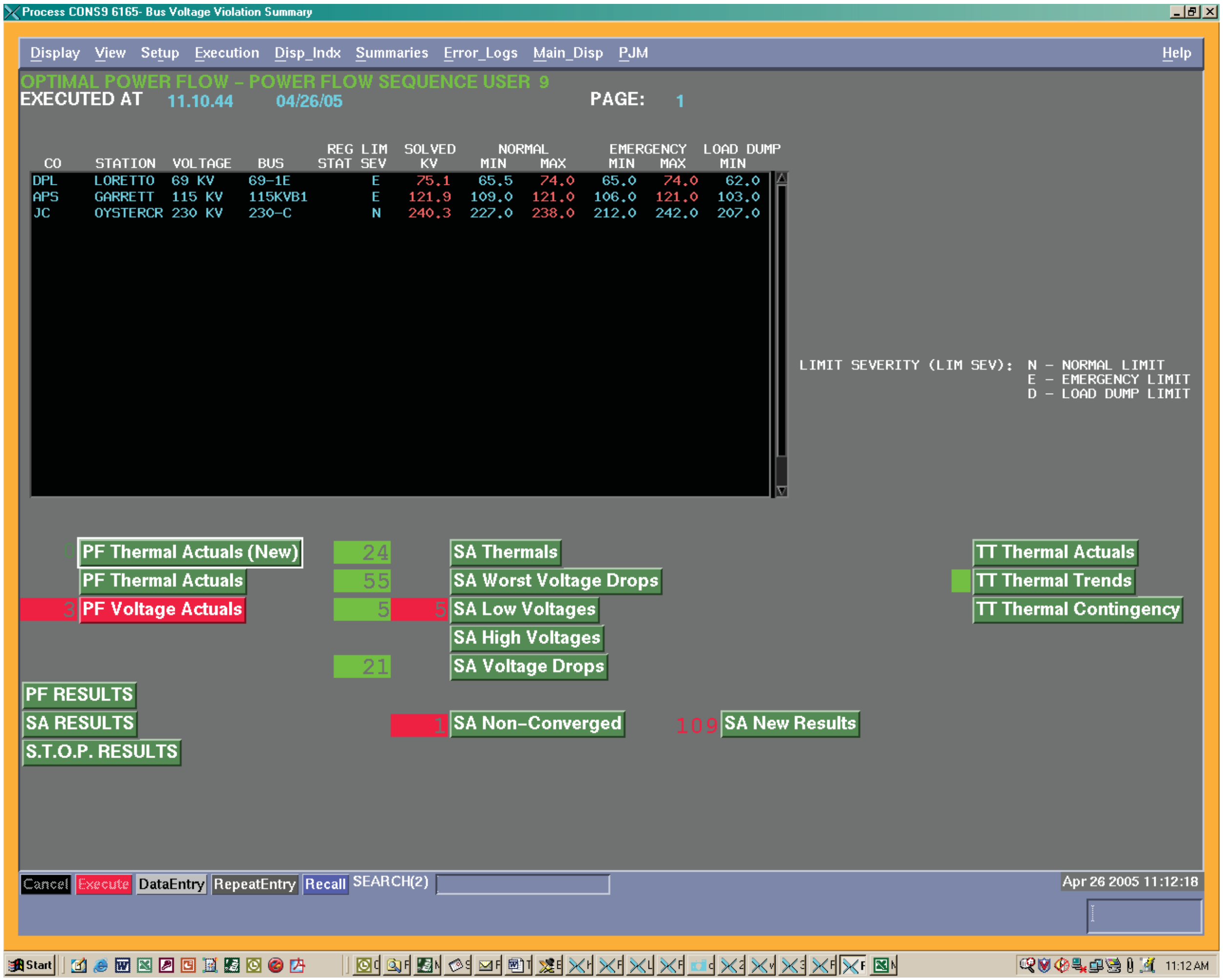


Exhibit 25: Voltage Actuals after Mitigation Steps

- Once the appropriate mitigation steps have been taken, the PJM Reliability Engineer will inform the MOC that their unit is clear for testing.
- The required mitigation steps may need to be implemented in stages, as the unit moves to its' full MVAR output level. In this example, as the nuclear unit increases its reactive output, the capacitors would be removed as needed in order to control voltages on the 500kv and 230kv systems.

Note: The mitigation strategy identified in this case may or may not be the strategy selected. Based on projected proximity to the Eastern Reactive Transfer Limit, the strategy selected may have included a combination of removing capacitors from service and reducing local unit reactive output. The PJM Power Director would discuss all possible options with the LCC.

Attachment G: PJM Generator Markets and Operations Process Flow Diagram

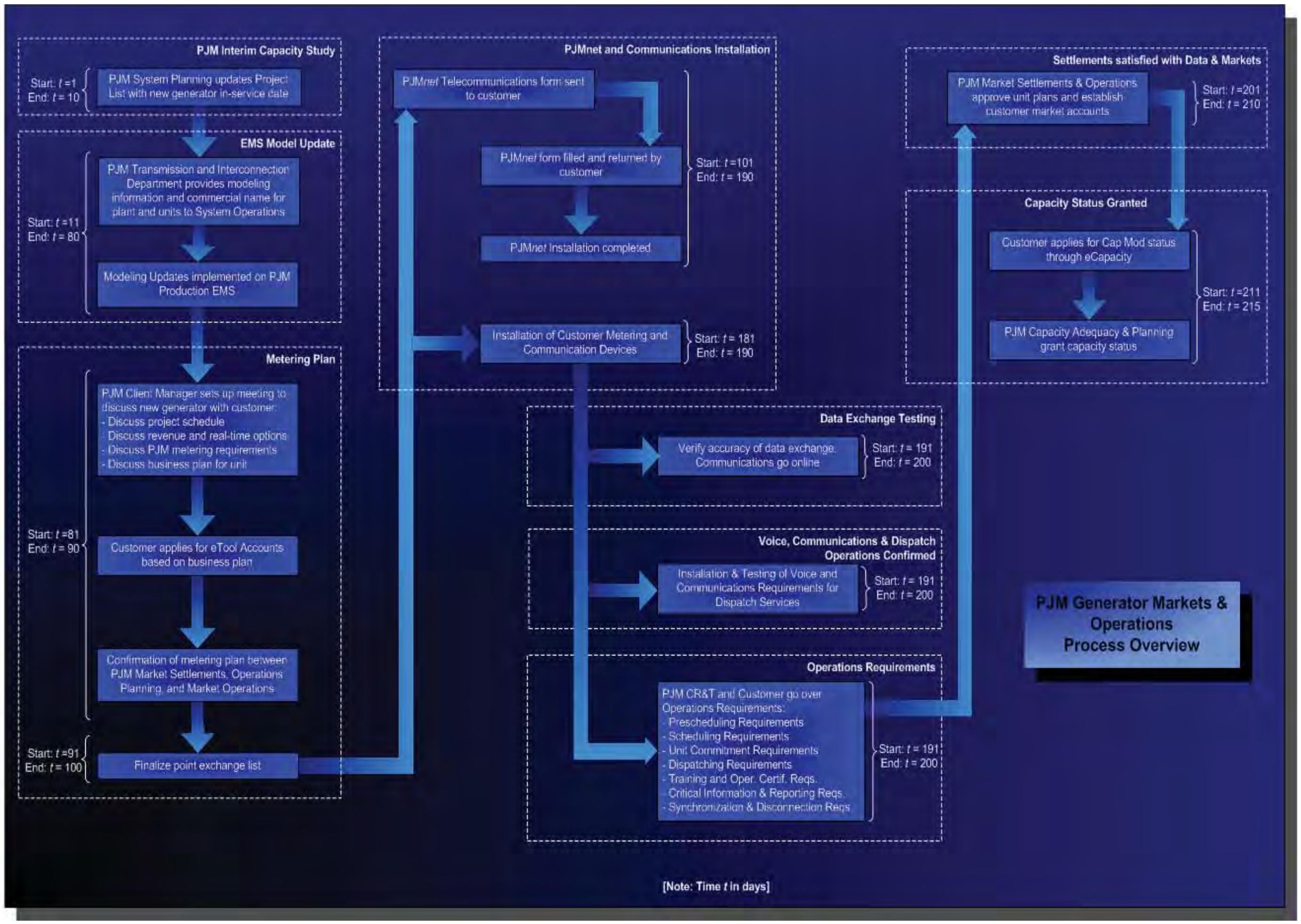


Exhibit 26: PJM Generator Markets and Operations Process Overview

Attachment H: Implementation Team Role Clarity Diagram

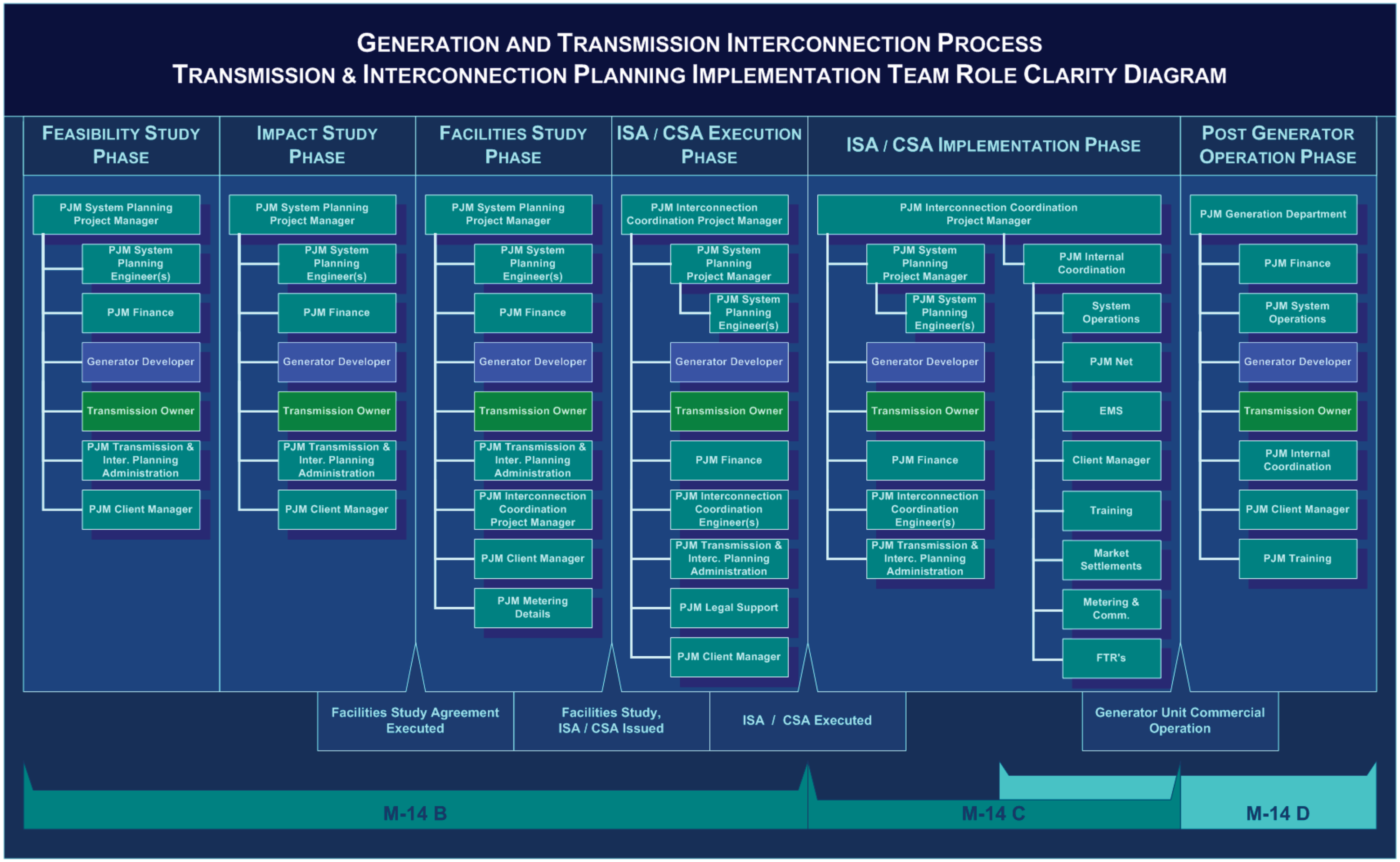


Exhibit 27: Implementation Team Role Clarity Diagram

Attachment I: Generator Data Confidentiality Agreement

GENERATOR DATA

CONFIDENTIALITY AGREEMENT

This GENERATOR DATA CONFIDENTIALITY AGREEMENT (“Agreement”) is made and entered into by _________ a (state of organization) (type of organization) (hereinafter “Transmission Owner”), __________ a _(state of organization) (type of organization) (hereinafter “Generator”), and PJM Interconnection, L.L.C. a Delaware Limited Liability Company (hereinafter “PJM”) (each may be referred to herein as “Party” or collectively as “Parties”).

WITNESSETH

WHEREAS, Transmission Owner and Generator recognize that, while PJM has the overall power system reliability responsibility in the PJM region, owners of transmission facilities within the PJM region perform certain reliability functions with respect to their individual transmission systems and distribution systems.

WHEREAS, Generator acknowledges that PJM historically has provided certain confidential data regarding Generator’s generating facilities to Transmission Owner, and that the Confidential Information specified in the Generator-Data Release Matrix incorporated herein by reference may be needed to allow the Transmission Owner to perform security analysis and to carry out the reliability functions described above, Generator agrees that PJM may provide such Confidential Information to Transmission Owner pursuant to the terms and conditions of this Agreement.

WHEREAS, Transmission Owner acknowledges that Generator’s data, is confidential and must be protected in accordance with the terms and conditions of this Agreement.

WHEREAS, the Parties intend to enter into this Agreement to provide for that data sharing and confidentiality of the data.

NOW, THEREFORE, Transmission Owner, Generator, and PJM agree as follows:

1. Definitions

a. **Confidential Information** "Confidential Information" is defined as (i) Generator data provided or to be provided by PJM to Transmission Owner regarding Generator’s generating facilities pursuant to this Agreement and specified in the Generator-Data Release Matrix, as it may be modified from time to time; and (ii) Generator data already in the Transmission Owner’s possession upon the effective date of this Agreement. Confidential Information shall be disclosed only to the entities listed in Section 2.c.1. of this Agreement and only used to enable Transmission Owner to perform Transmission Owner’s Reliability Function.

b. **Transmission Function** “Transmission Function” is defined as the “transmission system operations” or “reliability functions” of the Transmission Owner as those terms are used in the Federal Energy Regulatory Commission’s (“FERC”) standards of conduct in 18 C.F.R. § 358.

c. **Transmission Owner’s Reliability Function** “Transmission Owner’s Reliability Function” consists of real-time energy management system applications, state estimator and security analyses, monitoring of its transmission system and underlying distribution system, transmission outage planning, operating reliability and operator training simulator, power flow analyses, contingency operating procedures for peak summer and peak winter load conditions, planned transmission circuit outage feasibility analyses, operating procedure development, and peak load analyses. The Parties may mutually agree to include in the definition of Transmission Owner's Reliability Function additional monitoring responsibilities not listed herein.

d. **Generator–Data Release Matrix** The Generator-Data Release Matrix, as it may be modified from time to time pursuant to Section 5 of this Agreement, specifies the Confidential Information that PJM is authorized to provide Transmission Owner pursuant to this Agreement. The Generator-Data Release Matrix is incorporated by reference into this Agreement. The Generator-Data Release Matrix shall include: (i) the name of the Transmission Owner; (ii) the name of the Generator; (iii) the identity of the generating facilities with regard to which PJM is authorized to provide Confidential Information to Transmission Owner pursuant to this Agreement; and (iv) the type of Confidential Information (real time and/or scheduled data) PJM is authorized to provide to Transmission Owner pursuant to this Agreement. The Generator-Data Release Matrix shall be signed by authorized representatives of the Generator and the Transmission Owner. Transmission Owner shall provide PJM with a copy of the initially executed Generator-Data Release Matrix and any modified Generator-Data Release Matrices executed thereafter. In no event will PJM provide Confidential Information to Transmission Owner pursuant to this Agreement prior to receipt of the Generator-Data Release Matrix.

2. Rights and Responsibilities

a. **Generator's Authorizations.** During the term of this Agreement, Generator authorizes PJM to provide to the Transmission Owner the Confidential Information specified in the Generator-Data Release Matrix, as it may be modified from time to time, pursuant to the terms and conditions of this Agreement.

b. **PJM's Responsibilities**

1. Upon receipt of the initial Generator-Data Release Matrix and/or any subsequent modified Generator-Release Matrices, PJM shall provide only the Confidential Information as defined in the initial Generator-Data Release Matrix or subsequent modified Generator-Release Matrices to the Transmission Owner. PJM shall provide the Confidential Information as defined in the Generator-Data Release Matrix or subsequent modified Generator-Data Release Matrices on an on-going basis until this Agreement is terminated or superseded.

2. Subject to Section 2.c. of this Agreement, PJM shall provide Confidential Information only to the Transmission Owner's Transmission Function personnel.

c. **Transmission Owner's Rights and Responsibilities**

1. Transmission Owner shall not disclose Confidential Information to any person except as permitted under this Agreement. Transmission Owner may disclose Confidential Information only to the Transmission Owner's Transmission Function personnel and other employees,

officers, directors, agents, consultants, contractors, attorneys, accountants, and advisors, including non-employees, (collectively "Representatives"), whose access is necessary, in the reasonable discretion of Transmission Owner, to perform Transmission Owner's Reliability Function or to interpret or implement this Agreement.

2. Section 2.c.1 notwithstanding, consistent with 18 C.F.R. § 358.5, the Transmission Owner shall not disclose Confidential Information to employees engaged in marketing or sales or any employee of any energy affiliate as defined in 18 C.F.R. § 358.3.

3. Transmission Owner shall be responsible for any breach of this Agreement by any of its Representatives. Transmission Owner promptly shall notify Generator and PJM of any actual or suspected breach of this Agreement by Transmission Owner or any of its Representatives. Such notification shall include the nature and cause of the breach, the Confidential Information that was disclosed, the identity of the persons involved, and actions taken by Transmission Owner to correct or mitigate the breach.

4. The Transmission Owner may disclose Confidential Information only to Representatives who have been informed of both the confidentiality restrictions contained in this Agreement and who have executed a Confidentiality Agreement Certification ("Certification") (a pro forma form of which is attached) under which they are bound by the terms and conditions of this Agreement.

5. Transmission Owner may use the Confidential Information only for the purpose of performing Transmission Owner's Reliability Function and shall not otherwise use the Confidential Information for its own benefit or for the benefit of any other person.

6. Transmission Owner does not, by virtue of this Agreement or otherwise, acquire any right title, or any interest of any kind in the Confidential Information. All Confidential Information shall remain the property of Generator. No license or other right under any patent or other proprietary right is granted or implied by the conveyance of the Confidential Information.

7. At Generator's expense, upon reasonable notice, during business hours, and at a date and time reasonably agreed upon by the Generator and Transmission Owner, Transmission Owner shall permit the Generator, and Generator shall have the right, to audit compliance with this Agreement to the extent reasonably necessary and remove all Confidential Information not destroyed in compliance with this Agreement. The Generator's right shall include the right to examine the records of Transmission Owner but not the right to examine information relating to other entities that own generating or transmission facilities.

8. Notwithstanding anything in this Agreement to the contrary, if required by applicable law or in the course of administrative or judicial proceedings, except for FERC proceedings, to disclose to a third party Confidential

Information, Transmission Owner shall be permitted to make disclosure of such Confidential Information; provided, however, that as soon as reasonably practicable after the Transmission Owner learns of the disclosure requirement and prior to making disclosure, Transmission Owner shall notify Generator of the disclosure requirement and Generator may direct, at its sole discretion and cost, any challenge to, or defense against, the disclosure requirement and Transmission Owner shall cooperate to the maximum extent practicable to minimize the disclosure of Confidential Information consistent with applicable law. In the event that the FERC or its staff, during the course of an investigation or otherwise, requests Confidential Information from Transmission Owner, Transmission Owner shall provide the requested Confidential Information to the FERC or its staff; provided that, consistent with 18 C.F.R. § 388.112, Transmission Owner must request that the Confidential Information be treated as confidential and non-public by the FERC and its staff and that the information be withheld from public disclosure. Transmission Owner shall notify Generator when it is notified by FERC or its staff, that a request for disclosure of, or decision to disclose, Confidential Information has been received, at which time Generator may respond before such Confidential Information would be made public, pursuant to 18 C.F.R. § 388.112.

9. Transmission Owner shall maintain a current list of all Representatives, (including their job titles, duties and responsibilities, employee or contract status, and the name

of the organization for which they are employed) who have signed the Certification and thereby are permitted access to the Confidential Information. Transmission Owner shall provide this list to Generator and PJM initially within 30 days of the execution of this Agreement and thereafter upon request. The Generator may challenge whether the Transmission Owner's release of the Confidential Information to Representatives on the above-described list is consistent with the terms of this Agreement by providing written notice to the Transmission Owner including the rationale for the challenge. Any dispute arising under this section shall be resolved pursuant to the PJM dispute resolution procedures set forth in Schedule 5 of the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., as may be amended from time to time ("PJM Operating Agreement").

10. Subject to Subsection 2.c.8 above, Transmission Owner shall protect and keep confidential all Confidential Information it receives from PJM. It may, copy, post, distribute, disclose or disseminate the Confidential Information only in the following manner. Transmission Owner may make a limited number of copies of written or electronic materials to enable Transmission Owner adequately to use the Confidential Information within the terms and conditions of this Agreement. If the Transmission Owner prints or electronically conveys any Confidential Information, it shall protect each copy as Confidential Information in accordance with this Agreement and mark each copy as "Confidential Information." In no

event shall the Transmission Owner protect Confidential Information using standards that are less stringent than those standards that the Transmission Owner employs in protecting its own confidential or proprietary information.

11. Upon the completion of the use of Confidential Information for the purpose of performing Transmission Owner's Reliability Function, the Transmission Owner shall destroy all Confidential Information no longer needed for the Transmission Owner's Reliability Function analyses or studies. Transmission Owner shall ensure that best efforts have been undertaken to destroy the Confidential Information.

3. **Dispute Resolution** If, at any time during the term of this Agreement, any Party questions whether any other Party is breaching the terms of this Agreement, or any dispute arises under the terms of this Agreement, either Party may request mediation using the same procedures laid out in PJM's dispute resolution procedures (Schedule 5 of the PJM Operating Agreement). No Party shall take any action contrary to this Agreement unless and until allowed to do so as the result of such mediation.

4. **Modification to Agreement** No Party shall have the unilateral right to modify the terms of this Agreement or the Generator-Data Release Matrix.

