Exhibit No. IMM-0001
Docket No. ER21-2091-000

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Mechanicsville Solar, LLC	)	Docket No. ER21-2091-000
	)	

ON BEHALF OF THE
INDEPENDENT MARKET MONITOR FOR PJM

SUMMARY OF DIRECT AND ANSWERING TESTIMONY OF JOSEPH E. BOWRING ON BEHALF OF THE INDEPENDENT MARKET MONITOR FOR PJM

The purpose of my testimony in this case is to identify flaws in the reactive capability rate proposed by the applicant and to explain why the generating facility owned by Mechanicsville Solar, LLC ("Mechanicsville Facility"), that is the subject of this proceedings are not eligible to receive the requested compensation from PJM Interconnection, L.L.C. under Schedule 2 to the PJM Open-Access Transmission Tariff ("Schedule 2"). Schedule 2 is provided as Exhibit No. IMM-0002.

The out of market payment requested by Mechanicsville, $516,146 per year, or $20,646 per MW-Year, or $56.56 per MW-day, is excessive. The *AEP* Method does not apply to solar facilities and should not be used to define the reactive revenue requirement for any unit in PJM markets. The capital recovery factor used by Mechanicsville to translate the capital investment into an annual revenue requirement is incorrect and not adequately supported.

PJM pays for reactive supply capability from generation and other sources in order to provide reactive supply and voltage control in its capacity as transmission provider for the PJM transmission system. The lines where the generating facilities in this case are interconnected are not monitored or reportable facilities. As a result, PJM is not required to pay for reactive supply capability under Schedule 2 from generators interconnected at those locations. Therefore, the generating facilities in this case are not eligible to file rate schedules for compensation from PJM under Schedule 2.

.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Mechanicsville Solar, LLC	)))	Docket No. ER21-2091-000

DIRECT AND ANSWERING TESTIMONY OF JOSEPH E. BOWRING ON BEHALF OF THE INDEPENDENT MARKET MONITOR FOR PJM

Q 1. PLEASE STATE YOUR NAME AND POSITION.

A. My name is Joseph E. Bowring. I am the Market Monitor for PJM. I am the President of Monitoring Analytics, LLC. My business address is 2621 Van Buren Avenue, Suite 160, Eagleville, Pennsylvania. Monitoring Analytics serves as the Independent Market Monitor (IMM) for PJM, also known as the Market Monitoring Unit (MMU or Market Monitor). Since March 8, 1999, I have been responsible for all the market monitoring activities of PJM, first as the head of the internal PJM Market Monitoring Unit and, since August 1, 2008, as President of Monitoring Analytics. The market monitoring activities of PJM are defined in the PJM Market Monitoring Plan, Attachment M and Attachment M-Appendix to PJM Open Access Transmission Tariff (OATT).[1]

Q 2. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain the Market Monitor's position on the proposed annual revenue requirement ("ARR") filed in this proceeding by Mechanicsville Solar, LLC ("Mechanicsville") for its 25 MW solar generating facility located in Hanover, VA ("Mechanicsville Facility").

Mechanicsville proposes an annual revenue requirement of $516,146 per year, or $20,646 per MW-Year, or $56.56 per MW-day. The proposed ARR is excessive.

The proposed ARR is a disproportionately large share of the total capital costs of the resource. The proposed ARR is significantly higher than the average rate paid for

---

1 *See PJM Interconnection, L.L.C.*, 86 FERC ¶ 61,247; 18 CFR § 35.34(k)(6).

reactive power in PJM. The proposed ARR is greater than the clearing price in the last PJM capacity market auction for the Rest of RTO LDA. The proposed ARR exceeds the $2,199 per MW-year level of the ancillary services revenue offset included in the PJM market rules. The ARR should capped at $2,199 per MWh-Year. The proposed annual carrying charge is incorrect and not adequately supported. The Market Monitor has calculated an appropriate capital recovery factor ("CRF").

Q 3. HAVE YOU PROVIDED TESTIMONY ON COMPENSATION FOR REACTIVE POWER IN OTHER PROCEEDINGS BEFORE THE FERC?

A. Yes. I provided testimony in the *Panda Stonewall* reactive supply capability case (Docket No. ER21-1821-002) and the *Whitetail Solar 3, et al.* reactive supply capability case (Docket No. ER20-1851-004 et al.). I provided an affidavit in support of opposition to an offer of settlement in the Meyersdale Storage, LLC, reactive supply capability case (ER21-864-000).

Q 4. HAVE YOU PARTICIPATED IN OTHER FERC PROCEEDINGS RELATED TO REACTIVE POWER?

A. Yes, I was invited to participate in a Commission technical conference and provided comments to the Commission in a proceeding convened to "discuss compensation for Reactive Supply and Voltage Control (Reactive Supply) within the Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs)."[2] Specifically, the proceeding explored "types of costs incurred by generators for providing Reactive Supply capability and service; whether those costs are being recovered solely as compensation for Reactive Supply or whether recovery is also through compensation for other services; and different methods by which generators receive compensation for Reactive Supply (e.g., Commission-approved revenue requirements, market-wide rates, etc.)."[3]

On February 22 and March 23, 2022, the Market Monitor filed comments and reply comments responding to the Commission's Notice of Inquiry in Docket No. AD22-

---

2 *Reactive Supply Compensation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD16-17-000. I participated in a workshop convened June 20, 2016. The Market Monitor filed comments on July 29, 2016, and reply comments on September 20, 2016.

3 *Id*. at 1.

2. The Notice of Inquiry included questions (at P 28 (question no. 5.d)) specifically addressing the over recovery issue. The Notice of Inquiry also included questions (at PP 20–28 (question no. 5) addressing the appropriateness of continuing to use the *AEP* Method in reactive capability proceedings, particularly proceedings to establish ARRs for asynchronous generators.

The Market Monitor has intervened in and actively participated in FERC reactive power cases during the past five years.

The Market Monitor includes analysis and recommendations related to reactive power in the State of the Market Reports for PJM.[4]

I.

Q 5. WHY SHOULD THE PROPOSED ANNUAL REVENUE REQUIRMENT BE REJECTED?

A. The proposed payment to the 25 MW Mechanicsville facility (ARR) of $516,146 per year, or $20,646 per MW-Year, or $56.56 per MW-day is excessive.

The *AEP* Method that is typically used in reactive capability proceedings was developed for use with generating facilities that have very different engineering and operational characteristics.[5] Regardless of whether the *AEP* Method is itself appropriate for use in establishing reactive capability costs, there is no corresponding method for defining the reactive capability costs, if any, associated with solar facilities.

Even by the standards of the *AEP* Method, an ARR of $516,146 per year, or $20,646 per MW-Year, or $56.56 per MW-day, is excessive, has not been demonstrated to have a rational basis, has not been demonstrated to be just and reasonable, and should be rejected. The average revenue requirement for reactive

---

4 *See*, for example, *2020 State of the Market Report for PJM*, Section 10 (Ancillary Services Markets), which can be accessed at: <*http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020.shtml*>.

5 *See American Electric Power Service Corp.*, 80 FERC ¶ 63,006 (1997), *aff'd*, 88 FERC ¶ 61,141 (1999); *see also Reactive Power Capability Compensation*, Notice of Inquiry, 177 FERC ¶ 61,118 (2021) (“Notice of Inquiry”).

capability is about $2,000 per MW-year. The revenue requirement for reactive capability included in the PJM Capacity Market is $2,199 per MW-year.

There is no reasonable basis for such a wide disparity in cost for the same service. This result has not been explained or supported by Mechanicsville. This disparity is inconsistent with competitive markets.

II.

Q 6. HOW DO PJM MARKET RULES PROVIDE THE OPPORTUNITY TO RECOVER REACTIVE CAPABILITY COSTS?

A. The PJM market rules that account for recovery of reactive revenues are built into the auction parameters, specifically, the VRR Curve. The PJM market rules explicitly account for recovery of reactive revenues of $2,199 per MW-year through inclusion in the Net CONE parameter of the capacity market demand (VRR) curve.[6] The Net CONE parameter directly affects clearing prices by affecting both the maximum capacity price and the location of the downward sloping part of the VRR curve.

Q 7. HOW DOES THE $2,199 PER MW-YEAR NUMBER AFFECT THE DEMAND CURVE FOR CAPACITY?

A. Elimination of the ancillary services revenue offset of $2,199 per MW-Year would mean that the prices on the capacity market demand curve (VRR curve) for each MW level would be higher and the clearing prices for capacity that result from the interaction of the supply curve and the VRR curve, would be higher. The result would be the recovery of additional reactive capacity revenues in the price of capacity for all resources.

Q 8. WHY IS THE DEMAND CURVE RELEVANT?

A. If there were no nonmarket recovery of reactive revenue, there would be no reactive revenue offset to Net CONE and the demand curve would result in higher capacity market prices, all else held constant. If there were no nonmarket recovery of reactive revenue, the shape and location of the demand curve would give unit owners the opportunity to recover all reactive capability costs in the capacity market.

---

[6] *See* OATT Attachment DD § 5.10(a)(v)(A).

This is how the capacity market works for all the other costs of a generating plant other than short run marginal costs.

Payments based on cost of service approaches result in distortionary impacts on PJM markets. Elimination of the reactive revenue requirement and the recognition that capital costs are not distinguishable by function would increase prices in the capacity market. The VRR curve would shift to the right, the maximum VRR price would increase and offer caps in the capacity market would increase. The simplest way to address this distortion would be to recognize that all capacity costs are recoverable in the PJM markets.

The best approach would be to eliminate cost of service rates for reactive capability and allow for recovery of capacity costs through existing markets, including a removal of any offset for reactive revenue in offers and in the capacity market demand (VRR) curve. A second best approach would be to limit the revenue requirement that could be filed for under the OATT Schedule 2 to a level less than or equal to the reactive revenue credit included in the capacity market design, in the VRR curve net CONE value, currently $2,199 per MW-year.

III.

Q 9. SHOULD THE *AEP* METHOD BE USED TO CALCULATE THE RATE FOR THE MECHANICSVILLE FACILITY?

A. No. The current process does not actually compensate resources based on their costs of investment in reactive power capability. The *AEP* Method assigns costs between real and reactive power based on a unit’s power factor. This is effectively an allocation based on a subjective judgment rather than actual investment. There are few if any identifiable costs incurred by generators in order to provide reactive power. Separately compensating resources based on a judgment based allocation of total capital costs was never and is not now appropriate in the PJM markets. Generating units are fully integrated power plants that produce both the real and reactive power required for grid operation.

The *AEP* Method originated with a regulated utility assigning costs between two sources of regulated revenue requirement. The practice persists in PJM only because it provides a significant, guaranteed stream of riskless revenue. Generation owners have an incentive to maximize such guaranteed revenue streams.

There is no logical reason to have a separate fixed payment for any part of the capacity costs of generating units in PJM. If separate cost of service rates for reactive continue, they need to be correctly integrated in the PJM market design.

The best and straightforward solution is to remove cost of service rates for reactive supply capability and to remove the offset. Investment in generation can and should be compensated entirely through markets. Removing cost of service rules would avoid the significant waste of resources incurred to develop unneeded cost of service rates.

The result would be to pay generators market based rates for both real and reactive capacity.

The *AEP* Method never accurately reflected the investment costs of providing reactive power, nor was it intended to do so. The *AEP* Method is a cost of service allocation approach designed to assign the regulated revenue requirement for generating units to a regulated generation function and a regulated transmission function. The *AEP* Method was designed to split that cost recovery for generating units in a reasonable way, based on a judgment about what is reasonable. The *AEP* Method was never about actually identifying specific capital costs associated solely with the provision of reactive power. Cost of service approaches apply allocation factors to accounting line items based on assumptions. The assumptions are that X percent of a type of equipment at a generating plant is associated with reactive power while (1-X) percent is associated with real power. The false precision of the *AEP* Method is entirely based on arbitrary assumptions. Even proponents of the *AEP* Method do not assert that the goal is to recover only the costs associated with a specific portion of a power plant required for the production of reactive power, or, in most cases, that such identification is even possible. That is not what the *AEP* Method was intended to do or is intended to do. The *AEP* Method does not define costs that are uniquely associated with the production of reactive power.

The *AEP* Method is based on the incorrect premise that the capacity costs of an integrated power plant are separable. The capacity costs of an integrated power plant are not separable.

The fundamental flaw in the *AEP* Method approach is the assumption that the costs of providing reactive power are a function of the power factor. The power factor is the ratio of real power (expressed as megawatts or MW) to the total output (apparent power) of a generator (expressed as megavolt-amperes or MVA). The remaining output is reactive power (expressed as megavolt amperes reactive or MVAR). The allocator typically used by proponents of the *AEP* Method to assign costs to reactive power generation is $(1 – (PowerFactor)^2)$. The power factor has superficial attraction as an appropriate allocator. The power factor is the core determinant of the reactive allocation factor in the *AEP* Method. Small changes in the power factor have large impacts on the costs allocated to reactive power. For a power factor of .95, the allocator is 9.75 percent while for a power factor of .90, the allocator is 19.00 percent, and for a power factor of .70, the allocator is 51.00 percent. For a resource claiming a power factor of .70, does that mean that more than half of the generator's costs were incurred in order to provide reactive power? Does this mean that 51 percent of the costs of the generator, exciter, and electrical equipment should be recovered through a cost of service rate? The answer to both questions is no. But resources have filed for guaranteed reactive revenue requirements on that basis.

The power factor has taken on somewhat mythical significance in the discussion of reactive power. There are frequently long discussions of power factors in reactive cases. The ratio of real to reactive power can vary significantly. The typical actual operating power factor of generators in PJM is determined by their voltage schedule and is usually between .97 and .99. The resultant *AEP* Method power factor allocator consistent with this actual reactive output of PJM generators and the actual tariff defined reactive output to generators is 5.91 to 1.99 percent. The nameplate power factor of thermal generating units is typically .85. But the nameplate power factor stamped on the generator at the factory and not based on actual operation on an actual grid. The nameplate power factor is meaningless for the actual operation of the power plant. The nameplate power factor does not mean that 27.75 percent of the power plant capital costs are associated with reactive power, although many resources have made that request because that is the power factor allocator based on the nameplate rating.

The power factor is not an appropriate allocator and does not reflect the actual capital costs associated with producing reactive power. The power factor has taken on a disproportionate significance in reactive rate cases because it is the single most important allocator in the *AEP* Method. That significance illustrates the fundamental flaws in the *AEP* Method.

The power factor does not measure reactive capability. The power factor does not determine a plant's reactive capability. The power factor does not identify costs associated with reactive capability or provide a reasonable basis for allocating those costs to reactive or real power production.

IV.

Q 10. WHAT ARE THE ISSUES WITH THE COMPANY'S PROPOSED ANNUAL CARRYING CHARGE CALCULATION?

A. Mechanicsville calculates an annual carrying charge which is a form of capital recovery factor (CRF). This CRF was initially presented in the prepared direct testimony of W. Wade Horigan on June 7, 2021 (Exhibit No.MVS-3), and then modified by Witness Horigan on February 11, 2022 (Exhibit No. MVS-3). Witness Horigan derives a fixed charge carrying rate which is the sum of a CRF and a fixed operating expense rate. The latest CRF presented by Witness Horigan is the sum of a sinking fund depreciation factor and the before tax weighted average cost of capital. Witness Horigan's updated derivation removed the income tax factor that was included in Witness Horigan's original derivation. Neither derivation accurately reflects the tax liability and the return on and the return of the capital investment.

The CRF is a rate, multiplied by the relevant investment, which defines the annual payment needed to provide a return on and of capital for the investment over a defined time period. CRFs include as inputs the weighted average cost of capital and its components, including the rate of return on equity and the interest rate on debt and the capital structure, in addition to depreciation and taxes. The Market Monitor's CRF accurately reflects the tax liability associated with the annual payment. The depreciation used in the calculation of the CRF should reflect the depreciation used for tax purposes. The sinking fund depreciation factor does not reflect the actual depreciation used by Mechanicsville and therefore should not be used in the calculation of the revenue requirement for the Mechanicsville facility.

Witness Horigan did not account for the actual tax treatment of the facility and did not adequately explain his tax treatment, did not account for the actual expected life of the facility, did not adequately explain or support his depreciation method, and did not account for the actual cost of capital of the facility.

Q 11. HOW DO YOU PROPOSE TO CALCULATE THE CAPITAL RECOVERY FACTOR (CRF)?

A. The best approach for calculating capital recovery over a defined period is the Capital Recovery Factor (CRF) used by the Market Monitor. I have attached to my testimony as Exhibit No. IMM-0003, a Capital Recovery Factors (CRF) Technical Reference prepared by the Market Monitor. The technical reference explains in detail the components for accurately and consistently calculating a CRF.

The CRF should be required for use in all cost based ratemaking provisions used in PJM, which now include black start service rates and reactive capability rates.

The CRF as proposed by the Market Monitor provides the necessary and sufficient level of revenue to pay the annual tax liability and the return on and return of the capital investment. The CRF approach proposed by the Market Monitor is based on the weighted average cost of capital (WACC) capital budgeting method. Under the WACC approach, the after tax cash flow is discounted at the after tax WACC rate and the payback of the investment in each cost recovery year reflects the defined capital structure. This approach can be efficiently reduced to a single formula for the CRF. FERC accepted this approach for black start service and directed PJM to include the CRF formula in the PJM tariff.[7] Additional details on the derivation of the CRF formula and examples are available in the MMU's CRF Technical Reference.

The Market Monitor used the CRF approach to determine an annual revenue requirement based on the capital cost data and financing structure provided in the Horigan Testimony. The results are shown in Exhibit Nos. IMM-0004 and IMM-0005. For a 20 year cost recovery period, the Market Monitor's CRF is 0.094192 and the corresponding annual revenue payment is $320,329.[8] [9] The Market Monitor's CRF is lower than the CRF proposed by Horigan. The Market Monitor's annual revenue payment in Exhibit No. IMM-0004 reflects a reduction to the

---

7 *See PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,080 at PP 43–44 (2021).

8 The formula for the CRF is equation (1.4) in the CRF Technical Reference. The calculation assumes the half year convention for the timing of revenue and tax payments.

9 This value reflects the capital cost recovery and does not include fixed operating expenses to protect confidential information.

reactive capital cost to account for an investment tax credit (ITC). It is not clear from the Horigan Testimony if an ITC adjustment was applied. The Mechanicsville Solar plant would have been eligible for an ITC and it should be reflected in the reactive cost recovery. The annual payment for capital cost recovery proposed by Horigan apparently does not reflect an ITC. The Market Monitor's payment is lower than the payment proposed by Horigan. The Market Monitor's CRF calculations in Exhibits Nos. IMM-0004 and IMM-0005 reflect 100 percent bonus depreciation that allows generators placed in service after September 27, 2017, to fully depreciate the capital investment in the first year of operation. Exhibit No. IMM-0005 shows the Market Monitor's proposed capital cost recovery assuming a reduction for an ITC is not warranted.

Exhibit Nos. IMM-0004 and IMM-0005 also show the CRFs and corresponding capital recovery payments for recovery periods exceeding 20 years. For example, the Market Monitor's CRF for a 40 year cost recovery period is 0.075621. The corresponding annual payment is $257,172 under the assumption that the reduction of the reactive capital cost by an ITC is applicable.[10]

Witness Horigan has not explained why a 20 year life rather than a 30 or 40 year life is appropriate for the Mechanicsville facility. It is my experience that comparable solar units frequently assert that they have useful life well in excess of 20 years. Such longer life should be reflected in the CRF.

Witness Horigan has not explained the actual cost of capital for the Mechanicsville facility or explained why the actual cost of capital should not be used in the calculation of the CRF.

The tables in Exhibits Nos. IMM-0004 and IMM-0005 are included to illustrate the implications of the issues with the company's CRF calculations for the annual revenue requirement, based on the assumptions that the company's allocation of costs to reactive are correct. I do not support using the annual revenue requirements in Exhibits Nos. IMM-0004 and IMM-0005, but include the calculations solely for the purpose of showing the implications of the incorrect CRF calculations proposed by Mechanicsville.

10 This value reflects the capital cost recovery and does not include fixed operating expenses to protect confidential information.

V.

Q 12. WHERE IS THE MECHANICSVILLE GENERATING FACITLITY INTERCONNECTED?

A. The Mechanicsville generating facility is interconnected to a 34.5 kV distribution line terminating at the Old Church 34.5 kV substation, which is owned and operated by Virginia Electric and Power Company, ("VEPCO) a subsidiary of Dominion Energy.

The lines to which the Mechanicsville Facility is interconnected are referred to as the "Lines."

Q 13. WHAT IS REQUIRED FOR A GENERATING UNIT TO BE ELIGIBLE TO RECEIVE COMPENSATION FROM PJM UNDER SCHEDULE 2 TO THE PJM OPEN ACCESS TRANSMISSION TARIFF?

A. The eligibility of a generating unit to collect rates for reactive supply capability under Schedule 2 to the PJM OATT (Schedule 2) requires that the generating facility provide the reactive supply capability that is necessary for PJM to provide, in PJM's role as Transmission Provider, Reactive Supply and Voltage Control service on the PJM Transmission System.

This eligibility implies that the generating facility must be interconnected directly to the PJM system.

The Mechanicsville Facility is not eligible for reactive payments because it is not connected directly to the PJM system.

Q 14. WHAT IS REACTIVE SUPPLY CAPABILITY?

A. Reactive supply capability is the capability to produce MVAR that can be relied upon by the Transmission Provider to provide reactive supply and voltage control, an ancillary service under the PJM tariff. Reactive supply and voltage control are necessary to ensure the reliable operation of the grid.[11]

---

[11] 75 FERC ¶ 61,080 (1996).

PJM procures reactive supply capability from generators located on the high voltage transmission system that it plans and operates. Reactive power is local and cannot be transferred over long distances.

Q 15. WHAT DOES SCHEDULE 2 PROVIDE?

A. Schedule 2 provides, in part:

> In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.
>
> Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider. The Transmission Customer must purchase this service from the Transmission Provider.

Q 16. IS COMPENSATION FOR REACTIVE SUPPLY CAPABILITY UNDER OATT SCHEDULE 2 THE ONLY COMPENSATION THAT PJM PROVIDES RELATED FOR REACTIVE POWER?

A. No. Schedule 2 explicitly states the separate compensation that applies to Market Sellers following dispatch instructions:

> In addition to the charges and payments set forth in this Tariff, Schedule 2, Market Sellers providing reactive services at the direction of the Office of the Interconnection shall be credited for such services, and Market Participants shall be charged for

such services, as set forth in Tariff, Attachment K-Appendix, section 3.2.3B.

Schedule 2 explains that when PJM actually calls upon a resource to provide reactive output, that output is paid directly based on lost opportunity costs under Section 3.2.3B of the PJM energy market rules.[12] As Schedule 2 states, these charge and payments are separate from the charges and payments for reactive supply capability set forth in Schedule 2.[13]

Q 17. WHAT IS PJM'S ROLE IN IMPLEMENTING SCHEDULE 2?

