PJM Manual 38:

Operations Planning

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Prepared By
Operations Planning Division

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Current Revision

Revision 21 (01/21/2027)

- Cover to Cover Periodic Review
  - Section 2.2.1 - Added reference to Attachment C.
  - Attachment C: New attachment for Outage Coordination Guideline

~~**Revision 20 (01/22/2026):**~~

- ~~Cover to Cover Periodic Review~~
  - ~~Section 2.2: Added PJM RTEP long term study (MTOPOC).~~
  - ~~Attachment B: Added MISO solar generation to the study process.~~

Introduction

Welcome to the ***PJM Manual for Operations Planning***. In this Introduction, you will find the following information:

- What you can expect from the PJM Manuals in general (see "*About PJM Manuals*").
- What you can expect from this PJM Manual (see "*About This Manual*").
- How to use this manual (see "*Using 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 PJM RTO and the PJM Energy Market. The Manuals are grouped under the following categories:

- Transmission
- PJM Energy Market
- Generation and transmission interconnection
- Reserve
- Accounting and Billing
- PJM Administrative services

For a complete list of all PJM Manuals, go to the Library section on PJM.com

About This Manual

The ***PJM Manual for Operations Planning*** focuses on how PJM and the PJM Members are expected to carry out reliability coordination duties in accordance with the PJM Reliability Plan.

The ***PJM Manual for Operations Planning*** consists of three sections. These sections are listed in the table of contents beginning on page ii.

Intended Audience

The Intended Audiences for the ***PJM Manual for Operations Planning*** are:

- *PJM technical support staff*— Prepare and disseminate the reliability analyses.
- *Transmission Owner and Generation Owner Operators* — Use the operation planning information to supplement Real-time Operations tools.
- *PJM system operators* — Use the operation planning information and perform current day analysis to supplement Real-time Operations tools.

References

There are several reference documents that provide background or relate to the ***PJM Manual for Operations Planning***:

- PJM M-12 Balancing Operations
- PJM M-03: Transmission Operations
- PJM M-03B: Transmission Operating Procedures (CEII)
- PJM M-10: Pre-Scheduling Operations
- PJM M-37: Reliability Coordination

Using This Manual

Because we believe that explaining concepts is just as important as presenting the procedures, we start each section with an overview. Then, we present details and procedures. This philosophy is reflected in the way we organize the material in this manual. The following paragraphs provide an orientation to the manual's structure.

What You Will Find In This Manual

- A table of contents that lists two levels of subheadings within each of the sections.
- An approval page that lists the required approvals and a brief outline of the current revision.
- Sections containing the specific guidelines, requirements, or procedures including PJM actions and PJM Member actions.
- Attachments that include additional supporting documents, forms, or tables.
- A section at the end detailing all previous revisions of the PJM Manual.

Section 1: Seasonal Operating Studies

Welcome to the *Seasonal Operating Studies* section of the ***PJM Manual for Operations Planning.*** This section of the manual addresses PJM preparation of seasonal operating studies.

1.1 PJM Seasonal Operating Studies

The PJM Operations Assessment Task Force (OATF) is responsible for the preparation of seasonal operating studies (two per year: summer and winter). OATF is composed of representatives from the Transmission Owners (TOs) and PJM. PJM provides the leader of the OATF and is responsible for the analysis and publication of results.

The study assesses the PJM RTO Bulk Electric System as it is expected to exist during the upcoming peak season. The purpose of the study is to determine the ability of the PJM system to be operated reliably in accordance with NERC, RF, and SERC standards. The results of the study are based on the assumed system conditions which differ from actual operating conditions due to unplanned generation and transmission outages, the effects of unseasonable weather on load, and unit availability other than what was simulated in the study. Refer to the OATF Scope in Attachment A.

Power flow cases are developed which represent probable system conditions during the upcoming peak season. Thermal and reactive limits are identified and supplemental sensitivity analyses are performed to address areas of concern. [NERC Standard TOP-002].

PJM Actions:
PJM is responsible for the following activities:

- Providing a leader of the OATF.
- Preparing a study plan for the seasonal study and gaining approval of the plan from the OATF and the PJM System Operations Subcommittee – Transmission (SOS-T).
- Requesting and receiving data from the TOs and incorporating the TOs' data into the analysis.
- Running the power flow cases and sensitivities.
- Analyzing the results and developing analysis for review by the TOs.
- Publishing the study results, upon review by the TOs, to PJM System Operations and the TOs.
- Providing summary documentation and training to System Operators.

PJM TO Member Actions:
PJM TO Members are responsible for performing the following activities:

- Providing a representative to the OATF.
- Providing data, as requested by PJM, in order to create the power flow cases to accomplish the study.
- Cooperating with PJM and the other TO members to complete the study and review the results.
- Communicating the results, as necessary, within the respective TO organization.
- Providing summary documentation and training to System Operators.

1.2 Interregional Studies and Assessments

PJM participates on a number of interregional studies and assessments that are prepared under of the auspices of the Eastern Interconnection Reliability Assessment Group (ERAG). ERAG will conduct “assessments to identify key reliability issues and the risks and uncertainties affecting adequacy and security of the Bulk Power System in the Eastern Interconnection.” The PJM representative is responsible for providing necessary data and information used in the analysis.

In addition, PJM participates in several regional seasonal assessments to analyze the anticipated performance of the upcoming SERC and NPCC regions. These studies include:

- The SERC seasonal assessment
- NPCC CO-12 (NPCC seasonal assessment)

Interregional studies and assessments are an important source of information about projected conditions for upcoming peak seasons. The results of such studies are distributed to PJM Operations Staff and System Operators to ensure that they have the benefit of all such analyses.

PJM coordinates upcoming outages with NYISO and performs Operations Planning studies. PJM reviews the NYISO seasonal assessment studies.

