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

1.3 Planning Assumptions and Model Development

1.3.1 Reliability Planning

PJM’s planning analyses are based on a consistent set of fundamental assumptions regarding load, generation and transmission built into power flow models. Load assumptions are based on the annual PJM entity load forecast independently developed by PJM (found at http://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.aspx.) This forecast includes the basis for all load level assumptions for planning analyses throughout the 15 year planning horizon. Generation and transmission planning assumptions are embodied in the base case power flow models developed annually by PJM and derived from the Eastern Reliability Assessment Group processes and procedures pursuant to NERC standards MOD-010-0, -011-0, and -012-0. As necessary, PJM updates those models with the most recent data available for its own regional studies. All PJM base power flow and related information are available pursuant to applicable Critical Energy Infrastructure Information, Non-Disclosure and OATT-related requirements (accessible via http://www.pjm.com/planning/rtep-development/powerflow-cases.aspx or by contacting the PJM Planning Committee contacts.) Each type of RTEP analysis (e.g., load deliverability, generator deliverability etc.) encompasses its own methodological assumptions as further described throughout the rest of this Manual. Additional details regarding the reliability planning criteria, assumptions, and methods can be found in following sections and this manual’s Attachments.

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
J. Include Probabilistic Risk Assessment (PRA) of Aging Transmission System Infrastructure beginning in 4Q, 2006. PRA is employed to mitigate transformer risk on the bulk power system. The consequences of a failure, both reliability and economic impacts, are then considered to implement, when appropriate, a proactive, PJM-wide approach to mitigate operational and market impacts to such failures.

The RTEP will not:

A. Include an evaluation of Transmission Owner transmission expansion or enhancement plans for local area load supply, which are not needed for reliability, market efficiency or operational effectiveness of the Transmission System and do not otherwise negatively impact the Transmission System. These Transmission Owner projects (Supplemental Projects) will be identified in the RTEP for information purposes and tracked for possible future impact implications.

B. Include any upgrades based solely on scaling up of generation to solve load flow studies for years 6 through 15.

B.3 Procedure

I. Solicit input and coordinate with Transmission Expansion Advisory Committee (TEAC) and, as appropriate, TEAC’s Subregional RTEP Committee.

A. Present the preliminary results of the most recent, applicable NERC regional reliability council (ReliabilityFirst and SERC) Reliability Assessments and the most recent PJM Regional Transmission Expansion Plan (RTEP).

B. Present a summary of the transmission expansion or enhancement needs that will be addressed in the RTEP.

C. Provide periodic updates to the TEAC on status of the RTEP.

D. Solicit input on future transmission needs and requirements from those who will not be contacted directly as listed below.

E. Schedule and facilitate Subregional RTEP committee reviews as may be needed to foster the goal of a transparent and participatory planning process.

II. Identify known Transmission System expansion or enhancement needs from the following plans and analysis results:

A. Most recent, applicable Reliability Assessments (ReliabilityFirst and SERC) – (on PJM website)

B. Most recent PJM Annual Report on Operations – (on PJM website)

C. PJM Load Serving Entity (LSE) capacity plans

D. Generator and Transmission Interconnection requests

E. Transmission Owner transmission plans
F. Interregional transmission plans.

G. Firm Transmission Service Requests

H. PJM Transmission Expansion Advisory Committee (TEAC) and Subregional RTEP Committee input

I. PJM Development of Economic Transmission Enhancements

III. PJM will consider the RTEP impacts of each Generation Interconnection Customer (“GIC”) and/or Transmission Interconnection Customer that is currently engaged in discussion with PJM concerning plans for siting generating and/or transmission facilities.

Typical items to be included are as follows:

A. GIC and/or Merchant Transmission Facilities developer project status, schedule, and milestones.

B. PJM will review the status of studies currently being performed or scheduled to be performed by PJM for the GIC and/or Merchant Transmission Facilities developer.

IV. GIC and/or Merchant Transmission Facilities developer plans will be included in the RTEP based on the following criteria:

A. Developer must be presently engaged in discussion with PJM concerning their plans for siting generating and/or transmission facilities and actively pursuing those plans.

