PJM Manual 14B:

PJM Region Transmission Planning Process

Revision: 41

Effective Date: April 19, 2018

Prepared by
Transmission Planning Department

Table of Contents

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Table of Exhibits

Approval

Approval Date: 05/07/2018
Effective Date: 04/19/2018

Aaron Berner, Manager

Transmission Planning

Current Revision

Revision 41 (04/19/2018):

- Cover to Cover Periodic Review
- Updated Section 1.3 and Attachment H.1 per NERC MOD requirement standard numbering
- Updated Section 2.3.8 bullet formatting
- Updated Section 2.3.13 by removing language regarding winter temperature ratings sets
- Updated Attachment C.5.3.3 to add OVEC to study area definitions
- Updated Attachment C.7.3 to reference low side of transformer in generator deliverability procedures
- Updated Attachment D.2.2 to correct references to contingency types in table 2 and step 3

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 the Library section on PJM.com.

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.

Section 1A: Critical Energy Infrastructure Information (CEII)

1A.1 CEII Definition

PJM adopts the Federal Energy Regulatory Commission's ("FERC" or "Commission") definitions of Critical Energy Infrastructure Information ("CEII") and Critical Infrastructure at 18 CFR §388.113 (c) as follows:

- Critical Energy Infrastructure Information means specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure that:
    - Relates details about the production, generation, transportation, transmission, or distribution of energy;
    - Could be useful to a person in planning an attack on critical infrastructure;
    - Is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552; and
    - Does not simply give the general location of the critical infrastructure.
- Critical Infrastructure means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.

1A.2 Introduction

1A.2.1 General Intent

PJM's intent is to provide a process for eligible recipients to access CEII consistent with the Commission's standards for handling CEII material. PJM information that contains CEII can only be obtained by complying with PJM's CEII authorization process.

1A.2.2 Examples of CEII

The Commission considers certain information to be CEII. For example, information filed in the FERC-715, Part 2, Part 3, and Part 6 (http://www.ferc.gov/legal/ceii-foia/ceii.asp) is considered by the FERC to be 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 data and related information used in transmission system analysis such as contingency and monitored element files. Power flows specifically configured for short circuit analysis that do not contain load and generation dispatch are not considered CEII. Other information may also qualify as CEII under the Commission's definitions.

1A.2.3 Rules When CEII Includes Confidential Member Information

Regarding all types of PJM information, 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 governed by the PJM Operating Agreement Section 18.17 and the Open Access Transmission Tariff Sections 222-223. Certain information is a combination of CEII information filed or provided by a number of "owners" and may include confidential information. To the extent CEII material sought from PJM includes confidential information of a PJM Member, including PJM Transmission Owners or Generation Owners, PJM will require the requester to demonstrate the affected members give consent to the release of the confidential information contained within the CEII material by PJM to comply with the Tariff and Operating Agreement. Power flows may, but generally do not, contain confidential information. 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. Confidential information of members, if any, may be redacted prior to release of CEII if the CEII requester is unable to demonstrate to PJM that the affected members give consent to the release of the confidential material.

1A.2.4 Reservation of Rights to Amend CEII Rules

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 in accordance with PJM's manual revision procedures posted on PJM.com.

1A.3 PJM CEII Rules

1A.3.1 CATEGORIES OF PJM CEII REQUESTERS PROCEDURES

1A.3.1.1 Authorized Entities Procedures

The process to request CEII from PJM is as follows for an employee or authorized agent/ consultant of : (i) a PJM Member; (ii) a PJM Transmission Owner; (iii) a PJM Generation Owner or operator of generating units in the PJM Region; (iv) a NERC registered Transmission Owner/ Operator; (v) a PJM Interconnection Customer; (vi) another RTO or similar independent system operator recognized by the Federal Energy Regulatory Commission; (vii) a NERC Planning Coordinator or Transmission Planner; (viii) a Non-incumbent Developer pre-qualified to be a Designated Entity pursuant to Schedule 6 of the Operating Agreement; or (viii) a natural gas local distribution company and/or a natural gas pipeline operator serving customers within the PJM Region (individually "Authorized Entity" and together "Authorized Entities"). The process outlined below allows for individual employees or individual authorized consultants of Authorized Entities to obtain CEII. PJM's procedures set forth below allow an organization to submit requests on behalf of multiple individuals within Authorized Entities.