PJM and MISO coordinate on a semiannual basis to review the past season’s system operations and also review the upcoming season’s reliability assessment.

Section 2: Outage Coordination

Welcome to the *Outage Coordination* section of the ***PJM Manual for Operations Planning***. In this section, you will find the following information:

- Generator Outage Coordination
- Transmission Outage Coordination
- Neighbor Outage Coordination and Resolution

[NERC Standard TOP-003: R1, R2]

[NERC Standard IRO-010: R1, R2]

2.1 Generator Outage Coordination

Generation Owners are required submit/communicate Outage Requests in eDART for all outages to PJM in advance of the outage start date. PJM staffs are required to analyze submitted outages to ensure outages do not violate PJM reliability criteria and market rules. This notification process is not limited to MW reduction; it also includes changes to D-Curve information, voltage regulator status, and other equipment outages that could result in the loss of multiple generators at a common plant. The PJM M-10: Pre-Scheduling Operations, Section 2: Outage Reporting, documents the PJM generator outage submittal, coordination, and approval process.

2.2 Transmission Outage Coordination

Transmission Owners are required to submit/communicate Outage Requests in eDART for all outages to PJM in advance of the outage start date. PJM will provide all relevant information required for system studies, such as critical facility status, load, generation, operating reserve projection. In addition, PJM retrieves and incorporates into the study known Interchange Transactions, external transmission outages, and external generation outages via the NERC SDX secure site. PJM updates the SDX outage information every 15 minutes. PJM staffs are required to analyze submitted outages to ensure outages do not violate PJM reliability criteria and market rules. Attachment B: Reliability Analysis Procedure describes the process PJM apply to ensure transmission outages are properly analyzed and coordinated. The PJM M-03: Transmission Operations, Section 4: Reportable Transmission Facility Outages, documents the PJM transmission outage submittal, coordination, and approval process.

2.2.1 Advance RTEP / Multi-TO Project Outage Coordination (MTOPOC) Analysis

Due to the nature of some RTEP upgrades such as line rebuilds or reconductors and transformer replacements, the associated outage requests have the potential to be of long

duration and may create significant operational issues. Following the PJM Board approval process, PJM Planning and Operations Planning staff may identify a subset of RTEP projects with a projected need for advanced coordination. PJM Operations staff will perform the Multi-TO Project Outage Coordination (MTOPOC) outage analysis which covers the one to two year out time frame on a rolling basis. PJM Planning and Operations Planning staff will work together with the incumbent Transmission Owner(s) to discuss and coordinate outage sequences, and to assess the need for mitigation steps. These mitigation steps may include, but are not limited to, performing upgrades to limiting facilities, relay changes, use of Short-Term Emergency ratings, and installation of mobile capacitor in order to minimize the impact of long duration outages. This type of advanced coordination is required in order to enhance reliability by minimizing conflicts, congestion, and expected outage duration. Please refer to Attachment C: Outage Coordination Guidelines for submitting transmission and generation outage requests that fall into MTOPOC timeframe.

2.3 Neighbor Outage Coordination and Resolution

Internal PJM Outages: PJM serves as overall coordinator with respect to PJM Member Transmission/Generation facility outages with potential impact to neighboring BA and RC. PJM works with the member Owner, and any impacted BA, TOP, or neighboring RC to resolve any identified outage conflicts ahead of the outage. Ultimately, if the conflict cannot be resolved to all parties' satisfaction, PJM may need to deny or reschedule the original outage in order to ensure overall system reliability. PJM Transmission Owners shall coordinate outages with any impacted PJM neighboring Transmission Owners/Operators, including, but not exclusive to, tie lines. See Attachment B: Reliability Analysis Procedure, Section B.6 "Internal Outage Analysis Process" for an overview of PJM evaluation of internal outage impacts.

External Outages: PJM serves as coordinator for neighboring BA, TOP, or RC outages with impact to PJM Member Transmission/Generation Owner facilities. PJM will work with the neighboring reliability entity to determine any required resolution, including the cancelation or rescheduling of the outage as required. See Attachment B: Reliability Analysis Procedure, Section B.7 "Analyze External Outages" for an overview of PJM evaluation of external outage impacts.

Any actions required in order to accommodate any portion of an internal or external Outage shall be identified within the PJM Operational Planning Analysis.

Section 3: Next Day Reliability Analysis

Welcome to the *Next Day Reliability Analysis* section of the ***PJM Manual for Operations Planning***. In this section, you will find the following information:

- Process for developing the next day reliability analysis

3.1 Overview

The purpose of the next day reliability analysis is to ensure that a comprehensive operating plan can be developed which meets all of the reliability requirements and provides for a level of uncertainty in facility availability that is inevitable in Real-time Operations.

The next day analysis brings together the latest available information regarding outages, system topology, load forecast, unit commitment, and interchange schedules, as the inputs to the analysis. The PJM EMS study model utilized in the analysis is derived from a recent Real-time State Estimator case, which reflects the Real-time PJM EMS model, the full list of BES facilities monitored as part of PJM's Real-time, and the full list of contingencies screened as part of PJM's Real-time analysis. The base case study model is run in the EMS study mode and is modified to reflect anticipated system conditions during the next operating day.

The results include an analysis of all BES facilities at projected peak and valley conditions for the next operating day, with a full AC analysis of all BES facilities for the full contingency list PJM screens in Real-time Operations. The analysis includes all SOLs and IROLs for thermal, voltage, and voltage drop exceedances. The analysis is shared with the operators on shift, TOs, and neighboring RCs and BAs.