5. **Modification to Generator-Data Release Matrix** The Generator-Data Release Matrix may be modified from time to time by the Generator and the Transmission Owner pursuant to procedures set forth in this Section 5. Such modifications may include adding or deleting generating facilities with regard to which PJM will provide Confidential Information to

Transmission Owner and/or the type of Confidential Information relating to the specified generation facilities that PJM is authorized to provide Transmission Owner. The respective designated PJM Operating Committee representative for the Transmission Owner and the Generator shall be authorized to approve and execute the initial Generator-Data Release Matrix, and to make any subsequent modifications thereto on behalf of the Transmission Owner and Generator respectively. In the event Transmission Owner or Generator does not have a PJM Operating Committee representative, then its Members Committee representative shall be authorized to approve and execute the initial Generator-Data Release Matrix and any subsequent modified Generator-Data Release Matrices. Any Generator-Data Release Matrix modified pursuant to this Section 5 shall be incorporated by reference into this Agreement and execution of a separate Generator Data Confidentiality Agreement will not be required. All Confidential Information provided Transmission Owner pursuant to a modified Generator-Data Release Matrix is Confidential Information as defined in this Agreement and must be treated and maintained under the terms and conditions of this Agreement. Transmission Owner shall provide PJM with any Generator-Data Release Matrices modified pursuant to this Section 5. PJM shall provide Transmission Owner only with the Confidential Information specified in the most recent Generator-Data Release Matrix in its possession.

6. **Assignment** This Agreement may not be assigned, delegated, or transferred by any Party without the other Parties' written consent provided, however, that any Party may, without the consent of the other Parties, assign its rights and obligations under this Agreement to an entity that becomes its successor in interest by acquiring all, or substantially all, of such Party's assets through merger, consolidation, sale, foreclosure, or corporate reorganization. Such consent shall not be unreasonably withheld or delayed. This Agreement shall bind the successors and assignees of the Parties to this Agreement.

7. Term.

This Agreement shall become effective on the date executed and remain effective until superseded or terminated by mutual agreement of the Parties.

8. Survival of Confidentiality

The terms and conditions of this Agreement with regard to treatment of Confidential Information under this Agreement shall remain in effect until the Confidential Information is destroyed pursuant to the terms of this Agreement, and shall survive the termination of this Agreement until such time as all Confidential Information protected under the terms and conditions of this Agreement is destroyed. Termination shall be prospective only and shall not affect any obligation of the Parties with respect to Confidential Information provided to Transmission Owner prior to the effective date of this Agreement or pursuant to the this Agreement. Notwithstanding the effective date of this Agreement, any Confidential Information disclosed by PJM to the Transmission Owner prior to such effective date shall be deemed Confidential Information pursuant to the terms hereof.

9. Agreement Not Applicable Nothing herein shall apply to any Confidential Information that:

a. after disclosure by Transmission Owner, Confidential Information entered the public domain without any action or fault of the Transmission Owner;

b. is obtained from any individual, firm or entity which had the unrestricted right to disclose it;

c. is required to be publicly disclosed under court or governmental order, subject to compliance with the procedures set forth in Section 2.c.11 hereof.

10. Remedies

a. Transmission Owner and Generator understand and agree that monetary damages may not be an adequate remedy for a breach of this Agreement. Any monetary damages as a result of a breach of this Agreement shall be limited to one million dollars, which shall include any and all damages, including, but not limited to, punitive and legal fees or expenses or costs incurred in enforcing this Agreement, or recovering damages from any breach hereof. In the event of any breach or threatened breach by either Generator or Transmission Owner, the other Party shall be entitled to injunctive and other equitable relief, and that there shall be no pleading in defense thereto that there would be an adequate remedy at law. Such remedy shall be in addition to all other remedies available to it at law, or in equity.

b. Notwithstanding anything in this Agreement to the contrary, PJM shall not be liable for any claims, demands or costs arising from, or in any way connected with its performance under this Agreement, other than actions, claims or demands based on gross negligence or willful misconduct. Any monetary damages as a result of any such action, claim or demand against PJM based on gross negligence or willful misconduct shall be limited to one million dollars, which shall include any and all damages including but not limited to punitive damages and legal fees or expenses or costs incurred in enforcing this Agreement, or recovering damages from any breach hereof.

11. **Entire Agreement** This Agreement along with the Generator- Data Release Matrix, as it may be modified from time to time, incorporated by reference herein constitute the entire Agreement between the Transmission Owner, Generator, and PJM regarding the subject matter hereof, and shall not be subject to change or amendment except in writing signed by authorized representatives of the Transmission Owner, Generator, and PJM. All provisions of this Agreement are severable, and the unenforceability of any provision shall not affect the validity or enforceability of the remaining provisions.

12. **Relationship to Other Agreements** This Agreement supersedes the Interim Generator Data Confidentiality Agreement executed by the Parties. This Agreement does not supersede any existing generation interconnection agreements or other agreements in effect between the Transmission Owner and the Generator that govern the treatment of exchanged generator data. This Agreement also does not preclude the Generator and Transmission Owner from entering into a separate agreement regarding the exchange of generator data not included in the Generator-Data Release Matrix.

13. **Authority to Enter into this Agreement** Transmission Owner, Generator, and PJM each represent and warrant that it has full legal authority to enter into this Agreement and to abide by the terms and conditions of, and fulfill the responsibilities set forth in, this Agreement

14. **No Waiver** No failure or delay by either Transmission Owner, Generator, or PJM in exercising any right, power or privilege hereunder shall operate as a waiver thereof, nor shall any single or partial exercise

thereof preclude any other or further exercise of any other right, power or privilege hereunder.

15. **Notices** Communications shall be sent to the Parties at the addresses indicated herein, or to such other address as either Party may specify in writing.

16. **No Warranties/Relationship of the Parties** Generator makes no, and shall not be deemed to have made any, covenant, warranty or representation as to the accuracy or completeness of any Confidential Information disclosed by it. Generator shall not have any liability relating to or arising from Transmission Owner's use of any Confidential Information. This Agreement does not establish a partnership, agency, joint venture or similar relationship, obligate either Party to enter into such a relationship, and/or constitute any agreement by the Parties not to compete.

17. **Counterparts; Facsimile Execution** This Agreement may be executed in counterparts, with each executed counterpart having the same force and effect as the original counterpart. This Agreement shall be deemed binding upon the Parties if each Party executes this Agreement, sends the executed Agreement via facsimile to the other Parties, and receives confirmation of receipt of the executed Agreement from the other Parties.

18. **Applicable Law** Pennsylvania law applies to this Agreement and any disputes arising thereunder resulting in litigation shall be litigated in the courts of Pennsylvania.

IN WITNESS WHEREOF, Transmission Owner, Generator, and PJM have caused this Agreement to be executed by their respective authorized officials.

TRANSMISSION OWNER

By:______________________________ ____________________ __________
Name Title Date

GENERATOR

By:______________________________ ____________________ __________
Name Title Date

PJM INTERCONNECTION, L.L.C.

By:______________________________ ____________________ __________
Name Title Date

CONFIDENTIALITY AGREEMENT CERTIFICATION

I [name] hereby certify that Confidential Information is being provided to me pursuant to the terms and restrictions of the Generator Data Confidentiality Agreement dated _______________ between [Transmission Owner] and [Generator] and PJM Interconnection, L.L.C. ("Confidentiality Agreement") and I agree to be bound by the terms and conditions of the Confidentiality Agreement. I understand that the Confidential Information, including any portion of any notes, memoranda, studies, or any other writing that I or [Transmission Owner] creates and that contains information from the Confidential Information, shall not be disclosed to anyone other than in accordance with the terms and conditions of the Confidentiality Agreement, and shall be used only for the purpose of performing Transmission Owner's Reliability Function. My obligation under this Confidentiality Agreement Certification shall survive my termination or change of duty or employment status.

Printed Name: ____________________________

Signature: _______________________________

Title: ___________________________________

Company/Organization: _____________________________Date: _______________

Attachment J: Generator – Data Release Matrix

Generator - Data Release Matrix

_____________________________(Transmission Owner) requests the following data from
___________________________(Generation Owner)
organized in the state of___________________________.

An "X" marked in any of the four data columns (Real Time MW, Real Time MVAR, Unit Status, or Scheduled Data) indicates that the Transmission Owner requests such data for reliability purposes.

Generator Unit Data	Real Time MW	Real Time MVAR	Unit Status	Scheduled Data (start date/time, return date/time, derate)

Authorization

Transmission Owner's Operating Committee Representative Signature:

Name:
Address:

Phone Number:
Fax Number:

PJM's Operating Committee Representative Signature:

Name:
Address:

Phone Number:
Fax Number:

Generation Owner's Operating Committee Representative Signature:

Name:
Address:

Phone Number:
Fax Number:

Attachment K: Template Letter for a Transmission Owner Seeking Generator Data Within its Zone to be Released by PJM

[*TO Company Name*]
[*TO's Street Address*]
[*TO's City, State, and Zip Code*]
[*Date*]

[*GO Representative Name*]
[*GO Company Name*]
[*GO's Street Address*]
[*GO's City, State and Zip Code*]

To [*GO Representative Name*]:

In order for [*TO Company Name*] to perform reliability analysis, we require PJM to provide us generator data that your company provides to PJM. Your generator lies within our transmission zone and this information is integral to the reliability analysis that we must perform to ensure the transmission grid remains reliable.

Please authorize PJM Interconnection to release to [*TO Company Name*] the generator data that is within our transmission zone. We request this data for each of the following units: [*List generator units here*]. Please sign three copies of this letter and send two of them to PJM, addressed to the Manager of the Power System Coordination Department. PJM will retain one of the data release authorization forms and send the other form to the initiating transmission owner. PJM's Law Department will keep a record of this data release authorization form

Sincerely,

TO Officer Signature
[*TO Officer Name*]
[*TO Company Name*]

Generator Owner Authorization
I authorize PJM to provide the above requested generation data to [*TO Name*].

GO Officer Signature
[*GO Officer Name*]
[GO Company Name]

Attachment L: Wind Farm Communication Model

Manual dispatch directives to multiple wind owners delay controlling actions resulting in less efficient market operations and a potential adverse impact to system reliability. Manual dispatch to a subset of owners at a common Wind Farm may result in customers questioning curtailments and additional administrative procedures to ensure fair/equitable reductions to an aggregate plant on a rotating basis. A single SCED basepoint for a Wind Farm to a single MOC Generation System Operator is an effective solution to ensure efficient and reliable operations.

The purpose of this section is to define a dependable real-time communications model to manage wind, ensuring:

1. A single MOC Generation System Operator (single operational contact) for the processing of all real-time dispatch electronic signals and operational issues.
2. Accurate outage data, which is essential for an accurate Wind Power Forecast
3. Prompt wind reduction, which typically would occur as a last resort just prior to emergency procedures.

> Note 1: This communication model may be expanded to include other renewable resources as PJM develops forecast tools or their penetration levels increase.
>
> Note 2: The MOC Generation System Operators (single operational contact) will need to meet the PJM certification and training requirements outlined in PJM Manual 40: Certification and Training Requirements.

Option 1: PJM Operations would prefer a model where there is a single MOC Generation System Operator (single operational contact) responsible for the entire Wind Farm operations. The single contact would be responsible for all day-ahead and real-time bidding into PJM Systems (eMkt), process an SCED basepoint, real-time communications with PJM Dispatch, as well as providing accurate turbine outage information within eDart. Settlements can be allocated by PJM based on ownership shares.

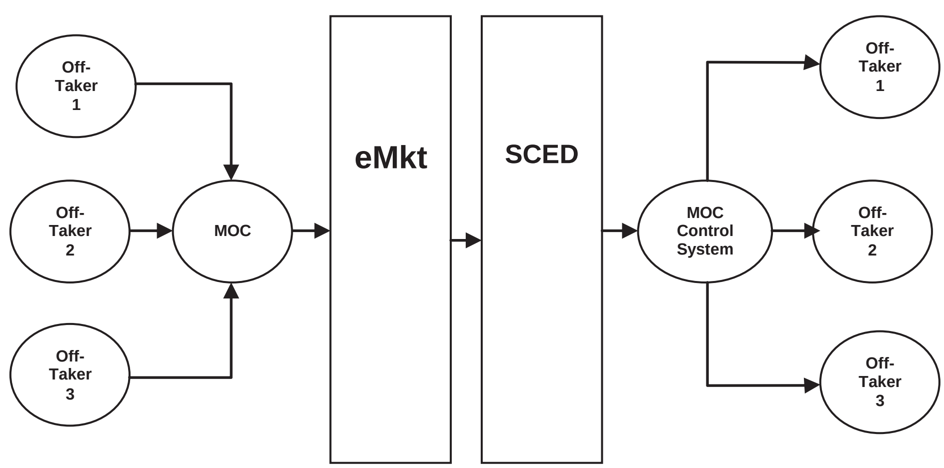


Exhibit 28: Wind Farm Communication Model 1

Option 2: The alternate solution would still require a single MOC Generation System Operator (single operational contact), however, each owner/off taker would still be able to interact with eMkt, providing day-ahead bids and hourly updates. The single operational contact would be responsible for processing SCED basepoints, all real-time communications with PJM Dispatch, as well as providing accurate turbine outage information within eDart. PJM SCED would send individual basepoints to each owner/off taker as well as sending an aggregate base point to the operational contact. Settlements will model individual owner/offtakers.

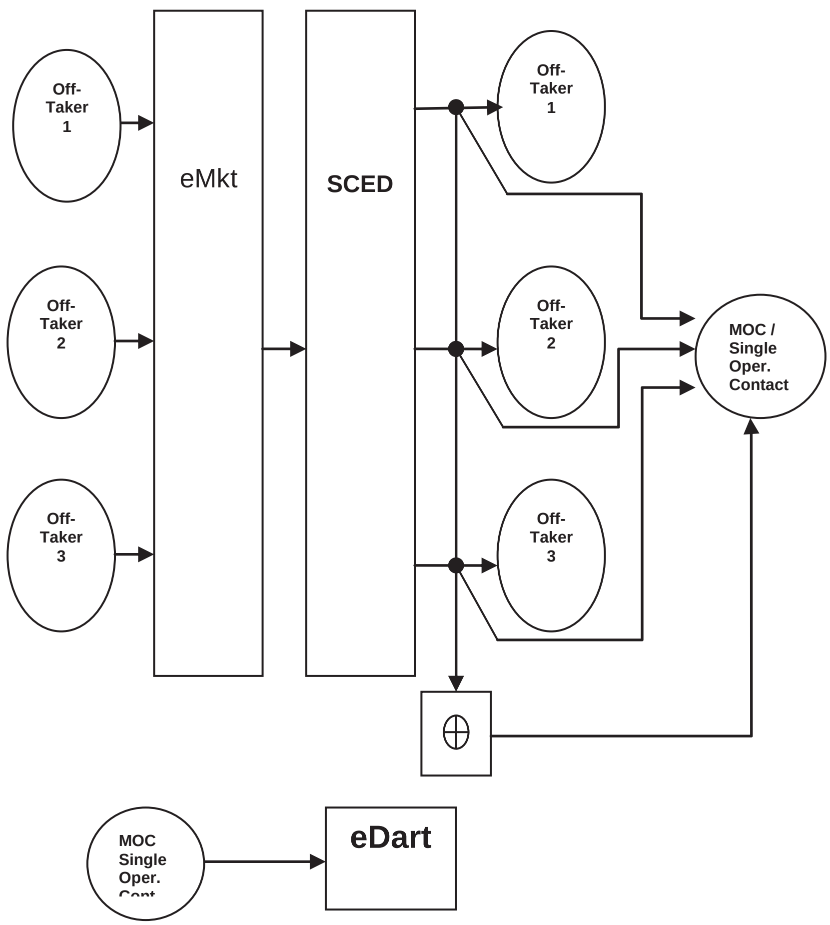


Exhibit 29: Wind Farm Communication Model 2

APPENDIX A: Behind the Meter Generation Business Rules

Definition and Purpose of Behind-the-Meter Generation (BtMG)

(1) The purpose of these rules is to permit market participants operating Behind-the-Meter Generation (BtMG) to receive the associated benefits. These benefits are recognized by allowing such generation to net for the purposes of calculating transmission, capacity, ancillary services, and administrative fee charges.

(2) The netting rules for BtMG are set forth in the PJM Open Access Transmission Tariff (“PJM Tariff”), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (“Operating Agreement”), and the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region (“RAA”). These documents filed with the Federal Energy Regulatory Commission will take precedence in the event of any conflict or ambiguity between these rules and the filed documents.

Eligibility for BtM Netting

(3) These rules apply to BtMG used by end-use customers, municipal electric systems, electric cooperatives, and electric distribution companies to serve load. The load must be located at the same electrical location as the BtMG, such that no transmission or distribution facilities are utilized to transmit energy from the BtMG to the load. An exception to the prohibition on use of distribution facilities rule is allowed, in cases where permission to use the requisite distribution facilities has been obtained from the owner, lessee, or operator of such facilities. Such permission must be submitted in writing to PJM from the owner, lessee or operator of such distribution facilities.

(4) BtMG netting is only available to entities that have Network Integration Transmission Service agreements with PJM.

(5) These business rules do not supersede any elements of existing retail service agreements or standby service agreements between an entity and its Load Serving Entity or the Electric Distribution Company to which the associated load is connected.

BtM Netting – General Rules

(6) BtMG does not include at any time, any portion of a generating unit’s capacity that is designated as a Capacity Resource; or in any hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

(7) Generation Owners shall not be eligible to receive payments, pursuant to Schedule 2 of the PJM Tariff, for reactive service for portions of generating units upon becoming a BtM Generator. Generation Owners subject to this rule shall cooperate with PJM in making any regulatory filings that may be required to implement this rule.

(8) The need for metering for small BtMG will be treated on a case-by-case basis, depending on local operational security needs. For the purposes of this rule, small BtMG shall be individual generating units that are less than 10 MW, or multiple generating units that are collectively less than 10 MW. Generally, these units will not require

metering for operational security purposes. Rules for metering are detailed in the PJM Manual for Generator Operational Requirements (M-14D).

(9) BtMG that is 10 MW or greater (or has been identified as requiring metering for operational security reasons) must have both revenue metering and telemetering for operational security purposes. Single unit small BtM generators that collectively total more than 10 MW, may be aggregated behind the meter and metered as a single unit to meet this requirement should PJM require metering for the aggregate generation. Rules for metering are detailed in the PJM Manual for Generator Operational Requirements (M-14D).

(10) BtMG will be recognized in PJM transmission and generation adequacy planning models. Load and generation will be modeled separately where practicable.

(11) If multiple generation units are located behind the meter, each unit can be designated as either a Capacity Resource or as BtMG on a unit specific basis or on a partial unit basis.

(12) A party may change all or a portion of a unit's capability from Capacity and/or Energy Resource status to BtMG status, or from BtMG status to Capacity and/or Energy Resource status (provided the generator has met the applicable requirements for Capacity Resource status), but cannot be used for both purposes simultaneously for a designated portion of a unit's capability. Any portion of a unit that has been qualified as a Capacity Resource is subject to the same requirements as any other PJM Capacity Resource. Because of the number of procedural requirements associated with changing to or from BtMG status, such changes shall be limited to once per year in accordance with the schedule set forth below.

(13) A Capacity Resource that changes to BtMG, or a new generator that requests BtMG status will be able to net its full installed capacity value for the first calendar year for transmission and the first Planning Period for capacity. The netting value for all succeeding years will be based on actual generator performance over the 5 CP and 1 CP days.

(14) Requests for BtMG changes for transmission charges, black start service, and reactive service must be received by PJM by December 1 and will become effective the following January 1. The change shall remain in effect for a period no less than one calendar year.

(15) Requests for BtMG changes for capacity obligations must be received by PJM by December 1 and will become effective the following June 1. The change shall remain in effect for a period no less than one Planning Period.

(16) Requests for BtMG changes for energy-based ancillary service charges (i.e., those ancillary services charged on a MWh basis such as regulation, spinning and operating reserves) and for administrative fee charges can be made anytime. The change will become effective on the first of the month following PJM's communication that all logistical modifications (as may be required, for example, to metering or billing/settlement records) have been completed. The change shall remain in effect for a period no less than 12 months from the month the change becomes effective.

(17) If a generator is granted BtMG status for one purpose (such as capacity), it must become BtMG for all other purposes described in Rules 14, 15 and 16 above, and in accordance with the timetables established in those rules. A generator that changes its

status to BtMG pursuant to Rules 14 and 16 will be deemed to have given notice pursuant to Rule 15 to request BtMG status for capacity obligations for the Planning Period immediately following the Planning Period in which the Rule 14 and/or 15 BtMG request was made/effective., so as to comply with the notice requirements provided in Section 2.5.2 of the PJM Tariff.

(18) The timing requirements established in Rules 14, 15 and 16 are not affected by a transfer of ownership; BtMG status changes are only permitted according to the timetable described in Rules 14, 15 and 16 above.

(19) If Non-Retail BtMG is subject to a reduced netting credit as described in Rule 34 below, that generator is ineligible to change its behind the meter status until the full effect of that reduction has been fully rolled out.

(20) If a Capacity Resource moves behind the meter, its injection rights will be treated the same as if the unit had been deactivated. Those injection rights are defined in Section 230 of the PJM Tariff, generally, and Section 230.3.3 specifically with respect to rights that apply if a generation resource is deactivated.

Participation in Load Management Programs

(21) BtMG may participate in all relevant PJM demand side response programs (e.g. the PJM Interchange Energy Market and the PJM Capacity Market (RPM)) under the terms and conditions in effect at the time the BtMG requests participation in the program, subject to Rule 22 below.

(22) A generator may be used for Load Management (LM) credit or it can be used to net against load as a BtM generator, but cannot be used for both purposes simultaneously. The election of BtM or LM status must remain in effect for an entire planning period.

(23) A BtM generator may participate in the PJM Load Response programs under the terms and conditions in effect at the time the BtM generator requests to participate in the program.

Generation Netted Against Load

(24) The load associated with BtMG must have a Load Serving Entity (LSE). The LSE will be responsible for supplying energy, capacity, ancillary services and transmission for that portion of the load not supplied by the BtMG. For the purposes of this rule, the load not supplied by the BtMG shall include load normally supplied by the BtMG during periods when the BtMG is not operating.

a. The capacity obligation for the load will be based on the average of the net load at the site(s) (gross load minus operating BtMG, not to be less than zero) at the time of the Zone’s transmission peak (1CP) during the five (5) coincident peak hours, in accordance with the 5CP methodology in effect for the Zone.

b. Network Integration Transmission Service charges will be calculated as the net load at the site(s) (gross load minus operating BtMG, not to be less than zero) at the time of the Zone’s transmission peak (1CP).

c. Regulation and Spinning Reserve obligations will be calculated based on the net MWh of load at the site (hourly gross load minus operating BtMG, not to be less than zero) in real time.

d. Day-Ahead Operating Reserves will be charged based on the net amount of load at the site(s) that clear(s) in the PJM Day-Ahead energy market.

e. Balancing Operating Reserve deviations will be measured based on the net change of both the BtMG and the load between day-ahead and real-time.

f. PJM Schedule 9 administrative fees based on real time load and generation will be charged on the net value of load or generation as measured in real time.