Interconnection Studies in response to requests for Generator and/or Transmission Interconnections will be conducted in accordance with the following scope:

Identify transmission enhancements required to meet reliability requirements over the next 5 years.

No studies will be conducted beyond 5 years for interconnection projects.

“But-for” costs will be applicable toward all system upgrades identified in the RTEP Baseline.

A. GIC and/or Merchant Transmission Facilities developer plans will be treated equal to LSE plans submitted via EIA 411 in that they will be explicitly modeled and explicitly included in the RTEP report.

B. GIC and/or Merchant Transmission Facilities developer plans, which have not been released publicly, will be masked to the greatest extent possible to preserve the confidentiality of the developer’s identity and specific site location(s).

C. GIC and/or Merchant Transmission Facilities developer plans, which were developed as a result of a PJM feasibility study or are being developed in conjunction with a PJM feasibility study being performed concurrent with the RTEP process, will be evaluated explicitly during the RTEP.

D. GIC and/or Merchant Transmission Facilities developer plans which have not undergone a PJM feasibility study or are not actively being developed as a result of
an agreement executed with PJM to perform a feasibility study concurrent with the RTEP process, will only be considered to the extent that the GIC generator installation or Merchant Transmission Facilities developer facility may affect the sensitivity of transmission enhancement or expansion alternatives which are being evaluated.

V. PJM will exchange information and data with each Transmission Owner (TO) for the purpose of developing RTEP assumptions in preparation for the Subregional RTEP Committee assumptions meeting. Typical items to be included are as follows:

A. TOs will verify their transmission and capacity plans.

B. TOs and PJM will discuss the status, impact, and schedule of relevant studies in which they are mutually engaged in performing.

C. TOs will provide information concerning the contractual rights and obligations which PJM must consider per the RTEP protocol as listed in Schedule 6 of the PJM Operating Agreement.

D. TOs will provide PJM with any information related to concerns, operating procedures, or special conditions for each of the TO’s systems that PJM should consider related to the analysis to be performed for the RTEP.

E. TOs will discuss the accuracy of PJM’s load flow representation for each of the TO’s systems including the impact of using the present representation for each of the TO’s underlying systems.

F. TOs will identify system needs which are currently not identified by published transmission plans but could be included for consideration during the RTEP analysis.

G. TOs will provide the names, addresses, telephone numbers, FAX number, and email address for personnel identified to interact with PJM on matters dealing with the RTEP process.

H. TOs will provide a confidentiality statement regarding all information released to the TO by PJM during the course of the RTEP process.

I. TOs will provide information on new loads or changing loads that will impact the transmission plan.

VI. PJM will include available information from neighboring TOs / Regional Transmission Operators, gained in the course of interregional planning activities, related to plans in other regions which may impact the PJM RTEP.

VII. RTEP Analysis General Assumptions:

A. PJM System Models will be drawn from the PJM and applicable regional reliability council (ReliabilityFirst and SERC) central planning database which includes transmission plans consistent with the most recent FERC 715 Report and most recent Regional EIA-411 Reports.
B. LSE capacity models are to be based on the most recent Regional EIA-411 Reports.

C. GIC capacity plans will be modeled as described in Procedures III and IV.

D. When the PJM load in the RTEP model exceeds the sum of the available in-service generation plus generation with an executed ISA, PJM will model new generation to accommodate additional load growth by including queued generation that has received an Impact Study.

E. PJM Load Forecasts are to be based on the most recent LAS Report.

F. Power Flow models for world load, capacity, and topology will be based on the most recent Eastern Reliability Assessment Group (ERAG) power flow base cases.

G. Generation outage rates will be based on the most recent generator unavailability data available to PJM. Estimates, based on historical outage rates for similar in-service units, will be used for all generating units in the neighboring regions and for all future PJM units.

H. Firm sales to, and firm purchases from, regions external to PJM will be modeled consistent with the provisions for the interchange schedule as outlined in section H.1.2 of Attachment H to this manual.