PJM Actions:

- Performs the next day analysis using the Attachment B: Reliability Analysis procedure.
- Coordinates action plans with affected Transmission Owners and external systems. Schedules out-of-merit generation as required.
- Finalizes PJM's initial summary Operational Planning Analysis [OPA], leveraged for reliability and to inform the PJM DA Market.
    - Refines the summary PJM OPA, as needed based on DA Market, ahead of the Operating Day.
    - Makes such plans available to Balancing Authorities, Transmission Operators, and Reliability Coordinators, as well as PJM member Transmission Owners, via a secure site posting and corresponding awareness to report availability through email notification.
        - The secure site requires individual CEII access with a PJM.com account. Site Declaration: For use by transmission and reliability personnel only. This site

contains confidential transmission information and cannot be shared with market participants. Anyone with access to this site and the data contained herein is required to maintain the Federal Energy Regulatory Commission Standards of Conduct regarding data confidentiality.

PJM Member Actions:

- Coordinates scheduled transmission outages with PJM Staff.
- Communicates mitigation strategies with system operators.
- Member Transmission Owners whom conduct an internal Day Ahead Analysis should compare their own internal Day Ahead Analysis results with PJM's Day Ahead results (https://www.pjm.com/markets-and-operations/ops-analysis/private-outage-analysis-report.aspx). If there are any discrepancies or operating concerns between the two Day Ahead Analysis results, PJM Reliability Engineers should be contacted to discuss and implement mitigation strategies prior to the operating day.

Attachment A: OATF Scope

A.1 Purpose of Operating Study

The PJM Operations Assessment Task Force (OATF), under the direction of the PJM System Operations Subcommittee - Transmission (SOS-T), conducts a study for the summer and winter "study period" as defined below. The purpose of the study is to analyze a representation of the PJM system with the transmission and generation configuration approximating the conditions expected to exist during the study period (see Key Assumptions & Model Definition section for more detail). The study focuses on the current PJM RTO boundary and the boundaries of any applicable external companies that will be integrated into PJM prior to the study period at the time the scope for the study was drafted by PJM.

The PJM Operations Assessment Task Force (OATF) consists of representatives from PJM and Transmission Owner members including:

- Atlantic City Electric, American Electric Power, Baltimore Gas & Electric, Commonwealth Edison, Cleveland Public Power, Duke Energy Ohio / Kentucky, Duquesne Light, Dominion, Dayton Power & Light, Delmarva Power, FirstEnergy, PECO, Potomac Electric Power Company, PPL Electric Utilities, Public Service Electric & Gas, Rockland Electric Company, UGI Utilities, Neptune Transmission, Linden VFT, East Kentucky Power Cooperative, City of Rochelle/NextEra, Hudson Transmission Partners, SMECO, OVEC, and AMPT/Gridforce.

A.2 Scope Objectives

- Develop seasonal power flow base case representative of expected system conditions for the study period.
- Identify thermal overloads and voltage limit exceedances based on AC N-1 contingency analysis as well as switching and/or off-cost requirements for transmission control.
- Determine reactive transfer capability limitations for the current Eastern, Central, Western, 5004/5005, Bedington-Black Oak, AP South, AEP-Dominion, BC/PEPCO, CE-East, and Cleveland interfaces. Identify the import limits associated with the above reactive transfer capabilities.
- Determine the facilities that may limit thermal transfer capability into the major PJM load areas.
- Review and evaluate the effectiveness of existing operating procedures that are used to improve PJM transfer capabilities. Suggest practical system modifications to further improve PJM transfer capabilities. Revise operating guidelines as required.
- Identify conditions where the planned maintenance outages of PJM generation or transmission facilities negatively impact the reliability of the Bulk Power System.
- Identify the impact of delays in the installation of new transmission facilities.

- Perform sensitivity studies as listed in Section A.4 below.
- Perform analysis to determine survivability of maximum credible disturbance facility loss in Section A.5 below.

A.3 Key Assumptions and Model Definition

A.3.1 Base Case Parameters

- The PJM RTO load will be the sum of all 50/50 non-diversified peak loads of each transmission company zone obtained from the latest PJM Load Forecast Report. Forecasting judgment may be applied to these target loads to determine the actual megawatt load that will be modeled.
- The net PJM interchange level will be modeled to reflect typical seasonal values.
- The Hopatcong–Ramapo line flow will be set to a typical megawatt value for the conditions studied.
- The PS–ConEd phase angle regulators will be set to maintain a typical megawatt flow for the conditions studied.
- Neptune HVDC line flow will be set to a typical megawatt value for the conditions studied.
- Linden VFT will be set to a typical megawatt value for the conditions studied.
- HTP will be set to an estimated megawatt value for the conditions studied.

A.3.2 PJM System Representation

- The reactive load modeled at each of the company load buses should reflect actual experienced data. Whenever possible, the company reactive loads should not be factored from one load level to another.
- Whenever possible, supervisory controlled capacitors should be represented explicitly in the case.
- The power interchanges between companies external to PJM should reflect typical values.
- All major generating units should be modeled on their own low voltage generator buses.
- Generator voltage regulators should:
  - Control remote bus voltages in base cases.
  - Control generator terminal voltages in contingency cases.
- All generating units should be modeled with a reactive capacity that accurately reflects the limits experienced during actual operations.
- Any generating unit that is scheduled out for maintenance for a significant portion of the study period should be placed out of service in all base power flows.
- Any transmission line scheduled out of service for the majority of the study period should be placed out of service in all base power flows.

- Distribution capacitors, reactors, and synchronous condensers should be represented in the same manner that would be expected in actual system operations.
- The PJM system transmission line ratings used should be the seasonal normal and approved short-term emergency MVA line ratings consistent with each company's operating philosophy.
- The voltage schedules used should represent those expected to be followed during the study period for all controllable buses. The voltage schedules include both generator and LTC (Load Tap Changers) regulated buses.
- An accurate representation of all power systems external to PJM should be merged with the PJM power flow model.