A. PJM is the Transmission Provider responsible under Schedule 2 to procure reactive supply capability for its system to ensure that it will have the reactive power to operate its system at acceptable transmission voltages.

Schedule 2 authorizes PJM to charge its Transmission Customers for reactive supply capability and to pay generating facilities that provide the reactive supply capability that supports reactive supply and voltage control service. Most MVAR output from generating units located on the PJM system is the result of normal generating operations and is not in response to special PJM dispatch instructions.

The PJM system is interconnected to adjacent systems that PJM does not monitor, operate or have responsibility for, including transmission systems and distribution systems. The operators of those systems are responsible to ensure sufficient reactive supply capability for those systems.

Q 18. WHEN IS PJM THE TRANSMISSION PROVIDER?

A. Within the geographical PJM region, PJM takes responsibility to monitor and operate a defined set of high voltage transmission facilities.

As a Regional Transmission Organization (RTO), PJM is responsible for maintaining the bulk electric system (BES). NERC defines the BES as: all

---

12 *Id*.

13 OATT Attachment K–Appendix § 3.2.3B (Reactive Services) is included as Exhibit No. IMM-0006. The provisions of the Appendix K–Appendix incorporate into the OATT "for ease of reference" the provisions of Schedule 1 of the Operating Agreement (PJM Interchange Energy Market).

transmission and transmission related facilities operating at 100 kV or more.[14] But PJM's responsibility includes the responsibility to monitor and operate some transmission lines below the 100 kV threshold. PJM may exercise its judgment, subject to approval by FERC, to assume responsibility for lines with voltages as low as 69 kV or 34.5 kV.

PJM has primary responsibility for grid operation and for planning the PJM Transmission System. For example, PJM states whether a line is part of the PJM Transmission System. The key criteria for such determinations are whether the line is a Reportable Transmission Facility and a Monitored Transmission Facility.

PJM is the Transmission Provider for the PJM Transmission System.

In this case, none of the Lines are a Reportable Transmission Facility or a Monitored Transmission Facility.

Q 19. IF A GENERATING FACILITY IS INTERCONNECTED TO A SYSTEM THAT IS NOT MONITORED OR OPERATED BY PJM, WHO IS RESPONSIBLE FOR OPERATING THAT SYSTEM?

A. Generating units located at the distribution level are subject to the relevant rules of the owner/operator of those distribution lines, the transmission/distribution owner which may be the transmission owner or the traditional local utility, known as the electric distribution company, the EDC. Reactive power created by generators connected to facilities that are not PJM transmission facilities, including lower voltage transmission and distribution level facilities, provide a service to the transmission owner/EDC and not to PJM.

Q 20. HOW CAN THE LINES FOR WHICH PJM TAKES RESPONSIBILITY TO MONITOR AND OPERATE BE DETERMINED?

A. PJM Manual 3 (Transmission Operations) defines Reportable and Monitored transmission facilities.[15]

---

[14] NERC, Bulk Electric System Definition Reference, v. 3 (August 2018).

[15] *See* PJM Manual 3: Transmission Operations, Rev. 59 (May 27, 2021), Section 1.5.6 at 19–21, included as Exhibit No. IMM-0007.

The monitored facilities are included in the Transmission Facilities List. The Transmission Facilities List is located on the PJM website.

PJM's criteria for defining Reportable Transmission Facilities and Monitored Transmission Facilities are the appropriate criteria to determine what constitutes the PJM Transmission System and what facilities are not part of the PJM Transmission System.

The Facilities are not Reportable or Monitored Transmission Facilities.

PJM also publishes a map of all of its transmission facilities on its website.

PJM does not include any of the Lines on its map.

Q 21. HOW DO YOU RESPOND TO ARGUMENTS RAISED BY THE COMPANIES THAT THEY DO PROVIDE REACTIVE SUPPLY CAPABILITY?

A. All generators have the capability to create reactive power. The issue is whether that capability is for the PJM transmission system or the EDC system.

Q 22. DOES PJM'S AUTHORITY TO DISPATCH A GENERATING UNIT DEMONSTRATE REACTIVE SUPPLY CAPABILITY UNDER SCHEDULE 2?

A. No. Simply showing that a unit may respond to PJM dispatch instructions does not demonstrate PJM's reliance on the unit to provide reactive supply capability under Schedule 2 to the OATT.

PJM has dispatch authority over all generating facilities selling power in PJM. Such dispatch authority does not mean that PJM is relying on the Mechanicsville Facility to provide reactive supply capability in locations on the grid where PJM, in its role as the Transmission Provider, must provide reactive supply capability on the PJM Transmission System.

Q 23. DO THE TERMS OF INTERCONNECTION SERVICE AGREEMENT DEMONSTRATE REACTIVE SUPPLY CAPABILITY UNDER SCHEDULE 2?

A. No. The fact that PJM is party to a three party interconnection service agreement does not establish that a generation facility is interconnected directly to the PJM

Transmission System or provides reactive supply capability to the PJM Transmission System.

PJM may enter into three party interconnection service agreements (ISAs) that include the generating facility and the interconnecting transmission and distribution system owner. Such agreements provide generating facilities the ability to sell energy and/or capacity in PJM, regardless of whether the facilities are directly interconnected to the PJM Transmission System. There are provisions in such ISA agreements (which generally follow the form included at OATT Attachment O) that establish reactive supply capability obligations for the generating facility owner. When the directly interconnected system is the sole responsibility of the interconnecting transmission owner (including in its role as an electric distribution system owner), and is not monitored or operated by PJM, then any obligation to provide reactive supply capability is to the interconnecting transmission owner and is not to PJM.

I do not agree with Witness Price when he describes ISA obligations as to or from "PJM or VEPCO," "PJM and VEPCO" or "both."[16] VEPCO is the Interconnected Transmission Owner. The fact that PJM and VEPCO must coordinate their actions to maintain the grid does not mean that they share responsibilities for the local transmission/distribution system that is not part of the PJM Transmission System

Q 24. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[16] *See* MVS-0001 at 8:13, 10:14–15, 12:24–25, 13:1–4, 15:6, 16:13–15, 26:1–2, and 28:2, 24–25.

Exhibit IMM-0002
PJM OATT Schedule 2

PJM OATT Schedule 2 - Reactive Supply and Voltage Control from Generation or Other Sources Service

SCHEDULE 2
Reactive Supply and Voltage Control from Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider. The Transmission Customer must purchase this service from the Transmission Provider.

In addition to the charges and payments set forth in this Tariff, Schedule 2, Market Sellers providing reactive services at the direction of the Office of the Interconnection shall be credited for such services, and Market Participants shall be charged for such services, as set forth in Tariff, Attachment K-Appendix, section 3.2.3B.

The Transmission Provider shall administer the purchases and sales of Reactive Supply. PJMSettlement shall be the Counterparty to (a) the purchases of Reactive Supply from owners of Generation or Other Sources and Market Sellers and (b) the sales of Reactive Supply to Transmission Customers and Market Participants.

Charges

Purchasers of Reactive Supply and Voltage Control from Generation or Other Sources Service shall be charged for such service in accordance with the following formulae.

> Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Non-Zone Load = Allocation Factor * Total Generation Owner or other source owner Monthly Revenue Requirement
>
> Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Zone Load = Allocation Factor * Zonal Generation Owner or other source owner Monthly Revenue Requirement * Adjustment Factor
>
> Where:

Purchaser serving Non-Zone Load is a Network Customer serving Non-Zone Network Load or serving Network Load in a zone with no revenue requirement for Reactive Supply and Voltage Control from Generation or Other Sources Service, or a Transmission Customer where the Point of Delivery is at the boundary of the PJM Region.

Zonal Generation Owner or other source owner Monthly Revenue Requirement is the sum of the monthly revenue requirements for each generator or other source located in a Zone, as such revenue requirements have been accepted or approved, upon application, by the Commission.

Total Generation Owner or other source owner Monthly Revenue Requirement is the sum of the Zonal Generation or other source owner Monthly Revenue Requirements for all Zones in the PJM Region.

Allocation Factor is the monthly transmission use of each Network Customer or Transmission Customer per Zone or Non-Zone, as applicable, on a megawatt basis divided by the total transmission use in the Zone or in the PJM Region, as applicable, on a megawatt basis.

For Network Customers, monthly transmission use on a megawatt basis is the sum of a Network Customer's daily values of DCPZ or DCPNZ (as those terms are defined in Tariff, Part III, section 34.1) as applicable, for all days of the month.

For Transmission Customers, monthly transmission use on a megawatt basis is the sum of the Transmission Customer's hourly amounts of Reserved Capacity for each day of the month (not curtailed by PJM) divided by the number of hours in the day.

Adjustment Factor is determined as the sum of the total monthly transmission use in the PJM Region, exclusive of such use by Transmission Customers serving Non-Zone Load, divided by the total monthly transmission use in the PJM Region on a megawatt basis.

In the event that a single customer is serving load in more than one Zone, or serving Non-Zone Load as well as load in one or more Zones, or is both a Network Customer and a Transmission Customer, the Monthly Charge for such a customer shall be the sum of the Monthly Charges determined by applying the appropriate formulae set forth in this Schedule 2 for each category of service.

Payment to Generation or Other Source Owners

Each month, the Transmission Provider shall pay each Generation Owner or other source owner an amount equal to the Generation Owner's or other source owner's monthly revenue requirement as accepted or approved by the Commission. In the event a Generation Owner or other source owner sells a generator or other source which is included in its current effective monthly revenue requirement accepted or approved by the Commission, payments in that Generation Owner's or other source owner's Zone may be allocated as agreed to by the owners of the generator or other source in that Zone. Such Generation Owner or other source owners shall inform the Transmission Provider of any such agreement and submit either a filing to revise its cost-based rate or an informational filing in accordance with the requirements below in this Schedule 2. In the absence of agreement among such Generation Owners or other source owners, the Commission, upon application, shall establish the allocation. Generation Owners shall not be eligible for payment, pursuant to this Schedule 2, of monthly revenue requirement associated with those portions of generating units designated as Behind The Meter Generation. The Transmission Provider shall post on its website a list for each Zone of the annual revenue requirements for each Generation Owner receiving payment within such Zone and specify the total annual revenue requirement for all of the Transmission provider.

At least 90 days prior to the Deactivation Date or disposition date of a generator or other source receiving payment in accordance with a Commission accepted or approved revenue requirement for providing reactive supply and voltage control service under this Schedule 2, the Generation Owner or other source owner must either:

(1) submit to the Commission the appropriate filings to terminate or revise its cost-based revenue requirement for supplying reactive supply and voltage control service under this Schedule 2 to account for the deactivated or transferred generator or other source; or

(2) provide to the Transmission Provider and file with the Commission an informational filing that includes the following information:

(i) the acquisition date, Deactivation Date, and transfer date of the generator or other source;

(ii) an explanation of the basis for the decision by the Generation Owner or other source owner not to terminate or revise the cost-based rate approved or accepted by the Commission associated with the planned generator or other source deactivation or disposition;

(iii) a list of all of the generators or other sources covered by the Generation Owner's or other source owner's cost-based tariff from the date the revenue requirement was first established until the date of the informational filing;

(iv) the type (i.e., fuel type and prime mover) of each generator or other source;

(v) the actual (site-rated) megavolt-ampere reactive ("MVAR") capability, megavolt-ampere ("MVA") capability, and megawatt capability of each generator or other source, as supported by test data; and

(vi) the nameplate MVAR rating, nameplate MVA rating, nameplate megawatt rating, and nameplate power factor for each generator or other source.

The Generation Owner or other source owner must submit the informational filing in the docket in which its cost-based revenue requirement was approved or accepted by the Commission or as otherwise directed by the Commission.

The requirement to submit the filings at least 90 days prior to the Deactivation Date or disposition date of a generator or other source shall not apply to generators or other source deactivations or transfers occurring between June 18, 2015, and September 16, 2015. For generator or other source deactivations or transfers occurring between June 18, 2015, and September 16, 2015, the Generation Owner or other source owner shall submit the informational filing or filings to terminate or revise its cost-based revenue requirement by September 16, 2015.

Exhibit IMM-0003
Capital Recovery Factors
Technical Reference

Capital Recovery Factors (CRF) Technical Reference

Monitoring Analytics, LLC

April 25, 2022

Table of Contents

1 The Basics of CRF

A capital recovery factor (CRF) is used to convert the principal amount of a capital investment into an equivalent stream of uniform payments. A typical CRF formula found in engineering economics textbooks is given in equation (1.1).[1]

(1.1)

$$CRF = \frac{r(1+r)^N}{(1+r)^N - 1}$$

Variable r is an interest rate, N is the number of uniform annual payments and the payments are assumed to occur at the end of year. To derive equation (1.1) the CRF is first denoted by c, allowing the annual payment to be stated as $A = cK$ where K is the capital investment. Then c is the value that solves the following present value equation,

$$\begin{aligned} K &= \sum_{j=1}^{N} \frac{cK}{(1+r)^j} \\ &= cK \sum_{j=1}^{N} \left(\frac{1}{1+r}\right)^j \end{aligned}$$

The summation in the equation above is a finite geometric series. A general formula for the sum of a finite geometric series is given by

(1.2)

$$\sum_{j=H}^{W} v^j = \frac{v^H}{1-v}\left(1 - v^{W-H+1}\right).$$

H and W are positive integers and v is any number except one ($v \neq 1$). It is straightforward exercise to show that equation (1.2) is valid.[2]

Using equation (1.2) with $H = 1$, $W = N$ and $v = 1/(1+r)$ yields

$$\sum_{j=1}^{N} \left(\frac{1}{1+r}\right)^j = \frac{(1+r)^N - 1}{r(1+r)^N}.$$

Replacing the summation in the present value equation yields

$$K = cK\left(\frac{(1+r)^N - 1}{r(1+r)^N}\right)$$

---

1 For example, see pages 21-22 in "Economic Evaluation and Investment Decision Methods," Stermole, F.J. and Stermole, J.M. (1993).

2 If S is the sum on the left hand side of equation (1.2), then $S - vS = v^H - v^{W+1}$ and solving for S gives the right hand side of (1.2).

and solving for c produces equation (1.1).

1.1 CRF That Reflect Taxable Income

The revenue that results from a capital investment is taxable income. The revenue payment A, obtained by multiplying the capital investment amount K by the CRF in equation (1.1), would be too low in cases where the revenue is taxable. The goal, in the presence of taxes, is to have a CRF for which the product $CRF \cdot K$ yields an annual payment A that will provide the necessary and sufficient level of revenue to cover the investors' annual tax payments, and the return on and return of the capital investment. In other words, over the life of the project, the revenue in excess of the tax payments and investment return should equal the original capital investment. The annual revenue payment can be determined by solving an equation where the present value of the after tax cash flows resulting from the annual revenue payment is equal to the initial capital investment.

The composition of the after tax cash flow is dependent upon the capital budgeting model. The weighted average cost of capital (WACC) approach was used to develop the CRF for PJM Black Start Service which was accepted by FERC in August 2021.[3] [4] The WACC approach to capital budgeting discounts the after tax cash flow at the after tax weighted average cost of capital rate and payback of the investment in each recovery year reflects the assumed debt and equity financing structure.[5] The CRF must satisfy the following present value equation,

$$K = \sum_{j=1}^{N} \frac{CF_j}{(1+r)^j} \ .$$

K is the capital investment, CF_j is the after tax cash flow for year j, r is the WACC rate, and the revenue, tax and debt payments are assumed to occur at the end of the year. The model variables are defined in Table 1-1. In the WACC model, the after tax cash flow is revenue net of taxes, and the tax calculation includes an offset for depreciation. The after tax cash flow for year j is

$$\begin{aligned} CF_j &= cK - \left(cK - \delta_j K\right)s \\ &= cK(1-s) + \delta_j K s \end{aligned}$$

3 176 FERC ¶ 61,080 (August 10, 2021) at 43-44.

4 Additional details on the weighted average cost of capital approach to capital budgeting can be found in Section 17.3 in "Corporate Finance," Ross, Westerfield, Jaffe, 4th Edition, 1996.

5 The after tax weighted average cost of capital rate is equal to *Equity Funding Percent* x *Equity Rate* + *Debt Funding Percent* x *Debt Interest Rate* x (1- *Effective Tax Rate*).

where c is the CRF, K is the total capital investment including debt and equity, cK is the annual revenue payment, s is the effective tax rate and δ_j is the depreciation factor for year j. Upon replacing CF_j in the present value equation

$$K = cK(1-s)\sum_{j=1}^{N}\frac{1}{(1+r)^j} + Ks\sum_{j=1}^{N}\frac{\delta_j}{(1+r)^j}.$$

Equation (1.2) with $H = 1$, $W = N$ and $v = 1/(1+r)$ gives

$$\sum_{j=1}^{N}\frac{1}{(1+r)^j} = \frac{(1+r)^N - 1}{r(1+r)^N}$$

and substituting into the previous equation results in

$$K = cK(1-s)\left(\frac{(1+r)^N - 1}{r(1+r)^N}\right) + Ks\sum_{j=1}^{N}\frac{\delta_j}{(1+r)^j}.$$

Solving for c yields the CRF formula in equation (1.3).

(1.3)

$$CRF = \frac{r(1+r)^N}{(1-s)[(1+r)^N - 1]}\left\{1 - s\sum_{j=1}^{N}\frac{\delta_j}{(1+r)^j}\right\}$$

Table 1-1 Variable descriptions for the WACC capital budgeting model

Variable	Description
r	After tax weighted average cost of capital
s	Effective tax rate
N	Cost recovery period
δ_j	Depreciation factor for recovery year *j*

Substituting the parameter values shown in Table 1-2 into the CRF formula, assuming a five year capital recovery period and straight line depreciation yields a CRF of 0.274938. With a capital investment of $1 million, the annual payment is $274,938.

Table 1-3 provides a cash flow summary for a $1 million capital investment with a five year cost recovery period that uses straight line depreciation. The revenue for each year, equal to the product of the CRF and the capital investment amount, is $274,938. The tax payment for each year is equal to the effective tax rate times the revenue net of depreciation. The return on the capital investment in year 1 is equal to the product of the WACC rate and the initial capital investment of $1,000,000.

Table 1-2 Financial parameter and tax assumptions[6]

Parameter	Parameter Value
Equity Funding Percent	50.0000%
Debt Funding Percent	50.0000%
Equity Rate	12.0000%
Debt Interest Rate	7.0000%
Federal Tax Rate	21.0000%
State Tax Rate	9.0000%
Effective Tax Rate (s)	28.1100%
After tax Weighted Average Cost of Capital (r)	8.5162%

After accounting for the tax payment and return on investment in year 1, $168,711 is available as payback to the investors. The remaining capital investment is $831,289 at the end of year 1. The year 2 return on investment is the product of the WACC rate and the remaining capital investment at the end of year 1. Payback to investors is $183,079 in year 2. The cash flows for years 3 through 5 are analogous to the year 2 cash flow.

Table 1-3 Cash flow summary for 5 year, $1 million investment with straight line depreciation[7]

Recovery Year	1	2	3	4	5
Revenue	$274,938	$274,938	$274,938	$274,938	$274,938
Depreciation	$200,000	$200,000	$200,000	$200,000	$200,000
Tax Payment	$21,065	$21,065	$21,065	$21,065	$21,065
Return on capital investment	$85,162	$70,794	$55,202	$38,283	$19,923
Capital investment payback	$168,711	$183,079	$198,670	$215,590	$233,949
Remaining capital investment	$831,289	$648,209	$449,539	$233,949	$0

After the final revenue payment in year 5, the remaining capital investment is reduced to $0. Summing horizontally across the capital investment payback row in Table 1-3 produces $1,000,000. This example illustrates that the revenue payment determined by the CRF provides the necessary and sufficient annual revenue to pay the taxes associated with the revenue payment as well as the required return on and return of the capital investment. This important point is established as a general result in the following proposition.

Proposition 1.1. The CRF given by equation (1.3) is the unique value, assuming a WACC capital budgeting model with end of year payments, for which the resulting annual revenue payment is

[6] The effective tax rate (parameter s in the formula) is equal to *State Tax Rate + Federal Tax Rate x (1-State Tax Rate).*

[7] WACC model with end of year revenue and tax payments.

necessary and sufficient, over the term of the investment, to provide for the annual tax liability and the return on and return of the capital investment.

1.2 Half Year Convention

The revenue and tax payments would likely be made on a monthly or quarterly basis rather than occurring at the end of the year. A better model with respect to the timing of the revenue and tax payments is obtained by assuming the revenue and tax payments occur at the midpoint of each year. To derive a CRF corresponding to midyear revenue and tax payments, the present value equation from the previous section is modified to reflect the new timing assumption. Each after tax cash flow amount is assumed to occur a half year earlier than in the previous model. The revised present value equation is

$$K = \sum_{j=1}^{N} \frac{CF_j}{(1+r)^{j-0.5}} ,$$

or equivalently,

$$\mathrm{K} = \sqrt{1+r} \sum_{\mathrm{j}=1}^{\mathrm{N}} \frac{CF_j}{(1+r)^{\mathrm{j}}} .$$

Making the substitution,

$$CF_j = cK(1-s) + \delta_j Ks$$

and solving for c yields equation (1.4).

(1.4)

$$CRF = \frac{r(1+r)^N}{(1-s)[(1+r)^N - 1]} \left\{ \frac{1}{\sqrt{1+r}} - s \sum_{j=1}^{N} \frac{\delta_j}{(1+r)^j} \right\}$$

Using the parameter values in Table 1-2, with a five year capital cost recovery period and straight line depreciation, equation (1.4) yields a CRF of 0.260798. With an initial capital investment of $1 million, the annual payment is $260,798. Table 1-4 shows the corresponding cash flow summary.

Table 1-4 Cash flow summary for 5 year, $1 million investment with half year convention

Service Year	1	2	3	4	5
Revenue	$260,798	$260,798	$260,798	$260,798	$260,798
Depreciation	$200,000	$200,000	$200,000	$200,000	$200,000
Tax Payment	$17,090	$17,090	$17,090	$17,090	$17,090
Return on Capital Investment	$41,711	$67,959	$52,992	$36,751	$19,126
Payback of Capital Investment	$201,997	$175,749	$190,716	$206,957	$224,582
Remaining Capital Investment	$798,003	$622,255	$431,539	$224,582	$0

The calculation of the values in Table 1-4 is identical to the corresponding values in Table 1-3 except that the year 1 return on investment reflects a half year period. The return on investment in year 1 is equal to the product of the capital investment and the half year rate of return $\sqrt{1+r}-1$. The cash flow summary shows that the revenue payment determined by the CRF is necessary and sufficient to pay the taxes associated with the revenue payment as well as the required return on and return of the capital investment.