I. Only PJM’s share of generation will be modeled to serve PJM load. Generation located within PJM, but not committed to PJM, will be accounted for in the interchange schedule.

J. The Reliability Principles and Standards as shown on Attachment D to this Manual 14B, “PJM Reliability Planning Criteria.”

K. Stability analysis and short circuit studies will also be performed.

L. All PJM Transmission System facilities 100 kV and greater, and all tie lines to neighboring systems will be monitored.

M. Contingency analysis will include all facilities operated by PJM.

N. The published line and transformer daytime thermal ratings at ambient temperatures of 50°F (10°C) winter and 95°F (35°C) summer will be used as the default rating sets for all facilities. PJM will review Transmission Owner requests to use alternate temperature rating sets for their facilities.

O. The voltage limits applied for planning purposes will be the same as applied in PJM Operations.

P. PS/ConEd PAR Flows: Model a 1000MW import at Waldwick and 1000MW Export at Goethals and Farragut with Ramapo PARS controlling 920 MW to NYPP. Except, for load deliverability testing, the export to ConEd at Goethals and Farragut may be decreased to 600 MW to represent a 400 MW emergency PJM purchase from NY for the capacity deficiency conditions being modeled. Likewise, the Ramapo setting is changed to 1000 MW into New Jersey.
Q. Assumptions used for the economic analysis and comparison of alternatives will be included in the report.

R. Planning and Markets will, annually based on historical data, develop a circulation model to be applied to the 5 year RTEP base case. This assumption will be reviewed with the PJM Planning Committee prior to implementation.

VIII. Evaluate Transmission enhancement and expansion alternatives and develop a coordinated Regional Transmission Expansion Plan.

A. Develop solution alternatives for regional and subregional transmission needs.

B. Evaluate solutions on a regional basis and optimize solutions to address needs on a coordinated regional basis in a single plan.

C. Test the single regional plan for reliability, economy, flexibility, and operational performance based on forecasts for future years.

IX. RTEP Deliverables

A. A 5-year plan, which includes recommended regional transmission enhancements, including alternatives if applicable, that address the transmission needs for which commitments need to be made in the near term in order to meet scheduled in-service dates.

B. The 5-year plan will include planning level cost estimates and construction schedules.

C. The 5-year plan will specify the level of budget commitments which must be made in order to meet scheduled in-service dates. The commitment may include facility engineering and design, siting and permitting of facilities, or arrangements to construct transmission enhancements or expansions.

D. The 15-year plan will identify new transmission construction and right-of-way acquisition requirements to support load growth.

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.

B.4 Scenario Planning Procedure

Beginning in mid-2006, PJM will include scenario planning evaluations as part of the RTEP process. Scenario planning examines the long-term impacts on the reliability of the PJM system due to uncertainty with respect to certain assumptions implicit in the development of the RTEP. PJM will examine the effects of uncertainty with respect to selected variables such as economic growth effect on the load forecast, circulating transmission flow effects on system deliverability and generation sensitivities. In the course of the RTEP planning cycle
H.1 Power System Modeling Data

Accurate power system modeling data is a key component of quality power system analysis. PJM System Planning uses a variety of models and analytical techniques to create and maintain the simulation models used for the RTEP studies. The intended use of this Attachment is to supplement existing documentation by PJM and other entities that specify accurate modeling data requirements. PJM will continue to follow the data guidelines and standards set forth by NERC as part of the MOD standards and the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) Procedural Manual.

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.

H.1.1 Load Flow Analysis Models

Base case creation is a collaborative process between PJM and its members. From a technical standpoint PJM follows the guidelines set forth in the ERAG MMWG Procedural Manual. In the following sections, the logistics and transfer of information between PJM and its members are detailed.