(25) Under this “netting” arrangement, the EDC and/or LSE will be responsible for reporting both the load and generation information to PJM for use in the load forecast for generators for which metering is required for operational security purposes. The EDC may need to obtain this information from the LSE and both parties are required to cooperate to ensure PJM receives the information.

(26) For wholesale market participation, the interconnection requirements will be publicly available and, in cases where parallel operation will exist with the distribution or transmission system, determined by the EDC in accordance with applicable state or other jurisdictional requirements. The generator will be evaluated using the PJM interconnection process only if it is involved in a wholesale transaction.

BtM Netting – Non-Retail Participation

(27) Non-Retail BtMG netting provisions apply to behind the meter generation used by municipal electric systems, electric cooperatives, and EDCs to serve load, provided that, if distribution facilities are used to deliver energy from Non-Retail BtMG to load, then permission to use such distribution facilities has been obtained from the owner, lessee, or operator of such distribution facilities. Such permission shall be submitted to PJM in writing from the owner, lessee or operator.

(28) All entities using the Non-Retail BtMG option must have a Network Integration Transmission Service agreement with PJM.

(29) Non-Retail BtMG netting is subject to a threshold amount. The Non-Retail BtMG threshold is 1,500 MW for calendar year 2006 for transmission charges, black start service, and reactive service, and for the 2006/2007 Planning Period for capacity obligations. Each year thereafter, the Non-Retail BtMG threshold will be increased based on PJM RTO load growth. PJM RTO load growth will be determined based on the most recent forecasted weather-adjusted coincident summer peak divided by the weather-adjusted coincident peak for the previous summer. After applying the load growth factor, the Non-Retail BtMG threshold will be rounded to the nearest whole MW, and that rounded number will be the Non-Retail BtMG threshold for that current year or Planning Period and the base amount for calculating the Non-Retail BtMG threshold for the succeeding year or Planning Period.

(30) PJM shall communicate a change in the Non-Retail BtMG threshold through an email to all BtM generators and posting on the PJM website.

(31) If the amount of Non-Retail BtMG netting exceeds the Non-Retail BtMG threshold, the amount of Non-Retail BtMG shall be prorated back to the threshold. In such instance,

the amount of Non-Retail BtMG eligible for netting by an entity shall be the product of its total Non-Retail BtMG multiplied by the ratio of the Non-Retail BtMG threshold divided by the total amount of the Non-Retail BtMG in the PJM RTO (not to exceed 3,000 MW). [Example: if the Non-Retail BtMG threshold is 1,500 and the total amount of Non-Retail BtMG netting in the PJM RTO reaches 2,000, then 75 percent of an entity's Non-Retail BtMG would be eligible for netting.]

(32) The total amount of Non-Retail BtMG eligible for netting under the BtMG provisions is capped at 3,000 MW. If this cap is reached, no additional Non-Retail BtMG will be eligible for netting. Furthermore, within six months of reaching the cap, PJM shall file with the FERC to justify either continuation of the existing BtMG rules (including any expansion of the rules to include additional MW) or any change to the rules.

(33) Each calendar year, netting Non-Retail BtMG resources shall be required to operate during the first ten occurrences of Maximum Emergency Generation (MEG) conditions in the zone in which the resource is located. This obligation applies to an MEG condition called for either generation or transmission emergencies. Notice of an MEG event shall be communicated through the PJM all-call system.

(34) For each MEG condition in which netting Non-Retail BtMG is not on a scheduled outage but fails to operate, in whole or in part, the netting associated with that resource for purposes of charges for transmission service, reactive service, black start service, and capacity obligations will be reduced by ten percent of the amount of megawatts the resource failed to produce. The amount of megawatts that the resource failed to produce will be the difference between its full netting credit and its megawatt average output over the MEG period. [Example: if a netting Non-Retail BtM resource is required to operate with an output of 100 MW during a Maximum Emergency Generation condition, but only operates to a level of 75 MW, in the next year, the eligible netting from that resource will be reduced by 2.5 MW, which is the product of the following calculation:[(100 – 75) x .10]].

(35) Any reductions in netting will be applied in the succeeding calendar year with regard to transmission service, reactive service, and black start service, and the succeeding Planning Period with regard to netting related to capacity obligations.

(36) A generator that moved behind the meter is not eligible to move back in front of the meter until the impact of the reduced netting penalty described in Rule 34 above has been rolled out.

(37) Non-Retail BtMG may not schedule a unit outage in the months from June through September.

BtM Adjustment Process

(38) Parties seeking a BtMG adjustment of any type must notify PJM at BTMG@pjm.com. The BtMG request must contain the following information:

- Contact name, company, email address and phone number
- Name of generation unit(s) and EIA plant and unit identification numbers
- Summer net dependable rating of the unit(s)
- Name of the applicable Load Serving Entity and Electric Distribution Company

- If applicable, written approval from the owner, lessee or operator of a distribution facility used to deliver energy from the BtM generator to load
- For non-retail BtM generation, the phone number to be added to the PJM all-call list

(39) PJM will respond to the request and coordinate data and information flow between all affected parties (customer, LSE, EDC, etc.) to determine eligibility, peak load adjustments, etc.

Revision History

Revision 19 (10/01/2010):

Incorporated Wind Farm Communication Model as Attachment L.

Revision 18 (June 1, 2010):

- Revised Attachment D, E, and F to remove redundancy and reorder.
- Modified Attachment E to change requirement to submit completed PJM Leading and/or Lagging Test Form R to PJM within 30 calendar days after completion of the testing (changed from 10 days).
- Added bullet 7 under Section Data Requirements in Attachment D, "Company can either test or apply the best engineering judgment to construct D-curve at min load points."
- Added a line in Bullet 5 under Section Testing Requirements for both Units Larger than 70 MW and Black Start Units in Attachment E, "This requirement may require a departure from scheduled voltage during the test, provided no adverse effect on the validity of test results can be demonstrated."

Revision 17 (01/01/2010):

- Updated section 7.1.2 – language for voltage schedule exemption (VAR-001/002)
- Added language to section 7.1.5 – Black Start units operators shall not permit their fuel inventory for Critical Black start CTs to fall below 10 hours – if it falls below this level, unit operators shall notify PJM and place the unit in Max Emergency

Revision 16 (10/01/2009):

- Section 4: Data Exchange and Metering Requirements: Updated Sections 4.2.2 and 4.2.3 to address metering requirements for distributed renewable generation.
- Section 6: Pre-Operational Requirements: Updated Sections 6.3.1to address operations requirements for distributed renewable generation.
- Section 7: Generator Operations: Edits to voltage schedule details in Section 7.1.2.
- Section 8: Wind Farm Requirements: Minor edit in Section 8.1, updated Section 8.2.4 Generator Outage Reporting.
- Attachment D: PJM Unit Reactive Capability Curve Specification and Reporting Procedures: Updates in PJM Reactive Reserve Check (RRC) section.
- Attachment E: PJM Generator Reactive Capability Testing: Updates throughout "Testing Requirements for Units Larger than 70MW and Blackstart units" section; Replaced Lagging Form R and Leading Form R.

- Attachment F: Generator Reactive Testing Capability Procedures: Updates to Testing Procedure, Study Process Example, Communications and Coordination, Exit Strategy, and Results Reporting sections. Edits include identifying PJM Reliability Engineer as lead PJM coordinator for reactive testing process.

Revision 15 (04/01/2009):

- Section 4: Data Exchange and Metering Requirements: Updated Exhibits 4 and 5 to reflect the use of secure internet for small generators (100 MWs or less).
- Section 8: Wind Farm Requirements: Added new section describing Wind Farm Requirements
- Section 9: Generator Deactivations: Replaced PJM System Operations Generation Manager with PJM Power System Coordination Manager.
- Reactive Testing Attachments E & F: Renamed “Critical Steam” to “Near-term Steam” to avoid confusion with predefined Critical Infrastructure Facilities.
- Reactive Testing Attachments E & F: Added MOC requirement to review telemetered Generator MVAR accuracy with PJM Reliability Engineer in advance of commencing reactive test.
- Replaced “Control Area” with “Balancing Authority” to align with NERC definitions.

Revision 14 (12/17/2008):

Added existing Behind the Meter Generation Business Rules as Appendix A.

Revision 13 (5/23/2008)

Section 4: Data Exchange and Metering Requirements

- Updated Exhibits 4 and 5 to reflect the use of secure internet for small generators (50 MWs or less).

Section 5 and Section 7

- Modified to provide clarity regarding requirement to update generator reactive capability curves (D-Curves) following planned unit upgrades.

Section 7: Generator Operations

- Changes for new Bulk Electric System definition.

Revision 12 (12/03/2007)

- Provided clarification to Attachment E: PJM Generator Reactive Capability Testing and Attachment F: Generator Reactive Capability Testing Procedures, specifically, the ability to test outside May 1 – September 30th window on an exception basis, requirement to perform lagging test for 1 hour, requirement to report test results to

Operations Planning Department within 10 days, and requirement to review accuracy of MVAR telemetry prior to beginning the test.

Revision 11 (08/29/07)

Section 5: Participation in PJM Markets, Ancillary Services, Reactive Supply and Voltage Control from Generating Sources Service

- Added requirement for PJM to provide to the Generation Owner documentation of requirements for generator step-up transformer tap changes.

Section 7: Generator Operations, Critical Information and Reporting Requirements

- Added requirement for the Generator Operator to notify PJM of a status or capability change on any generator Reactive Power resource.

Attachment E: PJM Generator Reactive Capability Testing

- Modified Lagging Form R and Leading Form R to indicate that readings for Hour 2 are entered only if required.

Revision 10 (05/15/2007)

General Changes:

- Renamed references to Control Center Requirements and Dispatching Operations Manuals as Control Center and Data Exchange Requirements and Balancing Operations Manuals respectively.

Section 1: Black Start Replacement Process

- Changed Generation Department to Power System Coordination Department in section on Generator Commercial Naming Convention.

Section 8: Generator Deactivations

- Changed Generation Department to Power System Coordination Department in the text and in the process flow chart.

Section 9: Black Start Replacement Process - Process Flow Diagram

- Changed Generation Department to Power System Coordination Department.

Section 10: Generator Data Confidentiality Process

- Changed Generation Department to Power System Coordination Department.

Attachment D: PJM Generating Unit Reactive Capability Curve Specification and Reporting Procedures

- Changed Generation Department to Power System Coordination Department.

Attachment E: PJM Generator Reactive Capability Testing

- Clarified testing requirement as 20% of number of eligible assets per year.

Attachment F: Generator Reactive Capability Testing Procedures

- Changed Generation Department to Operations Planning Department.

Attachment K: Template Letter for a TO Seeking Generator Data

- Changed Generation Department to Power System Coordination Department.

Revision 09 (12/18/06)

Attachment E: PJM Generator Reactive Capability Testing

- Updated to reflect new exception criteria for PJM leading/lagging reactive tests.

Attachment F: Generator Reactive Capability Testing Procedures

- Updated to reflect new exception criteria for PJM leading/lagging reactive tests.

References to eMarket changed to eMKT throughout.

Definition of FTR changed to financial transmission rights (Section 5).

Introduction trimmed to eliminate redundant information.

Revision History permanently moved to the end of the manual.

Revision 08 (07/24/06)

Section 9: Black Start Replacement Process

- Updated to include new triggers for Black Start Replacement Process.
- Updated to reference the recently defined Minimum Critical Black Start Requirement.

Updated PJM List of Manuals (Exhibit 1).

Revision 07 (06/19/06)

Section 5: Participation in PJM Markets

- Change “unit” references to “resource” as they apply to Demand Side Response providing Ancillary Services.
- Change “Spinning” references to “Synchronized” as they apply to Demand Side Resources providing Ancillary Services.

Added Attachment F: Generator Reactive Capability Testing Procedures and relettered all following attachments.

Revision 06 (12/15/05)

Update to Attachment C on New PJM Customer Voice/All Call Communications Request Form to reflect most current version of the form.

Revision 05 (08/10/05)

Added new Section 9: Black Start Replacement Process.

Moved old Section 9: Generator Data Confidentiality Procedures to Section 10.

Revision 04 (04/12/05)

Modified Section 8 to include revised Generation Deactivation process and procedures as approved by FERC on January 25, 2005.

Revision 03 (02/01/05)

Addition of new Section 9 on PJM Generator Data Confidentiality Procedures

Update to Attachment D on PJM Generating Unit Reactive Capability Curve Specification and Reporting Procedures to incorporate recent changes to the Reactive Reserve Check (RRC) Reporting process.

Addition of new Attachment E on PJM Generator Reactive Capability Testing. Current Attachments E and F have been renamed to Attachments F and G respectively.

Addition of new attachment H including the Generator Data Confidentiality Agreement.

Addition of new attachment I including the Generator – Data Release Matrix

Addition of new attachment J including a template letter for a Transmission Owner seeking generator data within its zone to be released by PJM

Update to Section 7 on Generator Operations to include new seasonal review of PJM generator reactive capabilities and reference to new Attachment E.

Revision 02 (03/10/04)

Added new Section 8 on Generator Deactivations.

Revision 01 (12/31/03)

Update format

Renumber exhibits

Revision 00 (04/04/03)

This revision is the initial release of the PJM Manual for ***Generator Operational Requirements (M-14D)***. This manual is one among the four new manuals obtained from splitting the original PJM Manual for ***Generator Interconnections and Operations (M-14)***.

The summary of revisions for this manual follows:

Added new Section 1 on Generator Markets & Operations.

Added new Section 2 on Responsibilities of Generation Owners.

Added new Section 3 on *Control Center Requirements* based on excerpts from PJM Manual M-01 on ***Control Center and Data Exchange Requirements*** (Section 2 & 3).

Added new Section 4 on *Data Exchange and Metering Requirements* based on excerpts from old PJM Manual M-14 on ***Generation Interconnections and Operations*** (Sections 2 & 5).

Added new Section 5 on *Participation in PJM Markets* based on excerpts from old PJM Manual M-14 on ***Generation Interconnections and Operations*** (Sections 3 & 4).

Added new Section 6 on *Pre-Operational Requirements* based on excerpts from old PJM Manual M-14 on ***Generation Interconnections and Operations*** (Sections 4 & 5).

Added new Section 7 on *Generator Operations* based on excerpts from old PJM Manual M-14 on ***Generation Interconnections and Operations*** (Sections 4 & 5), PJM Manual M-3 on ***Transmission Operations*** (Section 3), and PJM Manual M-13 on ***Emergency Operations*** (Section 5).

PJM OPEN ACCESS

TRANSMISSION TARIFF

Effective Date: 8/6/2012

36.2 Interconnection Feasibility Study:

The following provision applies to Interconnection Requests that are submitted prior to May 1, 2012:

After receiving an Interconnection Request, a signed Generation Interconnection Feasibility Study Agreement or Transmission Interconnection Feasibility Study Agreement, as applicable, and the applicable deposit contained in Sections 36.1.01, 36.1.03, 110.1, 111.1, and 112.1 (as were in effect prior to May 1, 2012) of the Tariff from the Interconnection Customer, and, if applicable, subject to the terms of Section 36.1A.5, the Transmission Provider shall conduct an Interconnection Feasibility Study to make a preliminary determination of the type and scope of Attachment Facilities, Local Upgrades, and Network Upgrades that will be necessary to accommodate the Interconnection Request and to provide the Interconnection Customer a preliminary estimate of the time that will be required to construct any necessary facilities and upgrades and the Interconnection Customer’s cost responsibility, estimated consistent with Section 217 of the Tariff. The Interconnection Feasibility Study assesses the practicality and cost of accommodating interconnection of the generating unit or increased generating capacity with the Transmission System. The analysis is limited to load-flow analysis of probable contingencies and, for Generation Interconnection Requests, short-circuit studies. This study also focuses on determining preliminary estimates of the type, scope, cost and lead time for construction of facilities required to interconnect the project. For a Generation Interconnection Customer, the Interconnection Feasibility Study may provide separate estimates of necessary facilities and upgrades and associated cost responsibility reflecting the generating facility being designated as either a Capacity Resource or an Energy Resource. The study for the primary Point of Interconnection will be conducted as a cluster, within the project’s New Services Queue. The study for the secondary Point of Interconnection will be conducted as a sensitivity analysis. The Transmission Provider shall provide a copy of the Interconnection Feasibility Study and, to the extent consistent with the Office of the Interconnection's confidentiality obligations in Section 18.17 of the Operating Agreement, related work papers to the Interconnection Customer and the affected Transmission Owner(s). Upon completion, the Transmission Provider shall list the study and the date of the Interconnection Request to which it pertains on the Transmission Provider's OASIS. To the extent required by Commission regulations, the Transmission Provider shall make the completed Interconnection Feasibility Study publicly available upon request, except that the identity of the Interconnection Customer shall remain confidential. The Transmission Provider shall conduct Interconnection Feasibility Studies four times each year. For Interconnection Requests received during the three-month period ending January 31 the Transmission Provider shall use due diligence to complete Interconnection Feasibility Studies by April 30. For Interconnection Requests received during the three-month period ending April 30 the Transmission Provider shall use due diligence to complete Interconnection Feasibility Studies by July 31. For Interconnection Requests received during the three-month period ending July 31 the Transmission Provider shall use due diligence to complete Interconnection Feasibility Studies by October 31. For Interconnection Requests received during the three-month period ending October 31 the Transmission Provider shall use due diligence to complete Interconnection Feasibility Studies by January 31. In the event that the Transmission Provider is unable to complete an Interconnection Feasibility Study within such time period, it shall so notify the affected Interconnection Customer and the affected Transmission Owner(s) and provide an estimated completion date along with an explanation of the reasons why additional time is needed to complete the study.

The following provision applies to Interconnection Requests that are submitted on or after May 1, 2012:

After receiving an Interconnection Request, a signed Generation Interconnection Feasibility Study Agreement or Transmission Interconnection Feasibility Study Agreement, as applicable, and the applicable deposit contained in Sections 36.1.01, 36.1.03, 110.1, 111.1, and 112.1 of the Tariff from the Interconnection Customer, and, if applicable, subject to the terms of Section 36.1A.5, the Transmission Provider shall conduct an Interconnection Feasibility Study to make a preliminary determination of the type and scope of Attachment Facilities, Local Upgrades, and Network Upgrades that will be necessary to accommodate the Interconnection Request and to provide the Interconnection Customer a preliminary estimate of the time that will be required to construct any necessary facilities and upgrades and the Interconnection Customer's cost responsibility, estimated consistent with Section 217 of the Tariff. The Interconnection Feasibility Study assesses the practicality and cost of accommodating interconnection of the generating unit or increased generating capacity with the Transmission System. The analysis is limited to load-flow analysis of probable contingencies and, for Generation Interconnection Requests, short-circuit studies. This study also focuses on determining preliminary estimates of the type, scope, cost and lead time for construction of facilities required to interconnect the project. For a Generation Interconnection Customer, the Interconnection Feasibility Study may provide separate estimates of necessary facilities and upgrades and associated cost responsibility reflecting the generating facility being designated as either a Capacity Resource or an Energy Resource. The study for the primary Point of Interconnection will be conducted as a cluster, within the project's New Services Queue. The study for the secondary Point of Interconnection will be conducted as a sensitivity analysis. The Transmission Provider shall provide a copy of the Interconnection Feasibility Study and, to the extent consistent with the Office of the Interconnection's confidentiality obligations in Section 18.17 of the Operating Agreement, related work papers to the Interconnection Customer and the affected Transmission Owner(s). Upon completion, the Transmission Provider shall list the study and the date of the Interconnection Request to which it pertains on the Transmission Provider's OASIS. To the extent required by Commission regulations, the Transmission Provider shall make the completed Interconnection Feasibility Study publicly available upon request, except that the identity of the Interconnection Customer shall remain confidential. The Transmission Provider shall conduct Interconnection Feasibility Studies two times each year. For Interconnection Requests received during the six-month period ending October 31 the Transmission Provider shall use due diligence to complete Interconnection Feasibility Studies by the last day of February. For Interconnection Requests received during the six-month period ending April 30 the Transmission Provider shall use due diligence to complete Interconnection Feasibility Studies by August 31. Following the closure of an interconnection queue on October 31 and April 30, the Transmission Provider will utilize the following one month period to conduct any remaining scoping meetings and assemble the necessary analysis models so as to initiate the performance of the Interconnection Feasibility Studies on December 1 and June 1, respectively. In the event that the Transmission Provider is unable to complete an Interconnection Feasibility Study within such time period, it shall so notify the affected Interconnection Customer and the affected

Transmission Owner(s) and provide an estimated completion date along with an explanation of the reasons why additional time is needed to complete the study.

36.2.1 Substitute Point:

If the Interconnection Feasibility Study reveals any result(s) not reasonably expected at the time of the Scoping Meeting, a substitute Point of Interconnection identified by the Interconnection Customer, Transmission Provider, or the Interconnected Transmission Owner, and acceptable to the others, but which would not be a Material Modification, will be substituted for the Point of Interconnection identified in the Interconnection Feasibility Study Agreement. The substitute Point of Interconnection will be effected without loss of Queue Position and will be utilized in the ensuing System Impact Study.

36.2.2 Meeting with Transmission Provider:

At the Interconnection Customer’s request, Transmission Provider, the Interconnection Customer and the Interconnected Transmission Owner shall meet at a mutually agreeable time to discuss the results of the Interconnection Feasibility Study. Such meeting may occur in person or by telephone or video conference.

36.2.3 Reserved.

Effective Date: 5/1/2012 - Docket #: ER12-1177-000

36.2A Modification of Interconnection Request:

The Interconnection Customer shall submit to the Transmission Provider, in writing, any modification to its project that causes the project's capacity, location, or configuration to differ from any corresponding information provided in the Interconnection Request. The Interconnection Customer shall retain its Queue Position if the modification is in accordance with Sections 36.2A.1, 36.2A.2 or 36.2A.5, or, if not in accordance with one of those sections, is determined not to be a Material Modification pursuant to Section 36.2A.3. Notwithstanding the above, during the course of the Interconnection Studies, the Interconnection Customer, the Interconnected Transmission Owner, or Transmission Provider may identify changes to the planned interconnection that may improve the costs and benefits (including reliability) of the interconnection, and the ability of the proposed change to accommodate the Interconnection Request. To the extent the identified changes are acceptable to the Transmission Provider and Interconnection Customer, such acceptance not to be unreasonably withheld, Transmission Provider shall modify the project's Point of Interconnection, capacity, and/or configuration in accordance with such changes and shall proceed with any re-studies that Transmission Provider finds necessary in accordance with Sections 205.5 and/or 207.2, as applicable, provided, however, that a change to the Point of Interconnection shall be permitted without loss of Queue Position only if it would not be a Material Modification.