Changing the depreciation assumption to 3 year MACRS produces a CRF of 0.254231. The MACRS depreciation factors are shown in Table 1-8. The lower CRF relative to the straight line depreciation example reflects the lower tax payment under MACRS due to the accelerated depreciation schedule. In years 1 and 2, the tax payment in Table 1-5 is negative due to the accelerated depreciation assumption.[8] The cash flow summary in Table 1-5 shows that the revenue payment determined by the CRF, using 3 year MACRS depreciation, is at the necessary and sufficient level to provide for the taxes associated with the revenue payment as well as the required return on and return of the capital investment.

Table 1-5 Cash flow summary for 5 year, $1 million investment with 3 year MACRS

Service Year	1	2	3	4	5
Revenue	$254,231	$254,231	$254,231	$254,231	$254,231
Depreciation	$333,300	$444,500	$148,100	$74,100	$0
Tax Payment	($22,226)	($53,485)	$29,833	$50,635	$71,464
Return on Capital Investment	$41,711	$65,170	$44,515	$29,195	$14,343
Payback of Capital Investment	$234,747	$242,546	$179,883	$174,401	$168,424
Remaining Capital Investment	$765,253	$522,708	$342,825	$168,424	$0

The depreciation assumption has a significant impact on the CRF level. Generally, the faster the capital is depreciated for tax purposes, the lower the CRF. The Tax Cuts and Jobs Act (TCJA), signed into law on December 22, 2017 included bonus depreciation rates applicable to capital investments placed in service after September 27, 2017.[9] [10] Capital investments placed into service after September 27, 2017 and before January 1, 2023, are eligible for 100 percent bonus depreciation.[11]

8 It is assumed that the capital investor would use the negative tax liability from this project as an offset against the tax liability resulting from other revenue.

9 Tax Cuts and Jobs Act, Pub. L. No. 115-97, 131 Stat. 2096, Stat. 2105 (2017).

10 26 U.S. Code §11(b)

11 Bonus depreciation is 100 percent for capital investments placed in service after September 27, 2017 and before January 1, 2023. Bonus depreciation is 80 percent for capital investments placed in service after December 31, 2022 and before January 1, 2024, and the bonus depreciation level is reduced by 20

Assuming 100 percent bonus depreciation results in a CRF of 0.247523. The corresponding cash flow summary is given in Table 1-6. The CRF for straight line depreciation for a five year cost recovery period is 5.3 percent higher than the CRF corresponding to 100 percent bonus depreciation.

Table 1-6 Cash flow summary for 5 year, $1 million investment with bonus depreciation

Service Year	1	2	3	4	5
Revenue	$247,523	$247,523	$247,523	$247,523	$247,523
Depreciation	$1,000,000	$0	$0	$0	$0
Tax Payment	($211,521)	$69,579	$69,579	$69,579	$69,579
Return on Capital Investment	$41,711	$49,621	$38,692	$26,834	$13,965
Payback of Capital Investment	$417,334	$128,324	$139,252	$151,111	$163,980
Remaining Capital Investment	$582,666	$454,343	$315,091	$163,980	$0

The CRF for a capital investment with a 20 year recovery period is 0.103149 and the corresponding cash flow summary is given in Table 1-7 for a capital investment totaling $10,000,000.

percent for each subsequent year through 2026. Capital investments placed in service after December 31, 2026 are not eligible for bonus depreciation. See 26 U.S. Code §168(k)(6)(A).

Table 1-7 Cash flow summary for 20 year, $10 million investment with bonus depreciation

Service Year	Revenue	Depreciation	Tax Payment	Return on Capital Investment	Payback of Capital Investment	Remaining Capital Investment
1	$1,031,492	$10,000,000	($2,521,048)	$417,109	$3,135,431	$6,864,569
2	$1,031,492	$0	$289,952	$584,597	$156,943	$6,707,626
3	$1,031,492	$0	$289,952	$571,231	$170,308	$6,537,318
4	$1,031,492	$0	$289,952	$556,728	$184,812	$6,352,506
5	$1,031,492	$0	$289,952	$540,989	$200,551	$6,151,955
6	$1,031,492	$0	$289,952	$523,910	$217,630	$5,934,325
7	$1,031,492	$0	$289,952	$505,376	$236,164	$5,698,161
8	$1,031,492	$0	$289,952	$485,264	$256,276	$5,441,886
9	$1,031,492	$0	$289,952	$463,439	$278,101	$5,163,785
10	$1,031,492	$0	$289,952	$439,756	$301,784	$4,862,001
11	$1,031,492	$0	$289,952	$414,055	$327,484	$4,534,517
12	$1,031,492	$0	$289,952	$386,166	$355,373	$4,179,143
13	$1,031,492	$0	$289,952	$355,902	$385,638	$3,793,505
14	$1,031,492	$0	$289,952	$323,061	$418,479	$3,375,026
15	$1,031,492	$0	$289,952	$287,422	$454,117	$2,920,909
16	$1,031,492	$0	$289,952	$248,749	$492,791	$2,428,118
17	$1,031,492	$0	$289,952	$206,782	$534,758	$1,893,361
18	$1,031,492	$0	$289,952	$161,241	$580,298	$1,313,062
19	$1,031,492	$0	$289,952	$111,822	$629,717	$683,345
20	$1,031,492	$0	$289,952	$58,195	$683,345	$0

In each example, the annual revenue payment, equal to the product of the capital investment and the CRF obtained from equation (1.4) is the necessary and sufficient revenue amount to cover the tax liability and the return on and return of the investment capital. This observation is generalized in the following proposition.

Proposition 1.2. The CRF given by equation (1.4) is the unique value, assuming a WACC capital budgeting model with the half year convention, for which the resulting annual revenue payment is necessary and sufficient, over the term of the investment, to pay the annual tax liability and the return on and return of the capital investment.

Table 1-8 Modified Accelerated Cost Recovery System (MACRS) with half year convention[12]

Year	3 year Depreciation Factors	5 year Depreciation Factors	10 year Depreciation Factors	15 year Depreciation Factors	20 year Depreciation Factors
1	33.33%	20.00%	10.00%	5.00%	3.750%
2	44.45%	32.00%	18.00%	9.50%	7.219%
3	14.81%	19.20%	14.40%	8.55%	6.677%
4	7.41%	11.52%	11.52%	7.70%	6.177%
5		11.52%	9.22%	6.93%	5.713%
6		5.76%	7.37%	6.23%	5.285%
7			6.55%	5.90%	4.888%
8			6.55%	5.90%	4.522%
9			6.56%	5.91%	4.462%
10			6.55%	5.90%	4.461%
11			3.28%	5.91%	4.462%
12				5.90%	4.461%
13				5.91%	4.462%
14				5.90%	4.461%
15				5.91%	4.462%
16				2.95%	4.461%
17					4.462%
18					4.461%
19					4.462%
20					4.461%
21					2.231%

1.3 Proof of Proposition 1.2

Proposition 1.2. The CRF given by equation (1.4) is the unique value, assuming a WACC capital budgeting model with the half year convention, for which the resulting annual revenue payment is necessary and sufficient, over the term of the investment, to pay the annual tax liability and the return on and return of the capital investment.

Proof. K_0 is the initial capital invested and K_j, $j \geq 1$, represents the capital investment remaining at the midpoint of cost recovery year j. K_1 is the remaining capital investment at the midpoint of year 1 after using the year 1 revenue net of taxes and return on investment, as a payback to investors. The proposition states that the CRF in equation (1.4) is the unique value that will result in $K_N = 0$. Representing the CRF in equation (1.4) as c, the year 1 revenue net of taxes and return on investment is

12 See Appendix A, Table A-1, IRS Publication 946, United States Department of Treasury (2020).

$$cK_0(1-s)+\delta_1 K_0 s-K_0\left(\sqrt{1+r}-1\right).$$

The rate of return on the investment reflects a half year of return due to the half year convention. The equity investment that remains at the midpoint of year 1 is

$$K_1=K_0-\left(cK_0(1-s)+\delta_1 K_0 s-K_0\left(\sqrt{1+r}-1\right)\right)$$

$$=K_0\sqrt{1+r}-cK_0(1-s)-\delta_1 K_0 s.$$

The year 2 revenue net of taxes and return on investment is

$$cK_0(1-s)+\delta_2 K_0 s-rK_1$$

and the capital investment that remains at the midpoint of year 2 is

$$K_2\ =K_1(1+r)-cK_0(1-s)-\delta_2 K_0 s\,.$$

Substitution for K_1 yields

$$K_2\ =K_0(1+r)^{3/2}-cK_0(1-s)[(1+r)+1]-[\delta_1(1+r)+\delta_2]K_0 s\,.$$

Repeating this process through the end of the cost recovery period yields

(1.5)

$$K_N=K_0(1+r)^{N-1/2}-cK_0(1-s)\sum_{j=1}^{N}(1+r)^{j-1}-K_0 s\sum_{j=1}^{N}\delta_j(1+r)^{N-j}\,.$$

Equation (1.2) with $H=1$, $W=N$ and $v=1+r$ gives

$$\sum_{j=1}^{N}(1+r)^{j-1}=\frac{1}{1+r}\sum_{j=1}^{N}(1+r)^{j}=\frac{(1+r)^N-1}{r}.$$

Replacing the first summation in equation (1.5) yields

(1.6)

$$K_N=K_0(1+r)^{N-1/2}-cK_0(1-s)\left(\frac{(1+r)^N-1}{r}\right)-K_0 s\sum_{j=1}^{N}\delta_j(1+r)^{N-j}\,.$$

Replacing c in (1.6) with the CRF formula in (1.4) results in $K_N=0$. Equation (1.6) also establishes the uniqueness of the CRF. If there are two CRF values, for instance c_1 and c_2, satisfying the proposition, then each will produce $K_N=0$ and one can quickly deduce from the equation (1.6) that $c_1=c_2$.

Exhibit IMM-0004
CRF and Annual Payment–Capital Reduced for ITC

Recovery Period (years)	20	25	30	35	40
Reactive Capital Cost per Horigan Testimonty	$4,601,920	$4,601,920	$4,601,920	$4,601,920	$4,601,920
Investment Tax Credit[1]	$1,201,101	$1,201,101	$1,201,101	$1,201,101	$1,201,101
Capital Cost to be recovered through Reactive Compensation	$3,400,819	$3,400,819	$3,400,819	$3,400,819	$3,400,819
Capital Recovery Factor & Fixed Operating Expense Rate	0.094192	0.101904	0.080906	0.077718	0.075621
Annual Payment for Capital Cost Recovery	$320,329	$346,558	$275,148	$264,306	$257,172

[1] Assumes an investment tax credit of 30 percent was applied to 87.0 percent of the capital cost to be recovered through reactive compensation. The percent applicable value of 87.0 percent is the average capital cost ITC eligibility rate the MMU has encountered in its MOPR review related to the PJM capacity auctions.

Exhibit IMM-0005
CRF and Annual Payment–Capital not reduced for ITC

Recovery Period (years)	20	25	30	35	40
Reactive Capital Cost per Horigan Testimonty	$4,601,920	$4,601,920	$4,601,920	$4,601,920	$4,601,920
Investment Tax Credit[1]	$0	$0	$0	$0	$0
Capital Cost to be recovered through Reactive Compensation	$4,601,920	$4,601,920	$4,601,920	$4,601,920	$4,601,920
Capital Recovery Factor	0.094192	0.085913	0.080906	0.077718	0.075621
Annual Payment for Capital Cost Recovery	$433,463	$395,363	$372,324	$357,653	$348,000

[1] Assumes a reduction for ITC is not applicable.

Exhibit IMM-0006
OATT Attachment K–Appendix
Schedule 1 § 3.2.3B

PJM Attachment K - Section 3.2.3B Reactive Services satisfying the Additional Day-ahead Scheduling Reserve Requirement ("Additional Day-ahead Scheduling Reserves credits") shall equal the ratio of the Additional Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources and are allocated as Additional Day-ahead Scheduling Reserves charges per paragraph (ii) below.

(i) A Market Participant's Base Day-ahead Scheduling Reserves charge is equal to the ratio of the Market Participant's hourly obligation to the total hourly obligation of all Market Participants in the PJM Region, multiplied by the Base Day-ahead Scheduling Reserves credits. The hourly obligation for each Market Participant is a megawatt representation of the portion of the Base Day-ahead Scheduling Reserves credits that the Market Participant is responsible for paying to PJM. The hourly obligation is equal to the Market Participant's load ratio share of the total megawatt volume of Base Day-ahead Scheduling Reserves resources (described below), based on the Market Participant's total hourly load (net of operating Behind The Meter Generation, but not to be less than zero) to the total hourly load of all Market Participants in the PJM Region. The total megawatt volume of Base Day-ahead Scheduling Reserves resources equals the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement multiplied by the total volume of Day-ahead Scheduling Reserves megawatts paid pursuant to paragraph (c) of this section. A Market Participant's hourly Day-ahead Scheduling Reserves obligation can be further adjusted by any Day-ahead Scheduling Reserve bilateral transactions.

(ii) Additional Day-ahead Scheduling Reserves credits shall be charged hourly to Market Participants that are net purchasers in the Day-ahead Energy Market based on its positive demand difference ratio share. The positive demand difference for each Market Participant is the difference between its real-time load (net of operating Behind The Meter Generation, but not to be less than zero) and cleared Demand Bids in the Day-ahead Energy Market, net of cleared Increment Offers and cleared Decrement Bids in the Day-ahead Energy Market, when such value is positive. Net purchasers in the Day-ahead Energy Market are those Market Participants that have cleared Demand Bids plus cleared Decrement Bids in excess of its amount of cleared Increment Offers in the Day-ahead Energy Market. If there are no Market Participants with a positive demand difference, the Additional Day-ahead Scheduling Reserves credits are allocated according to paragraph (i) above.

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost for each Real-time Settlement Interval, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to the lesser of the Final Offer or Committed Offer;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable.

Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's applicable interval cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the applicable interval product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures

Exhibit IMM-0007
PJM Manual 3
(Transmission Operations)

PJM Manual 3: Revision 59

Exhibit IMM-0007
Docket No. ER21-2091-000

PJM Manual 03:

Transmission Operations

Revision: 59

Effective Date: May 27, 2021

Prepared by
Transmission Operations

Table of Contents

Table of Exhibits

Approval

Approval Date: 05/24/2021
Effective Date: 05/27/2021

Simon Tam, Manager

Transmission Operations

Current Revision

Revision 59 (05/27/2021):

- Periodic Review:
- Section 1.7: Removed applicability date and added email contact and timeline
- Section 3.4.2 and 3.5.4: NPIR changes for eDART nuclear voltage limits.
- Section 4.2.9: Added clarification language for rescheduling outages longer than 30 days into a different planning year.
- Added new Attachment G: Transmission Outage Ticket Best Practices

Introduction

Welcome to the ***PJM Manual for Transmission Operations***. 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 the PJM RTO and the PJM Energy Market. The manuals are grouped under the following categories:

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

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

About This Manual

The ***PJM Manual for Transmission Operations*** is one of a series of manuals within the Transmission set. This manual focuses on specific transmission conditions and procedures for the operation of the Bulk Electric System and Designated Transmission Facilities.

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

Intended Audience

The Intended audiences for the PJM Manual for Transmission Operations are:

- PJM dispatchers
- PJM Operations Planning staff
- Transmission Owners / Operators
- Generation Owners / Operators
- Local Control Center dispatchers
- PJM Members

References

There are several reference documents that provide both background and detail. The ***PJM Manual for Transmission Operations*** does not replace any of the information in these reference documents. These documents are the primary source for specific requirements and implementation details. The references to the ***PJM Manual for Transmission Operations*** are:

- Transmission Owners Agreement
- NYISO PJM Joint Operating Agreement
- EMS User's Manual
- PJM M-01: Control Center and Data Exchange Requirements
- PJM M-02: Transmission Service Request
- PJM M-3A: Energy Management System (EMS) Model Updates and Quality Assurance (QA)
- PJM M-12: Balancing Operations
- PJM M-13: Emergency Operations
- PJM M-37: Reliability Coordination
- PJM M-38: Operations Planning

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 the revision history.
- Sections containing the specific guidelines, requirements, or procedures including PJM actions and PJM Member actions.
- Attachments that include additional supporting documents, forms, or tables in this PJM Manual.
- A section at the end detailing all previous revisions of the PJM Manual.

Section 1: Transmission Operations Requirements

Welcome to the *Transmission Operations Requirements* section of the PJM Manual for **Transmission Operations**. In this section you will find the following information:

- An overview of the general services provided by PJM (see "Overview").
- A description of PJM's transmission operating guidelines (see "Transmission Operating Guidelines").
- A description of PJM's Real-Time Reliability Model (see "PJM's Real-Time Reliability Model").
- A description of PJM Transmission Facilities (see "PJM Transmission Facilities").
- A description of Transmission Owner facilities (see "Local Transmission Facilities").
- Guidelines on how to modify facilities in the Transmission Facilities List (see "Facilities under PJM Congestion Management Control").
- An overview of how Remedial Action Schemes (RAS) are reviewed, approved, communicated, and documented.

1.1 Overview

PJM is the Reliability Coordinator for the PJM RTO and is responsible for all regional Reliability coordination as defined in the NERC and Regional Standards and applicable PJM Operating Manuals.

PJM operates the transmission grid in compliance with good utility practice, NERC standards, and PJM policies, guidelines and operating procedures, including, but not limited to:

- This PJM Transmission Operations Manual,
- NERC and RRO Standards as references during normal and emergency operations of the PJM transmission grid,
- Individual Transmission Owners Operating Procedures submitted to PJM to identify specific operating problems that could affect operation of the interconnected PJM transmission grid.

The Bulk Electric System (BES) is defined as facilities 100 kV and higher. Transmission Owners (TOs) shall operate the Bulk Electric System Facilities and all System Operating Limits (SOL) (see M-37) in accordance with the PJM Operating Manuals and follow PJM instructions related to PJM responsibilities, including, but not limited to:

- Rules regarding TOs performing the physical operation and maintenance of all facilities with SOL,
- Directing changes in the operation of transmission voltage control equipment,
- Taking those additional actions required to prevent an imminent Emergency Condition or to restore the PJM transmission grid to a secure state in the event of a PJM system emergency.

Note:
PJM reviews this manual annually, with periodic updates as required. PJM coordinates identified issues with PJM TOs, PJM GOs and neighboring RCs. As PJM and neighboring Reliability Coordinators deem necessary, PJM will facilitate conference calls that include neighboring Reliability Coordinators, neighboring Transmission Operators, neighboring Balancing Authorities, PJM TOs and PJM GOs. PJM will notify PJM TOs and PJM GOs as necessary regarding issues communicated by neighboring Reliability Coordinators. PJM distributes revisions to this manual to neighboring Reliability Coordinators, neighboring Transmission Operators, neighboring Balancing Authorities, PJM Transmission Owners and PJM Generation Operators.

Note:
AEP is the registered TOP for the AEP 138 kV and below facilities. ITCI is the registered TOP for its facilities. PJM is the registered TOP for all other BES facilities on the AEP transmission system. Under normal operating conditions, AEP will coordinate with PJM to re-dispatch generation to control flows on their 138 kV and below monitored facilities. In an Emergency, a non-PJM registered TOP within the PJM footprint shall notify PJM of any unilateral actions it has taken with respect to generation re-dispatch as soon as practicable, but no later than 30 minutes, so that PJM is informed of the actions and can coordinate with impacted parties.

1.2 Responsibilities for Transmission Owner's Operating Entity

The responsibilities for a Transmission Owner's operating entity within PJM that are defined below are required to maintain the safe and reliable operation of the transmission system within PJM. Transmission Owners operate and maintain the transmission system and are responsible for local reliability. The transmission Owner under PJM’s direction takes all actions required to mitigate transmission system reliability emergencies. The responsibilities identified below are consistent with the NERC Functional Model for interconnected system operation.

This list is a collection of significant operational responsibilities and obligations of a Transmission Owner that are included in the PJM TOA and the PJM manuals. It is not intended to be an all-inclusive list of every responsibility and obligation of a Transmission Owner.

- Subject to code of conduct.
- Establish ratings of its transmission facilities and provides these ratings to PJM (Section 4.11 of TOA).
- Operates transmission facilities in accordance with good utility practice and PJM procedures (Section 4.5 of TOA).
- Maintains transmission facilities in accordance with good utility practice and PJM policies and procedures.
- Maintains appropriate voltage profiles.
- Provides local network integrity by defining operating limits, developing contingency plans and monitoring operations if applicable.

- Provides telemetry of transmission system to PJM and other Transmission Owners (Section 4.9 of TOA).
- Operates BES transmission system facilities under the direction of PJM (Section 4.5 of TOA).
- Requests PJM to assist in mitigating operating limit violations.
- Implement procedures called for by PJM (Section 4.5 of TOA).
- Provide real-time operations information to PJM and other Transmission Owners as required.
- Provide maintenance and construction plans to PJM and other Transmission Owners as required.
- Takes action to maintain local reliability and public safety (Section 4.7 of TOA).
- All actions impacting BES facilities shall be approved by PJM unless immediate actions are required to avoid loss of life, ensure safety or protect equipment. Such actions shall be communicated to PJM as soon as practical.
- Supplies engineering data for transmission system models to PJM and other Transmission Owners as required.
- Develops, documents, and communicates operator guidance, as necessary.
- Submit outage requests to PJM according to PJM requirements (Section 4.8 of TOA).
- Plan and coordinate transmission system outages with other transmission system operators as required (Section 4.8. of TOA).
- Work with other transmission system operators and PJM to mitigate identified reliability concerns for planned system outages.
- The Transmission Owner shall notify PJM (verbally and via eDART) of any known single contingency conditions that results in the loss of multiple generation units or any condition that prevent a generation unit to start-up after a trip. PJM will review the condition and will update the EMS active contingency set accordingly. The resultant contingency could be the largest MW lost in PJM and may result in additional synchronized reserve requirement (BAL-002-2).
- The Transmission Owner shall maintain a continuously staffed transmission control center. The control center should meet all of the communication and information system requirements defined in the PJM manuals (Section 2 of PJM Manual 01: Control Center and Data Exchange Requirements).

Note:
Under circumstances where the Transmission Owner or Generator Operator cannot follow the directive of PJM (such action would result in safety violation, damage equipment, or violate regulatory or statutory requirements), they shall immediately inform PJM of the inability to perform the directive so that PJM can implement alternate remedial actions.

Note:
A PJM Transmission Owner shall disconnect an affected facility if an overload on a transmission facility or an abnormal voltage or reactive condition persists and equipment is endangered. The PJM Transmission Owner shall notify PJM prior to switching so PJM can perform a study, if time permits, otherwise, immediately thereafter.