Except in the case of Organizational CEII requests described below, each individual requester of CEII from employees or authorized agents/consultants of Authorized Entities must complete a PJM CEII Request Form and must execute the appropriate PJM CEII Nondisclosure Agreement ("NDA"). Employee or authorized agent/consultant or an Authorized Entity must submit a PJM CEII Authorization Form (in addition to the requester's completed PJM CEII Request Form and appropriate PJM CEII NDA) that identifies each individual agent/consultant who may make individual requests for PJM CEII on behalf of such entity. The PJM CEII Authorization Form and CEII NDA are located on the PJM website at: http://www.pjm.com/library/request-access/form-ceii-request.aspx

Once the CEII requester has been verified by PJM as a legitimate CEII requester (i.e., a legitimate employee or authorized consultant of one of the organizations listed in paragraph 1A.3.1.1 above), such CEII requester may obtain CEII.

Organizational CEII Requests: Authorized Entities may enter into an organizational agreement with PJM which will allow the receiving organization to share CEII information under the terms of an applicable PJM CEII NDA an example of which is located on the PJM website at: http://www.pjm.com/library/request-access/form-ceii-request.aspx.aspxhowever, PJM may use other forms of organizational CEII NDAs as appropriate. Such organizational NDA will require individual recipients of CEII material to be listed and sign an attachment to the NDA which will require each individual to acknowledge his or her understanding of the restrictions on the use of CEII or further disclosures except as allowed under the terms of the organizational NDA. Each organization is required to keep the list of authorized individual recipients up to date and notify in PJM in writing of any changes to the status of the authorized individual recipients in accordance with the applicable NDA.

1A.3.1.2 Federal Agency and NERC Procedures

If the requester of CEII material is a representative of FERC, Department of Energy, Department of Homeland Security, NERC or a NERC Regional Entity (e.g. RF, SERC, etc.), PJM will release the information if PJM confirms that the requestor (requestors) are employees of these agencies and the CEII material is subject to the agencies rules of procedures applicable to CEII.

1A.3.1.3 PJM Authorized State Commission

The process to request CEII from PJM is as follows for an employee of a PJM Authorized State Commission: Each individual requester of CEII must complete a PJM CEII Request Form and must execute a PJM CEII Government NDA located on the PJM website at:http://www.pjm.com/library/request-access/form-ceii-request.aspx.

- After such CEII requester has been verified by PJM as a legitimate CEII requester (i.e., a legitimate employee of one of the governmental organizations listed above), such CEII requester may obtain the requested CEII.

1A.3.1.4 Procedures Applicable to Other CEII Requests

The process to request CEII from PJM is as follows for any other requester seeking CEII from PJM:

- Each individual requester of CEII must complete a PJM CEII Request Form and must execute an appropriate PJM CEII NDA. Where the individual requester of CEIIis an authorized agent/consultant for another entity, then an authorized employee of such entity must submit a PJM CEII Authorization Form (in addition to the requester's completed PJM CEII Request Form and the appropriate PJM CEII NDA) that identifies each individual agent(s)/consultant(s) who may make individual requests for PJM CEII on behalf of such entity. The PJM CEII Authorization Form is located on the PJM website at: http://www.pjm.com/documents/ferc-manuals/ceii.aspx.
- Upon receiving all completed required CEII forms, PJM will determine if the requested information is CEII, and, if it is, whether to release the CEII to the requester. PJM will use the information provided by the requester in the PJM CEII Request Form to (1) establish whether a requester has presented a legitimate need for the CEII; and (2) weigh the need for the CEII against the potential harmful effects of its release. In reviewing the request from such individual, PJM will confirm the authenticity of the CEII requester and whether the request is consistent with the requestor's business or educational interest as determined from a review of publicly available data such as the requestor's website. If PJM is unable to determine from publicly available information that the request is

consistent with the requestor's business or educational interest in such data, the request will be denied. A requester shall provide additional information (beyond the PJM CEII Request Form) to PJM upon PJM's request.

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/media/documents/merged-tariffs/oatt.pdf.

The PJM and PJM Transmission Owners 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 and PJM Transmission Owners planning implement~~s~~ a cycle centered ~~around~~ on activities of PJM~~'s~~ Planning, PJM Transmission Owners and PJM 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 Committees, and the PJM Planning Committee (PC) forums.