A.3.3 PJM Dispatch

- All generator economic dispatch data will be derived from historical bid data from the previous comparable season.
- Base load units will be modeled as must run.
- Discrete unit outages for the study period will be determined based on an average obtained from unavailable generator MW (maintenance and unplanned) on ten days from the three previous seasons that are at or near the load level to be studied.
- Non-Utility generation shall follow the same guidelines whenever the appropriate data is available.
- Hydro-generation, solar generation, and wind generation will be modeled at typical levels expected during the study period.
- Demand Response (DR) will be incorporated into the dispatch when appropriate, e.g., to resolve peak load system exceedances. The granularity of the DR modeling will be based on the available data and any software limitations.

A.4 Sensitivity Studies

- Sensitivity studies will be performed on facilities identified by the SOS-T as potential IROL facilities. Existing IROL facilities will be evaluated on a periodic basis to determine whether they still meet the IROL criteria as defined in PJM M-37: Reliability Coordination, Section 3.
- Sensitivity study will be performed on BC/PEPCO import capability.
- Sensitivity study will be performed by monitoring external facilities and applying external contingencies that are located electrically close to the PJM border. The additional study will help prevent issues along the seams of PJM and its neighbors.
- Analysis of specific N-2 conditions will also be performed to avoid situations where cascading outages could occur due to an N-1 contingency followed by relay-induced line tripping resulting from insufficient time for Operations to react.
- Analysis of planning and operational gas pipeline contingencies.
- Analysis of system conditions for the extreme 90/10 PJM load forecast.

- Analysis of maximum credible disturbance contingencies.
- Sensitivity study of solar and wind generation.

Due to the study timeline of work and deliverables, PJM may not be able to accommodate certain sensitivity studies requested by members of the OATF. In general, PJM cannot accommodate sensitivity studies involving:

- Analysis of load conditions that significantly diverge from the peak load for the study period (e.g., light load and shoulder period conditions).
- Analysis of a localized issue affecting only one company transmission zone.

A.5 Maximum Credible Disturbance Study

A maximum credible disturbance ('max-cred') is defined as having a reasonable possibility of occurring (being credible) and also of being outside the normal N-1 contingency criteria. For the purpose of assisting Generation Owners (GO) and Transmission Owners (TO) in determining critical assets pursuant to NERC Critical Infrastructure Protection (CIP) Standards, PJM will perform analysis to determine the survivability of max-cred facility losses. GO shall communicate Common Mode Impact contingencies to PJM and the affected Transmission Owner through the PJM SOS-T (contacting PJM Chairman and Transmission Owner Representative) for inclusion in the PJM OATF Maximum Credible Disturbance Contingency Analysis. TO shall review current set of maximum credible disturbance contingencies and supply changes to the PJM OATF representative prior to finalizing the OATF Scope. PJM will communicate max-cred contingencies that are not survivable to the impacted asset owner.

Attachment B: Reliability Analysis Procedure

Documentation Sources

- PJM M-03: Transmission Operations
- PJM M-03B: Transmission Operating Procedures (CEII)
- PJM M-10: Pre-Scheduling Operations
- NERC Standards FAC-011, IRO-008, IRO-010, IRO-014, IRO-017, TOP-002

Tools and information for Transmission & Generation Outage Analysis

- eDART – For viewing/revising transmission and generation outage tickets
- EMS
- Load forecasts
- Day-Ahead generation commitment
- DMT/SCED – For additional generation information
- ExSchedule
- SDX (System Data Exchange) – For external outages and BA-to-BA scheduled interchange
- Weather forecasts
- IEP (Intelligent Event Processor)
- TSA

B.1 Initial Preparation/Information Gathering:

- Obtain the load forecast for the study period.
- Obtain the PJM footprint and neighboring areas weather data for the study period.
- Obtain the list of internal transmission and generation outages that will occur on the study date from the eDART Outage Scheduling Application.
- Obtain external outage information via the following:
  - MISO and TVA daily outage reports.
  - SDX generation and transmission outages.
- Obtain interchange information via the following:
  - Utilize ExSchedule to review the PJM scheduled interchange values.
  - Utilize the SDX data to review the external BA-to-BA scheduled interchange values.
- Check for any current and/or projected system conditions that may impact the scheduled outages such as system wide peak loads, Heavy Load Voltage Schedule Alerts, GMD, etc.

Note:
PJM will cancel scheduled outages, regardless of submittal time, if the outage could jeopardize system reliability.

B.2 Study Case Set-up and Verification:

EMS Study Case Set-up

- Search and select a State Estimator (SE) saved case with load levels that are as close as possible to the peak (or valley) forecasted Balancing Authority loads for the study period.
- Utilize the EMS study package to retrieve the saved State Estimator solution into the power flow study.
- Adjust the transmission topology to reflect the study date conditions by making status changes to transmission equipment (lines, transformers, breakers, caps, reactors, etc.).

Note:
The eDART-to-EMS bridge can be used to automate the import of projected system topology.

- Adjust generation statuses to reflect the study date.

Note:
EMS automation can be used to load the forecasted PJM wind generation into the study case.

Generators returning from an outage are not guaranteed to be on-line for the study date in question. Use the load forecast in conjunction with the Unit Price information from DMT to make an engineering assessment of whether or not the unit will be on-line. If unsure, the analysis should be performed with the unit on and off-line to determine its impacts.