Personnel Requirements – Transmission system operators shall:

- Obtain required PJM Certification and Continuing Training Requirements (Section 1 and Section 2 of PJM Manual 40: Certification and Training Requirements).
- Be competent and experienced in the routine and abnormal operation of interconnected transmission systems.
- Be accountable to take any action required to maintain the safe and reliable operation of the transmission system.
- Have thorough knowledge of PJM procedures and their application.
- Have a working knowledge of NERC and applicable RRO Standards and how they coordinate with PJM manuals.
- Have a working knowledge of adjacent transmission system operator’s switching and blocking procedures.
- Have an understanding of routine protection schemes for the PJM transmission system.
- Have knowledge of how to evaluate desired system response to actual system response.
- Have knowledge of and be able to evaluate and take action on transmission system equipment problems.
- Have knowledge of the general philosophy of system restoration and the philosophy and procedures of their company as well as that of PJM.
- Have initial and continuing training that addresses the required knowledge and competencies and their application in system operations.
- Develop, document and maintain switching and blocking procedures consistent with OSHA 29 CFR Part 1910.269.
- Transmission system operators shall be accountable for directing field forces in transmission system switching activities.
- Follow-up on significant system events with an investigative process to analyze, document and report on operating abnormalities.

1.3 Transmission Operating Guidelines

PJM directs the operation to all SOL according to approved NERC Standards. In doing this, PJM considers transmission constraints, restrictions, and/or limitations in the overall operation of the PJM RTO. Describing this operation is the focus of this manual. The PJM RTO shall be operated such that the following are not exceeded:

- Transmission facility thermal limits
- Voltage limits
- Transfer limits
- Stability limits
- IROL

Although, the PJM RTO shall be operated such that limitations are not violated, it is recognized that occasionally, for various reasons, thermal limitations can be exceeded for short periods under controlled conditions without adversely impacting system reliability or damaging equipment. All exceptions must be documented in Manual-03B. For example, the Constraint Management Mitigation procedure can be used during short time switching periods when adhering to all of the requirements and parameters.

Should the PJM RTO at any time enter into an unknown operating state due to a catastrophic failure of the ICCP links or loss of EMS analysis tools, it will be considered an Emergency and operations shall be restored to respect proven reliable power system limits within 30 minutes in accordance with NERC standards. PJM relies on Transmission Owners to serve as a back-up to PJM, monitoring BES facilities, when the PJM EMS is inoperable (TOP-007-0). PJM Transmission Owners shall notify PJM dispatch within 15 minutes when their TO analysis packages are unavailable (TOP-004-2 R4). In general, PJM may be in an unknown state when both PJM and TO analysis packages are unavailable.

PJM operates the PJM RTO so that immediately following any single malfunction or failure, the facility loadings are within appropriate thermal limits, while maintaining an acceptable voltage profile. For details about PJM's thermal operation, please see Section 2: Thermal Operating Guidelines. For more information about PJM's voltage requirements, refer to Section 3: Voltage and Stability Operating Guideline. These potential malfunctions or failures, such as the sudden and unplanned loss of a generating unit, transmission line, or transformer, are called contingencies. PJM defines a contingency as a possible event resulting in the failure or malfunction of one or more facilities.

PJM Dispatch utilizes EMS Network Applications and market tools in order to maintain system reliability. Network applications evaluate pre/post-contingency thermal and voltage limits. In addition, the Transfer Limit Calculator (TLC) simulates transfers in order to assess voltage collapse conditions for reactive interfaces. PJM Operators generate reports which provide generator shift factors, phase angle regulator sensitivity factors, and load distribution factors. The information contained within these reports, the PJM State Estimator solution and unit bid information serves as the input data for PJM Market Tools. Through the use of PJM Market Tools, PJM Operators have the ability to use cost-effective generation adjustments to control thermal/voltage constraints on a pre-contingency basis.

Note:
PJM Transmission Owners that own BES facilities and serve load greater than 300 MW must have a real-time analysis package or have their BES facilities be observable within another TO analysis package.

Prior to initiating redispatch to control flows within limit criteria, PJM Dispatch compares PJM EMS Security Analysis results with Transmission Owners EMS Security Analysis Results. Pre-contingency, Post-Contingency flows and ratings are compared. If a difference exists between PJM and Transmission Owner Security Analysis results, PJM will operate to the most conservative results until the difference can be rationalized. If the difference is significant, the following guides will be followed to quickly resolve the difference:

- PJM and Transmission Owner identify modeling issue and operate to most conservative solution.
- PJM investigates modeling issue and attempts to resolve within 1 hour. This may involve verification of distribution factors using Seasonal PSS/E load flow case or the contingency definition via implementing contingency in a power flow solution and ensuring switching devices are in their proper position.
- If discrepancy is > 5% and expected to last 2 hours, PJM Dispatch will contact PJM support staff and request Transmission Owner to contact support staff.
- PJM and Transmission Owner on-call support staff will work toward resolving modeling difference.
- PJM and Transmission Owner agree to defer to most accurate analysis in lieu of operating to most conservative results, when difference is understood or resolved.
- PJM and Transmission Owner support staff attempt to correct modeling differences within 24 hours.

Contingency Analysis

- Single Contingency — One event that takes one or more facilities out of service. A Single Facility is any one component/facility with impact to the BES, excluding bus sections that can be removed from service by its own primary relay and breaker protective equipment. Single contingencies may disconnect multiple generating facilities (plant with single connection leads to the bulk power system) or multiple transmission facilities (radial lines with tapping substations) from service.
- PJM Security Analysis applications simulate the single facility failure or malfunction of critical equipment (facilities simulated in contingency analysis are not restricted to the PJM monitored facility list) including lines, transformers, Phase Angle Regulators (PARs), generators, capacitors, and reactors whose loss or failure could result in limit violations on PJM Monitored Facilities.

Note:
PJM does not normally model or operate to single breaker failures due to the low probability of occurrences; however, PJM Manual-03B contains an operating procedure to mitigate single breaker failures.

Note:
Under some unusual conditions, including severe weather or other special circumstances such a change to the Homeland Security Level, PJM should consider implementing conservative operation including control for the simultaneous occurrence of more than one contingency, substation circuit breaker outages, circuit breaker failure, and substation bus outages as appropriate (PJM M-13: Emergency Operations, Sections 3 and 4).

PJM uses appropriate pre and post contingency procedures which are documented in this manual to:

- Maintain acceptable voltage levels
- Maintain operation within stability limits
- Maintain operation within transfer limits
- Minimize the risk of cascading interruptions to the transmission system
- Prevent physical damage to system transmission facilities
- Eliminate thermal overloads

The consequences of violating these limits may lead to PJM RTO instability, voltage collapse, equipment damage, or loss of customer load. The objective of PJM is to operate the transmission facilities such that system reliability is maintained. Once a contingency occurs the system is readjusted as required and analysis for the next worst contingency is performed. The PJM dispatcher directs actions to restore the system to an acceptable state. For more information see Section 2: Thermal Operating Guidelines and Section 3: Voltage and Stability Operating Guidelines.

- Double Contingency — Two different events that occur simultaneously and result in the loss of two or more facilities.

Note:
A single contingency can consist of one or more transmission facilities. A double circuit tower line (DCTL) contingency is the simultaneous loss of two single contingencies.

Note:
If a Transmission Owner wishes to operate to control for DCTL contingencies, it may do so using its own internal equipment after communicating with the PJM dispatcher.

Note:
PJM system operations will implement actions to control for system congestion caused by DCTL contingencies resulting from the declaration of Conservative Operations. PJM will issue a PCLLRW when calculated post-contingency flows exceed Long Term Emergency (LTE) ratings. PJM will initiate redispatch of generation when calculated post-contingency flows exceed the Load Dump (LD) rating permitting off-cost generation to set LMP.

1.4 Reclosing Lines That Have Tripped

The PJM RTO uses varied philosophies when reclosing EHV (Extra High Voltage, defined as 345 kV and above) lines that have tripped and the automatic reclose has not been successful. These philosophies differ based on the EHV line automatic reclosing design and operating practice.

Note:
Transmission Owners shall promptly notify PJM of any BES facility that have tripped and coordinate restoration efforts.

1.4.1 PJM Mid-Atlantic Region

If an EHV aerial transmission line trips and does not automatically reclose, it should be manually reclosed within five minutes after tripping. If an EHV line trips and returns to service by automatically reclosing (or by manually reclosing if auto reclosing fails to occur and the line is tried-back once manually), the PJM dispatcher is authorized to operate at the current transfer levels or at reduced transfer levels. If an EHV line trips and does not return to service when reclosed automatically (or if manual reclosing also fails after the line is tried-back once manually), PJM performs the following activities:

- Immediately reduces the reactive operating limits to the level with the line out-of-service.
- Order the line to be tried-back within five minutes after conferring with the Transmission Owner(s) of the line.

If the line returns to service after the five minute try-back, the reactive operating limits may remain reduced until a patrol of the line has been completed or until the PJM dispatcher judges that the limit reduction is no longer necessary. If the aerial patrol does not locate the cause of the tripping, the reactive operating limits should be returned to normal. The Transmission Owners, however, must complete a foot patrol of the circuit no later than the next daylight period (weather permitting).

If an EHV line that was successfully reclosed 5 minutes after the trip-out trips a second time, the transfer limit should be re-evaluated and reduced if necessary until patrol is completed (or the source of the trouble is definitely determined by another means - aerial patrol, report of trouble, etc.). Manual try-backs on lines which trip a second time after having been successfully reclosed five minutes after tripping are not attempted until some period of time has elapsed (30 minutes or longer). PJM directs reclosing with the concurrence of the Transmission Owners.

1.4.2 PJM Western Region

The majority of the First Energy South 345 kV and 500 kV circuits utilize a high speed reclose of approximately 28 cycles without sync check and 34 cycles with sync check. The time delayed reclose varies greatly from station to station and is given in section IV.C.5 of the First Energy South System Operations Manual. Phase angle closing requirements also vary and are also given in the same section of the Manual.

If an EHV circuit locks out after a high speed reclose and one time delay reclose; FE South will patrol the circuit prior to trying it again. If a circuit utilizes supervisory control for one of its reclose attempts, FE South will evaluate the weather conditions prior to trying a supervisory reclose.

The Duke Energy Ohio-Kentucky 345 kV and 138 kV transmission circuits utilize automatic reclosing. If a circuit locks out after an automatic reclose, DEOK will patrol the circuit before attempting a reclose. For any supervisory reclose attempts, DEOK will work with PJM to evaluate weather, system, and equipment conditions prior to attempting the reclose.

1.4.3 PJM Southern Region

The Dominion Virginia Power 500 kV transmission lines within the PJM Southern region will automatically reclose multiple times. If the line goes to lockout, it is not to be reclosed manually until the line has been patrolled by Dominion Virginia Power operations personnel.

1.5 PJM's Real-Time Reliability Model

PJM's Real-Time Reliability Model is a computer representation of the power system facilities in the PJM RTO and other Balancing Authorities that may impact the reliable operation of the PJM system. The model resides and is maintained by the PJM staff on the PJM Energy Management System (EMS). The PJM EMS Network Application programs utilize the model to continuously calculate the real-time state and determine the security of the PJM system. The Security Constrained Economic Dispatch (SCED) dispatches every generator in the model. The model is also used to calculate real-time Locational Marginal Prices. The model is created and maintained from input data received by PJM from various sources including Transmission Owners, Generation Owners, Load Serving Entities, and other Balancing Authorities. The model is only as accurate as the input data used to derive it; therefore, timely and accurate data updates are critical.

1.5.1 Model Information and Data Requirements

- The Transmission Owner is responsible to provide the information and data needed by PJM about the Transmission Owner System.
- Telemetry data requirements are defined in the PJM M-01: Control Center and Data Exchange Requirement.
- System analytical model information and update requirements are defined in the PJM M-3A: Energy Management System (EMS) Model Updates and Quality Assurance (QA).

1.5.2 PJM Transmission System Model Update

PJM performs periodic updates to the PJM Real-Time Reliability Model. The Data Management Subcommittee representative must submit timely transmission model changes to be included in these updates consistent with the requirements contained within the PJM M-3A: Energy Management System (EMS) Model Updates and Quality Assurance (QA).

1.5.3 PJM Transmission Facilities

PJM Transmission Facilities are those facilities used in the transmission of electrical energy that:

- Are included in the PJM tariff.
- Have demonstrated to the satisfaction of PJM to be integrated with the PJM RTO Transmission System, and integrated into the planning and operation of the PJM RTO to serve all of the power and transmission customers within the PJM RTO.

- Transmission facilities that meet all other requirements including having sufficient telemetry to be deemed 'observable' by the PJM State Estimator, PJM Network Applications, or the PJM Real-Time Reliability Model can be considered for inclusion as monitored for real-time and contingency analysis for the purpose of identifying transmission constraints.
- The Transmission Owner of a facility that meets all requirements, including observability for the Real-Time Model, (see "Monitored Transmission Facilities") must specifically request that a facility be "Monitored" by PJM using the process and timeline identified at the end of this section (see "Process to Change the PJM Congestion Management Facilities List).
- Each Transmission Owner must specifically identify any tariff facility that is not under the operational control of PJM.
- Include NERC BES facilities.

1.5.4 Reportable Transmission Facility

Transmission Owners are required to report scheduled and forced outages for Reportable Transmission Facilities. Outage information is reported through eDART and through the status obtained via computer link to the EMS. In general, a Transmission Facility is reportable if a change of its status can affect, or has the potential to affect, a transmission constraint on any Monitored Transmission Facility or otherwise impedes the free-flowing ties within the PJM RTO and adjacent areas. All Transmission Facilities included in the PJM Reliability Model must be reported to PJM with as much advance notice as possible. The PJM Web site (http://www.pjm.com/markets-and-operations/ops-analysis/transmission-facilities.aspx) lists Reportable Transmission Facilities by Transmission Zone. Transmission Owners are responsible for ensuring the accuracy of this data. Updates are made as required correlating to system model updates. Note that ALL Congestion Management (monitored) and Reliability Coordination facilities are to be included by default as Reportable Transmission Facilities. As explained above, PJM has also identified other facilities as Reportable Transmission Facilities, because they can affect the overall transmission system. Instructions and a timeline for reporting outages are provided in Section 4 of this manual under the heading Reportable Transmission Facility Outages.

Codes associated with Reportable Facilities are defined as:

Yes, Reportable;

- The facility must be modeled in the PJM EMS and status information must be conveyed to the PJM EMS via the data link;
- The TO must generate eDART tickets when facility outages are required; and,
- Call the PJM dispatcher to ensure proper communication and coordination of switching and system security.

Low-Priority Reportable;

- The facility must be modeled in the PJM EMS and status information must be conveyed to the PJM EMS via the data link; and,
- The TO must generate eDART tickets when facility outages are required.

- Call the PJM dispatcher when the facility is returned to service to ensure proper time stamp.

No, Not Reportable;

- The facility may, or may not, be in the PJM EMS model; and,
- The facility is not expected to significantly impact PJM system security or congestion management.

With the growth of Reportable Facilities included in the PJM model, the Low-Priority Reportable Code is expected to accommodate the need to have facility status accurately modeled while reducing the need for phone calls to coordinate outages and streamlining this process.

PJM may require that all Tariff Facilities are Reportable. All EHV, 230 kV, and all tie-line facilities are flagged as Yes, Reportable and are not eligible for Low-Priority Reportable status. Tariff Facilities will generally default to Yes, Reportable. It may be acceptable to consider selected lower voltage Tariff facilities (161 kV, 138 kV, 115 kV and 69 kV) as Low-Priority Reportable depending upon the impact of the facility upon system security and/or congestion management. With recommendations from the TO, the PJM Manager, Power Systems Modeling Department is responsible for re-assigning Tariff facilities as Low-Priority Reportable or Not Reportable.

PJM operating studies focus on the impact of Reportable Facilities upon security. It is the TO's responsibility, after internal study, to ensure that system security will not be adversely impacted for the outage of a Low-Priority facility. The TO must notify PJM of a potential problem associated with a Low-Priority Reportable facility outage prior to switching. The TO should provide 30 minutes’ notice to the Power Director in order for PJM to confirm the TO’s analysis and make the appropriate adjustments. If, as a result of a Low-Priority Reportable outage, an unanticipated system security violation occurs, PJM will direct the TO to return the facility to service.

1.5.5 Observable Transmission Facility

- The term “observable” indicates that sufficient real-time analog and digital telemetry is supplied to PJM such that it is possible to accurately calculate the bus voltage and/or MVA flow for the facility in question.
- Facility must be accurately modeled in PJM EMS.
- The facility must have sufficient redundancy of telemetry to be “observable” in the PJM State Estimator.

1.5.6 Monitored Transmission Facility

Monitored Transmission Facilities are an Observable Facility and are broken into 2 categories:

- Monitored for Markets and Reliability Facilities are accepted for congestion control.
- Monitored for Reliability Facilities does not permit congestion to set LMP.

Both are monitored and controlled for limit violations using PJM’s Security Analysis programs. Control of limit violations to Monitored Transmission Facilities may result in constrained operation including manual redispatch; redispatch setting LMP and TLR curtailments. Additional details are contained within the PJM Balancing Operations Manual (M-12), Attachment B: Transmission Constraint Control Guidelines.

PJM OATT Facilities shall be monitored for any of the following criteria:

- Vital to the operation of the PJM RTO.
- Affects the PJM RTO's interconnected operation with other Balancing Authorities.
- Affects the capability and reliability of generating facilities or the power system model that is used by PJM to monitor these facilities.
- Significantly impact transmission facilities if outaged.
- Affects the PJM Energy Market if outaged.
- May result in constrained operations to control limit violations.
- A NERC BES facility.

PJM must be provided the applicable normal, emergency, and load dump ambient ratings for the transmission facility. Applicable ratings include sixteen ambient temperature sets (32F – 95F, day and night) and limiting equipment identification.

- Monitoring requested by the Transmission Owner.

The monitored facilities are included in the Transmission Facilities List. The Transmission Facilities List is located on the PJM website (http://www.pjm.com/markets-and-operations/ops-analysis/transmission-facilities.aspx).

Transmission Owners may add an Observable Transmission Facility as a Monitored Transmission Facility under PJM monitoring and control by sending notice to the Manager, PJM Power Systems Modeling Department. A Monitored Transmission Facility shall remain a Monitored Controllable Transmission Facility until the Transmission Owner requests in writing for it to be removed. See the previous information on Observable Transmission Facilities Discussion.

Note:
The PJM EMS has the capability to monitor contingency flows on any device such as a circuit breaker. The capability is known as Flow Device. Transmission Owners can submit ratings, as outlined in PJM Manual 3A, for devices/circuit breakers with limitations. The device/circuit breaker ratings will be monitored as part of the PJM EMS Security Analysis. Facility ratings can be found on the OASIS at the following link:

http://www.pjm.com/markets-and-operations/etools/oasis/system-information/ratings-information.aspx.

1.5.7 External Transmission Facilities

Those transmission facilities outside PJM RTO and/or facilities not entitled to transmission service under the PJM OATT are, for the purpose of transmission operations, considered external transmission facilities.

1.5.8 Non-PJM OATT Transmission Facilities

The Transmission Owners are responsible for the operation of their transmission facilities not included in the PJM OATT or at a lower voltage level than NERC BES facilities; provided, however, that the operation of these facilities does not compromise the reliable and secure operation of other transmission facilities within the PJM RTO. Transmission Owners are expected to comply with requests from PJM to take such actions with respect to coordination of the operation of their facilities not included in the PJM OATT as may be necessary to preserve the reliable and secure operation of the PJM RTO. At the request of the Transmission Owner, PJM will assist the Transmission Owners in alleviating any constraint within the PJM RTO. Because PJM may dispatch and schedule generation to alleviate a constraint only on a PJM OATT Facility, Transmission Owners do not rely on PJM procedures to control constraints on any facility not included in the PJM OATT. Generation assignments for transmission limitations on Non-PJM OATT facilities are the financial obligation of the Transmission Owner. Generation assignments for limits based on generating station/equipment limits on Non-PJM OATT facilities are the financial obligation of the Generation Owner requesting the limit.

1.5.9 Transmission Facilities Not Monitored by PJM

The Transmission Owners are responsible for the operation of their Local Area Transmission Facilities and facilities that are included in the PJM tariff but not “PJM Monitored Transmission Facilities”. However, the operation of Local Area Transmission Facilities should not compromise the reliable and secure operation of other transmission facilities in the PJM RTO. Transmission Owners are expected to comply with requests from PJM to take such actions with respect to coordination of the operation of their Local Area Transmission Facilities as may be necessary to preserve the reliable and secure operation of the PJM RTO.

1.5.10 Local Facility Protection

At the request of the Transmission Owner, PJM will assist the Transmission Owners in alleviating any local area constraint or condition. PJM may dispatch and schedule generation to alleviate a constraint only on Monitored Transmission Facilities, therefore Transmission Owners should not rely on PJM operating procedures to control constraints on their Non-Tariff facilities, Local Transmission Facilities or non-monitored facilities. Generation assignments for transmission limitations on non-monitored facilities are the financial obligation of the Transmission Owner.

1.5.11 Facilities under PJM Congestion Management (Reliability and Markets) Control

PJM has developed requirements that Transmission Owners must follow in order for PJM to operate generation to control loading or voltage on transmission facilities. All facilities under congestion management must be observed in the PJM EMS with sufficient telemetry to provide accurate and reliable state estimation (some redundant metering is generally required).

Generally, the Telemetry Requirements for Congestion Management Control are:

For a transmission facility to be under PJM Congestion Management Control, the facility must be “observable” (as defined later in this section) with sufficient telemetry redundancy in the PJM State Estimator. In general, the telemetry requirements for a line/transformer to be “observable” with sufficient redundancy are:

- The branch has MW/MVAR telemetry at both ends and there is some MW/MVAR telemetry for other branches/injections at buses connecting to the branch.

OR

- The branch has MW/MVAR telemetry at only one end there is good MW/MVAR telemetry for other branches/injections at buses connecting to the branch.

OR

- The branch has no MW/MVAR telemetry at either end but it has almost perfect MW/MVAR telemetry for other branches/injections at buses connecting to the branch.

In general, the telemetry requirements for a bus to be "observable" are:

- The bus has at least one voltage telemetry point and it also has some MW/MVAR telemetry for its branches and injections.

OR

- The bus does not have any voltage telemetry point but a voltage telemetry point is available at the immediate neighbor bus (of the same voltage level) AND the bus being evaluated has most of the MW/MVAR telemetry for its branches and injections.

Note:
See PJM M-01: Control Center and Data Exchange Requirements for specific requirements.

1.5.12 Process to Change the PJM Congestion Management Control Facilities List

The process and timeline required to make adjustments to the existing Congestion Management Control Facilities List is described in detail in the PJM M-3A: Energy Management System (EMS) Model Updates and Quality Assurance (QA).