Currently, the planning cycle will refer to an 18-month overlapping cycle beginning in September of the prior calendar year and extending to ~~the~~ February of the following calendar year. A new cycle will begin every September, which will overlap the previous cycle (Refer to Exhibit 1).

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 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/ops-analysis/transmission-facilities.aspx. The TEAC, Subregional RTEP Committee, and stakeholder opportunities to engage in the PJM planning process are described in this manual.

The analysis of OATT transmission facilities below 100kV ~~and~~that are not under PJM operational control is led by the Transmission Owner ~~(TO.)~~ and includes PJM Transmission Owner FERC Form 715 criteria and Supplemental Project criteria. This is appropriate since local Transmission Owner operations, maintenance and planning personnel oversee the~~se~~ Transmission Owner local systems. These facilities typically provide only local transmission function of interest to the customers in the nearby electrical vicinity. The ~~TO~~ Transmission Owner analysis ensures local facilities meet NERC (if applicable) 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 in order to meet specific service requests and maintain local system reliability in accordance with local Transmission Owner planning processes (~~the non-criteria based upgrades are called~~ Supplemental ~~RTEP~~ Projects~~.)~~, as detailed in the OATT, Attachment M-3). The Transmission Owner ~~will~~ initiates all reliability-based and ~~supplemental~~ Supplemental ~~upgrade~~ Project requests for facilities not under PJM's control or for facilities under PJM's control not violating PJM criteria, through a process described in OATT, Attachment M-3 and additional procedures adopted by the Transmission Owners and provided to PJM for posting. All such ~~projects~~ upgrades will be ~~introduced~~ presented through the TEAC or the Subregional RTEP Committees for review and comment in a three-part planning process that includes a minimum of one Assumptions Meeting, a minimum of one Needs Meeting and a minimum of one Project Solutions Meeting, prior to finalization of the Local Plan and inclusion in the RTEP~~to the PJM Regional planning process through PJM's TEAC and Subregional RTEP Committees~~. In this way these ~~TO~~ Transmission Owner initiated projects will be subject to ~~the same~~similar open, transparent and participatory PJM committee activities as are ~~PJM~~ PJM-initiated projects (see discussion of TEAC and Subregional RTEP Committees.)

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 Committees and Related Activities

The PJM TEAC functions in accordance with its established charter and provisions of ~~Schedule~~ Schedule 6 of the Operating Agreement. Additionally, in 2008 PJM began to facilitate more localized planning functions through the Subregional RTEP Committees. With the exception of those projects subject to OATT, Attachment M-3, ~~The~~ the Subregional RTEP Committees, 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~~ Subregional RTEP Committees 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 Committees ~~is~~ are responsible for the initial review of Subregional RTEP Projects. PJM will facilitate meetings as necessary for TEAC and Subregional RTEP Committees review and evaluation of PJM system reliability, operational performance ~~and~~, market efficiency ~~reinforcements~~ and Supplemental Projects. The Subregional RTEP Committees will forward all baseline Subregional ~~RTEP~~ Projects to the TEAC. TEAC or the Subregional RTEP Committees, as appropriate, will also have the opportunity to provide meaningful input regarding PJM or Transmission Owner developed assumptions, criteria and models used to identify system needs~~advice and recommendations regarding the study scope, assumptions and procedures~~ at an initial ~~assumptions~~ assumptions-setting meeting. This meeting will cover ~~both~~ reliability, ~~and~~ market efficiency, and local transmission planning 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~~ it 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 incorporated into the RTEP.

All ~~RTO~~ PJM 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~~ Subregional RTEP Committees meeting that includes their area. PJM, with stakeholder input, may initiate additional ~~subregional~~ Subregional RTEP Committee meetings ~~or local review~~ consistent with the OATT, Attachment M-3, to review and address stakeholder questions or concerns regarding needs or proposed solutions to ensure transparency throughout the PJM RTEP process, as may be necessary or beneficial. Separate ~~Local~~ local meetings or more localized reviews ~~occurs~~ may also be held by individual PJM Transmission Owners in the event that the individual PJM Transmission Owner, ~~taking into account stakeholder input,~~ decides that it is a more appropriate way to address local 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 Committees processes. All four planning paths to the PJM RTEP~~;~~, i.e., reliability planning (including FERC Form 715 criteria), economic planning, interconnection planning, and local Transmission Owner ~~Planning~~planning~~;~~ (including Supplemental Projects) flow through the TEAC and/or Subregional RTEP Committee ~~planning~~ meeting processes.