- To account for the MISO wind and solar impacts:
  - Utilize the MISO Wind and Solar Operations Displays webpage.
    - Note the actual MISO wind/solar output at the time of the initial SE saved case snapshot.
    - Note the peak MISO wind/solar forecast for the study date.
  - Due to ~85% of the MISO wind being physically remote from the PJM system, the wind farm units may not be explicitly modeled. However, their net effect can be reflected in the tie flows between PJM and the ‘WEST’ equivalent area in the EMS Model. Therefore, adjust the net interchange in the WEST area to reflect the MISO wind forecast as shown in the following example:

    - Example: The SE base case had 2,000 MW of wind output in the MISO footprint. The forecast indicates 3,000 MW of wind in MISO. Scale the PJM EMS 'WEST' area generation up by 1,000 MW to account for the additional wind.
- Turn off CTs running for congestion (or reliability, etc.) in the powerflow case. Adjust appropriate generation as needed.
- Adjust the Rating Temperature Sets for each transmission zone to reflect the highest expected temperatures for the study date.
- Verify that all Balancing Authority loads match their respective peak load forecasts. Utilize the EMS "Company Scale Load or Generation" function to manually scale the loads to match the forecasts if required.
- Adjust generation both internally and externally as needed to incorporate the projected scheduled interchange into the case.
- Update contingency list by pulling in the Real-time contingency list. Update the list, as needed, for changes in system conditions between the current time and the study period.

B.3 EMS Study Case Verification:

- Run power flow to verify that the case converges and make adjustments as necessary.
- Run Security Analysis (contingency analysis) and review the results. Determine if there are any pre-existing overloads and/or voltage issues and make adjustments as necessary.
- Control for any thermal or voltage exceedances before analyzing future outages in the study.
- Run TLC to verify the results. Adjust the case to bring transfers within limits.

B.4 Outage Analysis:

- Perform thermal and voltage (AC) analysis for all transmission and generation outages occurring during the study period.
- Perform Transient Stability Assessment (TSA) study for generation impacts and transmission outages with stability impact as indicated by the System Impact notes.
- Assess outage impact on nuclear bus voltage limits and stability according to the NPIR requirements.

B.5 Internal Outage Review Process:

- Consider the transmission outage submittal status according to PJM M-03: Transmission Operations (e.g., is it on-time, late, emergency, etc.).
- Consider generation outage categories (Planned, Maintenance, Unplanned) according to PJM M-10: Pre-Scheduling Operations, Section 2.1.
- Determine if any temporary switching is required to outage the facility, or return it to service, and if this switching may affect the transmission system.

- Determine if there are any operating procedures associated with the outage:
  - Review the Transmission Owner's description of work, System Impact note, or IEP rules.
  - Review PJM M-03B: Transmission Operating Procedures (CEII) to determine if any procedures are predefined that will require special contingencies to be active to address operational or stability concerns. Special contingencies may include the impact of pre-defined Remedial Action Schemes (RAS).
  - Review PJM M-03B: Transmission Operating Procedures (CEII) to determine if any predefined procedures require adjustment to thermal ratings or voltage limits to maintain system security.
- Implement/suppress contingencies in the study case as required to model any special operating procedures.
- Review Hotline, Protective Relay, and Protection System outage requests to identify any changes to normal fault clearing. Model any identified changes to normal fault clearing within the PJM EMS by modifying the applicable PJM Security Analysis contingencies to accurately study the system impact of Hotline, Protective Relay, and Protection System outages. (According to PJM M-03: Transmission Operations, Section 4: Transmission Owners must notify PJM of planned Hotline, Protective Relay, and Protection System outages by submitting these planned outage requests to eDART. All unplanned outages of this type are communicated to PJM Dispatch and subsequently submitted to eDART.)

Note:
For relay communication outages exceeding 5 days in duration, PJM will perform stability studies to assess impact to the BES. The communication outages may be on the redundant system in which case PJM will model the failure of the remaining communication for fast clearing and will assess stability based on the zone 2 clearing time. If there are any system performance issues as a result of the assessment, PJM will coordinate the next steps with the Transmission Owner.

- Determine if a morning load pick-up, off-peak, or multiple time/load studies need to be performed.
- Make necessary changes to the study case as a result of the outage review. For example, make contingency adjustments, implement special/operating/emergency procedures, make generator adjustments due to stability limits, etc.

B.6 Internal Outage Analysis Process:

- Implement the submitted (both planned and emergency) transmission and generation outages in the EMS study case.
- Process reactive tickets (D-curve changes and voltage regulator outages).
- Analyze generator reactive lead/lag tests.

- Run power flow and Security Analysis (contingency analysis) to determine any thermal, voltage, SOL, or IROL impacts arising from the outages and projected system conditions.
- Run the EMS Study Transfer Limit Calculator (TLC) to determine projected IROL facility operating limits.
- Perform an open-ended voltage study, based on projected system condition for the time of switching, for all long-line EHV outages. Note any changes to start times that may be required due to a high instantaneous voltage rise.
- Perform a transient stability (TSA) study for outages with stability impact and validate with PJM M-03B: Transmission Operating Procedures (CEII). If a generator is restricted for stability, document and communicate the restrictions according to the PJM M-03: Transmission Operations Section 3.9 stability procedure.
- Resolve thermal overloads, voltage, SOL, and/or IROL exceedances with non-cost operations first, such as system reconfiguration, then by adjusting generation, if required. Refer to PJM M-03: Transmission Operations and PJM M-03B: Transmission Operating Procedures (CEII) for additional details regarding thermal and voltage controlling actions.
- Initiate contact with the affected Member TOs and/or external Reliability Coordinators to coordinate possible mitigation options; inform them of outage conflicts, the potential for off-cost operations, and/or possible outage denial based on PJM Market rules and/or reliability concerns.

Note:
PJM considers outages based on priority order. Forced and emergency outages have the highest priority followed by “On-time” outages then “Late” outages. The outages are analyzed for reliability and expected off-costs. Each outage is studied and any constraints (actual or facility/contingency pair) trending toward a limit or exceeding a limit is noted in eDART. The trending or exceeding of a limit in the study is referred to as potential “congestion”. The limit may be any or a combination of thermal, voltage, or stability issues. If there is an expected constraint, PJM will mark the corresponding eDART ticket as “congestion expected”. The “congestion expected” flag is used to indicate a potential issue that may occur in the Day-Ahead Market or in Real-time Operations. If there are non-cost controlling actions, changes to the generation pattern, or changes to system conditions, the noted congestion may not occur in the Day-Ahead Market or in Real-time Operations.