The following language for 36.2A.1 and 36.2A.2 apply to Interconnection Requests which have entered the New Services Queue prior to May 1, 2012:

> 36.2A.1 Prior to return of the executed System Impact Study Agreement to the Transmission Provider, an Interconnection Customer may modify its project to reduce by up to 60 percent the electrical output (MW) (in the case of a Generation Interconnection Request) or by up to 60 percent of the transmission capability (in the case of a Transmission Interconnection Request) of the proposed project. For increases in generating capacity or transmission capability, the Interconnection Customer must submit a new Interconnection Request for the additional capability and shall be assigned a new Queue Position for the additional capability.
>
> 36.2A.2 After the System Impact Study Agreement is executed and prior to execution of the Interconnection Service Agreement, an Interconnection Customer may modify its project to reduce the electrical output (MW) (in the case of a Generation Interconnection Request) or the transmission capability (in the case of a Transmission Interconnection Request) of the proposed project by up to the larger of 20 percent of the capability considered in the System Impact Study or 50 MW.

The following language for 36.2A.1 and 36.2A.2 apply to Interconnection Requests which have entered the New Services Queue on or after May 1, 2012:

36.2A.1 Modifications Prior to Executing A System Impact Study Agreement

36.2A.1.1 Prior to the commencement of the Feasibility Study, an Interconnection Customer may request to reduce by up to 60 percent of the electrical output (MW) (in the case of a Generation Interconnection Request) or the capability (in the case of a Transmission Interconnection Request) without losing its current Queue Position. For Interconnection Requests received in months one through five of the New Services Queue the Interconnection Customer must identify this change prior to the close of business on the last day of the sixth month of the New Services Queue. For Interconnection Requests received during the sixth month of the New Services Queue the Interconnection Customer must identify this change no later than close of business on the day following the completion of the scoping meeting.

36.2A.1.2 After the start of the Feasibility Study, but prior to the return of the executed System Impact Study Agreement to the Transmission Provider, an Interconnection Customer may modify its project to reduce the size of the project as provided in this section 36.2A.1.2, subject to the limitation described in section 36.2A.6. The Interconnection Customer may reduce its project by up to 15 percent of the electrical output (MW) (in the case of a Generation Interconnection Request) or capability (in the case of a Transmission Interconnection Request) of the proposed project. For a request to reduce by more than 15 percent, an Interconnection Customer must request the Transmission Provider to evaluate if such a change would be a Material Modification and the Transmission Provider will allow the Interconnection Customer to reduce the size of its project: (i) to any size if the Transmission Provider determines the change is not a Material Modification; or (ii) by up to 60 percent of the electrical output (MW) (in the case of a Generation Interconnection Request) or capability (in the case of a Transmission Interconnection Request) if the Transmission Provider determines the change is a Material Modification, however, such a project that falls within this subsection (ii) would be removed from its current Queue Position and will be assigned a new Queue Position at the beginning of the subsequent queue and a new Interconnection Feasibility Study will be performed consistent with the timing of studies for projects submitted in the subsequent queue. All projects assigned such new Queue Positions will retain their priority with respect to each other in their newly assigned queue and with respect to all later queue projects in subsequent queues, but will lose their priority with respect to other projects in the queue to which they were previously assigned. For increases in generating capacity or transmission capability, the Interconnection Customer must submit a new Interconnection Request for the additional capability and shall be assigned a new Queue Position for the additional capability.

36.2A.2 Modifications After the System Impact Study Agreement but Prior to Executing an Interconnection Service Agreement

After the System Impact Study Agreement is executed and prior to execution of the Interconnection Service Agreement, an Interconnection Customer may modify its project to reduce the size of the project as provided in this section 36.2A.2, subject to the limitation described in section 36.2A.6. The Interconnection Customer may reduce its project by the greater of 10 MW or 5 percent of the electrical output (MW) (in the case of a Generation Interconnection Request) or capability (in the case of a Transmission Interconnection Request) of the proposed project. For a request to reduce by more than the greater of 10 MW or 5 percent, an Interconnection Customer must request the Transmission Provider to evaluate if such a change would be a Material Modification and the Transmission Provider will allow the Interconnection Customer to reduce the size of its project: (i) to any size if the Transmission Provider determines the change is not a Material Modification; or (ii) by up to the greater of 50 MW or 20 percent of the electrical output (MW) (in the case of a Generation Interconnection Request) or capability (in the case of a Transmission Interconnection Request) if the Transmission Provider determines the change is a Material Modification, however, such a project that falls within this subsection (ii) would be removed from its current Queue Position and will be assigned a new Queue Position at the beginning of the subsequent queue and a new System Impact Study will be performed consistent with the timing of studies for projects submitted in the subsequent queue. All projects assigned such new Queue Positions will retain their priority with respect to each other in their newly assigned queue and with respect to all later queue projects in subsequent queues, but will lose their priority with respect to other projects in the queue to which they were previously assigned.

36.2A.3

Prior to making any modifications other than those specifically permitted by Sections 36.2A.1, 36.2A.2 and 36.2A.5, the Interconnection Customer may first request that the Transmission Provider evaluate whether such modification is a Material Modification. In response to the Interconnection Customer's request, the Transmission Provider shall evaluate the proposed modifications prior to making them and shall inform the Interconnection Customer in writing of whether the modification(s) would constitute a Material Modification. For purposes of this Section 36.2A.3, any change to the Point of Interconnection (other than a change deemed acceptable under Sections 36.1.5, 36.2.1, or 36.2A.1) or increase in generating capacity shall constitute a Material Modification. The Interconnection Customer may then withdraw the proposed modification or proceed with a new Interconnection Request for such modification.

36.2A.4

Upon receipt of the Interconnection Customer's request for modification under Section 36.2A.3, the Transmission Provider shall commence and perform any necessary additional studies as soon as practicable, but, except as otherwise provided in this Subpart A, the Transmission Provider shall commence such studies no later than thirty (30) calendar days after receiving notice of the Interconnection Customer's request. Any additional studies resulting from such modification shall be done at the Interconnection Customer's expense. Transmission Provider may require the Interconnection Customer to pay the estimated cost of such studies in advance.

36.2A.5

Extensions of less than three (3) cumulative years in the projected date of Initial Operation of the Customer Facility are not material and shall be handled through construction sequencing.

The following language applies to Interconnection Requests which have entered the New Services Queue on or after May 1, 2012:

36.2A.6

An Interconnection Customer may be assigned a new queue position as provided for in sections 36.2A.1.2 or 36.2A.2 a total of two times for any single Interconnection Request. In the event that Interconnection Customer seeks to reduce the size of its project such that Transmission Provider determines the change is a material modification, and such change would result in the third assignment of a new queue position under sections 36.2A.1 .2 or 36.2A.2, then the Interconnection Request shall be terminated and withdrawn if the Interconnection Customer proceeds with such change.

Effective Date: 5/1/2012 - Docket #: ER12-1177-001

ATTACHMENT P

FORM OF
INTERCONNECTION CONSTRUCTION SERVICE AGREEMENT
By and Among
PJM Interconnection, L.L.C.
And
[Name of Interconnection Customer]
And
[Name of Interconnected Transmission Owner]

(PJM Queue Position #___)

1.0 Parties. This Interconnection Construction Service Agreement ("CSA") including the Schedules and Appendices attached hereto and incorporated herein, is entered into by and between PJM Interconnection, L.L.C. ("Transmission Provider" or "PJM") and the following Interconnection Customer and Interconnected Transmission Owner:

Interconnection Customer:

[full name] [OPTIONAL: (also referred to as "[short name"])]_____________________

Interconnected Transmission Owner:

[full name] [OPTIONAL: (also referred to as "[short name"])]_____________________

All capitalized terms herein shall have the meanings set forth in the appended definitions of such terms as stated in Part I of the Tariff.

2.0 Authority. This CSA is entered into pursuant to Part VI of the Tariff. The standard terms and conditions for construction are attached at Appendix 2 to this CSA and are hereby specifically incorporated as provisions of this agreement. Transmission Provider, the Interconnection Customer and the Interconnected Transmission Owner agree to and assume all of their respective rights and obligations as set forth in the standard terms and conditions for construction in Appendix 2 to this CSA. Further, Interconnection Customer and the Interconnected Transmission Owner each agrees to and assumes all of the rights and obligations of a Constructing Entity with respect to the facilities that each of them is responsible for constructing, as set forth in this CSA.

3.0 Customer Facility. This CSA specifically relates to the following Customer Facility at the following location:

a. Name of Customer Facility:

____

b. Location of Customer Facility:

____

4.0 Effective Date and Term.

4.1 Effective Date. This CSA shall become effective on the later of (i) the date the agreement has been executed by all Construction Parties, or (ii) the date of Interconnection Customer’s delivery of Security to the Transmission Provider, provided, however, that if the CSA is filed with the FERC unexecuted, the Effective Date shall be the date specified by the FERC. The Interconnected Transmission Owner shall have no obligation to begin construction of the Transmission Owner Interconnection Facilities prior to the Effective Date. Construction shall commence as provided in the Schedule of Work set forth in Schedule J to this CSA.

4.2 Term. This CSA shall continue in full force and effect from the Effective Date until the termination thereof pursuant to Section 14 of Appendix 2 to this CSA.

4.3 Survival. This CSA shall continue in effect after termination to the extent necessary to provide for final billings and payments, including billings and payments pursuant to Section 9 and/or Section 14 of Appendix 2 to this CSA, and to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while the CSA was in effect.

5.0 Construction Responsibility for

a. Customer Interconnection Facilities. Interconnection Customer is responsible for designing and constructing the Customer Interconnection Facilities described on the attached Schedule G to this CSA.

b. Construction of Transmission Owner Interconnection Facilities.

1. The Transmission Owner Interconnection Facilities regarding which Interconnected Transmission Owner shall be the Constructing Entity are described on the attached Schedule C to this CSA.

2. Election of Construction Option. Specify below whether the Constructing Entities have mutually agreed to construction of the Transmission Owner Interconnection Facilities that will be built by the Interconnected Transmission Owner pursuant to the Standard Option or the Negotiated Contract Option. (See Section 3.2 of the Appendix 2 to this CSA.)

_____Standard Option.

_____Negotiated Contract Option.

If the parties have mutually agreed to use the Negotiated Contract Option, the permitted, negotiated terms on which they have agreed and which are not already set forth as part of the Scope of Work and/or Schedule of Work attached to this CSA as Schedules I and J, respectively, shall be as set forth in Schedule H attached to this CSA.

3. Exercise of Option to Build. Has Interconnection Customer timely exercised the Option to Build in accordance with Section 3.2.3 of Appendix 2 to this CSA with respect to some or all of the Transmission Owner Interconnection Facilities?

______ Yes

______ No

If Yes is indicated, Interconnection Customer shall build, in accordance with and subject to the conditions and limitations set forth in Section 3.2.3 of Appendix 2 to this CSA, those portions of the Transmission Owner Interconnection Facilities described on Schedule D attached to this CSA.

[include c. below only if applicable to a Merchant Transmission interconnection:]

c. Construction of Merchant Network Upgrades.

1. The Merchant Network Upgrades regarding which Interconnected Transmission Owner shall be the Constructing Entity are described on the attached Schedule E to this CSA.

2. Election of Construction Option. Specify below whether the Constructing Entities have mutually agreed to construction of the Merchant Network Upgrades that will be built by the Interconnected Transmission Owner pursuant to the Standard Option or the Negotiated Contract Option. (See Section 3.2 of Appendix 2 to this CSA.)

_____Standard Option.

_____Negotiated Contract Option.

If the parties have mutually agreed to use the Negotiated Contract Option, the permitted, negotiated terms on which they have agreed and which are not already set forth as part of the Scope of Work and/or Schedule of Work attached to this CSA as Schedules I and J, respectively, shall be as set forth in Schedule H attached to this CSA.

3. Exercise of Option to Build. Has Interconnection Customer timely exercised the Option to Build in accordance with Section 3.2.3 of Appendix 2 to this CSA with respect to some or all of the Merchant Network Upgrades?

______ Yes

______ No

If Yes is indicated, Interconnection Customer shall build, in accordance with and subject to the conditions and limitations set forth in Section 3.2.3 of Appendix 2 to this CSA, those portions of the Merchant Network Upgrades described on Schedule F attached to this CSA.

6.0 [Reserved].

7.0 Scope of Work. The Scope of Work for all construction pursuant to this CSA shall be as set forth in the attached Schedule I, provided, however, that the scope of work is subject to change in accordance with Transmission Provider's scope change process for interconnection projects as set forth in the PJM Manuals.

8.0 Schedule of Work. The Schedule of Work for all construction pursuant to this CSA shall be as set forth in the attached Schedule J, provided, however, that such schedule is subject to change in accordance with Section 3.3 of Appendix 2 to this CSA.

9.0 [Reserved.]

10.0 Notices. Any notice or request made to or by any party regarding this CSA shall be made in accordance with the standard terms and conditions for construction set forth in Appendix 2 to this CSA to the representatives of the other parties, as indicated below:

Transmission Provider:

PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

Interconnection Customer:
____
____
____

Interconnected Transmission Owner:
____
____
____

11.0 Waiver. No waiver by any party of one or more defaults by another in performance of any of the provisions of this CSA shall operate or be construed as a waiver of any other or further default or defaults, whether of a like or different character.

12.0 Amendment. This CSA or any part thereof, may not be amended, modified, assigned, or waived other than by a writing signed by all parties.

13.0 Incorporation of Other Documents. All portions of the Tariff and the Operating Agreement pertinent to the subject of this CSA and not otherwise made a part hereof are hereby incorporated herein and made a part hereof.

14.0 Addendum of Interconnection Customer's Agreement to Conform with IRS Safe Harbor Provisions for Non-Taxable Status. To the extent required, in accordance with Section 2.4.1 of Appendix 2 to this CSA, Schedule L to this CSA shall set forth the Interconnection Customer's agreement to conform with the IRS safe harbor provisions for non-taxable status.

15.0 Addendum of Non-Standard Terms and Conditions for Construction Service. Subject to FERC approval, the parties agree that the terms and conditions set forth in the attached Schedule M are hereby incorporated by reference, and made a part of, this CSA. In the event of any conflict between a provision of Schedule M that FERC has accepted and any provision of the standard terms and conditions set forth in Appendix 2 to this CSA that relates to the same subject matter, the pertinent provision of Schedule M shall control.

16.0 Addendum of Interconnection Requirements for a Wind Generation Facility. To the extent required, Schedule N to this CSA sets forth interconnection requirements for a wind generation facility and is hereby incorporated by reference and made a part of this CSA.

17.0 Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. All Transmission Providers, Interconnected Transmission Owners, market participants, and Interconnection Customers interconnected with electric systems are to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and best practice recommendations from the electric reliability authority. All public utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

IN WITNESS WHEREOF, the parties have caused this Interconnection Construction Service Agreement to be executed by their respective authorized officials.

(PJM Queue Position #____)

Transmission Provider: PJM Interconnection, L.L.C.:

By:________________________ ________________ _______________

Name Title Date

Printed name of signer:____

Interconnection Customer: [Name of Party]

By:________________________ ________________ _______________
Name Title Date

Printed name of signer:____

Interconnected Transmission Owner: **[Name of Party]**

By:________________________ ________________ _______________
Name Title Date

Printed name of signer: ____

APPENDICES:

- **APPENDIX 1 - DEFINITIONS**
- **APPENDIX 2 - STANDARD CONSTRUCTION TERMS AND CONDITIONS**

SCHEDULES:

- **SCHEDULE A - SITE PLAN**
- **SCHEDULE B - SINGLE-LINE DIAGRAM OF INTERCONNECTION FACILITIES**
- **SCHEDULE C - TRANSMISSION OWNER INTERCONNECTION**

FACILITIES TO BE BUILT BY INTERCONNECTED TRANSMISSION OWNER

- **SCHEDULE D - TRANSMISSION OWNER INTERCONNECTION FACILITIES TO BE BUILT BY INTERCONNECTION CUSTOMER PURSUANT TO OPTION TO BUILD**
- **SCHEDULE E - MERCHANT NETWORK UPGRADES TO BE BUILT BY INTERCONNECTED TRANSMISSION OWNER**
- **SCHEDULE F - MERCHANT NETWORK UPGRADES TO BE BUILT BY INTERCONNECTION CUSTOMER PURSUANT TO OPTION TO BUILD**
- **SCHEDULE G - CUSTOMER INTERCONNECTION FACILITIES**

- **SCHEDULE H - NEGOTIATED CONTRACT OPTION TERMS**
- **SCHEDULE I - SCOPE OF WORK**
- **SCHEDULE J - SCHEDULE OF WORK**
- **SCHEDULE K - APPLICABLE TECHNICAL REQUIREMENTS AND STANDARDS**
- **SCHEDULE L - INTERCONNECTION CUSTOMER'S AGREEMENT TO CONFORM WITH IRS SAFE HARBOR PROVISIONS FOR NON-TAXABLE STATUS**
- **SCHEDULE M - SCHEDULE OF NON-STANDARD TERMS AND CONDITIONS**
- **SCHEDULE N - INTERCONNECTION REQUIREMENTS FOR A WIND GENERATION FACILITY**

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

APPENDIX 1

DEFINITIONS

From the PJM Tariff accepted for filing by the Commission
As of the effective date of this CSA

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

APPENDIX 2

STANDARD CONSTRUCTION TERMS AND CONDITIONS

Preamble

The construction of any Interconnection Facilities required to interconnect a Customer Facility with the Transmission System shall be in accordance with the following Standard Construction Terms and Conditions.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

1 Facilitation by Transmission Provider

Transmission Provider shall keep itself apprised of the status of the Constructing Entities' construction-related activities and, upon request of either of them, Transmission Provider shall meet with the Constructing Entities separately or together to assist them in resolving issues between them regarding their respective activities, rights and obligations under this Appendix 2 to this CSA. Each Constructing Entity shall cooperate in good faith with the other Construction Parties in Transmission Provider's efforts to facilitate resolution of disputes.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

2 Construction Obligations

2.1 Interconnection Customer Obligations

2.1.1 Generally:

Interconnection Customer shall, at its sole cost and expense, design, procure, construct, own and install the Customer Facility and the Customer Interconnection Facilities in accordance with this Appendix 2 to this CSA, Applicable Standards, Applicable Laws and Regulations, Good Utility Practice, the Scope of Work and the Facilities Study (to the extent that design of the Customer Interconnection Facilities is included therein), provided, however, that, in the event and to the extent that the Customer Facility is comprised of or includes Merchant Network Upgrades, subject to the terms of Section 3.2.3 of this Appendix 2, the Interconnected Transmission Owner, shall design, procure, construct and install such Merchant Network Upgrades.

2.1.2 Interconnection Customer Drawings:

On or before the applicable date specified in the Schedule of Work, Interconnection Customer shall submit to the Interconnected Transmission Owner and Transmission Provider initial drawings, certified by a professional engineer, of the Customer Interconnection Facilities. Interconnected Transmission Owner and Transmission Provider shall review the drawings to assess the consistency of Interconnection Customer's design of the Customer Interconnection Facilities with Applicable Standards and, to the extent that design of the Customer Interconnection Facilities is included in the Facilities Study, also shall assess the consistency of Interconnection Customer's design with the Facilities Study. After consulting with the Interconnected Transmission Owner, Transmission Provider shall provide comments on the drawings to Interconnection Customer within forty-five (45) days after its receipt thereof, after which time any drawings not subject to comment shall be deemed to be approved. All drawings provided hereunder shall be deemed to be Confidential Information.

2.1.3 Effect of Review:

Interconnected Transmission Owner's and Transmission Provider's reviews of Interconnection Customer's initial drawings of the Customer Interconnection Facilities shall not be construed as confirming, endorsing or providing a warranty as to the fitness, safety, durability or reliability of such facilities or the design thereof. At its sole cost and expense, Interconnection Customer shall make such changes to the design of the Customer Interconnection Facilities as may reasonably be required by Transmission Provider, in consultation with the Interconnected Transmission Owner, to ensure that the Customer Interconnection Facilities meet Applicable Standards and, to the extent that design of the Customer Interconnection Facilities is included in the Facilities Study, to ensure that such facilities conform with the Facilities Study.

2.2 Transmission Owner Interconnection Facilities and Merchant Network Upgrades

2.2.1 Generally:

(a) All Transmission Owner Interconnection Facilities necessary for the interconnection of the Customer Facility and (b) any Merchant Network Upgrades shall be designed, procured, installed and constructed in accordance with this Appendix 2, Applicable Standards, Applicable Laws and Regulations, Good Utility Practice, the Facilities Study and the Scope of Work under the Interconnection Construction Service Agreement(s).

2.2.2 Cost Responsibility:

Responsibility for the Costs of the Transmission Owner Interconnection Facilities and any Merchant Network Upgrades shall be assigned in accordance with Section 217 of the Tariff, as applicable, and shall be stated in the Interconnection Service Agreement.

2.2.3 Construction Responsibility:

Except as otherwise permitted under, or as otherwise agreed upon by the Interconnection Customer and the Interconnected Transmission Owner pursuant to, Section 3 of this Appendix 2, the Interconnected Transmission Owner shall be responsible for the design, procurement, construction and installation of the Transmission Owner Interconnection Facilities or any Merchant Network Upgrades. In the event that there are multiple Interconnected Transmission Owners, the Transmission Provider shall determine how to allocate the construction responsibility among them unless they have reached agreement among themselves on how to proceed.

2.2.4 Ownership of Transmission Owner Interconnection Facilities and Merchant Network Upgrades:

The Interconnected Transmission Owner shall own all Transmission Owner Interconnection Facilities and Merchant Network Upgrades that it builds. In addition, the Interconnection Customer will convey to the Interconnected Transmission Owner, as provided in Section 5.5 of this Appendix 2, title to all Transmission Owner Interconnection Facilities and Merchant Network Upgrades built by the Interconnection Customer pursuant to the terms of Section 3.2 of this Appendix 2. Nothing in this section shall affect the interconnection rights otherwise available to a Transmission Interconnection Customer under Subpart C of Part VI of the Tariff.

2.2A Scope of Applicable Technical Requirements and Standards:

Applicable Technical Requirements and Standards shall apply to the design, procurement, construction and installation of the Interconnection Facilities and Merchant A.C. Transmission Facilities only to the extent that the provisions thereof relate to the design, procurement, construction and/or installation of such facilities. Such provisions relating to the design, procurement, construction and/or installation of facilities shall be appended to the Interconnection Construction Service Agreement. The Interconnection Parties shall mutually agree upon, or in the absence of such agreement, Transmission Provider shall determine, which provisions of the Applicable Technical Requirements and Standards should be identified in the Interconnection Construction Service Agreement. In the event of any conflict between the provisions of the Applicable Technical Requirements and Standards that are appended to this Interconnection Construction Service Agreement and any later-modified provisions that are stated in the pertinent PJM Manual, the provisions appended to this Interconnection Construction Service Agreement shall control.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

2.3 Construction By Interconnection Customer

2.3.1 Construction Prior to Execution of Interconnection Construction Service Agreement:

If the Interconnection Customer procures materials for, and/or commences construction of, the Customer Interconnection Facilities, any Transmission Owner Interconnection Facilities, or any Merchant Network Upgrades that it has elected to construct by exercising the Option to Build under Section 3.2.3 of this Appendix 2, or for any subsequent modification thereto, prior to the execution of the Interconnection Construction Service Agreement or, if the Interconnection Construction Service Agreement has been executed, before the Interconnected Transmission Owner and Transmission Provider have accepted the Interconnection Customer's initial design, or any subsequent modification to the design, of such Interconnection Facilities and/or Merchant Network Upgrades, such procurement and/or construction shall be at the Interconnection Customer's sole risk, cost and expense.