PJM Committees (TEAC and Subregional RTEP Committees) review of all RTEP projects, regardless of the path of origin of the project, will occur during the February through August

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RTEP Stakeholder analysis and review periods
(see Exhibit 1.) However, additional local system needs that a PJM Transmission Owner identifies later in the year will follow the OATT, Attachment M-3 process for inclusion in the appropriate RTEP. Stakeholders will be provided all the information necessary for full participation in the discussions and evaluations, including: (1) the basic models, criteria, and assumptions ~~used as the basis for projects~~that underlie local transmission system plans, (2) the procedure to access the study information necessary to replicate the planning studies and 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~~ Transmission ~~owner~~ Owner ~~RTEP~~ projects (including both ~~newly~~ newly-planned Supplemental ~~RTEP p~~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 standard MOD-032. 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.

Attachment J contains the checklist for the new equipment energization process to be utilized by Transmission Owners and Designated Entities from inception to energization of upgrade projects.

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 will utilize many of 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 PJM Transmission Expansion Advisory Committee. 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 consideration.

1.3.3 End of Life Planning

The Transmission Owner's process specific to End of Life facilities may be memorialized as criteria under the Operating Agreement, Schedule 6, in its FERC Form 715 report, or under OATT, Attachment M-3 individually through its local planning criteria.

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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 http://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. End Of Life Analysis

Maintaining the Transmission System also requires a transparent and replicable study process for determining that a transmission facility should be replaced or subject to other capital improvement in accordance with good utility practice due to End of Life issues. The RTEP process shall incorporate Transmission Owner planned FERC Form 715 projects and Supplemental Projects in a manner that supports transparency and cost effective regional planning.

~~5.~~6. 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/Pages/default.aspx.) 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://pjm.com/committees-and-groups/committees.aspx.) In this manner, PJM, as the independent planning authority,

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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 , the various Nuclear Plant Licensees' Final Safety Analysis

[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

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 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.

1.5.3 End Of Life Planning

The End of Life decision making process is driven by each PJM Transmission Owner and memorialized through either a PJM Transmission Owner's planning criteria filed with its FERC Form 715 report or covered under OATT, Attachment M-3. Such End of Life criteria should include objective criterion that are reasonably measurable and replicable and quantifiable. Such criteria should be included with the material posted for the assumptions meeting for the applicable RTEP cycle.

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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+ Public Policy

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 B of this manual and Attachment B of Manual 14A.
3. Market efficiency driven upgrades, discussed in this Section 2.
4. Operational performance issue driven upgrades, discussed in this Section 2.
5. Public Policy Requirements based elements via State Agreement Approach

~~5.~~6. End of Life Local Area Planning discussed in this Section 2 provides that the Transmission Owner should identify End of Life needs, to the extent known, five years forward (e.g., asset replacement prioritization schedule).

2.1.1 Multi-Driver Approach

In the event that a proposed project is driven by more than one of the above stated drivers, PJM can develop a Multi-Driver Approach Project, as defined in Schedule 6 of PJM's Operating Agreement by identifying a more efficient or cost effective solution that follows one of the following methods:

Proportional Multi-Driver Method: Combining separate solutions that address reliability, economics and/or public policy into a single transmission enhancement or expansion that incorporates separate drivers into one Multi-Driver Project.

Incremental Multi-Driver Method: Expanding or enhancing a proposed single-driver solution to include one or more additional component(s) to address a combination of reliability, economic and/or public policy drivers.