Annual Updates

In the fourth quarter of each year, PJM will distribute to the Transmission Owners a current year +5 summer peak network model based on the most up to date MMWG case combined with the previous year’s RTEP case. This draft case will contain all upgrades identified during the previous year’s RTEP cycle. Within 4 weeks of receiving the initial draft network model, Transmission Owners will provide:

Network updates to the model that will advance the case to represent a current year + 5 base case with respect to the 1st Quarter of the following year. This update should be reviewed for correctness and compatibility with the final version of the base case under development

Complete NERC P1, P2, P3, P4, P5, P6 and P7 contingency file updates that correspond to the updated network model (Include any contingencies which may not change the powerflow model, but change contingency definitions)

Maximum credible disturbance (NERC TPL-001-4 Table 1 Extreme Events) contingencies

Any other significant changes such as new load or block load additions

Support, if necessary, for the development of network models for additional years and demand levels for both near term (years 1 through 5) and longer term (beyond 5 years) analyses.
Verification that all baseline, network and supplemental upgrades are included in the updated case along with a written description of any case modifications.

Notification of any changes to tie lines whether they are ties internal to PJM or to external companies.

**Interim Updates and Communication of Significant Modeling Updates**

In the event that PJM makes a major update to the RTEP analysis models outside of the annual model update window, PJM will notify PJM Transmission Owners of the modeling update through the Transmission Expansion Advisory Committee (TEAC) meetings. Also, PJM will notify neighboring entities that PJM determines may be impacted. In addition to the notification, PJM will make the updated affected models available upon request.

**Generation Owner Requirements:**

Specific information regarding generator capability per MOD 10 and MOD 12

**H.1.2 Load Flow Modeling Requirements**

In addition to the guidelines set forth by NERC and the ERAG MMWG procedural manual, PJM uses several specific procedures in establishing the base case so that it represents the best starting point for the annual RTEP analysis.

**Generator step-up transformers**

Generator models should represent the physical plant lay-out to the extent possible, explicitly modeling generator step-up transformers (GSUs) and Station Service loads (aka Auxiliary loads). This applies to units above 20 MW and connected to the BES system, consistent with BES requirements. Plants consisting of multiple units aggregating to 75 MW or more also require explicit representation of GSUs and station service loads.

**Modeling of Outages**

Known outages of Generation or Transmission Facilities with a duration of at least six months will be included under those system peak or off-peak conditions in the appropriate base case model. PJM may not model these outages in every case that is used for RTEP analysis, but will select appropriate scenarios to assess these changes. Additionally PJM will analyze a subset of maintenance outages submitted through eDart under those system peak or off-peak conditions.

**Interchange**

The PJM net interchange in the summer peak case is determined by the firm interchanges that are represented in the PJM OASIS system. That interchange, in the summer peak case, shall be represented as 100% of the confirmed firm import and export reservations. Reservations associated with individual generation units, or group of units at a facility, shall be used in representing the interchange. The interchange in light load cases follows the light load criteria as defined in the Light Load Reliability Analysis in section 2.3.10 of this manual.

**Generator Reactive Capability**

Annually, PJM updates the model for the generator reactive capability (GCAP) of each generator based on data used by PJM Operations, which includes default limits obtained from the most up to date d-curves as well as data provided by the Generator Owners.
Interconnection Projects With Interconnection Service Agreements (ISAs)

PJM includes queue projects with a signed ISA into the base case as well as verifying the accuracy of queue projects that have not yet signed an ISA. PJM also includes the interconnection, ratings and associated upgrades for each of these projects. Transmission Owners will verify the accuracy of the points of interconnection and the associated upgrades in their zones.

Real and Reactive Load

Each TO is responsible for modeling the active (real) and reactive load profile in its zone. PJM will scale the load in each zone to the targeted values reported in the latest annual PJM load forecast report.

Real loads will be scaled uniformly in each zone to meet the PJM 50/50 load forecast less any Demand Response (DR), Energy Efficiency (EE), or Behind the Meter (BTM) generation as necessary. Real loads will also be scaled uniformly within each zone for off-peak analysis. Reactive load in each area will be scaled at a constant power factor along with the real load for peak load analysis. For off-peak analysis including light-load, PJM will provide a case to the Transmission Owners, at their discretion, for updating their zonal reactive load profile.

Any deviation from the above method of load modeling method, associated with specific test procedures such as the PJM Load Deliverability Procedure or the PJM Light Load Reliability Test Procedure will be defined specifically in other sections of this manual.