2.3.2 Monitoring and Inspection:

The Interconnected Transmission Owner may monitor construction and installation of Interconnection Facilities and/or Merchant Network Upgrades that the Interconnection Customer is constructing. Upon reasonable notice, authorized personnel of the Interconnected Transmission Owner may inspect any or all of such Interconnection Facilities and/or Merchant Network Upgrades to assess their conformity with Applicable Standards.

2.3.3 Notice of Completion:

The Interconnection Customer shall notify the Transmission Provider and the Interconnected Transmission Owner in writing when it has completed construction of (i) the Customer Facility; (ii) the Customer Interconnection Facilities; and (iii) any Transmission Owner Interconnection Facilities and/or any Merchant Network Upgrades for which it has exercised the Option to Build under Section 3 of this Appendix 2.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

2.4 Tax Liability

2.4.1 Safe Harbor Provisions:

This Section 2.4.1 is applicable only to Generation Interconnection Customers. Provided that Interconnection Customer agrees to conform to all requirements of the Internal Revenue Service ("IRS") (e.g., the "safe harbor" provisions of IRS Notices 2001-82 and 88-129) that would confer nontaxable status on some or all of the transfer of property, including money, by Interconnection Customer to the Interconnected Transmission Owner for payment of the Costs of construction of the Transmission Owner Interconnection Facilities, the Interconnected Transmission Owner, based on such agreement and on current law, shall treat such transfer of property to it as nontaxable income and, except as provided in Section 2.4.2 of this Appendix 2, shall not include income taxes in the Costs of Transmission Owner Interconnection Facilities that are payable by Interconnection Customer under this Appendix 2. Interconnection Customer shall document its agreement to conform to IRS requirements for such non-taxable status in the Interconnection Service Agreement, the Interconnection Construction Service Agreement, and/or the Interim Interconnection Service Agreement.

2.4.2 Tax Indemnity:

Interconnection Customer shall indemnify the Interconnected Transmission Owner for any costs that Interconnected Transmission Owner incurs in the event that the IRS and/or a state department of revenue (State) determines that the property, including money, transferred by Interconnection Customer to the Interconnected Transmission Owner with respect to the construction of the Transmission Owner Interconnection Facilities and/or any Merchant Network Upgrades is taxable income to the Interconnected Transmission Owner. Interconnection Customer shall pay to the Interconnected Transmission Owner, on demand, the amount of any income taxes that the IRS or a State assesses to the Interconnected Transmission Owner in connection with such transfer of property and/or money, plus any applicable interest and/or penalty charged to the Interconnected Transmission Owner. In the event that the Interconnected Transmission Owner chooses to contest such assessment, either at the request of Interconnection Customer or on its own behalf, and prevails in reducing or eliminating the tax, interest and/or penalty assessed against it, the Interconnected Transmission Owner shall refund to Interconnection Customer the excess of its demand payment made to the Interconnected Transmission Owner over the amount of the tax, interest and penalty for which the Interconnected Transmission Owner is finally determined to be liable. Interconnection Customer's tax indemnification obligation under this section shall survive any termination of the Interconnection Construction Service Agreement.

2.4.3 Taxes Other Than Income Taxes:

Upon the timely request by Interconnection Customer, and at Interconnection Customer's sole expense, the Interconnected Transmission Owner shall appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against the Interconnected Transmission Owner for which Interconnection Customer may be required to reimburse Transmission Provider under the terms of this Interconnection Construction Service

Agreement, or Part VI of the Tariff. Interconnection Customer shall pay to the Interconnected Transmission Owner on a periodic basis, as invoiced by the Interconnected Transmission Owner, the Interconnected Transmission Owner's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Interconnection Customer and the Interconnected Transmission Owner shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Interconnection Customer to the Interconnected Transmission Owner for such contested taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Interconnection Customer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by the Interconnected Transmission Owner.

2.4.4 Income Tax Gross-Up

2.4.4.1 Additional Security:

In the event that Interconnection Customer does not provide the safe harbor documentation required under Section 2.4.1 of this Appendix 2 prior to execution of the Interconnection Construction Service Agreement, within 15 days after such execution, Transmission Provider shall notify Interconnection Customer in writing of the amount of additional Security that Interconnection Customer must provide. The amount of Security that a Transmission Interconnection Customer must provide initially shall include any amounts described as additional Security under this Section 2.4.4 regarding income tax gross-up.

2.4.4.2 Amount:

The required additional Security shall be in an amount equal to the amount necessary to gross up fully for currently applicable federal and state income taxes the estimated Costs of Local Upgrades and Network Upgrades for which Interconnection Customer previously provided Security. Accordingly, the additional Security shall equal the amount necessary to increase the total Security provided to the amount that would be sufficient to permit the Interconnected Transmission Owner to receive and retain, after the payment of all applicable income taxes ("Current Taxes") and taking into account the present value of future tax deductions for depreciation that would be available as a result of the anticipated payments or property transfers (the "Present Value Depreciation Amount"), an amount equal to the estimated Costs of Local Upgrades and Network Upgrades for which Interconnection Customer is responsible under the Interconnection Service Agreement. For this purpose, Current Taxes shall be computed based on the composite federal and state income tax rates applicable to the Interconnected Transmission Owner at the time the additional Security is received, determined using the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value Depreciation Amount shall be computed by discounting the Interconnected Transmission Owner's anticipated tax depreciation deductions associated with such payments or property transfers by its current weighted average cost of capital.

2.4.4.3 Time for Payment:

Interconnection Customer must provide the additional Security, in a form and with terms as required by Section 212.4, within 15 days after its receipt of Transmission Provider's notice under this section. The requirement for additional Security under this section shall be treated as a milestone included in the Interconnection Service Agreement pursuant to Section 212.5.

2.4.5 Tax Status:

Each Party shall cooperate with the other to maintain the other Party's tax status. Nothing in this Interconnection Construction Service Agreement or the Tariff is intended to adversely affect any Interconnected Transmission Owner's tax exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

2.5 Safety

2.5.1 General:

Each Construction Party shall perform all work hereunder that may reasonably be expected to affect any other Construction Party in accordance with Good Utility Practice, Applicable Standards and Applicable Laws and Regulations pertaining to the safety of persons or property. A Construction Party performing work within an area controlled by another Construction Party must abide by the safety rules applicable to the area.

2.5.2 Environmental Releases:

Each Construction Party shall notify each other Construction Party, first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Customer Facility or the Interconnection Facilities, any of which may reasonably be expected to affect another Construction Party. The notifying Construction Party shall (i) provide the notice as soon as possible, (ii) make a good faith effort to provide the notice within twenty-four hours after the Construction Party becomes aware of the occurrence, and (iii) promptly furnish to each other Construction Party copies of any publicly available reports filed with any governmental agencies addressing such events.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

2.6 Construction-Related Access Rights:

The Interconnected Transmission Owner and the Interconnection Customer herein grant each other at no charge such rights of access to areas that it owns or otherwise controls as may be necessary for performance of their respective obligations, and exercise of their respective rights, pursuant to this Appendix 2, provided that either of them performing the construction will abide by the safety, security and work rules applicable to the area where construction activity is occurring.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

2.7 Coordination Among Construction Parties:

The Transmission Provider, the Interconnection Customer, and all Interconnected Transmission Owners shall communicate and coordinate their activities as necessary to satisfy their obligations under this Interconnection Construction Service Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

3 Schedule Of Work

3.1 Construction by Interconnection Customer:

The Interconnection Customer shall use Reasonable Efforts to design, procure, construct and install the Customer Interconnection Facilities and any Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades that it elects to build by exercise of the Option to Build (defined in Section 3.2.3.1 below) in accordance with the Schedule of Work.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

3.2 Construction by Interconnected Transmission Owner

3.2.1 Standard Option:

The Interconnected Transmission Owner shall use Reasonable Efforts to design, procure, construct and install the Transmission Owner Interconnection Facilities and/or any Merchant Network Upgrades that it is responsible for constructing in accordance with the Schedule of Work.

3.2.1.1 Construction Sequencing:

In general, the sequence of the proposed dates of Initial Operation of Interconnection Customers seeking interconnection to the Transmission System will determine the sequence of construction of Network Upgrades.

3.2.2 Negotiated Contract Option:

As an alternative to the Standard Option set forth in Section 3.2.1 of this Appendix 2, the Interconnected Transmission Owner and the Interconnection Customer may mutually agree to a Negotiated Contract Option for the Interconnected Transmission Owner's design, procurement, construction and installation of the Transmission Owner Interconnection Facilities and/or any Merchant Network Upgrades. Under the Negotiated Contract Option, the Interconnection Customer and the Interconnected Transmission Owner may agree to terms different from those included in the Standard Option of Section 3.2.1 above and the corresponding standard terms set forth in the applicable provisions of Part VI of the Tariff and this Appendix 2. Under the Negotiated Contract Option, negotiated terms may include the work schedule applicable to the Interconnected Transmission Owner's construction activities and changes to same (Section 3.3 of this Appendix 2); payment provisions, including the schedule of payments; incentives, penalties and/or liquidated damages related to timely completion of construction (Section 3.2.1 of this Appendix 2); use of third party contractors; and responsibility for Costs, but only as between the Interconnection Customer and the Interconnected Transmission Owner that are parties to this Interconnection Construction Service Agreement; no other Interconnection Customer's responsibility for Costs may be affected (Section 217 of the Tariff). No other terms of the Tariff or this Appendix 2 shall be subject to modification under the Negotiated Contract Option. The terms and conditions of the Tariff that may be negotiated pursuant to the Negotiated Contract Option shall not be affected by use of the Negotiated Contract Option except as and to the extent that they are modified by the parties' agreement pursuant to such option. All terms agreed upon pursuant to the Negotiated Contract Option shall be stated in full in an appendix to this Interconnection Construction Service Agreement.

3.2.3 Option to Build

3.2.3.1 Option:

In the event that the Interconnected Transmission Owner and the Interconnection Customer are unable to agree upon the terms of an Interconnection Construction Service Agreement (a) on or before the date that is 30 days after Interconnection Customer's execution of the Interconnection Service Agreement, or (b) by such earlier date as is reasonable in the light of the schedule for construction of, as the case may be, the Transmission Owner Interconnection Facilities or Merchant Network Upgrades, as set forth in the Facilities Study, and subject to the terms and conditions set forth in Sections 2 and 3 of this Appendix 2, or if mutually agreed by and between the Interconnection Customer and the Transmission Owner, the Interconnection Customer shall have the right, but not the obligation ("Option to Build"), to design, procure, construct and install all or any portion of the Transmission Owner Interconnection Facilities and/or any Merchant Network Upgrades. In order to exercise this Option to Build, the Interconnection Customer must provide Transmission Provider and the Interconnected Transmission Owner with written notice of its election to exercise the option by no later than seven days after the date that is 30 days after Interconnection Customer's execution of the Interconnection Service Agreement, specifying either that a mutual agreement has been reached between the Interconnection Customer and the Interconnected Transmission Owner that the Interconnection Customer will exercise the Option to Build, or the specific terms and conditions of the Interconnection Construction Service Agreement upon which the Interconnected Transmission Owner and the Interconnection Customer are unable to agree and the efforts undertaken by the Interconnection Customer to resolve such disagreement; provided, however, that the Interconnection Customer and the Interconnected Transmission Owner may by mutual agreement extend the time period for exercise of the option.

3.2.3.2 General Conditions Applicable to Option:

In addition to the other terms and conditions applicable to the construction of facilities under this Appendix 2, the Option to Build is subject to the following conditions:

(a) The Interconnection Customer must obtain or arrange to obtain all necessary permits and authorizations for the construction and installation of the Transmission Owner Interconnection Facilities and/or any Merchant Network Upgrades that it is building, provided, however, that when the Interconnected Transmission Owner's assistance is required, the Interconnected Transmission Owner shall assist the Interconnection Customer in obtaining such necessary permits or authorizations with efforts similar in nature and extent to those that the Interconnected Transmission Owner typically undertakes in acquiring permits and authorizations for construction of facilities on its own behalf;

(b) The Interconnection Customer must obtain all necessary land rights for the construction and installation of the Transmission Owner Interconnection Facilities and/or any Merchant Network Upgrades that it is building, provided, however, that upon Interconnection Customer's reasonable request, the Interconnected Transmission Owner shall assist the Interconnection Customer in acquiring such land rights with efforts similar in nature and extent to those that the Interconnected Transmission Owner typically undertakes in acquiring land rights for construction of facilities on its own behalf;

(c) Notwithstanding anything stated herein, each Interconnected Transmission Owner shall have the exclusive right and obligation to perform the line attachments (tie-in work), and to calibrate remote terminal units and relay settings, required for the interconnection to such

Interconnected Transmission Owner's existing facilities of any Transmission Owner Interconnection Facilities and/or any Merchant Network Upgrades that the Interconnection Customer builds; and(d) The Transmission Owner Interconnection Facilities and/or any Merchant Network Upgrades built by the Interconnection Customer shall be successfully inspected, tested and energized pursuant to Sections 3.8 and 3.9 of this Appendix 2.

3.2.3.3 Additional Conditions Regarding Network Facilities:

To the extent that the Interconnection Customer utilizes the Option to Build for design, procurement, construction and/or installation of (a) any Merchant Network Upgrades, (b) any Transmission Owner Interconnection Facilities that are Local Upgrades or Network Upgrades to Transmission System facilities that are in existence or under construction by or on behalf of the Interconnected Transmission Owner on the date that the Interconnection Customer solicits bids under Section 3.2.3.7 below, or (c) Merchant Network Upgrades or Transmission Owner Interconnection Facilities that are to be located on land or in right-of-way owned or controlled by the Interconnected Transmission Owner, and in addition to the other terms and conditions applicable to the design, procurement, construction and/or installation of facilities under this Appendix 2, all work shall comply with the following further conditions:

(i) All work performed by or on behalf of the Interconnection Customer shall be conducted by contractors, and using equipment manufacturers or vendors, that are listed on the Interconnected Transmission Owner's List of Approved Contractors;

(ii) The Interconnected Transmission Owner shall have full site control of, and reasonable access to, its property at all times for purposes of tagging or operation, maintenance, repair or construction of modifications to, its existing facilities and/or for performing all tie-ins of Interconnection Facilities and/or Merchant Network Upgrades built by or for the Interconnection Customer; and for acceptance testing of any equipment that will be owned and/or operated by the Interconnected Transmission Owner;

(iii) The Interconnected Transmission Owner shall have the right to have a reasonable number of appropriate representatives present for all work done on its property/facilities or regarding the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades, and the right to stop, or to order corrective measures with respect to, any such work that reasonably could be expected to have an adverse effect on reliability, safety or security of persons or of property of the Interconnected Transmission Owner or any portion of the Transmission System, provided that, unless circumstances do not reasonably permit such consultations, the Interconnected Transmission Owner shall consult with the Interconnection Customer and with Transmission Provider before directing that work be stopped or ordering any corrective measures;

(iv) The Interconnection Customer and its contractors, employees and agents shall comply with the Interconnected Transmission Owner's safety, security and work rules, environmental guidelines and training requirements applicable to the area(s) where construction activity is occurring and shall provide all reasonably required documentation to the Interconnected Transmission Owner, provided that the Interconnected Transmission Owner previously has provided its safety, security and work rules and training requirements applicable to work on its facilities to Transmission Provider and the Interconnection Customer within 20 business days after a request therefor made by Interconnection Customer following its receipt of the Facilities Study;

(v) The Interconnection Customer shall be responsible for controlling the performance of its contractors, employees and agents; and

(vi) All activities performed by or on behalf of the Interconnection Customer pursuant to its exercise of the Option to Build shall be subject to compliance with Applicable Laws and Regulations, including those governing union staffing and bargaining unit obligations, and Applicable Standards.

3.2.3.4 Administration of Conditions:

To the extent that the Interconnected Transmission Owner exercises any discretion in the application of any of the conditions stated in Sections 3.2.3.2 and 3.2.3.3 of this Appendix 2, it shall apply each such condition in a manner that is reasonable and not unduly discriminatory and it shall not unreasonably withhold, condition, or delay any approval or authorization that the Interconnection Customer may require for the purpose of complying with any of those conditions.

3.2.3.5 Approved Contractors:

(a) Each Transmission Owner shall develop and shall provide to Transmission Provider a List of Approved Contractors. Each Transmission Owner shall include on its List of Approved Contractors no fewer than three contractors and no fewer than three manufacturers or vendors of major transmission-related equipment, unless a Transmission Owner demonstrates to Transmission Provider's reasonable satisfaction that it is feasible only to include a lesser number of construction contractors, or manufacturers or vendors, on its List of Approved Contractors. Transmission Provider shall publish each Transmission Owner's List of Approved Contractors in a PJM Manual and shall make such manual available on its internet website.

(b) Upon request of an Interconnection Customer, a Transmission Owner shall add to its List of Approved Contractors (1) any design or construction contractor regarding which the Interconnection Customer provides such information as the Transmission Owner may reasonably require which demonstrates to the Transmission Owner's reasonable satisfaction that the candidate contractor is qualified to design, or to install and/or construct new facilities or upgrades or modifications to existing facilities on the Transmission Owner's system, or (2) any manufacturer or vendor of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) regarding which the Interconnection Customer provides such information as the Transmission Owner may reasonably require which demonstrates to the Transmission Owner's reasonable satisfaction that the candidate entity's major transmission-related equipment is acceptable for installation and use on the Transmission Owner's system. No Transmission Owner shall unreasonably withhold, condition, or delay its acceptance of a contractor, manufacturer, or vendor proposed for addition to its List of Approved Contractors.

3.2.3.6 Construction by Multiple Interconnection Customers:

In the event that there are multiple Interconnection Customers that wish to exercise an Option to Build with respect to Interconnection Facilities of the types described in Section 3.2.3.3 to this Appendix 2, the Transmission Provider shall determine how to allocate the construction responsibility among them unless they reach agreement among themselves on how to proceed.

3.2.3.7 Option Procedures:

(a) Within 10 days after notifying Transmission Provider and the Interconnected Transmission Owner of its election to exercise the Option to Build, Interconnection Customer shall solicit bids from one or more Approved Contractors named on the Interconnected Transmission Owner's List of Approved Contractors to procure equipment for, and/or to design, construct and/or install, the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades that the Interconnection Customer seeks to build under the Option to Build on terms (i) that will meet the Interconnection Customer's proposed schedule; (ii) that, if the Interconnection Customer seeks to have an Approved Contractor construct or install Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades, will satisfy all of the conditions on construction specified in Sections 3.2.3.2 and 3.2.3.3 of this Appendix 2; and (iii) that will satisfy the obligations of a Constructing Entity (other than those relating to responsibility for the costs of facilities) under this Appendix 2.

(b) Any additional costs arising from the bidding process or from the final bid of the successful Approved Contractor shall be the sole responsibility of the Interconnection Customer.

(c) Upon receipt of a qualifying bid acceptable to it, the Interconnection Customer shall contract with the Approved Contractor that submitted the qualifying bid. Such contract shall meet the standards stated in paragraph (a) of this section.

(d) In the absence of a qualifying bid acceptable to the Interconnection Customer in response to its solicitation, the Interconnected Transmission Owner(s) shall be responsible for the design, procurement, construction and installation of the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades in accordance with the Standard Option described in Section 3.2.1 of this Appendix 2.

3.2.3.8 Interconnection Customer Drawings:

Interconnection Customer shall submit to the Interconnected Transmission Owner and Transmission Provider initial drawings, certified by a professional engineer, of the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades that Interconnection Customer arranges to build under the Option to Build. The Interconnected Transmission Owner and Transmission Provider shall review the drawings to assess the consistency of Interconnection Customer's design of the pertinent Transmission Owner Interconnection Facilities and/or

Merchant Network Upgrades with Applicable Standards and the Facilities Study. After consulting with the Interconnected Transmission Owner, Transmission Provider shall provide comments on such drawings to Interconnection Customer within sixty days after its receipt thereof, after which time any drawings not subject to comment shall be deemed to be approved. All drawings provided hereunder shall be deemed to be Confidential Information.

3.2.3.9 Effect of Review:

Interconnected Transmission Owner's and Transmission Provider's reviews of Interconnection Customer's initial drawings of the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades that the Interconnection Customer is building shall not be construed as confirming, endorsing or providing a warranty as to the fitness, safety, durability or reliability of such facilities or the design thereof. At its sole cost and expense, Interconnection Customer shall make such changes to the design of the pertinent Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades as may reasonably be required by Transmission Provider, in consultation with the Interconnected Transmission Owner, to ensure that the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades that Interconnection Customer is building meet Applicable Standards and conform with the Facilities Study.

3.3 Revisions to Schedule of Work:

The Schedule of Work shall be revised as required in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals, or otherwise by mutual agreement of the Construction Parties, which agreement shall not be unreasonably withheld, conditioned or delayed.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

3.4 Suspension:

The following provision applies to Interconnection Requests which have entered the New Services Queue prior to February 1, 2011:

Interconnection Customer shall have the right, upon written notice to Transmission Provider and Interconnected Transmission Owner, to suspend at any time all work by Interconnected Transmission Owner associated with the construction and installation of the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades required under an Interconnection Service Agreement or Interconnection Construction Service Agreement, with the condition that, notwithstanding such suspension, the Transmission System shall be left in a safe and reliable condition in accordance with Good Utility Practice and Transmission Provider's safety and reliability criteria. This suspension right permits the Interconnection Customer to request one or more suspensions of work for a cumulative period of up to three years for each Interconnection Request. Interconnection Customer's notice of suspension shall include an estimated duration of the suspension and other information related to the suspension.

The following provision applies to Interconnection Requests which have entered the New Services Queue on or after February 1, 2011:

Interconnection Customer shall have the right, upon written notice to Transmission Provider and Interconnected Transmission Owner, to suspend at any time all work by Interconnected Transmission Owner associated with the construction and installation of the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades required under an Interconnection Service Agreement or Interconnection Construction Service Agreement, with the condition that, notwithstanding such suspension, the Transmission System shall be left in a safe and reliable condition in accordance with Good Utility Practice and Transmission Provider's safety and reliability criteria. This suspension right permits the Interconnection Customer to request one or more suspensions of work for a cumulative period of up to (i) three years for an Interconnection Request for which the Transmission Provider determines that such suspension would not be deemed a Material Modification, or (ii) one year for an Interconnection Request for which the Transmission Provider determine that such suspension would be deemed a Material Modification. Interconnection Customer's notice of suspension shall include an estimated duration of the suspension and other information related to the suspension.