2.1.1.1 Principles and Guidelines for New Service Requests as an input to Multi-Driver Approach

Customer-Funded upgrades, as identified in Attachment B of PJM Manual 14A may be incorporated into the Multi-Driver Approach Project per the Regional Transmission Expansion Plan. New Service Customers, other than those proposing Merchant Network Upgrades, have the option, but not obligation to participate in a Multi-Driver Approach Project, at the direction of PJM. The following principles and guidelines must be adhered to for a New Service Request wishing to participate in a Multi-Driver Approach Project:

1. The Multi-Driver Approach Project must be more cost effective as a whole, than the sum of the individual projects
2. New Service Customer has the option, but not the obligation to participate in a Multi-Driver Approach Project. The New Service Customer must execute an agreement committing to be financially responsible for its portion of the Multi-Driver Approach Project, the cost of which shall not exceed the cost of the incremental upgrade required as part of the New Service Request, unless agreed to by the sponsoring New Service Customer(s).
3. New Service Customer's participation in the Multi-Driver Approach Project shall not impact the New Service Customer's Queue Position.
4. Commencement of service for the New Service Customer's Customer Facilities may be impacted by the in-service date of the Multi-Driver Approach Project.
5. The following cost allocation rules will apply to Multi-Driver Approach Projects: Schedule 12 of the PJM Tariff for the component of the upgrade to be funded for reliability violations or operational performance, economic constraints and/or Public Policy Requirements; and Part VI of the PJM Tariff for the New Service Customer's portion of the Multi-Driver Approach Project.

2.1.2 Reliability Planning

Exhibit 1 shows the 24-month Reliability 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 overlapping 18-month planning cycles (Refer to Exhibit 1) ~~toidentify~~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 Transmission Expansion Advisory Committee and Subregional RTEP Committees 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 year eight. 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.

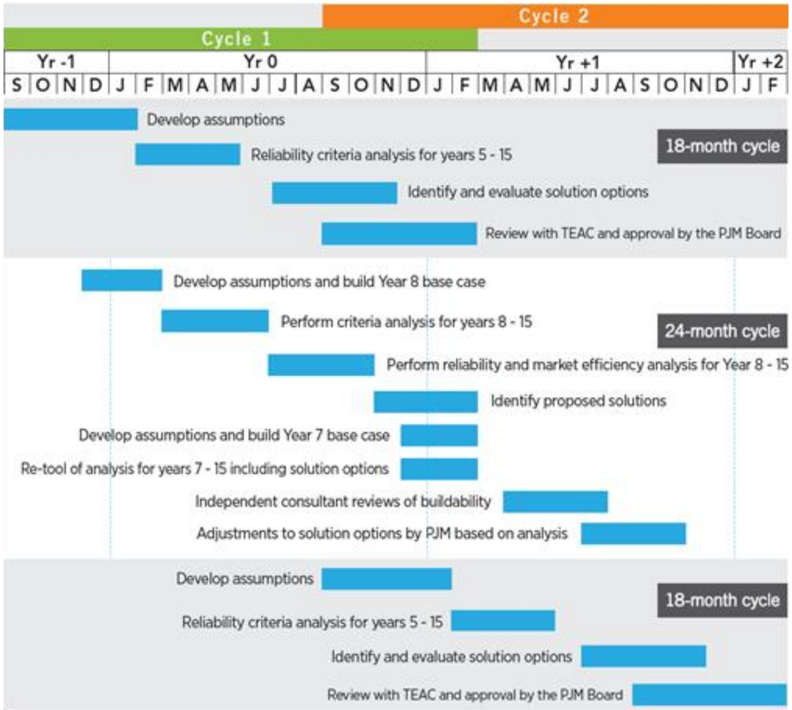

Exhibit 1: 24-Month Reliability Planning Cycle

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 constructability 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.

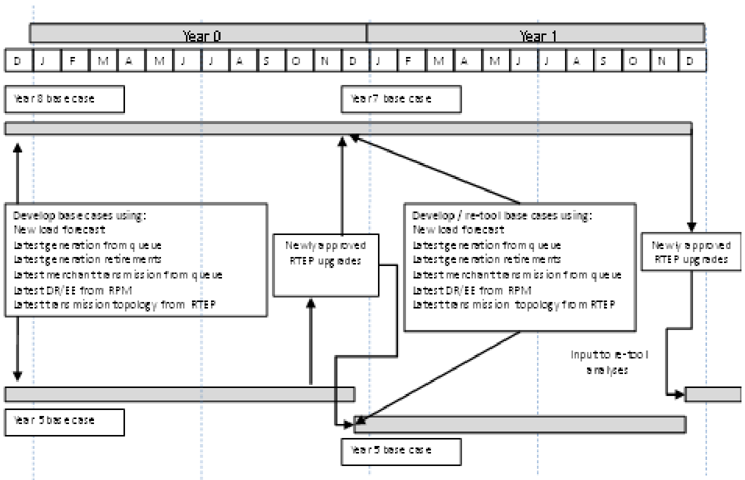

Exhibit 2: Base Case Development

2.1.3 Market Efficiency Planning

Exhibit 3 shows the 24-month Market Efficiency process used for the 15-year RTEP horizon. 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 Market Efficiency process is made up of two similar 12-month cycles to identify approved RTEP projects that may be accelerated or modified and one 24-month planning cycle to provide sufficient time for the identification and development of longer lead-time transmission upgrades.