For “On-time” outages, PJM ensures the constraint can be mitigated by applying both non-cost and off-cost operations. If there are no limit exceedances as a result, the outage will be approved.

For “Late” outages, PJM will apply only non-cost operations. If the non-cost operations (such as PAR adjustments, transformer tap adjustments, MVAR adjustments, switching of capacitors and reactors, switching of transmission facilities) can mitigate the constraint, then the outage will be approved. Note, the ticket is still marked as “congestion expected”. If the constraint cannot be mitigated, PJM will deny the outage for the scheduled time and work with the transmission owner to reschedule the outage.

If a constraint is impacted or can be helped with external generation sources, verify whether an IDC flowgate is in place and request the coordinated test for inclusion in M2M.

- Verify generator availability for expected off-cost operations. Check start-up times, no-load/ start-up costs, etc., to ensure the system reliability can be maintained.
- Verify corresponding generator outage tickets have been submitted in eDART for all transmission outages that bottle generator output.
- Cancel or reschedule generation outages or testing as needed to maintain system reliability. Communicate any cancellations:
    - With direct voice to voice communication to respective GO/MOC;
    - And logging such action within the eDART PJM comment section.

B.7 Analyze External Outages:

- Review and implement the external SDX transmission and generation changes in the EMS study case. Run powerflow and Security Analysis to determine any thermal or voltage impacts arising from the outages.

- Analyze thermal overloads and voltage issues for possible solutions. Communicate and resolve issues with other RCs (MISO, TVA, NYISO, etc.).
- Verify if additional peak, off-peak, morning load pick-up, or other studies need to be done. If so, obtain an appropriate case and re-analyze the outages.
- Run the Transfer Limit Calculator (TLC) and check for impacts to transfer limits.

B.8 Day-Ahead Market Coordination:

- Submit a copy of the PJM Transmission Log to the Day-Ahead Market operator by 11:00 hours. The following information must be submitted in the report:
  - Note any outage that is projected to cause congestion and is submitted on–time.
  - Note any outage submitted as an Emergency.
  - Note any outage requiring pre-contingency switching and include the pre-contingency switching solution.
- Bridge the Day-Ahead generation commitment into the EMS study case.
- Analyze the impacts of the Day-Ahead generation commitment.
  - Analyze the nuclear voltages (NPIR) and document the results in the Day-Ahead report. When the analysis identifies a nuclear voltage exceedance, PJM will inform the respective transmission owner, who in turn will inform the appropriate Nuclear Duty Officer (NDO). The notification may include a request for authorization to operate off-cost generation at the generation owner's expense to prevent an exceedance of the limit.
- Determine if any additional generation must be called on Day-Ahead to maintain transmission system reliability. Document required combustion turbines with notification + start-up times > 2 hours.

B.9 Non-Market BES Facilities:

Outage Approval Process

PJM will evaluate and approve transmission outages consistent with PJM M-03: Transmission Operations, PJM M-03B: Transmission Operating Procedures (CEII), PJM M-12: Balancing Operations, PJM M-37: Reliability Coordination, and PJM M-38: Operations Planning to ensure reliability is maintained on all BES facilities. Additional coordination may be required with the Transmission Owners for non-market BES facilities to ensure contingency results are consistent in Real-time Operations:

- For planned outages, the differences in contingency analysis results should be rationalized in advance and instruction provided to Real-time Operations as to which EMS analysis is more accurate (PJM or TO).
- An operating plan shall be agreed upon in advance, which may require the advanced scheduling of long-lead time generation at the expense of the Transmission Owner.

- The agreed upon controlling actions should be documented and communicated to PJM and TO or GO Dispatchers.
- Under certain conditions, a generator may violate GSU limits upon the loss of another facility. A generator will be permitted to operate above their emergency limits so long as a post-contingency reduction plan has been agreed upon. Pre-contingency reductions would be required in the absence of an agreed upon plan.

Resolving Modeling Differences

For planned outages, the differences in PJM and TO EMS Security Analysis results should be rationalized in advance and instruction provided to Real-time Operations.

Real-time Controlling Actions

Real-time controlling actions to Non-market BES facilities are prioritized as follows:

- Non-cost measures including:
  - PAR adjustments.
  - Transformer tap adjustments.
  - MVAR adjustments.
  - Switching capacitors and reactors in or out-of-service.
  - Switching transmission facilities in or out-of-service.
  - Curtailing transactions “Not-Willing-to-Pay” congestion.
- Issuing a Post-Contingency Local Load Relief Warning (PCLLRW).
- If the contingency overload is over its Emergency rating but below its Load Dump (LD) rating, PJM will manually direct the redispatch of effective generation at the request of the Transmission Owner. The effective generation will be cost-capped but not permitted to set LMP since the facility is not a “Market” facility. PJM will commit effective generation in order to minimize the total MW committed to control the constraint.
- If the contingency overload is over its Load Dump rating, PJM will manually direct the redispatch of effective generation to control the overload. The effective generation will be cost-capped but not permitted to set LMP since the facility is not a “Market” facility. PJM will commit effective generation in order to minimize the total MW committed to control the constraint.
- Controlling to GSU Limits: Under certain conditions, a generator may violate GSU limits upon the loss of another facility. A generator will be permitted to operate above their emergency limits so long as a post-contingency reduction plan has been agreed upon. Pre-contingency reductions are required in the absence of an agreed upon plan.