PJM will coordinate with TOs on an individual basis to ensure that non-conforming loads are properly modeled and not uniformly scaled.

Voltage Schedules

The setting of voltage schedules is crucial to the robustness of cases. PJM allows Transmission Owners to supply generator voltage schedule data. If the data is not provided PJM will use the default voltage schedules as defined in PJM Manual 03.

H.1.3 Submittal of Load Flow Data

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.

Acceptable Data Formats

For PSS/E users, cases should be submitted to PJM in a “.SAV” format in a PSS/E version that is readable by the current version of PSS/E that MMWG is using.

For users of PSLF or other modeling software, cases shall be submitted to PJM in a “.RAW” format that is PSS/E compatible and is readable by the current version of PSS/E that MMWG is using.

PJM’s migration of PSS/E versions may slightly lag MMWG, in that case it is acceptable to provide updates formatted for the current version that PJM is using.
TO’s can submit data in an agreed to version if they are unable to export to the latest MMWG compatible version.

**Timing**

Transmission Owners must comply with the schedule dictating the timeliness of the case creation process which will be included in the initial email sent to kick off the process. This schedule will include a minimum of 4 weeks to provide updates to the case and corresponding files for the first iteration, and 2 weeks for the second iteration.

**Load Flow Data Quality**

In the event that data provided by Transmission Owners does not pass all of the testing included in the MMWG data checker, PJM may request updated data.

Transmission Owners must provide unique bus names or circuit ID’s for each winding of all transformers.

Bus numbers must be within the allocated bus number range for each company.

Conventions used for the naming of Machine ID’s vary for different TO zones. PJM will coordinate with each TO individually to align with their preferred convention.

Certain specific modeling and naming conventions which must be followed by all TO’s include:

- High/Low Pressure units should be modeled on the same bus and designated with the corresponding machine ID “H” and “L”.
- No other machine ID should be named “H” or “L”.

With the exception of High/Low Pressure units, multiple machines modeled on the same bus must have the same status. Offline machines should not be modeled on the same bus as machines which have a status of online.

Machines at the same plant with different statuses should be modeled on separate busses connected by a very low impedance line (X=.002) as defined in the MMWG manual.

**H.1.4 Short Circuit Analysis Models**

Short Circuit data procedures are documented in the Attachment G.7 of this manual, which references ANSI/IEEE 551. The intended use of this attachment is to supplement these procedures and outline the data requirements which PJM follows in creating the short circuit cases used for analysis.

Short circuit models should be provided in Aspen “.olr” format, if possible.

Each TO provided Aspen “.OLR” case should model only the TO area and its tie lines. No outside areas should be included in the submission.

All area numbers in the TO provided cases should be consistent with MMWG designated area numbering convention. Area numbers such as 1, 2, 3, etc. are not acceptable.
The following checklist has been created for use by Transmission Owners and Designated Entities as a guideline for what is required by PJM throughout the baseline/supplemental transmission upgrade process from inception to energization.