The first step in the Market Efficiency process is to develop the set of assumptions that will be used for the subsequent analyses. These assumptions are vetted with stakeholders at the Transmission Expansion Advisory Committee meetings.

The scope of the near-term Market Efficiency analysis that is completed as part of each 12-month planning cycle includes a review of the congestion in year 1 and year 5 and existing approved RTEP projects. This review will identify approved RTEP projects that may be accelerated or modified and meet the Market Efficiency Benefit/Cost criteria as explained in accompanying sections of this Manual 14B.

Long-term Market Efficiency planning is also completed as part of the development of the RTEP to identify solutions that require longer lead times to implement. As part of the 24-month Market Efficiency planning cycle, PJM initially develops a base case for years 1, 5, 8, 11, and 15 that are used to evaluate congestion for the long-term planning horizon. A higher level base case is developed for year 15 and may require a less detailed model of the transmission system below the 500 kV level as explained in section 2.6.5 of this manual. Proposed solutions to address Market Efficiency projected congestion are developed by stakeholders and PJM staff during the first year of the 24-month planning cycle. As shown in Exhibit 3, during the second year of the 24-month cycle, the base cases used for the long-term analysis during the first year (i.e., now year 0, 4, 7, 10, and 14) will be updated, as appropriate, to reflect the latest assumptions regarding load, generation, demand response, transmission topology, or other input assumptions.

Congestion issues identified during the first year are validated and the proposed solutions are refined during the second year of the 24–month cycle. An independent consultant may be used to develop a cost estimate and evaluate the constructability of proposed solutions. Results from these long-term analyses are reviewed with the Transmission Expansion Advisory Committee throughout the 24-month planning process, and, ultimately, presented to the PJM Board of Managers for approval.

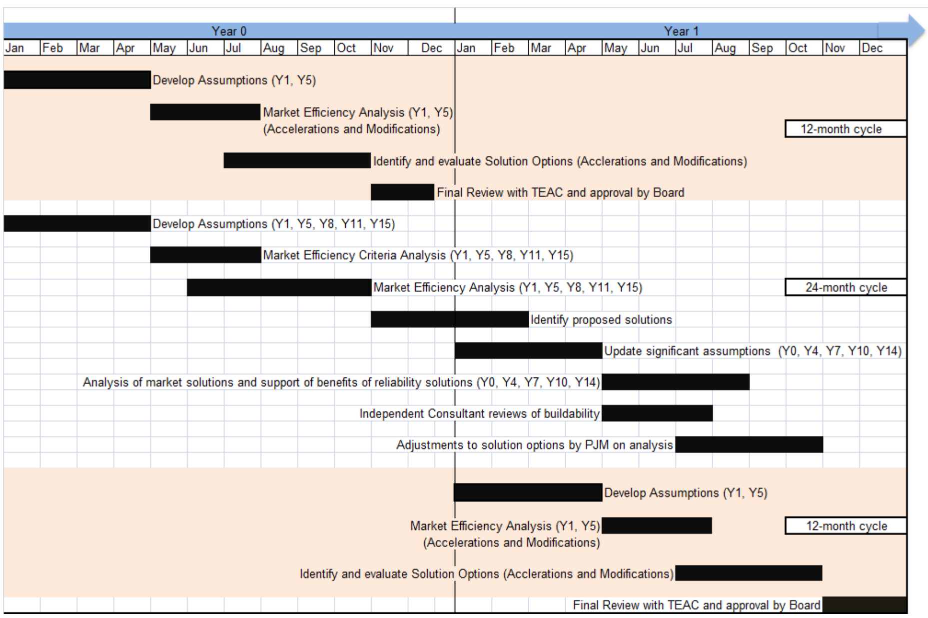

Exhibit 3: 24-Month Market Efficiency Cycle

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 (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.