3.4.1 Costs:

In the event of a suspension under this section, Interconnection Customer shall be responsible for all reasonable and necessary Cancellation Costs which Interconnected Transmission Owner or Transmission Provider (i) has incurred pursuant to the Interconnection Service Agreement or Interconnection Construction Service Agreement prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Transmission System during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and/or labor contracts which Interconnected Transmission Owner or Transmission Provider cannot reasonably avoid; provided, however, that prior to cancelling or suspending any such material, equipment or labor contract, Interconnected Transmission Owner or Transmission Provider, as the case may be, shall obtain Interconnection Customer's authorization to do so. Transmission Provider shall invoice Interconnection Customer pursuant to Section 9 of this Appendix 2 for Cancellation Costs for which the customer is liable under this section. Interconnected Transmission Owner and Transmission Provider shall use due diligence to minimize Cancellation Costs in the event of a suspension of work.

3.4.2 Duration of Suspension:

In the event Interconnection Customer suspends work by Interconnected Transmission Owner required under an Interconnection Service Agreement or Interconnection Construction Service Agreement pursuant to this Section 3.4, and has not requested Transmission Provider and the Interconnected Transmission Owner to recommence the work required under the applicable agreement(s) on or before the expiration of the time period allowed under this Section 3.4following commencement of such suspension, the Interconnection Construction Service Agreement and the Interconnection Service Agreement for the Interconnection Request for which Interconnection Customer suspended work shall be deemed terminated as of the end of such suspension time period. The suspension time shall begin on the date the suspension is requested, or on the date of Interconnection Customer's written notice of suspension to Transmission Provider, if no effective date was specified.

Effective Date: 5/1/2012 - Docket #: ER12-1177-001

3.5 Right to Complete Transmission Owner Interconnection Facilities:

In the event that, at any time prior to successful Stage Two energization of the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades pursuant to Section 3.9 of Appendix 2, the Interconnection Customer terminates its obligations under this Appendix 2 pursuant to Section 14.1.2 below due to a Default by the Interconnected Transmission Owner, the Interconnection Customer may elect to complete the design, procurement, construction and installation of the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades. The Interconnection Customer shall notify the Interconnected Transmission Owner and Transmission Provider in writing of its election to complete the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades within 10 days after the date of Interconnection Customer's notice of termination pursuant to Section 14.1.2 of this Appendix 2. In the event that the Interconnection Customer elects to complete the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades, it shall do so in accordance with the terms and conditions of the Option to Build under Section 3.2.3 of this Appendix 2 and shall be responsible for paying all costs of completing the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades incurred after the date of its notice of election to complete the facilities. Interconnection Customer may take possession of, and may use in completing the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades, any materials and supplies and equipment (other than equipment and facilities that already have been installed or constructed) acquired by the Interconnected Transmission Owner for construction, and included in the Costs, of the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades, provided that Interconnection Customer shall pay Transmission Provider, for the benefit of the Interconnected Transmission Owner and upon presentation by Interconnected Transmission Owner of reasonable and appropriate documentation thereof, any amounts expended by the Interconnected Transmission Owner for such materials, supplies and equipment that Interconnection Customer has not already paid. Title to all Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades constructed by Interconnection Customer under this Section 3.5 shall be transferred to the Interconnected Transmission Owner in accordance with Section 5.5 of this Appendix 2.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

3.6 Suspension of Work Upon Default:

Upon the occurrence of a Default by Interconnection Customer as defined in Section 13 of this Appendix 2, the Transmission Provider or the Interconnected Transmission Owner may by written notice to Interconnection Customer suspend further work associated with the construction and installation of the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades that the Interconnected Transmission Owner is responsible for constructing. Such suspension shall not constitute a waiver of any termination rights under this Interconnection Construction Service Agreement. In the event of a suspension by Transmission Provider or Interconnected Transmission Owner, the Interconnection Customer shall be responsible for the Costs incurred in connection with any suspension hereunder in accordance with Section 14.3 of this Appendix 2.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

3.7 Construction Reports:

Each Constructing Entity shall issue reports to each other Construction Party on a monthly basis, and at such other times as reasonably requested, regarding the status of the construction and installation of the Interconnection Facilities and/or any Merchant Network Upgrades. Each Construction Party shall promptly identify, and shall notify each other Construction Party of, any event that the Construction Party reasonably expects may delay completion, or may significantly increase the cost, of the Interconnection Facilities and/or of any Merchant Network Upgrades. Should a Construction Party report such an event, Transmission Provider shall, within fifteen days of such notification, convene a technical meeting of the Construction Parties to evaluate schedule alternatives.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

3.8 Inspection and Testing of Completed Facilities

3.8.1 Coordination:

Interconnection Customer and the Interconnected Transmission Owner shall coordinate the timing and schedule of all inspection and testing of the Interconnection Facilities.

3.8.2 Inspection and Testing:

Each Constructing Entity shall cause inspection and testing of the Interconnection Facilities and/or any Merchant Network Upgrades that it constructs in accordance with the provisions of this section. The Construction Parties acknowledge and agree that inspection and testing of facilities may be undertaken as facilities are completed and need not await completion of all of the facilities that a Constructing Entity is building.

3.8.2.1 Of Interconnection Customer-Built Facilities:

Upon the completion of the construction and installation, but prior to energization, of any Interconnection Facilities and/or Merchant Network Upgrades constructed by the Interconnection Customer and related portions of the Customer Facility, the Interconnection Customer shall have the same inspected and/or tested by an authorized electric inspection agency or qualified third party reasonably acceptable to the Interconnected Transmission Owner to assess whether the facilities substantially comply with Applicable Standards. Said inspection and testing shall be held on a mutually agreed-upon date, and the Interconnected Transmission Owner and Transmission Provider shall have the right to attend and observe, and to obtain the written results of, such testing.

3.8.2.2 Of Interconnected Transmission Owner-Built Facilities:

Upon the completion of the construction and installation, but prior to energization, of any Interconnection Facilities and/or Merchant Network Upgrades constructed by the Interconnected Transmission Owner, the Interconnected Transmission Owner shall have the same inspected and/or tested by qualified personnel or a qualified contractor to assess whether the facilities substantially comply with Applicable Standards. Subject to Applicable Laws and Regulations, said inspection and testing shall be held on a mutually agreed-upon date, and the Interconnection Customer and Transmission Provider shall have the right to attend and observe, and to obtain the written results of, such testing.

3.8.3 Review of Inspection and Testing by Interconnected Transmission Owner:

In the event that the written report, or the observation of either Constructing Entity or Transmission Provider, of the inspection and/or testing pursuant to Section 3.8.2 of this Appendix 2 reasonably leads the Transmission Provider or Interconnected Transmission Owner to believe that the inspection and/or testing of some or all of the Interconnection Facilities and/or Merchant Network Upgrades built by the Interconnection Customer was inadequate or otherwise deficient, the Interconnected Transmission Owner may, within 20 days after its receipt of the results of inspection or testing and upon reasonable notice to the Interconnection Customer, perform its own inspection and/or testing of such Interconnection Facilities and/or Merchant Network Upgrades to determine whether the facilities are acceptable for energization, which determination shall not be unreasonably delayed, withheld or conditioned.

3.8.4 Notification and Correction of Defects

3.8.4.1 If the Interconnected Transmission Owner, based on inspection or testing pursuant to Section 3.8.2 or 3.8.3 of this Appendix 2, identifies any defects or failures to comply with Applicable Standards in the Interconnection Facilities and/or Merchant Network Upgrades constructed by the Interconnection Customer, the Interconnected Transmission Owner shall notify the Interconnection Customer and Transmission Provider of any identified defects or failures within 20 days after the Interconnected Transmission Owner's receipt of the results of such inspection or testing. The Interconnection Customer shall take appropriate actions to correct any such defects or failure at its sole cost and expense, and shall obtain the Interconnected Transmission Owner's acceptance of the corrections, which acceptance shall not be unreasonably delayed, withheld or conditioned.

3.8.4.2 In the event that inspection and/or testing of any Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades built by the Interconnected Transmission Owner identifies any defects or failures to comply with Applicable Standards in such facilities, Interconnected Transmission Owner shall take appropriate action to correct any such defects or failures within 20 days after it learns thereof. In the event that such a defect or failure cannot reasonably be corrected within such 20-day period, Interconnected Transmission Owner shall commence the necessary correction within that time and shall thereafter diligently pursue it to completion.

3.8.5 Notification of Results:

Within 10 days after satisfactory inspection and/or testing of Interconnection Facilities and/or Merchant Network Upgrades built by the Interconnection Customer (including, if applicable, inspection and/or testing after correction of defects or failures), the Interconnected Transmission Owner shall confirm in writing to the Interconnection Customer and Transmission Provider that the successfully inspected and tested facilities are acceptable for energization.

3.9 Energization of Completed Facilities

(A) Unless otherwise provided in the Schedule of Work, energization of the Interconnection Facilities related to interconnection of a Generation Interconnection Customer and, when applicable as determined by Transmission Provider, of the Interconnection Facilities and/or Merchant Network Upgrades related to interconnection of a Transmission Interconnection Customer, shall occur in two stages. Stage One energization shall consist of energization of the Customer Interconnection Facilities and of the Transmission Owner Attachment Facilities and will occur prior to initial energization of the Customer Facility. Stage Two energization shall consist of (1) initial synchronization to the Transmission System of any completed generator(s) at the Customer Facility of a Generation Interconnection Customer, or of applicable facilities, as determined by the Transmission Provider, associated with Merchant Transmission Facilities of a Transmission Interconnection Customer, and (2) energization of the remainder of the Transmission Owner Interconnection Facilities and/or of any Merchant Network Upgrades. Stage Two energization shall be completed prior to Initial Operation of the Customer Facility.

(B) In the case of Interconnection Facilities and/or Merchant Network Upgrades related to interconnection of a Transmission Interconnection Customer for which the Transmission Provider determines that two-stage energization is inapplicable, energization shall occur in a single stage, consisting of energization of the Interconnection Facilities and the Customer Facility. Such a single-stage energization shall be regarded as Stage Two energization for the purposes of the remaining provisions of this Section 3.9 and of Section 5.5 of this Appendix 2.

3.9.1

Stage One energization of the Interconnection Facilities and/or, as applicable, Merchant Network Upgrades may not occur prior to the satisfaction of the following additional conditions:

(a) The Interconnection Customer shall have delivered to the Interconnected Transmission Owner and Transmission Provider a writing transferring to the Interconnected Transmission Owner and Transmission Provider operational control over any Transmission Owner Attachment Facilities that Interconnection Customer has constructed; and

(b) The Interconnection Customer shall have provided a mark-up of construction drawings to the Interconnected Transmission Owner to show the “as-built” condition of all Transmission Owner Attachment Facilities that Interconnection Customer has constructed.

3.9.2 As soon as practicable after the satisfaction of the conditions for Stage One energization specified in Sections 3.8 and 3.9.1 of this Appendix 2, the Interconnected Transmission Owner and the Interconnection Customer shall coordinate and undertake the Stage One energization of facilities.

3.9.3 Stage Two energization of the Interconnection Facilities and/or, as applicable, Merchant Network Upgrades may not occur prior to the satisfaction of the following additional conditions:

(a) The Interconnection Customer shall have delivered to the Interconnected Transmission Owner and Transmission Provider a writing transferring to the Interconnected Transmission Owner and Transmission Provider operational control over any Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades that Interconnection Customer has constructed and operational control of which it has not previously transferred pursuant to Section 3.9.1 of this Appendix 2; and

(b) The Interconnection Customer shall have provided a mark-up of construction drawings to the Interconnected Transmission Owner to show the "as-built" condition of all Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades that Interconnection Customer has constructed and which were not included in the Stage One energization, but are included in the Stage Two energization.

(c) Telemetering systems shall be operational and shall be providing Transmission Provider and the Interconnected Transmission Owner with telemetered data as specified pursuant to Section 8.5.2 of Appendix 2 to the Interconnection Service Agreement.

3.9.4 As soon as practicable after the satisfaction of the conditions for Stage Two energization specified in Sections 3.8 and 3.9.3 of this Appendix 2, the Interconnected Transmission Owner and the Interconnection Customer shall coordinate and undertake the Stage Two energization of facilities.

3.9.5 To the extent defects in any Interconnection Facilities are identified during the energization process, the energization will not be deemed successful. In that event, the Constructing Entity shall take action to correct such defects in any Interconnection Facilities and/or Merchant Network Upgrades that it built as promptly as practical after the defects are identified. The affected Constructing Entity shall so notify the other Construction Parties when it has corrected any such defects, and the Constructing Entities shall recommence efforts, within 10 days thereafter, to energize the appropriate Interconnection Facilities and/or Merchant Network Upgrades in accordance with Section 3.9; provided that the Interconnected Transmission Owner may, in the reasonable exercise of its discretion and with the approval of Transmission Provider, require that further inspection and testing be performed in accordance with Section 3.8 of this Appendix 2.

3.10 Interconnected Transmission Owner's Acceptance of Facilities Constructed by Interconnection Customer:

Within five days after determining that Interconnection Facilities and/or Merchant Network Upgrades have been successfully energized, the Interconnected Transmission Owner shall issue a written notice to the Interconnection Customer accepting the Interconnection Facilities and/or Merchant Network Upgrades built by the Interconnection Customer that were successfully energized. Such acceptance shall not be construed as confirming, endorsing or providing a warranty by the Interconnected Transmission Owner as to the design, installation, construction, fitness, safety, durability or reliability of any Interconnection Facilities and/or Merchant Network Upgrades built by the Interconnection Customer, or their compliance with Applicable Standards.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

4 Transmission Outages

4.1 Outages; Coordination:

The Construction Parties acknowledge and agree that certain outages of transmission facilities owned by the Interconnected Transmission Owner, as more specifically detailed in the Scope of Work, may be necessary in order to complete the process of constructing and installing all Interconnection Facilities and/or Merchant Network Upgrades. The Construction Parties further acknowledge and agree that any such outages shall be coordinated by and through the Transmission Provider.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

5 Land Rights; Transfer of Title

5.1 Grant of Easements and Other Land Rights:

Interconnection Customer at its sole cost and expense, shall grant such easements and other land rights to the Interconnected Transmission Owner over the Site at such times and in such a manner as the Interconnected Transmission Owner may reasonably require to perform its obligations under this Appendix 2 and/or to perform its operation and maintenance obligations under the Interconnection Service Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

5.2 Construction of Facilities on Interconnection Customer Property:

To the extent that the Interconnected Transmission Owner is required to construct and install any Transmission Owner Interconnection Facilities on land owned by the Interconnection Customer, the Interconnection Customer, at its sole cost and expense, shall legally transfer to the Interconnected Transmission Owner all easements and other land rights required pursuant to Section 5.1 above prior to the commencement of such construction and installation.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

5.3 Third Parties:

If any of the easements and other land rights described in Section 5.1 above must be obtained from a third party, the Interconnected Transmission Owner's obligation for completing its construction responsibilities in accordance with the Schedule of Work, to the extent of the facilities that it is responsible for constructing for which such easements and land rights are necessary, shall be subject to Interconnection Customer’s acquisition of such easements and other land rights at such times and in such manner as the Interconnected Transmission Owner may reasonably require to perform its obligations under this Appendix 2, and/or to perform its operation and maintenance obligations under the Interconnection Service Agreement, provided, however, that upon Interconnection Customer’s request, the Interconnected Transmission Owner shall assist the Interconnection Customer in acquiring such land rights with efforts similar in nature and extent to those that the Interconnected Transmission Owner typically undertakes in acquiring land rights for construction of facilities on its own behalf. The terms of easements and land rights acquired by Interconnection Customer shall not unreasonably impede the Interconnected Transmission Owner’s timely completion of construction of the affected facilities.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

5.4 Documentation:

Interconnection Customer shall prepare, execute and file such documentation as the Interconnected Transmission Owner may reasonably require to memorialize any easements and other land rights granted pursuant to this Section 5. Documentation of such easements and other land rights, and any associated filings, shall be in a form acceptable to the Interconnected Transmission Owner.

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5.5 Transfer of Title to Certain Facilities Constructed By Interconnection Customer:

Within thirty (30) days after the Interconnection Customer's receipt of notice of acceptance under Section 3.10 of this Appendix 2 following Stage Two energization of the Interconnection Facilities, the Interconnection Customer shall deliver to the Interconnected Transmission Owner, for the Interconnected Transmission Owner's review and approval, all of the documents and filings necessary to transfer to the Interconnected Transmission Owner title to any Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades constructed by the Interconnection Customer, and to convey to the Interconnected Transmission Owner any easements and other land rights to be granted by Interconnection Customer in accordance with Section 5.1 above that have not then already been conveyed. The Interconnected Transmission Owner shall review and approve such documentation, such approval not to be unreasonably withheld, delayed, or conditioned. Within 30 days after its receipt of the Interconnected Transmission Owner's written notice of approval of the documentation, the Interconnection Customer, in coordination and consultation with the Interconnected Transmission Owner, shall make any necessary filings at the FERC or other governmental agencies for regulatory approval of the transfer of title. Within twenty (20) days after the issuance of the last order granting a necessary regulatory approval becomes final (i.e., is no longer subject to rehearing), the Interconnection Customer shall execute all necessary documentation and shall make all necessary filings to record and perfect the Interconnected Transmission Owner's title in such facilities and in the easements and other land rights to be conveyed to the Interconnected Transmission Owner. Prior to such transfer to the Interconnected Transmission Owner of title to the Transmission Owner Interconnection Facilities built by the Interconnection Customer, the risk of loss or damages to, or in connection with, such facilities shall remain with the Interconnection Customer. Transfer of title to facilities under this section shall not affect the Interconnection Customer's receipt or use of the interconnection rights related to Network Upgrades, Local Upgrades and/or Merchant Network Upgrades for which it otherwise may be eligible as provided in Subpart C of Part VI of the Tariff.

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5.6 Liens:

The Interconnection Customer shall take all reasonable steps to ensure that, at the time of transfer of title in the Transmission Owner Interconnection Facilities built by the Interconnection Customer to the Interconnected Transmission Owner, those facilities shall be free and clear of any and all liens and encumbrances, including mechanics' liens. To the extent that the Interconnection Customer cannot reasonably clear a lien or encumbrance prior to the time for transferring title to the Interconnected Transmission Owner, Interconnection Customer shall nevertheless convey title subject to the lien or encumbrance and shall indemnify, defend and hold harmless the Interconnected Transmission Owner against any and all claims, costs, damages, liabilities and expenses (including without limitation reasonable attorneys' fees) which may be brought or imposed against or incurred by Interconnected Transmission Owner by reason of any such lien or encumbrance or its discharge.

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6 Warranties

6.1 Interconnection Customer Warranty:

The Interconnection Customer shall warrant that its work (or the work of any subcontractor that it retains) in constructing and installing the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades that it builds is free from defects in workmanship and design and shall conform to the requirements of this Interconnection Construction Service Agreement for one (1) year (the "Interconnection Customer Warranty Period") commencing upon the date title is transferred to Interconnected Transmission Owner in accordance with Section 5.5 of this Appendix 2. The Interconnection Customer shall, at its sole expense and promptly after notification by the Interconnected Transmission Owner, correct or replace defective work in accordance with Applicable Technical Requirements and Standards, during the Interconnection Customer Warranty Period. The warranty period for such corrected or replaced work shall be the unused portion of the Interconnection Customer Warranty Period remaining as of the date of notice of the defect. The Interconnection Customer Warranty Period shall resume upon acceptance of such corrected or replaced work. All Costs incurred by Interconnected Transmission Owner as a result of such defective work shall be reimbursed to the Interconnected Transmission Owner by the Interconnection Customer on demand; provided that the Interconnected Transmission Owner submits the demand to the Interconnection Customer within the Interconnection Customer Warranty Period and provides reasonable documentation of the claimed costs. The Interconnected Transmission Owner's acceptance, inspection and testing, or a third party's inspection or testing, of such facilities pursuant to Section 3.8 of this Appendix 2 shall not be construed to limit in any way the warranty obligations of the Interconnection Customer.

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6.2 Manufacturer Warranties:

Prior to the transfer to the Interconnected Transmission Owner of title to the Transmission Owner Interconnection Facilities built by the Interconnection Customer, the Interconnection Customer shall produce documentation satisfactory to the Interconnected Transmission Owner evidencing the transfer to the Interconnected Transmission Owner of all manufacturer warranties for equipment and/or materials purchased by the Interconnection Customer for use and/or installation as part of the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades built by the Interconnection Customer.

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7 [Reserved.]

8 [Reserved.]

9 Security, Billing And Payments

The following provisions shall apply with respect to charges for the Costs of the Interconnected Transmission Owner for which the Interconnection Customer is responsible.

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9.1 Adjustments to Security:

The Security provided by Interconnection Customer at or before execution of the Interconnection Service Agreement (a) shall be reduced as portions of the work on required Local Upgrades and/or Network Upgrades is completed, and/or (b) shall be increased or decreased as required to reflect adjustments to Interconnection Customer's cost responsibility, as determined in accordance with Section 217, to correspond with changes in the Scope of Work developed in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

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9.2 Invoice:

The Interconnected Transmission Owner shall provide Transmission Provider a quarterly statement of the Interconnected Transmission Owner's scheduled expenditures during the next three months for, as applicable, (a) the design, engineering and construction of, and/or for other charges related to, construction of the Interconnection Facilities and/or Merchant Network Upgrades for which the Interconnected Transmission Owner is responsible under this Interconnection Construction Service Agreement, or (b) in the event that the Interconnection Customer exercises the Option to Build pursuant to Section 3.2.3.1 of this Appendix 2, for the Interconnected Transmission Owner's Costs associated with the Interconnection Customer's building Attachment Facilities, Local Upgrades and Network Upgrades (including both Direct Connection Network Upgrades, Direct Connection Local Upgrades, Non-Direct Connection Network Upgrades and Non-Direct Connection Local Upgrades), including but not limited to Costs for tie-in work and Cancellation Costs. Provided, however, such Interconnected Transmission Owner Costs may include oversight costs (i.e. costs incurred by the Interconnected Transmission Owner when engaging in oversight activities to satisfy itself that the Interconnection Customer is complying with the Interconnected Transmission Owner's standards and specifications for the construction of facilities) only if the Interconnected Transmission Owner and the Interconnection Customer mutually agree to the inclusion of such costs under the Option to Build pursuant to the provisions of Section 3.3.3.1 of this Appendix. Transmission Provider shall bill Interconnection Customer on behalf of the Interconnected Transmission Owner, for the Interconnected Transmission Owner's expected Costs during the subsequent three months. Interconnection Customer shall pay each bill within twenty (20) days after receipt thereof. Upon receipt of each of Interconnection Customer's payments of such bills, Transmission Provider shall reimburse the Interconnected Transmission Owner. Interconnection Customer may request that the Transmission Provider provide a quarterly cost reconciliation. Such a quarterly cost reconciliation will have a one-quarter lag, e.g., reconciliation of costs for the first calendar quarter of work will be provided at the start of the third calendar quarter of work, provided, however, that Section 9.3 of this Appendix 2 shall govern the timing of the final cost reconciliation upon completion of the work.