Maintaining System Reliability

PJM is required to ensure system reliability is maintained; ensuring there is an operating plan for all BES facilities. If PJM or a TO analysis indicates that a planned facility outage would result in non-converged contingencies, post-contingency voltages below LD limits, post-contingency voltage drop exceedances, actual voltages below normal limits, or actual flows in excess of normal ratings after all non-cost measures are exhausted, the TO will be required to schedule generation through PJM or the planned outage will be cancelled.

Note:
A PCLLRW is not an acceptable controlling measure under system conditions where there are pre-contingency exceedances of the operating criteria or when there is insufficient time to dump load post-contingency.

B.10 Information Dissemination:

For outage approval studies:

- Approve outage tickets in eDART by 14:00 EPT two-business days prior to the start of the outage.
  - If an outage is not approved, it shall be rescheduled or moved into a canceled or denied state.
- If PJM denies a transmission outage, PJM shall:
  - Notify via direct person-to-person communications a primary/secondary outage scheduler for the impacted TO(s);
    - If direct contact cannot be made with a TO outage scheduler, PJM shall notify the real-time desk for the respective TO of the outage denial.
  - Log the reason for denial, and the notified TO representative(s).

For Day-Ahead studies:

- Prepare and post the RC Day-Ahead report on a secure area of PJM website. The secure site requires individual CEII access with a PJM.com account. Site Declaration: For use by transmission and reliability personnel only. This site contains confidential transmission information and cannot be shared with market participants. Anyone with access to this site and the data contained herein is required to maintain the Federal Energy Regulatory Commission Standards of Conduct regarding data confidentiality.
  - The report consists of outages, contingencies, mitigation strategies, interchange schedules, study results, voltage regulation, MVAR testing schedule, and TLC Limits.
  - Report internal (PJM) outages, 100 kV and above, that may impact internal or external facilities, outages causing congestion on market BES facilities, and outages impacting non-market BES facilities.
- Commit additional needed generation for specific constraints.
- Review the Day-Ahead report with the PJM Dispatchers and Shift Supervisor.

Attachment C : Outage Coordination Guidelines

C.1 Purpose

Dwindling reserve margins and increased RTEP outages resulting from major system upgrades (e.g. reconductoring/transformer replacement/EHV station construction) are making it more challenging to ensure necessary maintenance is performed on both transmission and generation equipment, which is required to maintain system reliability. The following guidelines are intended to highlight best practices to promote efficient outage coordination and timely system upgrades.

C.2 Transmission:

C.2.1 Notification

- Transmission outages should be submitted with sufficient advance notification to allow PJM ample time to perform long-term outage analysis and coordinate with both Transmission and Generation Owners.
- Transmission Owners should, at a minimum, submit outages to meet the on-time and notification rules as outlined in M-03, Section 4.2. Every effort should be made to submit outages further in advance to allow for enhanced coordination.
- If a not-on-time outage is submitted, the Transmission Owner should consider the reliability impacts on future on-time tickets to avoid conflicts and delays, unless the outage is classified as Emergency. Not on-time outages greater than 30 days submitted in the near-term horizon should be coordinated with PJM's Transmission Operations Department.

C.2.2 Coordination

- Due to the increased volume of critical transmission outages that are required, generation outages should be coordinated and aligned with transmission outages so that generation is not bottled and congestion can be mitigated to maintain reliability.
- Transmission Owners and PJM should review and account for scheduled generation outages as part of this process.
- Maintenance on tie-lines should be coordinated between Transmission Owners so that total duration and number of outages can be reduced (both owners should look for opportunities to schedule work at the same time).

C.2.3 Flexibility

- Transmission outages are studied and coordinated with the latest available forecasts and outage information. As weather, emergency outages, and system conditions change, outages may need to be delayed in near-term to maintain reliability. Flexibility should be built into outage plans to help mitigate potential unreliable system conditions even when Emergency Procedures are not in effect.

C.2.4 Scheduling

- Any outages of lines, busses or transformers 500kV and above or "congestion expected", or limiting generation are considered higher impact outages:
  - For higher impact outages, crews should work extended hours while ensuring crew safety is maintained to minimize overall outage duration.
  - For higher impact outages, Transmission Owners should evaluate scheduling additional crews to minimize outage duration.

C.2.5 Recall

- For higher impact outages, outage work should be sequenced to maximize recall availability.
- Transmission Owners should periodically review all active and future outage tickets in DART to ensure accuracy of listed recall times. Ticket start and end dates and equipment should also be reviewed for accuracy.
- Transmission Owners should detail project recall times in the description of tickets with multiple recall times (e.g. a bus cannot be restored but the line can be recalled)

C.2.6 Equipment

- Sufficient part inventory should be maintained to ensure unanticipated injects can be quickly resolved by minimizing delays in outage return. Inventory best practices are outlined in the Spare Equipment Philosophy document.
- To the extent possible, the facility should not remain out-of-service while parts are on order awaiting delivery.
- Evaluate if any work can be performed safely and reliably as in-service work prior to removing equipment from service. For example, can work on structures be performed prior to starting the outage for the remaining work?

C.2.7 Hotline work

- To the extent possible, facilities should remain in-service while maintenance is performed.

C.2.8 Switching

- Facilities should be returned to service when crews are not actively working on the facility. If facilities are switched on a daily basis, switching times should be coordinated with PJM to ensure facility is in service at the peak.
- Tie-line switching should be coordinated directly between Transmission Owners in order to avoid any delays which contribute to total outage duration.
- Transmission Owners should verify that all takeout/restore switching is listed on each DART ticket to promote efficient outage coordination. Transmission outage ticket best practices are outlined in M-03, Attachment G.

C.3 Generation:

C.3.1 Notification

- Generation Owners should provide advance notification to allow PJM ample time to perform long-term outage analysis and coordinate work with both Transmission and Generation Owners. Every effort should be made to submit generation outages as far in advance as possible (ideally three years out) in order to enhance coordination.