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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.

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 following the completion of case builds and concludes with review by the TEAC and approval by the PJM Board (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. The annual review shall include system peak load for either year one or year two, and for year five.

For the annual evaluation of the near-term, sensitivity cases shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in system response.

- Real and reactive forecasted load
- Expected transfers
- Expected in service dates of new or modified transmission facilities
- Reactive resource capability
- Generation additions, retirements, or other dispatch scenarios
- Controllable loads and demand side management

Duration or timing of known transmission outages

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 is 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~~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. In addition to studying all contingency types listed in TPL-001 Table 1, PJM also studies bus tie breaker openings without a fault as a single contingency. 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.

PJM will coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that contingencies on adjacent systems which may impact their system are included in the contingency list.

2.3.6 Baseline Thermal Analysis

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

2.3.7 Baseline Voltage Analysis

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

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

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

Post-Contingency voltage analysis shall also include the impact of tripping generators where the simulated generator bus voltages or the high side of the generation step up (GSU) transformer are less than known or assumed minimum generator steady state of ride through voltage limitations. All violations will be reported and tentative solutions will be developed. The results of these studies will be reviewed through the TEAC.

2.3.8 NERC P3 and P6 "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 P3 and P6 as well as lower voltage facilities that are monitored by PJM Operations will be included in the assessment. 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
    - o Transformer tap adjustment enabled
    - o 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-dipatched
  - 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 P3 and P6 "N-1-1" Methodology

Thermal Test Methodology:

The PJM NERC P3 and P6 "N-1-1" Analysis will test the outage of every single contingency (N-1 condition)

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

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 throw-over.

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 P0 and P1 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 flow gates 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 P2, P3, P4, P5 and P6 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 flow gates 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 P1, P2, P4, P5 and P7. NERC TPL P0, 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.2. The resulting system enhancements from all Light Load reliability analysis are expected to be in-service prior to November 1 of the Delivery Year under study.

2.3.12 Spare Equipment Strategy Review

PJM will annually evaluate the spare equipment strategy that could result in the unavailability of major transmission equipment that has a lead time of one year or more (such as a transformer) and assess the impact of this possible unavailability on system performance using NERC category P0, P1 and P2 contingency categories identified in Table 1 of NERC TPL-001-4. This assessment will consider the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

2.3.13 Winter Peak Reliability Analysis

The winter peak reliability analysis ensures that the Transmission System is capable of delivering the system generating capacity at winter peak. The PJM 50/50 winter peak demand level was chosen as being representative of a typical winter peak 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 winter peak demand level.

The starting point power flow is the same power flow case set that is used for the baseline analysis, with adjustments to the model for the winter peak demand level, winter peak load profile, winter ratings, interchange, and accompanying generation dispatch. The PJM portion of the model is adjusted, and the MMWG winter model is used for areas surrounding PJM.

Interchange levels for the various PJM zones will reflect all yearly long term firm (LTF) transmission service, except MAAC which will reflect the historical average. Load level, interchange, and generation dispatch for non-PJM areas impacting PJM facilities are based on statistical averages for previous winter peak periods. Thus the same baseline network model and criteria apply. The flowgates ultimately used in the winter peak reliability analysis are determined by running all applicable contingencies maintained by PJM planning and monitoring all PJM market monitored facilities and all NERC BES facilities. The contingencies used for winter peak reliability analysis will include NERC TPL category P1, P2, P3, P4, P5, P6, and P7. NERC TPL Category P0, 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 used in other baseline reliability tests also apply. Details of the winter peak reliability analysis procedure, including methods of creating the study dispatch, can be found in Attachment D.3. The resulting system enhancements from all Winter Peak reliability analysis are expected to be in-service prior to December 1 of the Delivery Year under study (For example, 2021 Winter Peak studies December of 2021 through February of 2022, System enhancements identified in this study are expected to be in-service prior to December 1, 2021).

2.3.14 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.

2.3.15 Maximum Credible Disturbance Review

The maximum credible disturbance review, identifies extreme events as defined in Table 1 of NERC Standard TPL-001-4, and assess their impact on system reliability. If the initial analysis shows cascading caused by the occurrence of extreme events, PJM will perform an evaluation of possible action designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s). This can include a stability analysis of the area and an evaluation of possible actions to reduce the likelihood of the event or mitigate the consequences and impacts on the system.