<table>
<thead>
<tr>
<th>Project Phase</th>
<th>Task</th>
<th>Delivery</th>
<th>Timeframe</th>
<th>PJM Manual Reference</th>
<th>PJM Contact Department</th>
<th>Comments</th>
<th>Online Training link</th>
</tr>
</thead>
<tbody>
<tr>
<td>P</td>
<td>Submit minimum required rating (lines and xfmrs) – not required for supplemental projects</td>
<td>Email to contact</td>
<td>Before Project Approval</td>
<td>M-14B</td>
<td>Transmission Planning</td>
<td></td>
<td></td>
</tr>
<tr>
<td>P</td>
<td>Submit planning model parameters</td>
<td>IDEV/Project File</td>
<td>Before Project Approval</td>
<td>M-14B</td>
<td>Transmission Planning</td>
<td></td>
<td></td>
</tr>
<tr>
<td>P</td>
<td>Submit planning contingency changes</td>
<td>CON File</td>
<td>Before Project Approval</td>
<td>M-14B</td>
<td>Transmission Planning</td>
<td></td>
<td></td>
</tr>
<tr>
<td>P</td>
<td>Submit breaker diagrams</td>
<td>Email to contact</td>
<td>Before Project Approval</td>
<td>M-14B</td>
<td>Transmission Planning</td>
<td></td>
<td></td>
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<tr>
<td>P</td>
<td>Project Description/Cost/Time Estimate</td>
<td>Email to contact</td>
<td>Before Project Approval</td>
<td>M-14B</td>
<td>Transmission Planning</td>
<td></td>
<td></td>
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<tr>
<td>EP</td>
<td>Construction Schedule/Project Sequence</td>
<td>Email to contact</td>
<td>6-8 months prior to UC phase</td>
<td>M-14C</td>
<td>Infrastructure Coordination</td>
<td></td>
<td></td>
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<tr>
<td>EP</td>
<td>Submit projected outage timeframes</td>
<td>Email to contact</td>
<td>6-8 months prior to UC phase</td>
<td>M-14C</td>
<td>Infrastructure Coordination</td>
<td></td>
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<tr>
<td>UC</td>
<td>Quarterly updates</td>
<td>Email to contact</td>
<td>Throughout UC phase</td>
<td>M-14C</td>
<td>Infrastructure Coordination</td>
<td></td>
<td></td>
</tr>
<tr>
<td>EP/UC</td>
<td>Task Description</td>
<td>System &amp; Ticket Details</td>
<td>Due Date</td>
<td>System Responsible</td>
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<tr>
<td>EP/UC</td>
<td>Submit as built impedance and all other applicable equipment parameters (i.e. Tap Settings, Capacitor Size etc.)</td>
<td>eDART – Network Model Ticket</td>
<td>6-12 months prior to IS</td>
<td>M-03A; 3.2; Model Management</td>
<td></td>
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<tr>
<td>EP/UC</td>
<td>Submit final In-Service Date</td>
<td>eDART – Network Model Ticket</td>
<td>6-12 months prior to IS</td>
<td>M-03A; 3.2; Model Management</td>
<td></td>
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<tr>
<td>EP/UC</td>
<td>Submit target build date</td>
<td>eDART – Network Model Ticket</td>
<td>6-12 months prior to IS</td>
<td>M-03A; 3.2; Model Management</td>
<td></td>
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<tr>
<td>EP/UC</td>
<td>Submit equipment names</td>
<td>eDART – Network Model Ticket</td>
<td>6-12 months prior to IS</td>
<td>M-03A; 3.2; Model Management</td>
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<tr>
<td>EP/UC</td>
<td>Submit final one-line diagrams</td>
<td>eDART – Network Model Ticket</td>
<td>6-12 months prior to IS</td>
<td>M-03A; 3.2; Model Management</td>
<td></td>
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<tr>
<td>EP/UC</td>
<td>Submit Transmission Outage Tickets</td>
<td>eDART</td>
<td>2-12 months prior to IS</td>
<td>M-03; 4.2; Transmission Operations</td>
<td></td>
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<tr>
<td>EP/UC</td>
<td>Submit Ratings (Lines and Transformers)</td>
<td>eDART – TERM</td>
<td>No later than 2 weeks prior to IS</td>
<td>M-03A; 3.2; Real-Time Data Management <a href="mailto:TERMTickets@pjm.com">TERMTickets@pjm.com</a></td>
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<td>EP/UC</td>
<td>Submit Telemetry</td>
<td>Email</td>
<td>No later than 2 weeks prior to IS</td>
<td>M-03A; 3.2; Real-Time Data Management <a href="mailto:PJMTelemetrySupport@pjm.com">PJMTelemetrySupport@pjm.com</a></td>
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<tr>
<td>UC/IS</td>
<td>Notification of In-Service status</td>
<td>Email</td>
<td>Once facility is energized</td>
<td>M-14C; Infrastructure Coordination</td>
<td></td>
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</tbody>
</table>

¹Key: P = Pending (or before Pending), EP = Engineering and Procurement, UC = Under Construction, IS = In-Service