1.6 PJM Procedure to Assign Line Designations for New Facilities 500 kV and Above

The following details the PJM process for assigning line designations for new facilities 500 kV and above:

- PJM Transmission Planning receives approval from PJM Transmission Expansion Advisory Committee (TEAC) and PJM Board for new 500 kV and above facilities.
- PJM Transmission Planning notifies PJM Operations Planning (OPD) of approval of new 500 kV and above facility.
- PJM OPD reviews the new circuit configuration and the master list of existing PJM 500 kV and above facilities.
- PJM OPD notifies the appropriate TO of the preliminary designated line number.
- PJM OPD proposes the new circuit designation to:
    - Manager Dispatch.
    - Manager EMS Support.
    - Manager Power Systems Modeling.

- Manager Transmission Planning.
- Manager Forward Market Operations.
- Manager Real-Time Market Operations.

- Upon PJM internal approval, PJM OPD finalizes the new proposed designation by notifying:
  - PJM: Dispatch, EMS Support, Power Systems Modeling, and Transmission Planning.
  - Committees: SOS-T, PC, and OC.
  - TO: Appropriate TOs.

1.7 PJM Procedure to Review Remedial Action Schemes (RAS)

The following details the PJM and committee structure review process for Remedial Action Schemes (RAS) and general timeline. The process is applicable to new, retiring, or functional modified schemes. The procedure is designed to ensure sufficient analysis, notice, documentation, PRC-012-2 requirements, and training on these RAS are established ahead of implementation. The process is outlined in the following steps:

1. All proposed new RASs must meet the NERC RAS definition.
2. Owner forwards scheme to PJM for review by submitting PRC-012-2 Attachment 1 via the email address RAS@pjm.com (PRC-012-2 R1).
3. PJM Planning, PJM Operations Planning, and Transmission Owner(s) review scheme and system impact using PRC-012-2 Attachment 2. PJM will provide feedback to the owner within four full calendar months of receipt or on a mutually agreed upon schedule (PRC-012-2 R2).
   a. PJM will provide a recommendation to the owner, including if the scheme meets the RAS definition.
   b. PJM will also identify whether the scheme is needed for reliability purposes including operational performance.
   c. If the scheme is required for immediate reliability concerns, operational performance, or to restore the system to the state existing prior to a significant transmission facility event:
      i The scheme will be implemented as soon as possible.
      ii PJM will use reasonable best efforts to post the RAS information immediately.
4. PJM documents the scheme and revises Manual-03B.
5. RAS/SPS owner discusses the scheme at the PJM Committees, ultimately achieving full Reliability Coordinator endorsement through the stakeholder process. The Committee review should be done in the following order to allow technical feedback to be addressed prior to the higher Committee review:
   a. PJM System Operations Subcommittee (SOS).
   b. PJM Relay Subcommittee (RS) (conditional).

i Only for RAS impacting facilities 200 kV and above. The review can be done prior to the SOS meeting depending on the meeting schedules.

c. PJM Operating Committee (OC).

d. PJM Market Implementation Committee (MIC).

e. PJM Planning Committee (PC).

f. PJM Markets and Reliability Committee (MRC).

6. PJM discusses the scheme at the PJM Dispatcher Training Subcommittee.

The committee review of the RAS and documentation process should be completed within two months. For a new and modified RAS not required for immediate reliability concerns, operational performance, or to restore the system to the state existing prior to a significant transmission facility event, a minimum of 90 days will be required between posting the RAS information and the actual implementation date of the RAS.

RAS owners shall submit results of operational performance analysis pursuant to PRC-012-2 Requirement 5 and Corrective Action Plans (CAPs) pursuant to PRC-012-2 Requirements 6 and 7 to RAS@pjm.com.

Note:
PJM will periodically evaluate RAS for retirement. When PJM identifies a scheme that may no longer be needed, PJM will discuss and assess with both the RAS owner and the Transmission Owner(s).

The retirement evaluation may be triggered by several factors:

1. RTEP project that the scheme is associated with has been completed.

2. Reliability issue that the scheme was designed to address no longer exists.

3. System changes have mitigated the congestion the scheme was designed to address.

4. Scheme has not been armed for several years.

PJM will evaluate operationally impactful external RASs on an annual basis. PJM will consider registered RASs based on neighboring TOP/RC feedbacks and will study their impact on the PJM system. For impactful external RASs, PJM will include their status in Operations Planning studies and in Real-time assessments (TOP-001-4 R10.5).

Section 2: Thermal Operating Guidelines

Welcome to the *Thermal Operating Guidelines* section of the ***PJM Manual for Transmission Operations***. In this section you will find the following information:

- How PJM operates to prevent thermal problems (see “Thermal Limit Operations Criteria”).

2.1 Thermal Limit Operation Criteria

The PJM RTO is operated so that loading on all PJM SOL are within normal continuous ratings, and so that immediately following any single facility malfunction or failure, the loading on all remaining facilities can be expected to be within emergency ratings. (All deviations from normal procedure must be approved and documented in PJM Manual-03B.)

This principle requires that actions should be taken before a malfunction or failure occurs in order to control post-contingency loading on a pre-contingency basis. Some examples of possible pre-contingency actions include pre-arranged approved switching, use of approved special purpose relays, Phase Angle Regulator tap adjustments (PARs), redispatch, and transaction curtailment. These actions can be used pre-contingency to control post-contingency operation so as not to exceed emergency ratings. These pre-contingency options are simulated by PJM when performing the day-ahead analysis of the system.

Following any malfunction or failure, all remaining facilities or procedures of PJM are utilized, as required in accordance with Exhibit 1 or as practical, to restore PJM RTO conditions within 30 minutes to a level that restores operation within normal ratings and protects against the consequences of the next malfunction or failure. Transmission overloads, both actual and post-contingency, are corrected within this time requirement. PJM uses the following techniques to control contingency or system violations:

- Adjusting PARs.
- Switching reactive devices in/out of service or adjusting generator MVAR output.
- Switching transmission facilities in/out of service.
- Adjusting generation MW output via redispatch.
- Adjusting imports/exports.
- Issuing a TLR (Transmission Loading Relief).

If the above directed actions do not relieve an actual or simulated post-contingency violation, then emergency procedures may be directed, including dropping or reducing load as required.

A Transmission Owner has the right to use its own devices after coordinating with PJM (i.e., Phase Angle Regulators - PARs) to correct for double circuit tower line contingency overloads in their own system, ensuring that this corrective action does not aggravate an existing contingency or create a new contingency. When a Transmission Owner detects a double circuit tower line contingency and the PJM RTO detects a single contingency, both of which require different corrective strategies, the Transmission Owner and the PJM RTO dispatchers communicate to work out an overall solution for both problems, provided the net impact in MWs shifted for other Transmission Owners does not exceed that which is required for the single contingency.

Note:
Under normal operations, PJM does not operate for double-circuit tower line (DCTL) contingencies. However, PJM may operate for DCTL contingencies if Conservative Operations are declared.

Note:
Generation redispatch for DCTL contingencies will be borne by the Transmission Owner and will not be allowed to set LMP while not under Conservative Operations.

Note:
PJM system operations will implement actions to control for system congestion caused by DCTL contingencies resulting from the declaration of Conservative Operations. PJM will issue a PCLLRW when calculated post-contingency flows exceed Long Term Emergency (LTE) ratings. PJM will initiate redispatch of generation when calculated post-contingency flows exceed the Load Dump (LD) rating permitting off-cost generation to set LMP.

2.1.1 Facility Ratings

Three sets of thermal limits are provided for all monitored equipment:

- Normal limit
- Emergency limit
- Load dump limit

PJM systems expect Normal (continuous), Emergency (long term and short term emergency are set equal unless specifically approved otherwise) and Load Dump limits.

Eight ambient temperatures are used with a set for the night period and a set for the day period; thus, 16 sets of three ratings are provided for each monitored facility. Ambient temperatures of 95°, 86°, 77°, 68°, 59°, 50°, 41°, and 32°F for both day and night periods are collated to constitute the 16 rating set selections. All Transmission Owners' and the PJM RTO's security analysis programs must be able to handle all 16 sets and allow operating personnel to select the appropriate rating set to be used for system operation. With a minimum of two set selections required daily (day/night), the Transmission Owner and the PJM RTO security analysis programs use these 16 ambient temperature rating sets for monitoring actual and contingency overloads. All temperatures associated with the ambient temperature rating data sets are in degrees Fahrenheit.

Certain facility ratings can be further adjusted by average bus voltage. The PJM RTO security analysis programs do not reflect these voltage adjustments in the 16 ambient temperature rating set selections. Coordination is required to ensure reliable PJM RTO operations.

The PJM RTO examines the set of thermal ratings that apply to Monitored Transmission Facilities during all operating periods. The PJM RTO dispatcher selects the ambient temperature rating sets, using the system weather forecasts. The PJM RTO dispatcher performs the following actions:

- Any discrepancy between the PJM RTO and a Transmission Owner for a facility rating is logged and reported to the PJM EMS Support Department for resolution. The immediate resolution for a rating discrepancy is to use the lower of the two disputed values until a more permanent resolution can be affected.
- If it becomes necessary in actual operations to initiate off-cost operation for a facility, the operation is based on PJM RTO security analysis program information, unless a more limiting condition is detected by the Transmission Owner's security analysis program.
- When a Transmission Owner's facility is experiencing constraints in an area that has an actual temperature (degrees Fahrenheit) less than the ambient temperature rating set being used by the on-line programs, the actual temperature in the area is used to select a more appropriate rating set for that facility. The selection is made from the remaining 15 sets. This adjustment is exercised when both the PJM RTO and the Transmission Owner are in agreement, and have logged that agreement.
- Any adjustment to facility ratings, such as the temporary use of a different rating, must be approved by PJM. These changes must be submitted to PJM through the Transmission Equipment Ratings Monitor (TERM) consistent with PJM M-3A: Energy Management System (EMS) Model Updates & Quality Assurance (QA), Appendix A: TERM Processing Ratings Data Check List. TERM is an internet-based interactive database located through eDART. The procedure and the rating are reviewed prior to approval by PJM. If an emergency rating change is needed, the change can initially be approved via phone call to PJM; however, a TERM ticket must still be entered by the next business day.

PJM requires a separation between Emergency and Load Dump ratings in order to enhance PJM Operator awareness. In the event where the Transmission Owner (TO) calculated Load Dump and Emergency Ratings are the same, the Emergency Rating submitted by the TOs shall be, at a minimum, 3% lower than the submitted LD rating. If this change results in a normal rating that is higher than the LTE rating, the TO shall, at a minimum, make the normal rating equal to the LTE rating.

Load Dump ratings are determined to aid the system operator in identifying the speed necessary to relieve overloads. Operation at a Load Dump rating should not result in any facility tripping when actually loaded at that value for at least 15 minutes. For a facility loading to approach the Load Dump rating, either multiple contingencies must have occurred or the system had been operated beyond first contingency limits.

Note:
PJM dispatchers must return actual flows below Emergency ratings within 15 minutes and below Load Dump ratings within 5 minutes, as indicated in the tables below.

2.1.2 Short-Term Emergency Ratings

The existence of approved short–term emergency (STE) ratings can affect the time allowed before implementing load shedding. If ratings exist that have a shorter-term rating than the long-term emergency (LTE) ratings, then additional time may be available prior to implementing load shedding.

If the actual flow is greater than the LTE rating but less than the STE rating, then the time to correct (using load shedding) is equal to the time referenced by the STE rating. (e.g. if a 30 minute STE rating is provided and the actual flow exceeds the LTE rating but does not exceed the 30 minute STE rating, then the time to correct using load shedding, is 30 minutes not 15 minutes).

If other real-time monitoring is available such as transformer temperature, line tension, etc., the Transmission Owner may request that special procedures for their use be evaluated by PJM, and, if appropriate, included in Manual-03B to evaluate the urgency of identified load shed as an alternatives.

If the actual flow is greater than the STE rating but less than the Load Dump rating, then the time to correct, using load shedding is 15 minutes.

Only those facilities designated in Attachment F of this manual with STE ratings will have those STE ratings observed. Any facility with STE ratings that do not exist in Attachment F will be controlled to the LTE rating.

2.1.3 How to Change Facility Ratings

Facility ratings may change due to equipment outages, equipment upgrades, or other identified reasons. Changes to facilities ratings must be requested by the Transmission Owner via TERM. Similar to the process for submitting a transmission outage request, the request to change ratings should be made consistent with PJM M-3A: Energy Management System (EMS) Model Updates and Quality Assurance (QA), Appendix A: TERM Processing Ratings Data Check List.

PJM's EMS Support Department evaluates the request. The request must be evaluated before the start date of the ticket, but preferably, it is approved two days prior to the start date. PJM's EMS Support Department evaluates the request by comparing the old and new ratings and checking them against any future outages for reasonableness. The Transmission Owner can look into TERM to see if their request has been approved.

After a request has been approved, PJM's EMS Support Department implements the changes into the EMS. The Transmission Owner can see the actual date of implementation via TERM. If there is no implementation date listed, the change has not been put into PJM's EMS yet.

While the change is being implemented by EMS Support, they will inform both PJM Dispatch and Operations Planning of the upcoming change so they can account for it in their future analysis.

Note that, if an emergency rating change is needed (typically outside of normal business hours), the change can initially be approved via phone call to PJM; however, a TERM ticket must still be entered by the next business day.

Legend
NON-COST
OFF-COST
LOAD SHEDDING

Thermal Limit Exceeded	Corrective Actions	Time to Correct
Normal Rating (Actual flow greater than Normal Rating but less than Emergency Rating)	Non-cost actions, off-cost actions, emergency procedures except Load Shed Directive (See Manual M-13, Emergency Procedures).	Within 15 minutes of exceedance, load shed is not used.
Emergency Rating (Actual flow greater than Emergency Rating but less than Load Dump Rating)	All of the above including Load Shed Directive to control flow below Emergency Rating.	Within 15 minutes of exceedance (Note 2)
Load Dump Rating (Actual flow greater than Load Dump Rating)	All of the above including Load Shed Directive to control flow below Emergency Rating.	Within 5 minutes of exceedance (Note 1) (Note 3)

Exhibit 1: PJM Actual Overload Thermal Operating Policy

Note:
1: For unplanned load shed events, TO must initiate load dump action within 5 minutes after PJM issues a Load Shed Directive. TO must not exceed the time based duration of any Emergency rating/Load Dump rating.

2: TOs have the option of providing STE limits that are at least 30 minutes in duration. The STE rating allows the time before load shed to be extended provided the actual flow does not exceed the STE rating. If the actual flow is above the LTE but below STE, load must be shed within the times indicated in Attachment F for the facility, if other corrective actions were not successful.

3: A load shed directive will be issued in an amount sufficient to get below Emergency rating.

Thermal Limit Exceeded	If Post-Contingency simulated loading exceeds limit	Time to correct
Normal	Trend – continue to monitor. Take non-cost actions to prevent contingency from exceeding emergency limit.	N/A
Emergency	Use all effective actions and emergency procedures except Load Shed Directive	Within 30 minutes
Load Dump	All of the above including Load Shed Directive if analysis indicates potential for post-contingency cascading.	Within 30 minutes

Exhibit 2: PJM Post-Contingency Simulated Thermal Operating Policy

Note:
System readjustment should take place within 30 minutes. PCLLRW should be issued as post-contingency limit exceedance approaches 60 minutes in duration. However, PCLLRW can be issued sooner at the request of the Transmission Owner or if the PJM Dispatcher anticipates controlling actions cannot be realized within 60 minutes due to longer generator start-up + notification times.

Section 3: Voltage & Stability Operating Guidelines

Welcome to the *Voltage & Stability Operating Guidelines* section of the ***PJM Manual for Transmission Operations***. In this section you will find the following information:

- A description of the voltage, voltage related transfer, and stability limits (see "Voltage, Transfer, & Stability Limits").
- A description of the voltage operation and voltage limits (see "Voltage Operation and Voltage Limits").
- A description of the voltage control actions for low voltage operation (see "Voltage Control Actions, Low Voltage Operation").
- A description of the voltage control actions for high voltage operation (see "Voltage Control Actions, High Voltage Operation").
- How PJM operates capacitors (see "Bulk Electric System Capacitor Operations").
- A description of the transfer limits (see "Transfer Limits").
- A description of the stability operation (see "Stability Limits").
- A description of PJM's load relief expectations for voltage concerns (see "Load Relief Expectations").
- A description of Interconnection Reliability Operating Limits (IROLs).

3.1 Voltage, Transfer, and Stability Limits

In addition to the thermal limits referenced in Section 2, PJM operates the PJM RTO considering voltage and stability related transmission limits as follows:

- Voltage Limits – High, Low, and Load Dump actual voltage limits, High and Low emergency voltage limits for contingency simulation, and voltage drop limits for wide area transfer simulations to protect against wide area voltage collapse.
- Transfer Limits – The MW flow limitation across an interface to protect the system from large voltage drops or collapse caused by any viable contingency.
- Stability Limits – limit based on voltage phase angle difference to protect portions of the PJM RTO from separation or unstable operation.

3.2 Voltage Operating Criteria and Policy

PJM will operate the facilities that are under PJM's operational control such that no PJM monitored facility will violate normal voltage limits on a continuous basis and that no monitored facility will violate emergency voltage limits following any simulated facility malfunction or failure.

Typically, high voltage emergency limits are equipment related while low voltage limits are system related.

If a limit violation develops, the system is to be returned to within normal continuous voltage limits and the system is to be returned to within emergency voltage limits for the simulated loss of the next most severe contingency consistent with the timelines in the charts below. A 60-minute maximum time is allowed prior to issuing a Post-Contingency Local Load Relief Warning.

In addition, the post-contingency voltage, resulting from the simulated occurrence of a single contingency outage, should not violate any of the following limits:

- Post-contingency simulated voltage lower than the Emergency Low voltage limit, or higher than the Emergency High voltage limit.
- Post-contingency simulated voltage drop greater than the applicable Voltage Drop limit.
- Post-contingency simulated angular difference greater than the setting of the synchro-check relay less an appropriate safety margin (ten degrees for a 500 kV bus). The angular difference relates to the ability to reclose transmission lines.

PJM bus voltage limits by voltage level are as shown in Exhibit 3.

PJM operation requires that actions should be taken on a pre-contingency basis in order to control operations after a malfunction or failure happens. Some examples of possible pre-contingency actions include pre-arranged approved switching of capacitors or reactors, Phase Angle Regulator tap adjustments (PARs), redispatch, and transaction curtailment. These actions can be used pre-contingency to control post-contingency operation so as not to exceed emergency ratings on a simulated basis. These pre-contingency options are considered by PJM for inclusion in the day-ahead analysis. PJM does not have an Under Voltage Load Shed program, controlling to voltage limits on a pre-contingency basis in order to avoid load shed.

Voltage Drop Violation limits are utilized to prevent voltage instability, which could result in system voltage collapse. Voltage Drop Violation limits will be evaluated by PJM based on studied system voltage characteristics. These limits can vary over a range of values depending on local transmission system characteristics.

Load dump limits are provided to aid the system operator in identifying the speed necessary to relieve constraints. Operation at a load dump limit should not result in any facility tripping or voltage collapse when actually operated at that value for at least 15 minutes. In order for an operator to be faced with actual voltages approaching the load dump limit either multiple contingencies must have occurred or the system had been operated beyond first contingency limits. PJM will review with each TO the PJM default voltage limits and the appropriateness of using individual TO limits based on design and documented past operation.

The following chart details PJM's Voltage Operating Policy for an actual violation.

Voltage Limit Exceeded	If Actual voltage limits are violated	Time to Correct
Normal High	Use all effective non-cost and off-cost actions.	Within 15 minutes
Normal Low	Use all effective non-cost actions, off-cost actions, and emergency procedures except Load Shed Directive.	Within 15 minutes, load shed is not used.
Emergency Low	All of the above including Load Shed Directive if voltages are decaying.	Within 5 minutes
Load Dump Low	All of the above including Load Shed Directive if analysis indicates potential for voltage collapse.	Immediate
Pre-Contingency Transfer Limit Warning Point (95%)	Use all effective non-cost actions. Prepare for off-cost actions. Prepare for emergency procedures except Load Shed Directive.	Not applicable
Pre-Contingency Transfer Limit	All of the above including Load Shed Directive if analysis indicates potential for voltage collapse.	Within 15 minutes or less depending on the severity

The following chart details PJM's Voltage Operating Policy for a Post-Contingency Simulated Operation.

Voltage Limit Exceeded	If post contingency simulated voltage limits are violated	Time to Correct
Emergency High	Use all effective non-cost actions.	Within 30 minutes
Normal Low	Use all effective non-cost actions.	Not applicable
Emergency Low	Use all effective non-cost actions, off-cost actions, and emergency procedures except Load Shed Directive.	Within 15 minutes, load shed is not used.
Load Dump Low	All of the above including Load Shed Directive* if analysis indicates potential for voltage collapse.	Within 5 minutes
Voltage Drop Warning	Use all effective non-cost actions.	Not applicable
Voltage Drop Violation	All effective non-cost and off-cost actions including Load Shed Directive* if analysis indicates potential for voltage collapse.	Within 15 minutes
Post-Contingency Transfer Limit Warning Point (95%)	Use all effective non-cost actions. Prepare for off-cost actions. Prepare for emergency procedures except Load Shed Directive.	Not applicable
Post-Contingency Transfer Limit	All of the above including Load Shed Directive if analysis indicates potential for voltage collapse.	Within 15 minutes or less depending on the severity

Note:
*Load shed, if necessary, will be implemented in 30 minutes to correct post contingency simulated voltage violations.

Note:
PCLLRW should be issued as post-contingency limit exceedance approaches 60 minutes in duration. However, PCLLRW can be issued sooner at the request of the Transmission Owner or if the PJM Dispatcher anticipates controlling actions cannot be realized within 60 minutes.

3.3 Voltage Limits

PJM and the Transmission Owners established PJM Baseline Voltage Limits to protect equipment and assure the reliable operation of the Bulk Electric System. Deviations and exceptions to these Baseline limits are recognized based on equipment and local system design differences. The PJM Baseline Voltage Limits are shown in Exhibit 3.

3.3.1 Voltage Limit Exceptions

Some transmission systems within the PJM RTO are operated by PJM (in accordance to the design of the Transmission Zone) to different voltage limits. Transmission Zone and station limits are posted at https://edart.pjm.com/reports/voltagelimits.csv. The posting can also be viewed from the system information page at https://www.pjm.com/markets-and-operations/etools/oasis/system-information.aspx.

These limits apply on a Transmission zonal and station basis and are used in lieu of the PJM Baseline Voltage Limits.

- Transmission Owners can submit voltage limit changes using eDART.
- Generation Owners can request voltage limit monitoring by using the process as defined in Section 3.5.4.