PJM will also assess the impact of extreme events using stability analysis. Extreme events contained in Table 1 of NERC TPL-001-4 that produce more severe impacts shall be identified and a list created of those events will be maintained and distributed to the appropriate entities. The rationale for those contingencies selected for evaluation shall be available as supporting information. If the initial analysis shows cascading by the occurrence of extreme events, PJM will perform an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s).

2.3.16 Long Term Reliability Review

The PJM RTEP reliability review process examines the longer term planning horizon, which spans the current year plus 6 through the current year plus 15, using a 24-month reliability planning cycle. At the beginning of the first year of the cycle, a 5-year out base case, a long-term 8-year out base case and a 10-year out base case are developed and evaluated. At the beginning of the second year of the cycle, new 5-year out, 7-year out and 10-year out base cases are developed and evaluated. 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 P2, P3, P4, P5, P6 and P7 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 consistentwith the methods for the near term analyses. The analysis for the longer term horizon evaluates all NERC P0 and P1 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.

2.3.17 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.

Subregional RTEP Committee initial assumptions meeting

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***.

PJM development of criteria violations and stakeholder participation

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.

2.3.18 Corrective Action Plan

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

- Installation, modification, retirement or removal of Transmission and Generation facilities and any associated equipment
- Installation, modification or removal of Protection Systems or Remedial Action Schemes.

- Installation or modification of automatic generation tripping as a response to a single or multiple contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan

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

2.4 RTEP integrates Baseline Assumptions, Reliability Upgrades and Request Evaluations

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) pro-ration of Stage 1B ARR; or (3) 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 present all the RTEP market efficiency enhancements to the TEAC Committee for review and comment. 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 at a Transmission Expansion Advisory Committee meeting. 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

Transmission solutions to mitigate congestion causing a pro-ration of existing or future 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.

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.

At this time PJM will also facilitate a TEAC meeting, as appropriate, to review congestion and solicit feedback from the stakeholders' review of the projected congestion data. All stakeholders can provide input to PJM's consideration of the congestion data to be considered for market efficiency solutions to identified economic issues.

Parties wishing formally to submit proposals to address congestion as identified in the Market Efficiency Analysis may do so as described in section 2.6.7 of this manual.

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 current year plus 1 and current year plus 5 using the "as is" transmission network topology without modeling future RTEP upgrades. A second set of simulations will be conducted for each year 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 1 but not in year 5 then the upgrade which eliminates this congestion in the year 5 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 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 for the current 24-month cycle (current year plus 1, current year plus 5, current year plus 8 and current year plus 11) 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.

When the economic efficiency project evaluations have been completed, PJM will schedule a TEAC 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. At this meeting PJM will provide a summary of the analysis results, including an update of the Market Efficiency analysis.

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. 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 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

3 Hybrid transmission upgrades include 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.

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:

- Anticipated high-level project schedule and milestone dates
- 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

2.6.7 Submitting Proposals

Any TEAC member or other entity (consistent with PJM Operating Agreement Schedule 6 provisions), may formally submit proposals for evaluation under the Market Efficiency analysis within the RTEP proposal window. These proposals will be posted on the PJM Website. Market Efficiency Proposals will not be accepted for acceleration or modifications to existing approved RTEP projects.

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), Post Contingency Local Load Relief Warning (PCLLRW) events, and persistent uplift payments.

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.

For Uplift payments, PJM will annually review the persistent uplift payments and the system condition or driver for the payment. PJM will assess the impact of planned RTEP upgrades on the drivers for the uplift and the need for additional planned upgrades will be evaluated. The evaluation of the need for additional upgrades will consider the frequency and amount of the uplift payment as well as any outage or short term system conditions that may have caused the uplift. Upgrades will be considered to mitigate uplift payments that are expected to continue in the future.

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.

2.8 Evaluation of End of Life Issues

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For each End of Life project, which is dependent on the Transmission Owner's process and to the extent available, each Transmission Owner should: (i) identify the owner of the asset(s); and (ii) provide an asset-specific condition assessment that supports the need and proposed solution for the End of Life replacement facility or capital improvement consistent with the Transmission Owner's criteria.