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9.3 Final Invoice:

Within 120 days after the Interconnected Transmission Owner completes construction and installation of the Interconnection Facilities and/or Merchant Network Upgrades for which the Interconnected Transmission Owner is responsible under this Interconnection Construction Service Agreement, Transmission Provider shall provide Interconnection Customer with an accounting of, and the appropriate Construction Party shall make any payment to the other that is necessary to resolve, any difference between (a) Interconnection Customer's responsibility under the Tariff for the actual Cost of such facilities, and (b) Interconnection Customer's previous aggregate payments to Transmission Provider for the Costs of such facilities. Notwithstanding the foregoing, however, Transmission Provider shall not be obligated to make any payment to either the Interconnection Customer or the Interconnected Transmission Owner that the preceding sentence requires it to make unless and until the Transmission Provider has received the payment that it is required to refund from the Construction Party owing the payment.

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9.4 Disputes:

In the event of a billing dispute between any of the Construction Parties, Transmission Provider and the Interconnected Transmission Owner shall continue to perform their respective obligations pursuant to this Interconnection Construction Service Agreement so long as (a) Interconnection Customer continues to make all payments not in dispute, and (b) the Security held by the Transmission Provider while the dispute is pending exceeds the amount in dispute, or (c) Interconnection Customer pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet any of these requirements, then Transmission Provider shall so inform the other Construction Parties and Transmission Provider or the Interconnected Transmission Owner may provide notice to Interconnection Customer of a Breach pursuant to Section 13 of this Appendix 2.

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9.5 Interest:

Interest on any unpaid, delinquent amounts shall be calculated in accordance with the methodology specified for interest on refunds in the FERC's regulations at 18 C.F.R. Section 35.19a(a)(2)(iii) and shall apply from the due date of the bill to the date of payment.

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9.6 No Waiver:

Payment of an invoice shall not relieve Interconnection Customer from any other responsibilities or obligations it has under this Interconnection Construction Service Agreement, nor shall such payment constitute a waiver of any claims arising hereunder.

10 Assignment

10.1 Assignment with Prior Consent:

Except as provided in Section 10.2 below, no Construction Party shall assign its rights or delegate its duties, or any part of such rights or duties, under the Interconnection Construction Service Agreement without the written consent of the other Construction Parties, which consent shall not be unreasonably withheld, conditioned or delayed. Any such assignment or delegation made without such written consent shall be null and void. A Construction Party may make an assignment in connection with the sale, merger, or transfer of a substantial portion or all of its properties, including the Interconnection Facilities which it will own upon completion of construction and the transfer of title required by Section 5 of this Appendix 2, so long as the assignee in such a sale, merger, or transfer assumes in writing all rights, duties and obligations arising under this Interconnection Construction Service Agreement. In addition, the Interconnected Transmission Owner shall be entitled, subject to Applicable Laws and Regulations, to assign the Interconnection Construction Service Agreement to any Affiliate or successor that owns and operates all or a substantial portion of the Interconnected Transmission Owner's transmission facilities.

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10.2 Assignment Without Prior Consent

10.2.1 Assignment to Owners:

Interconnection Customer may assign the Interconnection Construction Service Agreement without the Interconnected Transmission Owner's or Transmission Provider's prior consent to any Affiliate or person that purchases or otherwise acquires, directly or indirectly, all or substantially all of the Customer Facility and the Customer Interconnection Facilities, provided that prior to the effective date of any such assignment, the assignee shall demonstrate that, as of the effective date of the assignment, the assignee has the technical competence to comply with the requirements of this Appendix 2 and assumes in a writing provided to the Interconnected Transmission Owner and Transmission Provider all rights, duties, and obligations of Interconnection Customer arising under this Appendix 2. However, any assignment described herein shall not relieve or discharge the Interconnection Customer from any of its obligations hereunder absent the written consent of the Interconnected Transmission Owner, such consent not to be unreasonably withheld, conditioned or delayed.

10.2.2 Assignment to Lenders:

Interconnection Customer may, without the consent of the Transmission Provider or the Interconnected Transmission Owner, assign the Interconnection Construction Service Agreement to any Project Finance Entity(ies), provided that such assignment shall not alter or diminish Interconnection Customer's duties and obligations under this Interconnection Construction Service Agreement. If Interconnection Customer provides the Interconnected Transmission Owner with notice of an assignment to any Project Finance Entity(ies) and identifies such Project Finance Entities as contacts for notice purposes pursuant to Section 20 of this Appendix 2, the Transmission Provider or Interconnected Transmission Owner shall provide notice and reasonable opportunity for such entity(ies) to cure any Breach under this Appendix 2 in accordance with this Appendix 2. Transmission Provider or Interconnected Transmission Owner shall, if requested by such lenders, provide such customary and reasonable documents, including consents to assignment, as may be reasonably requested with respect to the assignment and status of the Interconnection Construction Service Agreement, provided that such documents do not alter or diminish the rights of the Transmission Provider or Interconnected Transmission Owner under this Appendix 2, except with respect to providing notice of Breach to a Project Finance Entity. Upon presentation of the Transmission Provider's and/or the Interconnected Transmission Owner's invoice therefor, Interconnection Customer shall pay the Transmission Provider and/or the Interconnected Transmission Owner's reasonable documented cost of providing such documents and certificates. Any assignment described herein shall not relieve or discharge the Interconnection Customer from any of its obligations hereunder absent the written consent of the Interconnected Transmission Owner and Transmission Provider.

10.3 Successors and Assigns:

This Interconnection Construction Service Agreement and all of its provisions are binding upon, and inure to the benefit of, the Construction Parties and their respective successors and permitted assigns.

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11 Insurance

11.1 Required Coverages For Generation Resources Of More Than 20 Megawatts or Merchant Transmission Facilities:

Each Constructing Entity shall maintain, at its own expense, insurance as described in paragraphs A through E below. All insurance shall be procured from insurance companies rated "A-" or better by AM Best and authorized to do business in a state or states in which the Interconnection Facilities will be located. Failure to maintain required insurance shall be a Breach of the Interconnection Construction Service Agreement.

A. Workers Compensation Insurance with statutory limits, as required by the state and/or jurisdiction in which the work is to be performed, and employer's liability insurance with limits of not less than one million dollars ($1,000,000).

B. Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification), products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death and property damage.

C. Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

D. Excess / Umbrella Liability Insurance with a limit of liability of twenty million dollars ($20,000,000.00) per occurrence. These limits apply in excess of the employer's liability, commercial general liability and automobile liability coverages described above.

E. Professional Liability, including Contractors Legal Liability, providing errors, omissions and/or malpractice coverage. Coverage shall be provided for the Constructing Entity's duties, responsibilities and performance outlined in this Interconnection Construction Service Agreement, with limits of liability as follows:

$10,000,000 each occurrence
$10,000,000 aggregate

An Interconnected Entity may meet the Professional Liability Insurance requirements by requiring third-party contractors, designers, or engineers, or other parties that are responsible for design work associated with the transmission facilities or Interconnection Facilities necessary for the interconnection to procure professional liability insurance in the amounts and upon the terms prescribed by this section 11.1(E), and providing evidence of such insurance to the other Interconnected Entity. Such insurance shall be procured from companies rated "A-" or better by AM Best and authorized to do business in a state or states in which the Interconnection Facilities are located. Nothing in this section relieves the Interconnected Entity from complying with the insurance requirements. In the event that the policies of the designers, engineers, or other parties used to satisfy the Interconnected Entity's insurance obligations under this section become invalid for any reason, including but not limited to, (i) the policy(ies) lapsing or otherwise terminating or expiring; (ii) the coverage limits of such policy(ies) are decreased; or (iii) the policy(ies) do not comply with the terms and conditions of the Tariff; Interconnected Entity shall be required to procure insurance sufficient to meet the requirements of this section, such that there is no lapse in insurance coverage. Notwithstanding the foregoing, in the event an Interconnected Entity will not design or construct or cause to design or construct any new transmission facilities or Interconnection Facilities, Transmission Provider, in its discretion, may waive the requirement that an Interconnected Entity maintain the Professional Liability Insurance pursuant to this section.

Effective Date: 9/17/2010

11.1A. Required Coverages For Generation Resources Of 20 Megawatts Or Less:

Except as provided in section 11.1B below, each Constructing Entity shall maintain the types of insurance as described in section 11.1 paragraphs A through E above in an amount sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. Additional insurance may be required by the Interconnection Customer, as a function of owning and operating a generating facility. All insurance shall be procured from insurance companies rated "A-" or better by AM Best and authorized to do business in a state or states in which the Interconnection Facilities are located. Failure to maintain required insurance shall be a Breach of the Interconnection Construction Service Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

11.2 Additional Insureds:

The Commercial General Liability, Automobile liability and Excess/Umbrella liability policies procured by each Constructing Entity (the "Insuring Constructing Entity") shall include each other Construction Party (the "Insured Construction Party"), its officers, agents and employees as additional insureds, providing all standard coverages and covering liability of the Insured Construction Party arising out of bodily injury and/or property damage (including loss of use) in any way connected with the operations, performance, or lack of performance under this Interconnection Construction Service Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

11.3 Other Required Terms:

The above-mentioned insurance policies (except workers' compensation) shall provide the following:

(a) Each policy shall contain provisions that specify that it is primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Insuring Constructing Entity shall be responsible for its respective deductibles or retentions.

(b) Each policy, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of the Interconnection Construction Service Agreement, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Construction Parties.

(c) Provide for a waiver of all rights of subrogation which the Insuring Constructing Entity's insurance carrier might exercise against the Insured Construction Party.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

11.3A No Limitation of Liability:

The requirements contained herein as to the types and limits of all insurance to be maintained by the Constructing Entities are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Construction Parties under the Interconnection Construction Service Agreement.

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11.4 Self-Insurance:

Notwithstanding the foregoing, each Constructing Entity may self-insure to meet the minimum insurance requirements of this Section 11 to the extent it maintains a self-insurance program; provided that such Constructing Entity's senior secured debt is rated at investment grade or better by Standard & Poor's and its self-insurance program meets the minimum insurance requirements of this Section 11. For any period of time that a Constructing Entity's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, it shall comply with the insurance requirements applicable to it under this Section 11. In the event that a Constructing Entity is permitted to self-insure pursuant to this section, it shall notify the other Construction Parties that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Section 11.5.

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11.5 Notices; Certificates of Insurance:

Prior to the commencement of work pursuant to this Agreement, the Constructing Entities agree to furnish each other Construction Party with certificates of insurance evidencing the insurance coverage obtained in accordance with this Section 11. All certificates of insurance shall indicate that the certificate holder is included as an additional insured under the Commercial General Liability, Automobile liability and Excess/Umbrella liability coverages, and that this insurance is primary with a waiver of subrogation included. All policies of insurance shall provide for thirty days prior written notice of cancellation or material adverse change.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

11.6 Subcontractor Insurance:

In accord with Good Utility Practice, each Constructing Entity shall require each of its subcontractors to maintain and provide evidence of insurance coverage of types, and in amounts, commensurate with the risks associated with the services provided by the subcontractor. Bonding of contractors or subcontractors shall be at the hiring Constructing Entity's discretion, but regardless of bonding, the hiring principal shall be responsible for the performance or non-performance of any contractor or subcontractor it hires.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

11.7 Reporting Incidents:

The Construction Parties shall report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of the Interconnection Construction Service Agreement.

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12 Indemnity

12.1 Indemnity:

Each Constructing Entity shall indemnify and hold harmless the other Construction Parties, and the other Construction Parties' officers, shareholders, stakeholders, members, managers, representatives, directors, agents and employees, and Affiliates, from and against any and all loss, liability, damage, cost or expense to third parties, including damage and liability for bodily injury to or death of persons, or damage to property of persons (including reasonable attorneys' fees and expenses, litigation costs, consultant fees, investigation fees, sums paid in settlements of claims, penalties or fines imposed under Applicable Laws and Regulations, and any such fees and expenses incurred in enforcing this indemnity or collecting any sums due hereunder) (collectively, "Loss") to the extent arising out of, in connection with or resulting from (i) the indemnifying Constructing Entity's breach of any of the representations or warranties made in, or failure of the indemnifying Constructing Entity or any of its subcontractors to perform any of its obligations under, this Appendix 2, or (ii) the negligence or willful misconduct of the indemnifying Constructing Entity or its contractors; provided, however, that neither Constructing Entity shall have any indemnification obligations under this Section 12.1 in respect of any Loss to the extent the Loss results from the negligence or willful misconduct of the Construction Party seeking indemnity.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

12.2 Indemnity Procedures:

Promptly after receipt by a Person entitled to indemnity ("Indemnified Person") of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Section 12.1 above may apply, the Indemnified Person shall notify the indemnifying Constructing Entity of such fact. Any failure of or delay in such notification shall not affect a Constructing Entity's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Constructing Entity. The Indemnified Person shall cooperate with the indemnifying Constructing Entity with respect to the matter for which indemnification is claimed. The indemnifying Constructing Entity shall have the right to assume the defense thereof with counsel designated by such indemnifying Constructing Entity and reasonably satisfactory to the Indemnified Person. If the defendants in any such action include one or more Indemnified Persons and the indemnifying Constructing Entity and if the Indemnified Person reasonably concludes that there may be legal defenses available to it and/or other Indemnified Persons which are different from or additional to those available to the indemnifying Constructing Entity, the Indemnified Person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Constructing Entity shall only be required to pay the fees and expenses of one additional attorney to represent an Indemnified Person or Indemnified Persons having such differing or additional legal defenses. The Indemnified Person shall be entitled, at its expense, to participate in any action, suit or proceeding, the defense of which has been assumed by the indemnifying Constructing Entity. Notwithstanding the foregoing, the indemnifying Constructing Entity (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the Indemnified Person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the Indemnified Person, or there exists a conflict or adversity of interest between the Indemnified Person and the indemnifying Constructing Entity, in such event the indemnifying Constructing Entity shall pay the reasonable expenses of the Indemnified Person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the Indemnified Person, which shall not be unreasonably withheld, conditioned or delayed.

12.3 Indemnified Person:

If an Indemnified Person is entitled to indemnification under this Section 12 as a result of a claim by a third party, and the indemnifying Constructing Entity fails, after notice and reasonable opportunity to proceed under Section 12.2, to assume the defense of such claim, such Indemnified Person may at the expense of the indemnifying Constructing Entity contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

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12.4 Amount Owing:

If an indemnifying Constructing Entity is obligated to indemnify and hold any Indemnified Person harmless under this Section 12, the amount owing to the Indemnified Person shall be the amount of such Indemnified Person's actual Loss, net of any insurance or other recovery.

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12.5 Limitation on Damages:

Except as otherwise provided in this Section 12, the liability of a Construction Party under this Appendix 2 shall be limited to direct actual damages, and all other damages at law are waived. Under no circumstances shall any Construction Party or its Affiliates, directors, officers, employees and agents, or any of them, be liable to another Construction Party, whether in tort, contract or other basis in law or equity for any special, indirect, punitive, exemplary or consequential damages, including lost profits. The limitations on damages specified in this Section 12.5 are without regard to the cause or causes related thereto, including the negligence of any Construction Party, whether such negligence be sole, joint or concurrent, or active or passive. This limitation on damages shall not affect any Construction Party's rights to obtain equitable relief as otherwise provided in this Appendix 2. The provisions of this Section 12.5 shall survive the termination or expiration of the Interconnection Construction Service Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

12.6 Limitation of Liability in Event of Breach:

A Construction Party ("Breaching Party") shall have no liability hereunder to any other Construction Party, and each other Construction Party hereby releases the Breaching Party, for all claims or damages it incurs that are associated with any interruption in the availability of the Customer Facility, the Interconnection Facilities, Transmission System or Construction Service or damages to a Construction Party's facilities, except to the extent such interruption or damage is caused by the Breaching Party's gross negligence or willful misconduct in the performance of its obligations under this Interconnection Construction Service Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

12.7 Limited Liability in Emergency Conditions:

Except as otherwise provided in the Tariff or the Operating Agreement, no Construction Party shall be liable to any other Construction Party for any action that it takes in responding to an Emergency Condition, so long as such action is made in good faith, is consistent with Good Utility Practice and is not contrary to the directives of the Transmission Provider or the Interconnected Transmission Owner with respect to such Emergency Condition. Notwithstanding the above, Interconnection Customer shall be liable in the event that it fails to comply with any instructions of Transmission Provider or the Interconnected Transmission Owner related to an Emergency Condition.

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13 Breach, Cure And Default

13.1 Breach:

A Breach of the Interconnection Construction Service Agreement shall include:

(a) The failure to pay any amount when due;

(b) The failure to comply with any material term or condition of this Interconnection Construction Service Agreement including but not limited to any material breach of a representation, warranty or covenant (other than in Sections 13.1(a) and (c)-(e) hereof) made in this Appendix 2;

(c) Assignment of the Interconnection Construction Service Agreement in a manner inconsistent with the terms of this Appendix 2;

(d) Failure of a Constructing Entity to provide access rights, or a Constructing Entity's attempt to revoke or terminate access rights, that are provided under this Appendix 2; or

(e) Failure of any Construction Party to provide information or data required to be provided to another Construction Party under this Appendix 2 for such other Construction Party to satisfy its obligations under this Interconnection Construction Service Agreement.

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13.2 Notice of Breach:

A Construction Party not in Breach of this Interconnection Construction Service Agreement shall give written notice of an event of Breach to the Breaching Construction Party, to the third Construction Party, and to any other persons that the Breaching Construction Party identifies in writing to the other Construction Parties in advance. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach. In the event of a Breach by Interconnection Customer, Transmission Provider and the Interconnected Transmission Owner agree to provide notice of such Breach, at the same time and in the same manner as its or their notice to Interconnection Customer, to any Project Finance Entity, provided that the Interconnection Customer has provided Transmission Provider and the Interconnected Transmission Owner with notice of an assignment to such Project Finance Entity(ies) and has identified such Project Finance Entities as contacts for notice purposes pursuant to Section 20 of this Appendix 2.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

13.3 Cure and Default:

A Construction Party that commits a Breach and does not take steps to cure the Breach pursuant to this Section 13.3 is in Default of this Interconnection Construction Service Agreement.

13.3.1 Cure of Breach:

The Breaching Construction Party (a) may cure the Breach within thirty days from the receipt of such notice; or, (b) if the Breach cannot be cured within thirty days, may commence in good faith all steps that are reasonable and appropriate to cure the Breach within such thirty day time period and thereafter diligently pursue such action to completion.

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13.4 Right to Compel Performance:

Upon the occurrence of an event of Default, a non-Defaulting Construction Party shall be entitled to (a) commence an action to require the Defaulting Construction Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof, (b) withhold payments, (c) suspend performance hereunder, and (d) exercise such other rights and remedies as it may have in equity or at law.

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13.5 Remedies Cumulative:

Subject to Section 19.1 of this Appendix 2, no remedy conferred by any provision of this Appendix 2 is intended to be exclusive of any other remedy and each and every remedy shall be cumulative and shall be in addition to every other remedy given hereunder or now or hereafter existing at law or in equity or by statute or otherwise. The election of any one or more remedies shall not constitute a waiver of the right to pursue other available remedies.

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14 Termination

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

14.1 Termination

14.1.1 Upon Completion of Construction:

This Interconnection Construction Service Agreement shall terminate upon the later of the following: (i) completion of construction of all Interconnection Facilities and/or Merchant Network Upgrades; (ii) transfer of title under Section 5 of this Appendix 2; (iii) final payment of all Costs due and owing under this Interconnection Construction Service Agreement; and (iv) the delivery to the Interconnected Transmission Owner of final "as-built" drawings of any Interconnection Facilities and/or Merchant Network Upgrades built by the Interconnection Customer.

14.1.2 Upon Default By Either Constructing Entity:

Either Constructing Entity may terminate its obligations hereunder in the event of a Default by the other Constructing Entity as defined in Section 13.3 of this Appendix 2.

14.1.3 By Interconnection Customer:

Subject to its payment of Cancellation Costs as explained in Section 14.3 below, the Interconnection Customer may be relieved of its obligations hereunder upon sixty (60) days written notice to Transmission Provider and the Interconnected Transmission Owner.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

14.2 [Reserved.]

14.3 Cancellation By Interconnection Customer

14.3.1 Applicability:

The following provisions shall survive and shall apply in the event that Interconnection Customer terminates the Interconnection Construction Service Agreement pursuant to this Section 14.1.3.

14.3.1.1 Cancellation Cost Responsibility:

Upon the cancellation of the Interconnection Construction Service Agreement by the Interconnection Customer, the Interconnection Customer shall be liable to pay to the Interconnected Transmission Owner or Transmission Provider all Cancellation Costs in connection with Construction Service for the Interconnection Customer pursuant to this Interconnection Construction Service Agreement, including Section 14.3.1.2 of this Appendix 2. In the event the Interconnected Transmission Owner incurs Cancellation Costs, it shall provide the Transmission Provider, with a copy to the Interconnection Customer, with a written demand for payment and with reasonable documentation of such Cancellation Costs. The Interconnection Customer shall pay the Transmission Provider each bill for Cancellation Costs within thirty (30) days after, as applicable, the Interconnected Transmission Owner's or Transmission Provider's presentation to the Interconnection Customer of written demand therefor, provided that such demand includes reasonable documentation of the Cancellation Costs that the invoicing party seeks to collect. Upon receipt of each of Interconnection Customer's payments of such bills of the Interconnected Transmission Owner, Transmission Provider shall reimburse the Interconnected Transmission Owner for Cancellation Costs incurred by the latter.

14.3.1.2 Disposition of Facilities Upon Cancellation:

Upon cancellation of the Interconnection Construction Service Agreement by an Interconnection Customer, Transmission Provider, after consulting with the Interconnected Transmission Owner, may, at the sole cost and expense of the Interconnection Customer, authorize the Interconnected Transmission Owner to (a) cancel supplier and contractor orders and agreements entered into by the Interconnected Transmission Owner to design, construct, install, operate, maintain and own the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades, provided, however, that Interconnection Customer shall have the right to choose to take delivery of any equipment ordered by the Interconnected Transmission Owner for which Transmission Provider otherwise would authorize cancellation of the purchase order; or (b) remove any Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades built by the Interconnected Transmission Owner or any Transmission Owner Interconnection Facilities (only after title to the subject facilities has been transferred to the Interconnected Transmission Owner) and/or Merchant Network Upgrades built by the Interconnection Customer; or (c) partially or entirely complete the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades as necessary to preserve the integrity or reliability of the Transmission System, provided that Interconnection Customer shall be entitled to receive any rights associated with such facilities and upgrades as determined in accordance with Part VI of the Tariff; or (d) undo any of the changes to the Transmission System that were made pursuant to this Interconnection Construction Service Agreement. To the extent that the Interconnection Customer has fully paid for equipment that is unused upon cancellation or which is removed pursuant to subsection (b) above, the Interconnection Customer shall have the right to take back title to such equipment; alternatively, in the event that the Interconnection Customer does not wish to take back title, the Interconnected Transmission Owner may elect to pay the Interconnection Customer a mutually agreed amount to acquire and own such equipment.