PJM Baseline Limits	LD	EL	NL	NH	Vdrop Warning	Vdrop Limit
765 kV						
kV	688.5	703.8	726.8	803.3	5.0%	8.0%
P.U.	0.90	0.92	0.95	1.05	n/a	n/a
500 kV						
kV	475.0	485.0	500.0	550.0	2.5%	5.0%
P.U.	0.95	0.97	1.00	1.10	n/a	n/a
345 kV						
kV	310.5	317.4	327.8	362.3	5.0%	8.0%
P.U.	0.90	0.92	0.95	1.05	n/a	n/a
230 kV						
kV	207.0	211.6	218.5	241.5	5.0%	8.0%
P.U.	0.90	0.92	0.95	1.05	n/a	n/a
161 kV						
kV	144.9	148.1	153.0	169.1	5.0%	10.0%
P.U.	0.90	0.92	0.95	1.05	n/a	n/a
138 kV						
kV	124.2	127.0	131.1	144.9	5.0%	10.0%
P.U.	0.90	0.92	0.95	1.05	n/a	n/a

PJM Baseline Limits	LD	EL	NL	NH	Vdrop Warning	Vdrop Limit
115 kV						
kV	103.5	105.8	109.3	120.8	5.0%	10.0%
P.U.	0.90	0.92	0.95	1.05	n/a	n/a
69 kV						
kV	62.1	63.5	65.6	72.5	5.0%	10.0%
P.U.	0.90	0.92	0.95	1.05	n/a	n/a

Exhibit 3: PJM Baseline Voltage Limits

Note:
1: Transmission Owners shall not set UVLS settings on BES facilities higher than the PJM Load Dump Voltage Limit (0.90 pu).

2: Voltage Drop criteria are not applicable for Operational Planning Analysis or Real-time Assessment of pre-/post-contingency radial buses. However, the low/high voltage criteria are applicable to all BES facilities.

3.4 Notification and Mitigation Protocols for Nuclear Plant Voltage Limits

The maintenance of acceptable actual and post-contingency voltages at the substations of nuclear power plants is critical to assuring that the nuclear safety systems will work properly if required. In order to provide this assurance, the nuclear power plant operators must be notified whenever actual or post-contingency voltages are determined to be below acceptable limits. This requirement applies to all contingencies involving the tripping of the nuclear plant generator or any transmission facility as the contingent element. The notification is required even if the voltage limits are the same as the standard PJM voltage limits.

Nuclear plants may have voltage limits that are more restrictive than standard PJM voltage limits. In the case where standard PJM voltage limits, as defined by the Transmission Owner (TO), are more restrictive, PJM will direct redispatch without consultation of nuclear plants after all non-cost measures are implemented; however, PJM will still notify the Nuclear Owner of the violation to the limit. Off-cost generation will set Locational Marginal Prices (LMP). In the case where nuclear plant voltage limits are more restrictive than standard PJM voltage limits, all costs required to mitigate the violations will be borne by the generation owner.

PJM's EMS models and operates to the most restrictive substation voltage limit for both actual and N-1 contingency basis. PJM will initiate notification to nuclear plants if the PJM EMS results indicate nuclear substation voltage violations. This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes.

3.4.1 Communication

All communication of future and current operations between PJM and the nuclear plant should be through the Transmission Owner (TO). If there is any confusion about a communication, the plant can talk directly with PJM, however, the Transmission Owner should be appraised of the discussion – if PJM to a nuclear plant direct discussions are needed the preferred method would be a 3-way call among all parties (i.e., inclusion of TO). If off-cost operations are required based on a more restrictive Nuclear Plant voltage limit, the Nuclear Plant or their representative (Nuclear Duty Officer) may consult with the related MOC and evaluate whether an alternative such as operating at a reduced output would alleviate the voltage violation and is more cost effective. PJM will provide the approximate nuclear plant reduction, if applicable.

3.4.2 Information Exchange

Normally, PJM does not provide information relative to transmission operation to any individual Market participant without providing that information to all. However, in this unique condition where the public safety requirement is to have a reliable source for safe unit shutdown and/or accident mitigation; it is imperative that specific information be provided to a nuclear plant (this information should not be provided to their marketing members). If PJM operators observe voltage violations or anticipate voltage violations (pre or post-contingency) at any nuclear stations; PJM operators are permitted to provide the nuclear plant with the actual voltage at that location, the post-contingency voltage at that location (if appropriate) and limiting contingency causing the violation. The operation for more restrictive Nuclear Plant Voltage Limits at these nuclear stations should not be posted or provided to the Market via Data Viewer, once off-cost operations are initiated.

PJM Actions:

- PJM notifies nuclear plant, through Transmission Owner, of calculated post-contingency violations to modeled voltage limits (Transmission Owner or more limiting Nuclear Plant Voltage Limits).
- PJM notify nuclear plant, through Transmission Owner, of violations to actual voltage limits (Transmission Owner or more limiting Nuclear Plant Voltage Limits).
- Violations of more restrictive Nuclear Plant Voltage Limits must be agreed upon by the nuclear plant and logged by PJM.
- All non-cost actions should be implemented prior to MW adjustments.
- All costs required to mitigate violations of more restrictive Nuclear Plant Voltage Limits will be borne by the generation owner.
- Controlling actions must be cost-capped, if applicable.
- LMP shall not be used to control the voltage at these locations.
- TLR shall not be used to control the voltage at these locations.
- PJM will monitor the appropriate voltage limits based on changes provided.
- PJM notify nuclear plant, through Transmission Owner, when voltage level is restored within limits (and stable).
- Attempt to control more restrictive nuclear plant voltage limitations within 30 minutes.

Transmission Owner Actions:

- The Transmission Owner shall independently monitor for Nuclear Plant actual and contingency voltage violations as reflected on the Transmission System.
- Transmission Owner will communicate this notification from PJM to the nuclear plant (Transmission Owner or more limiting Nuclear Plant Voltage Limit violations).
- Transmission Owners will monitor the appropriate voltage limits based on changes to more limiting Nuclear Plant Voltage Limits as provided by the Nuclear Duty Officer (NDO).

Nuclear Plant Actions:

- Nuclear plant will notify PJM, through Transmission Owner Shift Managers, when different (new or default) voltage limits shall be used based on various plant service loading conditions, design basis calculation revisions.
- Determine internal plant options, and if appropriate, provide revised limits.
  - o **NOTE**: Revised Nuclear Voltage Limits will also be communicated through eDART's Nuclear Voltage Limit feature, a zero MW ticket, or M-03 Attachment C.
- Coordinate with MOC to evaluate PJM provided redispatch option (no cost or unit information will be provided).
- Provide PJM with decision to redispatch – if applicable.
- Provide PJM with decision that nuclear plant will closely monitor plant activities and will take action within the plant if conditions change and inform PJM not to implement off-cost.
- Provide PJM with clear direction if they do not want PJM to perform redispatch.

Note:
PJM dispatch's goal is to resolve all voltage security violations (i.e., N-1 contingency) within 30 minutes, however; inherent communication delays related to off-cost agreement for nuclear plant voltage limits may not permit this goal to be achieved.

3.5 Voltage Control Actions

PJM is responsible for the overall coordination of the Bulk Electric System voltage scheduling. In general, since voltage schedules have a significant effect on local voltages PJM authorizes the Local Transmission Control Center to establish and adjust generator voltage schedules after gaining PJM approval. Whenever the voltage schedule impacts the overall PJM economic/ reliable operation, PJM shall exercise its operational control and direct changes to the generation voltage/reactive schedules, capacitor/reactor schedule/status, and transformer LTC operation for the overall reliable/economic operation of PJM.

- PJM requires that automatic capacitor switching capability on facilities 230 kV and above be documented in Section 3 of this manual. PJM authorizes the Local Transmission Control Center to automatically or manually switch/adjust reactive devices connecting to 138 kV and below without notifying PJM. Transmission Owners shall evaluate the impact of switching BES capacitor/reactors or adjusting BES LTC on voltage limits and lagging/leading MVAR reserves. The evaluation may require use of EMS Security Analysis or other analysis packages depending on system conditions and proximity to limits. Transmission Owners shall request PJM to study the impact of switching capacitor/reactors or LTC adjustments if the TO determines they are unable to analyze the impact on SOL related equipment.

- When deviating from the generator voltage schedule the Transmission Owner shall coordinate with the PJM dispatcher so that PJM can determine if the change is detrimental to PJM reliable/economic operation.
- When PJM requests to change voltage or VAR schedule, PJM should discuss the changes with the Transmission Owner and if the recommendation does not cause a defined limitation the Transmission Owner should implement the PJM request. PJM has operational control of the reactive facilities (transmission caps, LTC's, and generator regulation). If internal plant limits (or Transmission Owner local limits) restrict the request they should be logged so that PJM can investigate and recommend changes to plant facilities if appropriate.
- Generation Owners that possess generation resources equipped with Power System Stabilizers are required to communicate PSS status to the appropriate Transmission Owner as well as to PJM via the eDART outage reporting system.

3.5.1 EHV Transformer LTC Operation

The PJM dispatcher has operational control of and coordinates the operation of the EHV LTC transformer taps. In general, EHV LTC transformer tap changers are not operated under automatic voltage control but are operated in coordination with all other Bulk Electric System voltage control facilities.

Operation of the PJM RTO is coordinated in an attempt to minimize capacitor switching operation and transformer tap changes. PJM coordinates with the Local Control Centers, all switching of the Bulk Electric System capacitors & reactors to assist the system for actual or post-contingency situations. Local conditions may require some deviations.

3.5.2 Voltage Control Options for Non-Tariff Facilities

On occasion, PJM is requested to dispatch generation to protect PJM member equipment/facilities where that equipment is not included in the PJM tariff, and therefore not accommodated by standard PJM redispatch. PJM will accommodate requests for scheduling and dispatching off-cost generation. In the examples below, PJM describes conditions where charging for off-cost generation may result.

Off-cost examples:

- If requested to run generation for a distribution related problem PJM will accommodate a member’s request for “off-cost” operation. Appropriate billing will be made to the requestor. [A PJM Transmission Owner may request limits to PJM OATT facilities to protect their distribution system reliability (non-PJM OATT facilities). PJM will bill the PJM Member for any resulting off-cost operation.]

- If requested to run generation to protect a generating station or other non-tariff facility, PJM can accommodate a PJM member's request for the "off-cost" generation assignment. PJM will bill the PJM Member for any resulting off-cost operation.
- If requested to run generation for a Transmission Owner determined non-PJM reliability limit, PJM will accommodate that member's request for "off-cost" operation. Appropriate billing will be made to the requestor.

As an alternative to PJM directed off-cost generation, the requestor could enter into an agreement with any generation provider; this agreement would be treated independent from the PJM billing process.

3.5.3 Bulk Electric System Capacitor/SVC Operation

The PJM dispatcher coordinates the operation of Bulk Electric System capacitors. Capacitors should be kept in service whenever they are beneficial to the PJM RTO transfer capability or reliability.

Note:
The capacitor banks at each installation operate independently of each other under normal switching operations. Under normal conditions, the PJM dispatcher does not request that both banks of capacitors at one location be brought on or off simultaneously; generally at least five minutes between switching is desirable. The PJM dispatcher monitors the system voltage profile and the transfer capability of the PJM RTO and requests capacitor switching or transformer tap changes in a timely manner.

Operation of the PJM RTO is coordinated in an attempt to minimize capacitor switching operation and transformer tap changes. PJM coordinates with the Local Control Centers, all switching of the 230 kV and 500 kV capacitors and variable reactors to assist the system for actual or post-contingency situations. Local conditions may require some deviations. The 500 kV LTC transformer taps should be adjusted to control the system voltage regardless of the capacitor's in or out-of-service status. A bank of capacitors should not be switched in-service if the voltage on the bus, upon which it is located, would violate voltage limits.

The PJM RTO maximum voltage limits should not be exceeded on an actual or simulated post-contingency basis. As the PJM RTO voltage approaches limits, the PJM dispatcher analyzes and estimates the future system voltages and decides if there will be a need to remove any or all capacitors from service. The PJM dispatcher arranges to remove capacitors from service prior to the PJM RTO voltage reaching the maximum limits.

If PJM's simulated post-contingency analysis or a Transmission Owner's real-time monitoring program detects that the first contingency loss of a facility results in a Bulk Electric System bus exceeding its Emergency High limit, the PJM dispatcher evaluates the removal of any or all capacitors at that bus from service as necessary.

Prior to expected light-load periods, capacitors should be switched out-of-service before reaching limits if the PJM dispatcher expects that the switching operation is required in the future.

- ACE's 230 kV capacitor bank at Dennis is under automatic control of Dennis SVC and 230 kV capacitor bank at Cardiff is under automatic control of Cardiff SVC.

- DPL's 230 kV capacitor bank at Indian River is under automatic control of Indian River SVC.
- First Energy South 500 kV switched capacitor banks at the Black Oak Substation are all under automatic control of the Black Oak Static Var compensator (SVC).
- First Energy South 230 kV switched capacitor bank #3 at the Shingletown will be switched automatically in and out of service depending on the Shingletown 230 kV bus voltage. Automatic switching in-service will be initiated when the Shingletown bus voltage is at 228.8 kV and switched out-of-service when the Shingletown bus voltage is at 239.2 kV.
- First Energy South 230 kV switched capacitor bank #2 at Montgomery will be switched automatically in and out of service depending on the Montgomery 230 kV bus voltage. Automatic switching in-service will be initiated when the Montgomery bus voltage is at 225 kV and switched out-of-service when the Montgomery bus voltage is at 236 kV.
- First Energy South 230 kV switched capacitor bank at Damascus will be switched automatically in and out of service depending on the Damascus 230 kV bus voltage. Automatic switching in-service will be initiated when the Damascus bus voltage is at 220.8 kV and switched out-of-service when the Damascus bus voltage is at 234.6 kV.
- First Energy South 500 kV switched capacitor bank at the Meadow Brook Substation is under automatic control of the Meadow Brook Static Var compensator (SVC).
- First Energy East (JC) 230 kV capacitor banks at the Atlantic and Larrabee Substations are all under automatic control of the Atlantic Static Var Compensator (SVC).
- First Energy East (JC) 230 kV capacitor banks at the West Wharton Substation are all under automatic control of the West Wharton Static Var Compensator (SVC).
- First Energy East (PN) 500 kV capacitor banks at the Hunterstown Substation are under automatic control of the Hunterstown Static Var Compensator (SVC).
- First Energy East (PN) 230 kV capacitor banks at the Altoona Substation are under automatic control of the Altoona Static Var Compensator (SVC).
- First Energy East (PN) 230 kV capacitor banks at the Erie South and Four Mile Substations are under automatic control of the Erie South Static Var Compensator (SVC).

The following capacitor installations are equipped with Programmable Logic Controllers (PLCs) or under SVC's logic control and are the first automatically switchable 500 kV capacitors on the PJM RTO EHV system:

Capacitor Installation	Banks
Juniata	2-250 MVAR Banks
Conemaugh	2-200 MVAR Bank
Conastone	1-200 MVAR Bank
Limerick	1-200 MVAR Bank

Capacitor Installation	Banks
Hunterstown*	1-100 MVAR Bank

Exhibit 4: Capacitor Installations with PLCs

** Under normal operating conditions capacitor bank(s) is/are under the SVC logic control.*

To improve system voltages, the PJM dispatcher may switch capacitors with PLCs in service prior to switching in service non-PLC capacitors in other areas.

PLC initiated switching is limited to a basic voltage scheme:

- Capacitor automatic tripping generally is set to occur as follows:
  - Voltage above 555 kV – 15 seconds.
  - Voltage at 555-550 kV – 15 to 60 seconds.
  - Voltage at 550-545 kV – 1 to 15 minutes.
  - Voltage at 545 kV – 15 minutes.
- Capacitor automatic closing generally is set to occur as follows:
  - Voltage below 470 kV – 1 second.
  - Voltage at 475-470 kV – 1 to 15 seconds.
  - Voltage at 500-475 kV – 15 to 60 seconds.
  - Voltage at 510-500 kV – 1 to 15 minutes.
  - Voltage at 510 kV – 15 minutes.
- Juniata 500 kV Capacitors – Both capacitors are in the AUTO mode of operation. The voltage controlled operations are enabled for the capacitors in AUTO mode.
- Elroy 500 kV Capacitors - Two 300 MVAR capacitors (600 MVAR total) are located at Elroy 500 kV substation. Control systems have been set to have the first 300 MVAR of capacitors on system within 10 cycles from the beginning of the voltage collapse with the second 300 MVAR of capacitors on system 20 cycles from the beginning of the system event. Automatic switching will initiate when a 5% voltage reduction on all three phases over a 5 cycle time period occurs, resulting in the closure of the first cap bank CB (no time delay). 10 cycles after the first initiate the SEL 451 will initiate closure of the second cap bank CB.
- The LSR Auto/Manual 43 Control Switch, located on Elroy control panel #1, SHALL be placed in the manual position via EMS to disarm the auto scheme for the following conditions:
  - Maintenance outages at Elroy including Elroy 500 kV #2 Bus, 20-1 capacitor, 22-1 capacitor, 155 CB, or 175 CB.
  - PJM issues a High System Voltage Action.
- When PJM cancels the High System Voltage Action, the Elroy capacitors are to be placed in the auto position.

Note:
The Elroy 500 kV Capacitors do not have SCADA control to turn on, but SCADA is available to turn them off. They can be manually turned on, but require personnel on-site (45 minutes advance notice required). PJM can, in emergency conditions when all other means of reactive supply are exhausted, request PECO to send someone to turn on the Elroy capacitor banks provided that PJM Operations has determined that the capacitor banks are no longer needed for post contingency voltage control at that time and that the use of the capacitors for pre-contingency voltage control would not lead to a voltage collapse situation should a contingency occur.

The PJM Operations Planning staff develops modifications to transmission limitations as necessary. As additional capacitor installations are placed into service, new transmission limitations and operating guidelines are issued.

FE South EHV capacitors are operated in the manual mode but have automatic trips for high voltage:

Substation	Capacitor	HV Trip / Delay *
Bedington 500 kV	#2 162.5 MVAR	550 kV – 8 Sec
Bedington 500 kV	#3 162.5 MVAR	550 kV – 10 Sec

* Capacitors have a 5-minute time delay after tripping before they can be reclosed.

3.5.4 Addressing Voltage Limits at Generators and other Non-PJM OATT Facilities (including Distribution)

- For a limitation at a Generator, Generation station facility, or other non-PJM OATT facility, either the Transmission Owner or PJM Member can request PJM to operate for any requested voltage limits at a specific bus that are identified as more restricting than the PJM Baseline Voltage Limits.
- These requested voltage limits are submitted using the Manual-03 Attachment C form.
- Nuclear Generation Owners will enter the Nuclear Voltage Limits through eDART's Nuclear Voltage Limit Feature, a zero MW ticket, or M-03 Attachment C.
- PJM will evaluate these limits for reasonableness and inform the requestor.
- The PJM Member will be billed for any "Off-Cost" operation.

3.5.5 Open-Ended Voltage Rise Analysis

While a transmission line may be open-ended for only a short period of time during line energization and de-energization, the open terminal voltage may exceed acceptable levels as a result of line charging. This can cause serious equipment damage. The steady state voltage at the open end of an uncompensated transmission line is always higher than the voltage at the sending end. This phenomenon, known as the Ferranti effect, occurs because of the capacitive charging current flowing through the series inductance of the line. The equation representing the Ferranti effect is:

$$V_1 = V_2 / \cos(BL)$$

where:

- V1 – Open End Voltage.
- V2 – Closed End Voltage.
- B – Phase Constant (0.11587/mile for all compensated transmission lines).
- L – Line Length in Miles.

In the event PJM security analysis programs are not available, the Ferranti equation may be used as a guide to potential voltage rise during PJM 500 kV line switching operations. Voltage rise (V_1) for three (3) source terminal (closed end) voltage levels (V_2) are listed:

- 500 kV
- 525 kV
- 550 kV

PJM EMS “Try-back” displays reflect typically observed open-ended circuit terminal voltage for 500kV & 765kV lines.

PJM dispatch analyzes open-ended voltages when lines are energized/de-energized. PJM dispatch adjusts the system to ensure the instantaneous voltages do not violate the Emergency High Voltage Limit (if the Transmission Owner does not provide an Emergency High Voltage Limit, PJM will apply the Normal High Voltage Limit).

Transmission Owners are permitted to establish Short-term 30 Minute Emergency High Voltage Limits which can be used for short-duration events, such as planned switching. The short-term 30 Minute Emergency High Voltage Limits are higher than the Emergency High Voltage Limits. PJM Dispatch shall use the short-term 30 Minute emergency voltage limits when evaluating open-ended voltages. The following transmission zones have established Short-term 30 Minute Emergency High Voltage Limits:

- AEP 840 kV (765 kV System)

Depending on current/anticipated system conditions, there may not be a near-term time-frame conducive to controlling open-ended voltages within Emergency High Voltage Limit or Short-term 30 Minute Emergency High Voltage Limits.

3.6 Low Voltage Operation

The PJM dispatcher uses PJM Real-time data and security analysis based programs as the primary tool to evaluate the current state of the PJM EHV system on a simulated post-contingency basis, as well as the anticipated future conditions of the PJM EHV system on a simulated post-contingency basis. PJM security analysis programs detect the contingencies that can cause any monitored bus to violate its low voltage and voltage drop limits.

The PJM RTO uses the following techniques to control low voltage:

- Switching capacitors in-service.

- Switching reactors out-of-service.
- Adjust variable reactor tap positions.
- Adjusting voltage set point of static VAR compensators (SVC).
- Operating synchronous condensers.
- Changing transformer tap positions.
- Changing generation excitation.
- Adjusting generation MW output (i.e., to change line flows).
- Adjusting transactions.
- Adjusting PARs.
- Switching transmission facilities in/out of service.

The PJM Baseline Voltage Limits (see Exhibit 3) and how they would be applied to reliable system operation is:

- PJM will use the “PJM Baseline Voltage Limits” as the default “PJM Voltage Reliability Operating Limit”. If a PJM Transmission Owner identifies a specific voltage reliability limit, PJM will assess and use, if approved, that voltage reliability limit provided by the Transmission Owner as the PJM Voltage Reliability Operating Limit. However, the use will depend on the condition that the facility is specifically identified as a PJM Open Access Transmission Tariff (“PJM OATT”) facility, and the limit is specifically identified as required for reliable operation.
- The PJM Voltage Reliability Operating Limit will be either the PJM Baseline Voltage Limit or the Transmission Owner provided voltage reliability limit.
- PJM does not charge or bill a PJM Transmission Owner for off-cost operation of a PJM OATT facility as described above. In addition, these PJM Voltage Reliability Operating Limits will be used in PJM System Planning reinforcement evaluations. PJM shall evaluate the need to upgrade any restricting facility and study the validity of that reliability limit.