C.3.2 Coordination

- Due to the increased volume of critical transmission outages that are required, generation outages should be coordinated with transmission maintenance so that generation is not bottled and congestion can be mitigated to maintain reliability.
- Expect additional processing time due to increased complexity in outage evaluation analysis.

C.3.3 Flexibility

- Generation outages are studied and coordinated with the latest available forecasts and outage information. As weather, emergency outages, and system conditions change, outages may need to be delayed in near-term to maintain reliability. Flexibility should be accounted for in outage plans to help mitigate potential unreliable system conditions even when Emergency Procedures are not in effect.

C.3.4 Scheduling

- Staff should evaluate working extended hours while ensuring safety is maintained in order to minimize overall outage duration.

- Generation Owners should evaluate scheduling additional crews to minimize outage duration.

C.3.5 Equipment

- Sufficient parts inventory should be maintained to minimize delays in outage return.
- To the extent possible, the facility should not remain out-of-service while parts are on order awaiting delivery.

Revision History

Revision 20 (01/22/2026):

- Cover to Cover Periodic Review
  - Section 2.2: Added PJM RTEP long term study (MTOPOC).
  - Attachment B: Added MISO solar generation to the study process.

Revision 19 (01/23/2025):

- Periodic Review
- Section 3.1: Updated OPA report and removed posting time requirement.
- Attachment A: Updated OATF scope.
- Attachment B: Removed OPA report posting time requirement.

Revision 18 (02/22/2024):

- Periodic Review
  - Attachment A: Removed ITCI
  - Attachment A: Updated discrete unit outages based on last three seasons

Revision 17 (10/25/2023):

- Section 2.2.1: Added new section for advance RTEP outage coordination

Revision 16 (01/25/2023):

- Section 3.1: Added bullet for Transmission Owners conducting Day Ahead analysis should compare results with PJM Day Ahead report.
- Attachment A: Updated OATF scope.
- Attachment B: Updated Reliability Analysis procedure.

Revision 15 (01/26/2022):

- Periodic cover to cover review.
- Section 1.2: Updated ERAG study and participation.
- Attachment A: Updated OATF scope.

Administrative Change (02/24/2021):

- Attachment B: Aligned bullet and section title

Revision 14 (01/27/2021):

- Periodic Review. Made minor grammatical changes and added references to M-03B: Transmission Operating Procedures.

Revision 13 (01/23/2020):

- Periodic Review updated to address:
  - Updated NERC Standard references throughout.
  - Section 1.2: Updated interregional studies relating to NYISO studies.
  - Attachment A: Added sensitivity analysis of 90/10 load forecast to the OATF scope.
  - Attachment B: Updated Reliability Analysis procedure.

Revision 12 (02/01/2019):

- Cover to Cover Periodic Review.
- Attachment A: Updated OATF Scope.

Revision 11 (02/01/2018):

- Cover to cover periodic review
- Attachment A: Updated OATF Scope
- Attachment B: Updated Reliability Analysis Procedure

Revision 10 (02/01/2017):

- Cover to Cover Periodic review: Corrected typos and grammar, updated references, updated cited NERC standards.
- Section 2.1 and 2.2: Updated sections to provide more clarity on generation and transmission outage coordination.
- Section 2.3: Added new section “Neighbor Outage Coordination and Resolution” to help clarify roles and responsibilities around neighboring outages, and internal outages with neighboring impact.
- Attachment A: Updated the OATF Scope.
- Attachment B: Updated Reliability Analysis Procedure.

Revision 09 (02/01/2016):

- Periodic review: Corrected typos and grammar, revised terms for consistency, updated web link, and updated PJM reliability study procedures.
- Section 1.2: Updated interregional study.

Revision 08 (06/01/2015):

- Revised Attachment A, Section A.1, A.2, and A.3 with the change of EKPC name, adding in City of Rochelle and other minor changes due to system upgrades.

- Revised Attachment A, Section A.4 to specify periodic review of IROL facilities.
- Revised Attachment B to update the study process, to assess NPIR impact, to request Market-to-Market coordination, and to perform stability study.

Revision 07 (12/20/2012):

- Revised Attachment A, section A.4: added sensitivity study to monitor external facilities and contingencies along the PJM border. Added N-2 sensitivity analysis to avoid cascading outages due to relay-induced tripping.
- Revised Attachment A, section A.3.3: added note to incorporate significant DR into generation dispatch when appropriate (during summer OATF study)
- Revised Attachment B, section B.9: added the PJM action to redispatch if the contingency overload of a non-market BES facility is over its Load Dump rating.

Revision 06 (10/12/2011):

- Revised Attachment A: OATF Scope revised to include Duke Energy Ohio / Kentucky.
- Revised Attachment A: removed 50/50 diversified sensitivity study from OATF Scope

Revision 05 (05/01/2011):

- Annual Review
- Revised Attachment A: OATF Scope revised to include Cleveland Public Power (CPP) and the Cleveland reactive interface.
- Revised Attachment B: Transmission Reliability Analysis Procedure Section B.2 to include specific steps to capture the impacts of MISO wind in the study case.

Revision 04 (01/01/2010):

- Attachment B: Added details to incorporate Wind Power Forecast.

Revision 03 (06/26/2009):

- Annual Review
- Reformatted to assist in compliance tracking.

Revision 02 (02/10/2009):

- Section 3 and Attachment B: Provided clarifying details.
- Updated Attachment B: Transmission Reliability Analysis Procedure

Revision 01 (06/01/2008):

- Updated document to include reference to Bulk Electric System (BES)
- Modified Section 1: Seasonal Operating Studies, Subsection Interregional Studies and Assessments.
- Updated Attachment A: OATF Scope.

- Updated Attachment B: Transmission Reliability Analysis Procedure

Revision 00 (05/15/2007):

- New manual