14.3.2 Termination Upon Default:

In the event that Interconnection Customer exercises its right to terminate under Section 14.1.2 of this Appendix 2, and notwithstanding any other provision of this Interconnection Construction Service Agreement, the Interconnection Customer shall be liable for payment of the Interconnected Transmission Owner’s Costs incurred up to the date of Interconnection Customer’s notice of termination pursuant to Section 14.1.2 and the costs of completion of some or all of the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades or specific unfinished portions thereof, and/or removal of any or all of such facilities which have been installed, to the extent that Transmission Provider determines such completion or removal to be required for the Transmission Provider and/or Interconnected Transmission Owner to perform their respective obligations under Part VI of the Tariff or this Interconnection Construction Service Agreement, provided, however, that Interconnection Customer’s payment of such costs shall be without prejudice to any remedies that otherwise may be available to it under this Appendix 2 for the Default of the Interconnected Transmission Owner.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

14.4 Survival of Rights:

The obligations of the Construction Parties hereunder with respect to payments, Cancellation Costs, warranties, liability and indemnification shall survive termination to the extent necessary to provide for the determination and enforcement of said obligations arising from acts or events that occurred while the Interconnection Construction Service Agreement was in effect. In addition, applicable provisions of this Interconnection Construction Service Agreement will continue in effect after expiration, cancellation or termination to the extent necessary to provide for final billings, payments, and billing adjustments.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

15 Force Majeure

15.1 Notice:

A Construction Party that is unable to carry out an obligation imposed on it by this Appendix 2 due to Force Majeure shall notify each other Construction Party in writing or by telephone within a reasonable time after the occurrence of the cause relied on.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

15.2 Duration of Force Majeure:

A Construction Party shall not be responsible for any non-performance or considered in Breach or Default under this Appendix 2, for any non-performance, any interruption or failure of service, deficiency in the quality or quantity of service, or any other failure to perform any obligation hereunder to the extent that such failure or deficiency is due to Force Majeure. A Construction Party shall be excused from whatever performance is affected only for the duration of the Force Majeure and while the Construction Party exercises Reasonable Efforts to alleviate such situation. As soon as the non-performing Construction Party is able to resume performance of its obligations excused because of the occurrence of Force Majeure, such Construction Party shall resume performance and give prompt notice thereof to each other Construction Party.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

15.3 Obligation to Make Payments:

Any Construction Party's obligation to make payments for services shall not be suspended by Force Majeure.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

16 Subcontractors

16.1 Use of Subcontractors:

Nothing in this Appendix 2 shall prevent the Construction Parties from utilizing the services of subcontractors as they deem appropriate to perform their respective obligations hereunder, provided, however, that each Construction Party shall require its subcontractors to comply with all applicable terms and conditions of this Appendix 2 in providing such services.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

16.2 Responsibility of Principal:

The creation of any subcontract relationship shall not relieve the hiring Construction Party of any of its obligations under this Appendix 2. Each Construction Party shall be fully responsible to each other Construction Party for the acts and/or omissions of any subcontractor it hires as if no subcontract had been made.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

16.3 Indemnification by Subcontractors:

To the fullest extent permitted by law, a Construction Party that uses a subcontractor to carry out any of the Construction Party's obligations under this Appendix 2 shall require each of its subcontractors to indemnify, hold harmless and defend each other Construction Party, its representatives and assigns from and against any and all claims and/or liability for damage to property, injury to or death of any person, including the employees of any Construction Party or of any Affiliate of any Construction Party, or any other liability incurred by another Construction Party or any of its Affiliates, including all expenses, legal or otherwise, to the extent caused by any act or omission, negligent or otherwise, by such subcontractor and/or its officers, directors, employees, agents and assigns, that arises out of or is connected with the design, procurement, construction or installation of the facilities of either Constructing Entity described in this Appendix 2; provided, however, that no Construction Party or Affiliate thereof shall be entitled to indemnity under this Section 16.3 in respect of any injury, loss, or damage to the extent that such loss, injury, or damage results from the negligence or willful misconduct of the Construction Party or Affiliate seeking indemnity.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

16.4 Subcontractors Not Beneficiaries:

No subcontractor is intended to be, or shall be deemed to be, a third-party beneficiary of the Interconnection Construction Service Agreement.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

17 Confidentiality:

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Construction Party providing the information orally informs the Construction Party receiving the information that the information is confidential. If requested by any Construction Party, the disclosing Construction Party shall provide in writing the basis for asserting that the information referred to in this section warrants confidential treatment, and the requesting Construction Party may disclose such writing to an appropriate Governmental Authority. Any Construction Party shall be responsible for the costs associated with affording confidential treatment to its information.

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17.1 Term:

During the term of the Interconnection Construction Service Agreement, and for a period of three (3) years after the expiration or termination of the Interconnection Construction Service Agreement, except as otherwise provided in this Section 17, each Construction Party shall hold in confidence, and shall not disclose to any person, Confidential Information provided to it by any other Construction Party.

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17.2 Scope:

Confidential Information shall not include information that the receiving Construction Party can demonstrate: (i) is generally available to the public other than as a result of a disclosure by the receiving Construction Party; (ii) was in the lawful possession of the receiving Construction Party on a non-confidential basis before receiving it from the disclosing Construction Party; (iii) was supplied to the receiving Construction Party without restriction by a third party, who, to the knowledge of the receiving Construction Party, after due inquiry, was under no obligation to the disclosing Construction Party to keep such information confidential; (iv) was independently developed by the receiving Construction Party without reference to Confidential Information of the disclosing Construction Party; (v) is, or becomes, publicly known, through no wrongful act or omission of the receiving Construction Party or breach of this Appendix 2; or (vi) is required, in accordance with Section 17.7 of this Appendix 2, to be disclosed to any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this Interconnection Construction Service Agreement. Information designated as Confidential Information shall no longer be deemed confidential if the Construction Party that designated the information as confidential notifies the other Construction Parties that it no longer is confidential.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

17.3 Release of Confidential Information:

No Construction Party shall disclose Confidential Information of another Construction Party to any other person, except to its Affiliates (limited by the Commission's Standard of Conduct requirements), subcontractors, employees, consultants or to parties who may be or considering providing financing to or equity participation in Interconnection Customer on a need-to-know basis in connection with the Interconnection Construction Service Agreement, unless such person has first been advised of the confidentiality provisions of this Section 17 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Construction Party that provides Confidential Information of another Construction Party to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Section 17.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

17.4 Rights:

Each Construction Party retains all rights, title, and interest in the Confidential Information that it discloses to any other Construction Party. A Construction Party's disclosure to another Construction Party of Confidential Information shall not be deemed a waiver by either Construction Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

17.5 No Warranties:

By providing Confidential Information, no Construction Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, no Construction Party obligates itself to provide any particular information or Confidential Information to any other Construction Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

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17.6 Standard of Care:

Each Construction Party shall use at least the same standard of care to protect Confidential Information it receives as the Construction Party uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Construction Party may use Confidential Information solely to fulfill its obligations to the other Construction Parties under this Interconnection Construction Service Agreement or to comply with Applicable Laws and Regulations.

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17.7 Order of Disclosure:

If a Governmental Authority with the right, power, and apparent authority to do so requests or requires a Construction Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Construction Party shall provide the Construction Party that provided the information with prompt prior notice of such request(s) or requirement(s) so that the providing Construction Party may seek an appropriate protective order, or waive compliance with the terms of this Interconnection Construction Service Agreement. Notwithstanding the absence of a protective order, or agreement, or waiver, the Construction Party subjected to the request or order may disclose such Confidential Information which, in the opinion of its counsel, the Construction Party is legally compelled to disclose. Each Construction Party shall use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

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17.8 Termination of Interconnection Construction Service Agreement:

Upon termination of the Interconnection Construction Service Agreement for any reason, each Construction Party shall, within ten (10) calendar days of receipt of a written request from another party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure and deletion certified in writing to the requesting party) or to return to the requesting party, without retaining copies thereof, any and all written or electronic Confidential Information received from the requesting party.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

17.9 Remedies:

The Construction Parties agree that monetary damages would be inadequate to compensate a Construction Party for another Construction Party's Breach of its obligations under this Section 17. Each Construction Party accordingly agrees that each other Construction Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Construction Party breaches or threatens to breach its obligations under this Section 17, which equitable relief shall be granted without bond or proof of damages, and the receiving Construction Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed to be an exclusive remedy for the breach of this Section 17, but shall be in addition to all other remedies available at law or in equity. The Construction Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Construction Party, however, shall be liable for indirect, incidental, consequential, or punitive damages of any nature or kind resulting from or arising in connection with a Breach of any obligation under this Section 17.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

17.10 Disclosure to FERC or its Staff:

Notwithstanding anything in this Section 17 to the contrary, and pursuant to 18 C.F.R. § 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Construction Parties that is otherwise required to be maintained in confidence pursuant to this Interconnection Construction Service Agreement, the Construction Party, shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Construction Party must, consistent with 18 C.F.R. § 388.122, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Construction Parties are prohibited from notifying the other Construction Parties to the Interconnection Construction Service Agreement prior to the release of the Confidential Information to the Commission or its staff. A Construction Party shall notify the other Construction Parties when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time any of the Construction Parties may respond before such information would be made public, pursuant to 18 C.F.R. § 388.112.

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17.11

Subject to the exception in Section 17.10, no Construction Party shall disclose Confidential Information of another Construction Party to any person not employed or retained by the disclosing Construction Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Construction Party to be required in connection with a dispute between or among the Construction Parties, or the defense of litigation or dispute; (iii)_ otherwise permitted by consent of the Construction Party that provided such Confidential Information, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this Interconnection Construction Service Agreement or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization. Prior to any disclosures of another Construction Party's Confidential Information under this subparagraph, the disclosing Construction Party shall promptly notify the other Construction Parties in writing and shall assert confidentiality and cooperate with the other Construction Parties in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

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17.12

This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a Breach of this provision).

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17.13 Return or Destruction of Confidential Information:

If any Construction Party provides any Confidential Information to another Construction Party in the course of an audit or inspection, the providing Construction Party may request the other party to return or destroy such Confidential Information after the termination of the audit period and the resolution of all matters relating to that audit. Each Construction Party shall make Reasonable Efforts to comply with any such requests for return or destruction within ten days after receiving the request and shall certify in writing to the requesting Construction Party that it has complied with such request.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

18 Information Access And Audit Rights

18.1 Information Access:

Subject to Applicable Laws and Regulations, each Construction Party shall make available to each other Construction Party information necessary (i) to verify the costs incurred by the other Construction Party for which the requesting Construction Party is responsible under this Appendix 2, and (ii) to carry out obligations and responsibilities under this Appendix 2. The Construction Parties shall not use such information for purposes other than those set forth in this Section 18.1 and to enforce their rights under this Appendix 2.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

18.2 Reporting of Non-Force Majeure Events:

Each Construction Party shall notify each other Construction Party when it becomes aware of its inability to comply with the provisions of this Appendix 2 for a reason other than Force Majeure. The Construction Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including, but not limited to, the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this Section shall not entitle the receiving Construction Party to allege a cause of action for anticipatory breach of this Appendix 2.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

18.3 Audit Rights:

Subject to the requirements of confidentiality under Section 17 of this Appendix 2, each Construction Party shall have the right, during normal business hours, and upon prior reasonable notice to the pertinent Construction Party, to audit at its own expense the other Construction Party's accounts and records pertaining to such Construction Party's performance and/or satisfaction of obligations arising under this Interconnection Construction Service Agreement. Any audit authorized by this Section shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to obligations under this Appendix 2. Any request for audit shall be presented to the other Construction Party not later than twenty-four months after the event as to which the audit is sought. Each Construction Party shall preserve all records held by it for the duration of the audit period.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

19 Disputes

19.1 Submission:

Any claim or dispute that any Construction Party may have against another Construction Party arising out of this Appendix 2 may be submitted for resolution in accordance with the dispute resolution provisions of Section 12 of the Tariff.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

19.2 Rights Under The Federal Power Act:

Nothing in this Section shall restrict the rights of any Construction Party to file a complaint with FERC under relevant provisions of the Federal Power Act.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

19.3 Equitable Remedies:

Nothing in this Section shall prevent any Construction Party from pursuing or seeking any equitable remedy available to it under Applicable Laws and Regulations.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

20 Notices

20.1 General:

Any notice, demand or request required or permitted to be given by either Construction Party to another and any instrument required or permitted to be tendered or delivered by either Construction Party in writing to another may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Construction Party, or personally delivered to the Construction Party, at the address specified in the Interconnection Construction Service Agreement. If agreed to in advance by the Construction Parties, notices may be communicated via electronic means, so long as there is e-mail confirmation of delivery.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

20.2 Operational Contacts:

Each Construction Party shall designate, and shall provide to each other Construction Party contact information concerning, a representative to be responsible for addressing and resolving operational issues as they arise during the term of the Interconnection Construction Service Agreement.

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21 Miscellaneous

21.1 Regulatory Filing:

In the event that this Interconnection Construction Service Agreement contains any terms that deviate materially from the form included in Attachment P or from the standard terms and conditions in this Appendix 2, the Transmission Provider shall file the executed Interconnection Construction Service Agreement on behalf of itself and the Interconnected Transmission Owner with FERC as a service schedule under the Tariff. Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Section 17 of this Appendix 2. An Interconnection Customer shall have the right, with respect to any Interconnection Construction Service Agreement tendered to it, to request (a) dispute resolution under Section 12 of the Tariff or, if concerning the Regional Transmission Expansion Plan, consistent with Schedule 5 of the Operating Agreement, or (b) that Transmission Provider file the agreement unexecuted with the Commission. With the filing of any unexecuted Interconnection Construction Service Agreement, Transmission Provider may, in its discretion, propose to FERC a resolution of any or all of the issues in dispute between any Construction Parties.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

21.2 Waiver:

Any waiver at any time by any Construction Party of its rights with respect to a Breach or Default under this Appendix 2, or with respect to any other matters arising in connection with this Appendix 2, shall not be deemed a waiver or continuing waiver with respect to any other Breach or Default or other matter.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

21.3 Amendments and Rights under the Federal Power Act:

Except as set forth in this Section, this Interconnection Construction Service Agreement may be amended, modified, or supplemented only by written agreement of the Construction Parties. Such amendment shall become effective and a part of this Interconnection Construction Service Agreement upon satisfaction of all Applicable Laws and Regulations. Notwithstanding the foregoing, nothing contained in this Interconnection Construction Service Agreement shall be construed as affecting in any way any of the rights of any Construction Party with respect to changes in applicable rates or charges under Section 205 of the Federal Power Act and/or FERC's rules and regulations thereunder, or any of the rights of any Interconnection Party under Section 206 of the Federal Power Act and/or FERC's rules and regulations thereunder. The terms and conditions of this Interconnection Construction Service Agreement and every appendix referred to therein shall be amended, as mutually agreed by the Construction Parties, to comply with changes or alterations made necessary by a valid applicable order of any Governmental Authority having jurisdiction hereof.

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21.4 Binding Effect:

This Interconnection Construction Service Agreement, including the rights and obligations incorporated by reference therein from this Interconnection Construction Service Agreement, shall be binding upon, and shall inure to the benefit of, the successors and assigns of the Construction Parties.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

21.5 Regulatory Requirements:

Each Construction Party's performance of any obligation under this Interconnection Construction Service Agreement for which such party requires approval or authorization of any Governmental Authority shall be subject to its receipt of such required approval or authorization in the form and substance satisfactory to the receiving Construction Party, or the Construction Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Construction Party shall in good faith seek, and shall use Reasonable Efforts to obtain, such required authorizations or approvals as soon as reasonably practicable.

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22 Representations and Warranties

22.1 General:

Each Constructing Entity hereby represents, warrants and covenants as follows, with these representations, warranties, and covenants effective as to the Constructing Entity during the full time the Interconnection Construction Service Agreement is effective:

22.1.1 Good Standing:

Such Constructing Entity is duly organized or formed, as applicable, validly existing and in good standing under the laws of its state of organization or formation, and is in good standing under the laws of the respective State(s) in which it is incorporated and operates as stated in the preamble of the Interconnection Construction Service Agreement.

22.1.2 Authority:

Such Constructing Entity has the right, power and authority to enter into the Interconnection Construction Service Agreement, to become a party thereto and to perform its obligations thereunder. The Interconnection Construction Service Agreement is a legal, valid and binding obligation of such Constructing Entity, enforceable against such Constructing Entity in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors’ rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

22.1.3 No Conflict:

The execution, delivery and performance of the Interconnection Construction Service Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Constructing Entity, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Constructing Entity or any of its assets.

22.1.4 Consent and Approval:

Such Constructing Entity has sought or obtained, or, in accordance with the Interconnection Construction Service Agreement will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of such Agreement and it will provide to any Governmental Authority notice of any actions under such Agreement that are required by Applicable Laws and Regulations.

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SCHEDULE A

SITE PLAN

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

SCHEDULE B

SINGLE-LINE DIAGRAM OF INTERCONNECTION FACILITIES

SCHEDULE C

TRANSMISSION OWNER INTERCONNECTION FACILITIES TO BE BUILT BY INTERCONNECTED TRANSMISSION OWNER

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

SCHEDULE D

TRANSMISSION OWNER INTERCONNECTION FACILITIES TO BE BUILT BY INTERCONNECTION CUSTOMER PURSUANT TO OPTION TO BUILD

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

SCHEDULE E

MERCHANT NETWORK UPGRADES TO BE BUILT BY INTERCONNECTED TRANSMISSION OWNER

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

SCHEDULE F

MERCHANT NETWORK UPGRADES TO BE BUILT BY INTERCONNECTION CUSTOMER PURSUANT TO OPTION TO BUILD

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

SCHEDULE G

CUSTOMER INTERCONNECTION FACILITIES

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

SCHEDULE H

NEGOTIATED CONTRACT OPTION TERMS

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

SCHEDULE I

SCOPE OF WORK

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

SCHEDULE J

SCHEDULE OF WORK

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

SCHEDULE K

APPLICABLE TECHNICAL REQUIREMENTS AND STANDARDS

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

SCHEDULE L

INTERCONNECTION CUSTOMER'S AGREEMENT TO CONFORM WITH

IRS SAFE HARBOR PROVISIONS FOR NON-TAXABLE STATUS

{Include the appropriate language from the alternatives below:}

{Include the following language if not required:}

Not Required.

[OR]

{Include the following language if applicable to Interconnection Customer:}

As provided in Section 2.4.1 of Appendix 2 to this CSA and subject to the requirements thereof, Interconnection Customer represents that it meets all qualifications and requirements as set forth in Section 118(a) and 118(b) of the Internal Revenue Code of 1986, as amended and interpreted by Notice 88-129, 1988-2 C.B. 541, and as amplified and modified in Notices 90-60, 1990-2 C.B. 345, and 2001-82, 2001-2 C.B. 619 (the "IRS Notices"). Interconnection Customer agrees to conform with all requirements of the safe harbor provisions specified in the IRS Notices, as they may be amended, as required to confer non-taxable status on some or all of the transfer of property, including money, by Interconnection Customer to Interconnected Transmission Owner with respect to the payment of the Costs of construction and installation of the Transmission Owner Interconnection Facilities and/or Merchant Network Upgrades specified in this CSA.

Nothing in Interconnection Customer's agreement pursuant to this Schedule L shall change Interconnection Customer's indemnification obligations under Section 2.4.2 of Appendix 2 to the CSA.

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SCHEDULE M

SCHEDULE OF NON-STANDARD TERMS AND CONDITIONS

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

SCHEDULE N

INTERCONNECTION REQUIREMENTS FOR A

WIND GENERATION FACILITY

{Include the appropriate language from the alternatives below}

{Include the following language if the Customer Facility is not a wind generation facility}

Not Required

[OR]

{Include the following language when the Customer Facility is a wind generation facility}

Schedule N sets forth requirements and provisions specific to the interconnection of a wind generation facility that is greater than 20 MW. All other requirements pertaining to the interconnection of generation facilities above 20 MW set forth in Part IV of the Tariff continue to apply to wind generation facility interconnections.

A. <u>Technical Standards Applicable to a Wind Generation Facility</u>

i. <u>Low Voltage Ride-Through (LVRT) Capability</u>

A wind generation facility shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The Schedule N LVRT standard provides for a transition period standard and a post-transition period standard.

<u>Transition Period LVRT Standard</u>

The transition period standard applies to wind generation facilities subject to Commission Order No. 661 that have either: (i) Interconnection Service Agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generation turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generation facilities are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generation facility substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generation facility shall be required to withstand for a three-phase fault

shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generation facility step-up transformer (i.e. the transformer that steps the voltage up to the transmission interconnection voltage or “GSU”), after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generation facility may disconnect from the transmission system.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.

3. Wind generation facilities may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generation facilities may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator, etc.) within the wind generation facility or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the initial effective date of the Schedule N LVRT standard are exempt from meeting the Schedule N LVRT standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Schedule N LVRT standard.

Post-transition Period LVRT Standard

All wind generation facilities subject to Commission Order No. 661 and not covered by the transition period described above must meet the following requirements:

1. Wind generation facilities are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generation facility substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generation facility shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generation facility may disconnect from the transmission system. A wind generation facility shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.

3. Wind generation facilities may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generation facilities may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator) within the wind generation facility or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the initial effective date of the Schedule N LVRT standard are exempt from meeting the Schedule N LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Schedule N LVRT Standard.

ii. <u>Power Factor Design Criteria (Reactive Power)</u>

The power factor requirements for wind generation facilities set forth in section 4.7 of Appendix 2 to Attachment O of the Tariff can be met by using, for example, power electronic devices designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the Transmission Provider, or a combination of the two. The Interconnection Customer shall not disable power factor equipment while the wind generation facility is in operation. Wind generation facilities shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the System Impact Study shows this to be required for system safety or reliability.

iii. <u>Supervisory Control and Data Acquisition (SCADA) Capability</u>

The wind generation facility shall provide SCADA capability to transmit data and receive instructions from the Transmission Provider to protect system reliability. The Transmission Provider and the wind generation facility Interconnection Customer shall determine what SCADA information is essential for the proposed wind generation facility, taking into account the size of the facility and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000