3.7 High Voltage Operation

The PJM dispatcher uses PJM Real-time data and security analysis based programs as the primary tool to evaluate the current state of the PJM EHV system on a simulated post-contingency basis, as well as the anticipated future conditions of the PJM EHV system on a simulated post-contingency basis. PJM security analysis programs detect the contingencies that can cause any monitored bus to violate its high voltage limits.

The PJM RTO uses the following techniques to control high voltage:

- Switching capacitors out-of-service.
- Switching reactors in-service.
- Adjust variable reactor tap positions.
- Adjusting voltage set point of Static Var Compensators (SVC).

- Adjusting voltage set point of Static Synchronous Compensators (STATCOM).
- Operating synchronous condensers.
- Changing transformer tap positions.
- Changing generation excitation.
- Adjusting generation MW output (i.e., to change line flows) for actual voltage violations only.
- Adjusting PARs.
- Switching transmission facilities in/out of service.

PJM performs the following actions to correct high voltage conditions (see PJM M-13: Emergency Operations, Section 2.4.7 for additional Real-time emergency actions):

- The PJM dispatcher requests that switchable capacitors be disconnected and switchable reactors be connected.
- The PJM dispatcher requests Local Control Center operators to direct all generators, synchronous condensers and SVCs within their zone to absorb reactive power.
- The PJM dispatcher requests neighboring Balancing Authorities to assist in reducing voltage.
- The PJM dispatcher directs the adjustment 500/230 kV transformer taps to optimize system voltage. Adjustment of transformer taps will be coordinated and agreed to between PJM and the Transmission Owner before changes are made. The greatest effect to control system voltage is attained by adjusting all 500/230 kV transformer taps.
- The PJM dispatcher requests the Transmission Owners to open approved and effective EHV circuits. The PJM dispatcher performs the following tasks:
  - Verifies thermal conditions with on-line study programs.
  - Uses computer programs to study the simulated effects of switching and the steady state voltage response.
  - Directs operation to open both terminals by the TO (open the terminal without a controlling source or the highest voltage bus first).

Opening Lines for Voltage Control

When high voltage conditions are expected on the PJM RTO, the PJM dispatcher uses PJM Security Analysis programs to study possible actions (i.e., opening high voltage line) and coordinates an operational plan before the situation becomes severe. If system voltages get too high, it may be difficult (if not impossible) to remove a line from service due to the voltage rise experienced at the open end of the circuit being removed from service. Corrective actions have a maximum effect only when they are accomplished prior to experiencing the problem.

During high voltage conditions, opening high voltage circuit has a positive effect in reducing system voltages for two reasons:

- It increases losses on the rest of the PJM EHV system.
- It eliminates the capacitive charging of the line.

PJM has identified several circuits that, in the past, have been effective in controlling general PJM RTO high voltage conditions when they are removed from service. Suggested high voltage circuits to be studied are:

AEP area

- Jacksons Ferry-Wyoming 765 kV line
- Dumont-Greentown 765 kV line

Mid Atlantic Area

- Alburtis-Juniata (5009) 500 kV line
- Conemaugh-Juniata (5005) 500 kV line

Note:
This option may be preferable if one or both Conemaugh units are off-line.

- Juniata-TMI (5008) 500 kV line

Note:
Transmission Owners require a person on site prior to returning these lines to service. The PJM dispatcher schedules the return time of the line at least two hours in advance of switching.

Dominion and First Energy Areas

- Mt. Storm-Meadow Brook (529) 500 kV line
- Carson-Suffolk (544) 500 kV line
- Clover-Rawlings (556) 500 kV line
- Glebe–Virginia Hills-Ox (248) 230 kV line
- Braddock-Annandale (294) 230 kV line OR Braddock-Annandale (297) 230 kV line
- Yorktown–Hayes (2122) 230 kV line

Note:
Dominion prefers to only use this switching during Spring and Fall periods and requires 24 hours' notice before switching is performed for all lines except Glebe – Virginia Hills - Ox.

High voltage problems of localized nature may be more effectively controlled by selective measures in the particular area.

Restoring EHV Lines During High Voltage

The following guidelines should be utilized to restore the transmission facility to service:

- On-peak planned outages/returns should be delayed until projected system conditions permit open-ended voltages to be controlled within Emergency High Voltage Limits, but no longer than 24 hours.

- Off-peak planned outages/returns should be delayed until projected system conditions permit open-ended voltages to be controlled within Emergency High Voltages, but no longer than the next on-peak period.
- PJM Dispatch can deviate from guidelines above if reliability issues are projected with the transmission facility out-of-service or if delaying the outage raises reliability concerns.

Note:
On-Peak is defined as Monday – Friday, excluding Holidays. Off-peak is defined as Saturday – Sunday, and Holidays.

3.8 Transfer Limits (Reactive/Voltage Transfer Limits)

Post-contingency voltage constraints can limit the amount of energy that can be imported from and through portions of the PJM RTO. The PJM EMS performs automated online full AC security analysis transfer studies to determine Transfer Limits for the use in real-time operation. The PJM Transfer Limit Calculator (TLC) simulates worse case transfers, with the simulation starting point being the most recent State Estimator solution. The TLC executes in the PJM EMS approximately every 5 minutes automatically recommending updated Transfer Limits to the PJM Dispatcher. The TLC determines a collapse point for each interface. Each interface consists of a number of BES facilities. PJM has established the following Transfer Interfaces in the PJM RTO:

Transfer Interface	Interface Definition (From Bus - To Bus)
Eastern (Eastern)	• 5059 Breinigsville – Alburtis #1 500 kV line • 5058 Breinigsville – Alburtis #2 500 kV line • 5009 Juniata – Alburtis 500 kV line • 5066 Lauschtown – Hosensack 500 kV line • 5010 Peach Bottom – Limerick 500 kV line • 5025 Rock Springs – Keeney 500 kV line • 5063 Lackawanna - Hopatcong 500 kV line
Central (Central)	• 5004 Keystone – Juniata 500 kV line • 5005 Conemaugh – Juniata 500 kV line • 5012 Conastone – Peach Bottom 500 kV line
5004/5005 (5004/5005)	• 5004 Keystone – Juniata 500 kV line • 5005 Conemaugh – Juniata 500 kV line
Western	• 5004 Keystone – Juniata 500 kV line

Transfer Interface	Interface Definition (From Bus - To Bus)
(Western)	• 5005 Conemaugh – Juniata 500 kV line • 5068 Vinco – Hunterstown 500 kV line • 5055 / 522 Doubs – Brighton 500 kV line
Bedington – Black Oak (Bed-Bla)	• 544 Black Oak – Bedington 500 kV line
AP South (AP South)	• 583 Bismark – Doubs 500 kV line • 540 Greenland Gap – Meadow Brook 500 kV line • 550 Mt. Storm – Valley 500 kV line • 529 Mt. Storm – Meadow Brook 500 kV line
AEP - Dominion (AEP-DOM)	• Kanawha River – Matt Funk 345 kV line • Wyoming – Jacksons Ferry 765 kV line • Baker – Broadford 765 kV line
Cleveland (CLVLND)	• Hanna – Chamberlin 345 kV line • Hanna – Juniper 345 kV line • Star – Juniper 345 kV line • Star – North Medina 345 kV line • Erie West – Ashtabula 345 kV line • Mansfield – Glenwillow 345 kV line • Monroe – Lallendorf 345 kV line
CE-East (CE-EAST)	• Dumont - Wilton Center 765 kV line • Olive - University Park North 345 kV line • St. Johns - Crete 345 kV line • Sheffield - Burnham 345 kV line • Sheffield - Stateline 345 kV line • Munster - Burnham 345 kV line
BC/PEPCO (BC/PEPCO)	• 5055/522 Doubs - Brighton 500 kV line • 5013 Hunterstown - Conastone 500 kV line • 5012 Peach Bottom - Conastone 500 kV line

Transfer Interface	Interface Definition (From Bus - To Bus)
	• 560/5070 Possum Point – Burches Hill 500 kV line • Aqueduct - Dickerson 230 kV line • Doubs – Dickerson 23102 230 kV line • Cooper – Graceton 230 kV line • Edwards Ferry – Dickerson 230 kV line • Otter Creek – Conastone 230 kV line • Safe Harbor - Graceton 230 kV line • Face Rock – Five Forks #1 115 kV line • Face Rock – Five Forks #2 115 kV line

- The transfers across an interface are the MW flows across the transmission paths. The transfer limits are the MW transfer beyond which reactive and voltage criteria are violated.

The reactive transfer limits are used to limit the total flow over the interfaces. The reactive limits are either pre-contingency MW limits or post-contingency MW limits. The limits are based on a post-contingency voltage drop, a post-contingency low voltage, or the steady state voltage collapse point.

The PJM dispatchers continuously monitor and control the flow on each transfer interface so that the flows remain at or below the transfer limits. This ensures that no single contingency loss of generation or transmission in or outside the PJM RTO causes a voltage drop greater than the applicable voltage drop criteria.

In addition, special operating procedures are used to address reactive issues. Additional interfaces will be established by PJM Operations Planning as required.

3.9 Stability Limits

The PJM RTO established stability limits for preventing electrical separation of a generating unit or a portion of the PJM RTO. PJM recognizes three types of stability:

- Steady State Stability - A gradual slow change to generation that is balanced by load.
- Transient Stability - The ability of a generating unit or a group of generating units to maintain synchronism following a relatively severe and sudden system disturbance. The first few cycles are the most critical time period.
- Dynamic Stability - The ability of a generating unit or a group of generating units to damp oscillations caused by relatively minor disturbances through the action of properly tuned control systems.

PJM will operate the facilities that are under PJM operational control such that the PJM system will maintain angular and voltage stability following any single facility malfunction or failure.

In general, stability is not a limiting constraint on the PJM RTO.

In addition to the special operating procedures addressing stability limit issues in Manual-03B, PJM utilizes a real-time Transient Stability Assessment (TSA) tool. TSA can monitor and determine transient stability of the system subject to a select set of EMS contingencies for balanced and unbalanced faults. PJM models a select set of three-phase faults with normal clearing and single-phase faults with delayed clearing. The contingencies or faults are in alignment with most planning events as defined in TPL-001-4 categories P1 through P4.

TSA will also monitor and control for dynamic stability using a 3% damping criteria for the RTO. TSA will display contingencies and impacted generators not meeting 3% damping criteria for units 10 MVA or above, as simulated between 10 and 15 seconds. PJM will perform additional simulations to validate damping results not meeting criteria in Real-time.

TSA computes stability limits by using real time network models. It interfaces with the EMS and uses the State Estimation solution. Other input data includes the dynamic model for over 3000 generators and fault clearing times for specific equipment. For equipment without a specific fault clearing time, TSA will use zonal default clearing times. TSA also calculates and provides recommended stability control measures to prevent generator instability. Typically, the control measure is expressed in terms of generator-specific MW adjustment. In some cases, a Mvar adjustment may resolve a stability issue.

TSA is used to monitor and control the generators with known stability concerns as defined in PJM Manual-03B. Since TSA uses real-time system conditions to assess stability, the limits tend to be less conservative or less restrictive than the manual operational procedures. The operational procedure limits are usually determined using conservative assumptions in order to cover a wider range of operating conditions. For scheduled transmission outages, TSA studies are used to determine the stability limits. For forced outages, the Manual-03B operational procedure limits are used until a real-time TSA run is completed. PJM will also use the Manual-03B operational procedure stability limits in certain cases, such as when TSA is down.

3.9.1 Process for Handling Generator Stability Limitations

The Reliability Limited Generation Compensation Task Force established the following procedure on how PJM currently handles Stability Issues on the transmission system. When a stability issue is identified and advanced coordination is not possible, PJM will:

- Confirm/calculate the stability limit and communicate the limit to the generator(s) as quickly as possible and prior to DA market submission when practical.
- Create an interface that would be used in the Day Ahead and Real Time Market so that LMP will be utilized to reflect the stability constraints.
    - If the generator chooses to reduce their Economic Maximum bid below the stability limit, the constraint would not bind.
    - If the constraint does bind, it would be handled consistent with how PJM handles other transmission constraints on the system. All current market rules regarding Lost Opportunity Cost (LOC) would apply and LOC would be paid as currently defined in the Tariff when a transmission constraint is in effect.

For previously identified stability constraints already documented in a Manual-03B operational procedure, the generation owner may have already agreed to limit its output to ensure the stability constraint is mitigated. In such cases, an interface constraint in the Day Ahead and Real Time markets is not necessary.

3.10 Interconnection Reliability Operating Limit (IROL)

The Interconnection Reliability Operating Limit is the value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages. PJM M-37: Reliability Coordination defines PJM's methodology for determining, monitoring, and controlling IROL facilities.

3.11 Generator Voltage Schedules

PJM defines default Generator Voltage Schedules as follows:

	PJM Default Generator Voltage Schedules								
Voltage Level (kV)	765	500	345	230	161	138	115	69	**66**
Schedule (kV)	760.0	525.0	350.0	235.0	164.0	139.5	117.0	70.0	67.0
Bandwidth (+/- kV)	+/-10.0	+/- 8.0	+/- 7.0	+/- 4.0	+/- 4.0	+/- 3.5	+/- 3.0	+/- 2.0	+/- 1.5

PJM Transmission Owners must supply and communicate voltage schedules and a low and high bandwidth or the PJM default voltage schedule as noted in the above table to all Generation Owners and PJM in the zone for applicable generators meeting the following criteria:

- Individual generating units greater than 20 MVA.
- Generators that aggregate to 75 MVA or greater connected to a common bus.
- Black start generators.
- Any other Generation Owner that request a voltage schedule

The eDART Voltage Schedule application is used to ensure consistent tracking and reporting protocols for communication of generator voltage schedules between Transmission Owners, Generation Owners, and PJM. Effective June 1, 2020, it is the required method for voltage schedule communication for PJM generators. On an annual basis, PJM shall initiate a voltage schedule review, in which applicable generator voltage schedules shall be reviewed and updated as needed by Transmission Owners, for acknowledgement by Generation Owners through the eDART Voltage Schedule application or by email.

The eDART Voltage Schedule application allows Transmission Owners to specify voltage schedules for each applicable generator in the form of a Voltage Schedule ticket containing:

- A target voltage schedule,
- Upper and lower bandwidths,
- The regulated transmission bus.

The specified schedule shall be based on either the PJM default voltage schedule, or the Transmission Owner's specifications, which may be any one of following schedule types:

- Voltage
- Reactive Power
- Power Factor

The eDART Voltage Schedule application is used to ensure that all applicable generators have either a specified voltage schedule or an approved exemption (based on a Transmission Owner exemption request). Each generator voltage schedule will be submitted by the Transmission Owner into the application, followed by PJM's technical review, and then by the Generation Owner's acknowledgement.

Generation Owners shall communicate concerns regarding the assignment of the Transmission Owner voltage schedule/bandwidth or PJM Default Voltage Schedule/Bandwidth to PJM and the TO for resolution. This communication shall be made via the eDART Voltage Schedule application by using the GO Comment functionality.

A Transmission Owner wishing to exempt an applicable generator from following a voltage schedule shall submit an exemption request via the eDART Voltage Schedule application, including the engineering basis such as, but not limited to, stability limitations, generator connected to radial circuits or to a tap changer voltage controlled bus, customer voltage quality limitations etc., for such exemption. PJM, in coordination with the affected Transmission Owner, must review the request and provide approval (or denial) based on their analysis, before the change can go into effect.

PJM Transmission Owners have the authority to direct the Generation Owners to comply with the voltage schedule in automatic voltage control mode (AVR in service and controlling voltage). Generation Owners are required to maintain the same voltage schedule when AVR is out of service unless directed otherwise.

PJM Transmission Owners are required to coordinate voltage schedules, as well as adjustments to voltage schedules, with PJM Dispatch and the Generation Owners. PJM Dispatch will approve/deny adjustments based on PJM EMS Security Analysis results. PJM may elect to deviate from voltage schedules based on load levels, transfer patterns, transmission or generation outages, or as required to honor pre/post-contingency voltage limits or to maximize transfer capability based on PJM Security Analysis. The Transmission Owner will provide the Generation Owner with notification requirements for deviations from the specified voltage schedule, and the Transmission Owner will coordinate any deviations with PJM for resolution (see Notes 2 and 3 below).

Transmission Owners will provide the criteria used to develop the voltage schedule or reactive power schedule to the Generation Owner within 30 days of receiving a request. The Transmission Owner will notify PJM if unable to provide the criteria to the Generation Owner within 30 days of receiving the request.

PJM Transmission Owners have the authority to direct Generation Owners to adjust voltage schedules after coordinating with PJM Dispatch. PJM also has the responsibility and authority to direct Generation Owner to increase or decrease MVAR output as well as direct the switching of reactive control devices to maintain voltages as system conditions dictate. PJM will communicate these instructions to the Generation Owner through the Transmission Owners. Transmission Owners have the authority to instruct a Generation Owner to increase or decrease voltage/MVAR output to remain within the Transmission Owner voltage or PJM Default Voltage schedule/bandwidth.

Only PJM has the authority to request a Generation Owner to adjust MVAR output if such a direction adversely impacts the unit's MW output. In addition, only PJM has the authority to order a generator on line in the condensing or generating mode to provide voltage support. Also, if a generator is scheduled to come off line either by PJM or the Generation Owner, only PJM has the authority to order the generator to remain on line in the condensing or generating mode to provide voltage/MVAR support.

Generation Owners must coordinate any real-time voltage schedule issues with PJM and the Transmission Owner.

Note:
1: PJM monitors system and generator bus voltage via its EMS. In addition, PJM makes available to generators via ICCP and/or DNP protocols their designated voltage schedules and real-time bus voltages to allow the Generation Owners to monitor their unit's performance relative to the designated voltage schedule. PJM's expectation is that the Generation Owners maintain their assigned voltage schedule within the prescribed bandwidth and notify PJM and the TO when a generator is outside of its bandwidth continuously for 30 minutes unless otherwise specified by the Transmission Owner or exempted in Note 3. When the generator is again able to maintain its voltage schedule continuously for 30 minutes, notification to PJM and the TO that the generator is back on its voltage schedule is also required.

2: If a generator is unable to maintain its voltage schedule within defined bandwidths continuously for 30 minutes, *and* there is additional calculated leading or lagging MVAR reserves based on submitted Facility Reactive Capability Curves (D-Curves), the Generation Owner is required to notify PJM and the TO within 30 minutes and provide updated Facility Reactive Capability Curves (D-Curves) via eDART by the end of the next business day.

3: If a generator is unable to maintain voltage schedules within bandwidth continuously for 30 minutes, *and* it is operating at full lead MVARs in an attempt to stay within its voltage schedule maximum limit or at full lag MVARs in an attempt to stay within its voltage schedule minimum limit, based on submitted Facility Reactive Capability Curves (D-Curves), notifications to PJM and the TO are not required.

4: PJM requires PJM Transmission Owners to notify Generation Owners of applicable generators (that meet the criteria documented in 3.11 above) within their transmission zone of Transmission Owner voltage schedules or PJM default schedules. This notification shall include generators connected to systems owned by entities that are not PJM Transmission Owners such as municipalities or electric cooperatives. If the TO is not able to provide a TO voltage schedule to generators (municipalities, electric cooperatives etc.), the TO must notify PJM; and PJM will communicate the PJM default voltage schedule to the Generation Owner via the eDART Voltage Schedule application.

3.12 Reactive Reserve Check (RRC)

PJM leverages a process known as a Reactive Reserve Check (RRC) to assess the RTO's and its member's position with respective to dynamic and static reactive (var) power. Typically, an RRC is performed prior to Peak conditions, such as when a Heavy Load Voltage Schedule Warning (See M-13, PJM Emergency Procedures Manual) has been issued. An RRC may also be needed during light load conditions, such as a Minimum Generation Alert (See M-13, PJM Emergency Procedures Manual) issuance. In addition, PJM may issue an RRC once a week, such as a Sunday check, for testing purposes. For PJM, reactive power is expressed in MVAR, and for the purposes of an RRC, that MVAR reserve is expressed:

- as MVAR available (lagging) to the system for a Peak (heavy-load) RRC;
- as MVAR available (leading) to be taken off the system for a Valley (light-load) RRC.

Reactive assets for the PJM RTO area consist of PJM modeled generating units, synchronous condensers, static var compensators (SVCs), capacitors, and reactors.

PJM assesses the reactive reserve of the associated equipment via three (3) key metrics:

1. **Capability**: The lagging (and/or leading) capability for a given piece of reactive equipment.
   a. For generating units, synchronous condensers and SVCs, the capability is comprised of the permissible range of operation for the equipment, also known as the Reactive Power Capability Curve. For an RRC, PJM utilizes the lagging/leading MVAR points of the curve corresponding to the real-time real power (MW) output of the facility. Thus, capability is expressed as a maximum (lagging) and minimum (leading) MVAR range.
      i Reduced/expanded capability should be communicated through an eDART ticket and communicated to PJM Dispatch.
   b. For capacitors and reactors, the capability is single MVAR value corresponding to the maximum (lagging) MVAR capability for capacitors, or a minimum (leading) MVAR capability for reactors, PJM would anticipate at unity power factor.
2. **Status**: Status reflects the real-time connectivity to the PJM system, and is expressed as Online or Offline. Equipment real-time status is to be provided to (typically derived from circuit breaker status and/or MW/MVAR output) PJM via telemetry. Real-time status of an Automatic Voltage Regulator (AVR) for a given generator or synchronous condenser, or the automatic/manual response for a given SVC, must also be communicated to PJM Dispatch. Unless otherwise agreed to or communicated to PJM Dispatch:
   a. When a generator is above economic minimum real power output, PJM considers the AVR to be in-service/automatic mode and regulating voltage.
   b. When a synchronous condenser is online and connected to the grid, PJM considers the AVR to be in-service/automatic mode and regulating voltage.
   c. When an SVC is connected to the grid, PJM considers the SVC to be in automatic mode and regulating voltage.

3. **Availability**: The availability and/or unavailability of a reactive device in full is communicated to PJM through the absence of a PJM eDART ticket (availability) or the presence of an eDART ticket (unavailability) which identifies the equipment as being unavailable.

Note:
For the purposes of this manual and the RRC, in order to ensure the accuracy of PJM's RC/TOP tools, PJM Members shall provide timely updates to PJM Dispatch through appropriate tools regarding any impact to the Capability, Status, and/or Availability of their reactive equipment. This can be done via telemetry, through maintaining timely and appropriate updates with respect to eDART tickets, and/or direct communication to PJM Dispatch as the situation warrants.

PJM Actions:

- PJM dispatcher initiates the RRC within the eDART application and requests response for the entire PJM RTO or on a Control Zone basis, as necessary. (Default is entire PJM RTO).
- PJM dispatcher announces the RRC to members via PJM All-Call (or backup communications channels if PJM All-Call is not available).
- PJM dispatcher takes a snapshot of reactive reserves from the PJM EMS system for comparison purposes.
- PJM dispatcher works with member to resolve/rationalize reported differences in reactive reserves, correcting capability data as needed to ensure accurate Contingency Analysis results.

Generation Owner Actions:

- Outside of an RRC:
  - o Report Capability, Status and/or Availability of their reactive equipment per normal procedures/tools.
  - o Notify TO/PJM regarding unit reactive performance issues, and update eDART as appropriate.
- During an RRC:
  - o No action required, unless support directly requested by PJM/TO dispatcher.

Transmission Owner Actions:

- Outside of an RRC:
  - o Report Capability, Status and/or Availability of their dynamic/static reactive equipment per normal procedures/tools.
  - o Review eDART Reactive Capability Curves for units within the TO's zone, and update LCC EMS or reconcile deviations with PJM/GO as needed.

- Compare LCC EMS information on an equipment level basis to PJM EMS data via the *New Reactive Reserve Check: RRC Self-Check* form.

- During an RRC:
  - TO enters required data in eDART via the eDART RRC Web form or via XML upload.

Note:
TO members seeking to provide ICCP submittal to an RRC, or with questions regarding the RRC process, should reach out to RRCHelp@pjm.com.

Further information can be found via PJM eDART User Group, the PJM eDART site, the PJM Tech Change Forum, and related committee level meetings.

Section 4: Reportable Transmission Facility Outages

Welcome to the *Reportable Transmission Facility Outages* section of the ***PJM Manual for Transmission Operations***. In this section, you will find the following information:

- A description of the general principles of scheduling outages (see "General Principles").
- How the Transmission Owner schedules a transmission facility outage (see "Scheduling Transmission Outage Requests").
- How PJM processes a Transmission Outage Request (see "Processing Transmission Outage Requests").
- A description of the equipment failure procedures (see "Equipment Failure Procedures").
- A description of the Transmission Acceleration Outage Process.

4.1 General Principles

Transmission Owners have the right and obligation to maintain and repair their portion of the transmission system. PJM approves all Reportable Transmission Facility outages prior to removal of the equipment from service. PJM will coordinate scheduled outages of all Reportable Transmission Facilities with planned generation outages that are submitted to PJM and may affect PJM RTO operation. For purposes of scheduling, Reportable Transmission Facilities include, but are not limited to, lines, transformers, phase angle regulators, buses, breakers, disconnects, Bulk Electric System capacitors, reactors, and all related equipment.

Generation Owners that own transmission equipment such as circuit breakers, capacitor banks, etc., do not have the capability to submit outage requests on transmission equipment in eDART. As a result, for Reportable Transmission Facilities in each TO zone, the Generation Owner must notify the affected Transmission Owner who must then submit outage requests to PJM via eDART for this generation-owned equipment as soon as practical after they are informed of the outage. It is the responsibility of the Generation Owner to keep the Transmission Owner updated on the status of this equipment and any associated outage requests.

PJM maintains a list of Reportable Transmission Facilities. Each Transmission Owner submits the tentative dates of all transmission outages of Reportable Transmission Facilities to PJM as far in advance as possible.

Procedures and timelines are established for the scheduling, coordinating, requesting, studying, approving, and notifying of the transmission outage to/by the appropriate Transmission Owner and PJM. The procedures and timelines are identified in this section and are periodically reviewed and revised.

Under certain conditions such as extreme weather, peak load, heightened homeland security, etc., PJM will evaluate the need to operate the Power Grid in a more conservative manner. Actions that may be taken in these special circumstances include, but are not limited to, canceling by Transmission Owner, denying by PJM, or rescheduling outages and returning outaged equipment to service. The status of rescheduled outages is described in detail under the subheading, "*Rescheduling Outages".*

4.2 Scheduling Transmission Outage Requests

Each Transmission Owner shall submit the tentative dates of all planned transmission outages of Reportable Transmission Facilities to PJM via eDART as far in advance as possible and update PJM at least monthly. For transmission outages exceeding five days, the TO shall use reasonable efforts to submit the planned outage schedule via eDART one year in advance but no later than 0000 hours on the first of the month six months in advance of the requested start date along with a minimum of monthly updates.

PJM maintains a planned transmission outage schedule for a period of at least the next 13 months. The planned transmission outage schedule is posted, subject to change, on the PJM Open Access Same-time Information System (OASIS). Planned transmission outages are given priority based on the date of submission. All planned transmission outages will be posted on OASIS within 20 minutes of Transmission Owner submittal of the outage through the PJM eDART system, with further updates as new information is provided in eDART. PJM periodically reviews all submissions of planned transmission outages and considers the effect of proposed transmission outages upon the integrated operation of the transmission system using established operating reliability criteria, as described within Sections 2 and 3 of this manual. Advance notification assures that the outage is reflected in both the ATC analysis and the FTR Auction.

4.2.1 Outage Submittal Rules

- The TO is required to submit all outage requests in excess of 5 calendar days in duration before the 1st of the month six months in advance of the start of the outage.
- Outages exceeding 30 calendar days in duration for the following planning cycle (June 1 – May 31) must be submitted before February 1, preceding the planning year (i.e., for planning year "June 1, 2020 – May 31, 2021", outages would need to be submitted prior to February 1st, 2020).

The most restrictive deadline will be enforced. In other words, an outage exceeding 30 days in duration starting in June would have to be submitted no later than November 30th at 2359 hours to be considered on-time.

- The TO is required to submit all outage requests less than or equal to 5 calendar days in duration before the 1st of the month prior to the month of the requested start date of the outage.

Recognizing that this may not always be possible, the following table illustrates the different time frames in which an Outage Request can be submitted and the different Actions PJM can take. The "PJM Actions" are defined in more detail in the Section: "*Processing Transmission Outage Requests, PJM Actions*".

Request Submitted	Ticket Received Status	PJM Actions
Outage > 30 Calendar Days		

Request Submitted	Ticket Received Status	PJM Actions
Before February 1 (for the following planning cycle June 1 – May 31) OR by the 1st of the month six months prior to the starting month of the outage (whichever is more restrictive)	"On Time"	The outage will be approved, provided it does not jeopardize system reliability.
On or after February 1 (for the following planning cycle June 1 – May 31) OR on or after the 1st of the month six months prior to the starting month of the outage (whichever is more restrictive)	"Late"	The outage may be denied if it jeopardizes system reliability or causes congestion requiring off-cost operations.
5 Calendar days < Outage <= 30 Calendar Days		
Before the 1st of the month six months prior to the starting month of the outage	"On Time"	The outage will be approved, provided it does not jeopardize system reliability.
On or after the 1st of the month six months prior to the starting month of the outage	"Late"	The outage may be denied if it jeopardizes system reliability or causes congestion requiring off-cost operations.
Outage <= 5 Calendar Days		
Before the 1st of the month prior to the starting month of the outage	"On Time"	The outage will be approved, provided it does not jeopardize system reliability.
On or after the 1st of the month prior to the starting month of the outage.	"Late"	The outage may be denied if it jeopardizes system reliability or causes congestion requiring off-cost operations.

When the Transmission Owners notify PJM using eDART of an Outage Request, the notification includes the following information:

- Date.
- Facility and associated elements.
- All line and transformers that will be outaged or open ended as a result of the scheduled maintenance must be included in the outage request. For example, an outage request for CB work that open ends a line must include the line as being out of service in the ticket. This will ensure proper posting of all outages to the PJM OASIS and the NERC System Date Exchange (SDX) site.
- Planned switching times.

- Job description.
- Availability/emergency return time.

Note:
Outages can be classified by PJM as Market Sensitive if necessary. This option is used in specific instances. Market Sensitive is any equipment or facility that reveals the future status of a generating unit. Generally, these outages are not posted on the PJM OASIS.

4.2.2 Hotline / In Service Work Requests / Protective Relay Outages / Failures

To properly coordinate the operation of the Bulk Electric System, Transmission Owners must notify PJM of hot-line work and protective relay outages. Several days' notice is requested to enhance coordination. For hotline work impacting the protection system zone of clearance or increasing the clearing time, a ticket must be submitted at least by 8am three days prior to the start date in order to be considered "on-time". The notification includes the following information:

- An outage or degradation of either the primary or back-up relay protection associated with any EHV (345 kV and above) facility.

Note:
PJM will model any delayed clearing as a result of relay outages or degradation in the TSA tool for stability.

- An outage of any other major relay protection scheme significant to EHV operation.
- An outage of an automatic recloser protection associated with an EHV circuit or any hotline work (reclosers in or out) on EHV facilities. PJM dispatcher is informed prior to auto-reclosers being taken out of service. All planned outages shall be submitted via eDART. All unplanned outages shall be communicated to PJM Dispatch and submitted via eDART.

Note:
An eDART ticket is not required for RTU/Datalink outages. Refer to Manual 1 Section 3.2.4 for communication requirements for Unplanned RTU outages and Section 3.8.1 for communication requirements for Planned RTU outages.

Note:
Under normal system conditions, Transmission Owners may elect not to restore "automatic reclosing" during multiple-day daily EHV equipment Hotline work. However, "automatic reclosing" must be restored from June 1st – August 31st (peak loads). In addition, PJM may request the TO to restore automatic reclosing during other projected peak load conditions, during thunderstorms or inclement weather, or during other unusual conditions which could adversely impact system reliability.

- In the case of Bulk Electric System facilities with no back-up relay protection, the Transmission Owner or Generation Owner should remove the facility from service before removing the primary relay protection when possible. If the facility cannot be removed from service, the Transmission Owner or Generation Owner shall notify PJM Dispatch verbally and through eDART of the impacted facility(s) and the remote fault clearing points. PJM Dispatch will modify the EMS Network Contingency analysis to reflect the remote clearing.

- In the case of any EHV automatic recloser outages, some limitations may need to be placed on the number of reclosers that may be outaged concurrently. Under normal conditions, PJM does not restrict the number of automatic reclosers that are out-of-service. However, under certain operating conditions, the number of automatic reclosers out-of-service in that electrical area may need to be limited if an analysis indicates potential reliability concerns. For example, if an EHV line is out-of-service, this will hold true. In this case, the requesting Transmission Owners are informed of the situation and asked to reschedule the work.
- Instances when relay testing or construction personnel are working in EHV substations, other than those in conjunction with scheduled facility outages previously approved by PJM, which may jeopardize the reliable operation of the substation.
- Transmission and Generation Owners shall notify PJM Dispatch of any protection system failures (as soon as possible) or unavailability (as scheduled) that impact the capability of protection relay systems on any facility on the list of Reportable facilities if such unavailability may result in a change in remote clearing, requiring PJM to modify PJM EMS Network Application Contingencies or switching the impacted facility out-of-service. PJM Dispatch shall notify affected Transmission Owners, Transmission Operators and Reliability Coordinators to ensure contingencies are modeled properly in Security Analysis and/or transient analysis. (PRC-001-1 R2.2). PJM Dispatch shall log such contingency modifications in the PJM logging system.

Note:
PJM relies on Transmission and Generation Owners to identify, assess, and notify PJM of changes, degradations, or outages to relay systems that impact normal fault clearing.

Note:
Facilities with degraded or no relay protection will be switched out-of-service; unless by doing so would create a load shed situation. In this case, PJM would model the remote clearing points and operate to control any resulting contingencies using normal operating procedures including PCLLRWs. These actions should be completed within 30 minutes of identification of the protection problem.

4.2.3 Energizing New Facilities

In order for PJM to properly model changes in system configuration, as much advanced notification as possible is required when a new facility, a reconfigured facility, is scheduled to be energized. This also includes a re-conductoring or equipment replacement that changes the impedance or rating of a facility. Transmission Owners must notify PJM of such changes by checking the Cut-In flag in the eDART outage ticket. This information should be submitted to PJM as far in advance as possible to ensure inclusion in the quarterly EMS model update but at minimum shall be consistent with the outage submittal rules. If energizing a new facility involves multiple outages in different periods, the Cut-In flag shall only be checked for the outage that upon completion will result in the energized facility.

4.2.4 Protection System Coordination

Each Generation Owner shall coordinate any new protection system or protection system change with their local Transmission Owner and PJM (email to Regional_Compliance@PJM.com). PJM will collect the information on these changes from the Generation Owner and post on the secure PJM Relay Subcommittee SharePoint site. [PRC-001-1, R3 and R5].

Note:
PJM relies on Transmission and Generation Owners to notify PJM of changes or degradations to relay systems that changes normal fault clearing. PJM models such change within the PJM EMS system by modifying PJM Security Analysis Contingencies.

4.2.5 Generator Voltage Regulator Changes

An outage of any unit generator voltage regulator, supplementary excitation control, or power system stabilizers must be communicated to PJM though eDART as far in advance as possible. The Generator Owner must submit these outages. (Refer to the PJM M-14D: Generator Operational Requirements.)

4.2.6 Peak Period Outage Scheduling Guidelines

Transmission Owners should avoid scheduling any outage in excess of 5 days in duration with a restoration time greater than 72 hours that may result in increased risk to system reliability during peak summer and winter periods. These periods are defined as June 15 – September 15 and January 1 – February 28, respectively.

Due to the risk of having other unexpected forced outages during the peak periods, the outages resulting in the following conditions with a restoration time greater than 72 hours will be denied:

- Actual or post-contingency thermal or voltage issues with insufficient generation for control.
- Constraints that are load sensitive with limited controlling actions.
- Stability issues.
- Bottled generation.
- Localized congestion requiring significant generation reduction to control.
- Non-localized congestion requiring wide-spread generation reduction to control.

Transmission Owners shall screen for such outages prior to submittal in eDART and look to reschedule these outages during non-peak periods. PJM may grant exception to ensure RTEP upgrades are installed within specified timeframes or as special circumstances warrant.

4.2.7 Outage Scheduling Exceptions

- PJM reserves the right to approve, deny, or reschedule any outage deemed necessary to ensure system reliability on a case by case basis regardless of date of submission.
- Outages not submitted on-time but scheduled in conjunction with existing outages will be reviewed and approved by PJM on a case-by-case basis in order to take advantage of expected system conditions.

- A "Late" outage (see Table in Section 4.2.1), regardless of duration, not expected to impact the transmission system reliability or result in system congestion at any point within the scheduled duration, may be approved.

4.2.8 Emergency and Forced Outages

PJM recognizes that Emergency Outages must be taken. If it is determined that the outage may create an unreliable operating condition the outage will not be approved, but it will be recognized by PJM that the outage will occur.

Transmission Owners report forced transmission outages of Transmission Facilities to PJM, to directly connected Balancing Authorities and to any Other PJM member that may be affected as soon as the forced transmission outage occurs or as soon as it is anticipated that forced outage will occur. The Transmission Owner also submits an eDART ticket for the outage with all pertinent information that is available at that time and updates the ticket as new information becomes available.

For emergency outages that require the scheduling of manpower, ordering of parts, etc. and therefore cannot come out of service immediately the TO shall submit a ticket in eDART for the future date in which the outage is expected to come out of service, set the Emergency flag, and write a description in the eDART ticket explaining the emergency condition and why the outage cannot come out of service immediately.

4.2.9 Rescheduling Outages

A planned transmission outage that is rescheduled or cancelled because of inclement weather or at the direction or request of PJM retains its "On-Time" status (if applicable) and priority as a planned transmission outage with the PJM approved rescheduled date.

If an outage request is rescheduled or cancelled for reasons other than inclement weather and not at the direction of PJM, the rescheduled or cancelled and resubmitted outage is treated as an unplanned outage request.

Note:
Transmission Owners should use reasonable efforts to assess all outages for the next two days and submit changes to outage tickets due to last minute cancellation, revision to scheduled return time of active outage, or other modification to PJM whenever possible by 06:00 a.m. but by no later than 09:30 a.m. for input into the day-ahead market model.

The revised outage request may lose its priority as an "On-Time" outage as indicated by the following below.

Revisions to "On-Time" scheduled outages lasting 5 Days or less:

- If the revised outage request will occur entirely during the originally scheduled month(s), it will retain its "On-Time" status if applicable.
- If the revised outage request will occur during a different month(s), the revision must be submitted by the first of the month prior to the revised month(s) in which the outage will take place to be considered "On-Time".
- If the revised outage request results in the ticket duration being greater than 5 days, the ticket's "On-Time" status will be re-evaluated as if submitted for the first time.
- If any piece of equipment is added to the ticket's outaged equipment list by the TO.

Revisions to “On-Time” scheduled outages exceeding 5 Days in duration:

- If the revised outage request will occur entirely during the originally scheduled month(s), it will retain its “On-Time” status if applicable.
- If the outage request moves to a new month which is further out into the future, the revision must be submitted by the first of the month prior to the revised month in which the outage will take place to be considered “On-Time”.
- If the outage request moves to a new month which is nearer to the current date, the revision must be submitted by the first of the month six (6) months prior to the revised month in which the outage will take place to be considered “On-Time”.
- If the scheduled outage is more than 30 days and the revised outage request results in the ticket crossing into a different Planning Year, the ticket’s “On-Time” status will be re-evaluated as if submitted for the first time.
- If the revised outage request results in the ticket duration being greater than 30 days, the ticket’s “On-Time” status will be re-evaluated as if submitted for the first time.
- If any piece of equipment is added to the ticket’s outaged equipment list by the TO.

Revisions to “Late” scheduled outages will be re-evaluated by PJM as “On-Time” or “Late” as dictated by the rules in the Section entitled “Outage Submittal Rules” (Section 4.2.1).

PJM coordinates outage rescheduling with the PJM Transmission Owners to minimize impacts on system operations.

4.2.9.1 Direct Billing for Late Outages

In order to avoid cancellation or rescheduling of a late outage, a Transmission Owner may elect to pay for off-cost operations associated with the outage consistent with OATT Attachment K and OA Schedule 1 in cases where PJM can specifically identify and assign the costs to the T.O. and after review and approval of such request by PJM.

PJM may assign to the Transmission Owner, at their consent, the generation off-cost or reductions in demand associated with their late outage submittal related to RTEP upgrades provided that delay of such outage would result in failure to meet the reliability based in-service date. Should the T.O. elect not to pay for the off-cost operations, the emergency RTEP outage will be posted as a special notice on the PJM OASIS.

In order to minimize market impact, direct billing costs outlined in this section apply only to those outages where controlling generation or reductions in demand can be identified in advance yet are not included in the LMP calculation. Outages resulting in overloads where the generator costs cannot be isolated thereby resulting in congestion do not fall under this proposal. A Transmission Owner would not be directly assigned costs associated with late outages due to unforeseen circumstances such as but not limited to inclement weather, existing outage extensions, permitting or zoning issues, equipment delivery delays, generation, or reductions in demand availability.

4.2.10 Coordinating Outage Requests with Other TOs

In the event that a contemplated scheduled outage of one Transmission Owner’s facility affects the availability of another Transmission Owner’s facility, it is the responsibility of the Transmission Owner initiating the request to notify the affected TO or other Balancing Authorities for their consideration before submitting the request to PJM. If agreeable to all

Transmission Owners or Balancing Authorities, the initiating Transmission Owner submits an outage request to PJM all other PJM Members that may be affected are notified.

4.2.11 Coordinating Outage Requests with other RTOs

In the event of a contemplated scheduled outage of a tie between the PJM RTO and neighboring entity, the Transmission Owner initiating the request discusses the outage with the directly connected Balancing Authority and/or Transmission Operator for their consideration. Likewise, if it is expected that such an outage will be extended beyond its scheduled time, this is discussed with the directly connected Balancing Authority and/or Transmission Operator. If agreeable to the directly connected Balancing Authority and/or Transmission Operator, the initiating Transmission Owner submits an outage request to PJM, all other systems that may be affected are notified. This procedure also applies to a tie between the PJM RTO and an adjacent Balancing Authority and/or Transmission Operator whenever the PJM RTO initiates an outage request. Adjacent Balancing Authorities and/or Transmission Operators are expected to follow a similar procedure.

4.2.12 Coordinating Outage Requests with Planned Nuclear Generation Outages

When a Transmission Owner submits an Outage Request that will open a Nuclear Generating Station's Unit Breaker the following guidelines shall be observed:

- All Nuclear Unit breaker Outage Requests shall be coordinated closely with the Nuclear Station to coincide with a Unit outage.
- In the case that the Outage Request cannot be delayed until the next Unit Outage, the Nuclear station should be given at least six weeks' notice. The schedule for opening the Unit Breaker must be closely coordinated with the station. The length of time that the breaker remains open should be minimized.

PJM will work with the Nuclear Station's and the Transmission Owner's outage needs.

The Nuclear Generating Stations coordinate the scheduling of a Unit Breaker outage and internal plant equipment outages and testing to minimize station risk. Adherence to outage schedule and duration is critical to the plant during these evolutions. Emergent plant or transmission system conditions may require schedule adjustments, which should be minimized. Any change to the outage schedule that impacts the Unit Breakers shall be communicated to the nuclear generator operator.

4.2.13 Coordinating Outage Requests with Impacted Generators

Transmission Owners will adhere to all PJM requirements regarding Transmission Outage Requests previously detailed in this section.

Transmission Owners will determine if their transmission outage impacts area generation. If the transmission outage forces an area generator off line, the Transmission Owner will notify the impacted generator.

PJM and Transmission Owners coordinate transmission outages with planned outages for generators submitted to PJM. In the maintenance planning process, if submitted in a timely manner, planned generator outage requests are given priority over planned transmission outage requests, and hence Transmission Owners should make an effort in aligning transmission outage work with the planned outage for generation.

In accordance with PJM Open Access Transmission Tariff, Attachment K – Appendix, section 1.9.2, if a Transmission Owner is planning to submit an outage that will make a generator facility unavailable, such outage shall be coordinated with the affected Generation Owner or the plant operator.

In addition to adhering to the on-time outage submittal rules, the Transmission Owner must inform the affected Generation Owner or the plant operator of such outage, as early as practical, but no later than six weeks prior to start of the transmission outage and should document on the transmission outage ticket the date of notification and the person / group that was notified. The Transmission Owner must communicate the subsequent changes to the transmission outage schedule to the Generation Owner or the plant operator. Failure to provide notification to the Generation Owner or the plant operator could result in denial of the transmission outage request.

PJM resolves potential outage conflicts based on system reliability. PJM performs the following activities:

- Reviews the transmission and generator maintenance schedules to coordinate major transmission and generator outages and communicates with submitting PJM Members to assist in attempting to minimize anticipated constrained operations.
- Recommends adjustments to transmission outage schedules throughout the year to coincide with planned generator outages within the PJM RTO and surrounding Balancing Authorities.
- Communicates with submitting PJM Members to assist in attempting to minimize the forecast PJM RTO production cost based on anticipated market-based prices.

4.3 Processing Transmission Outage Requests

Transmission Owners submit Outage Requests in eDART for all outages to PJM in advance of the outage start date. The Outage Request shall be submitted as far in advance as possible. PJM considers all transmission outages in the following priority order:

- Forced or emergency transmission outages.
- Transmission outage requests submitted “On Time” (refer to Section 4.2.1 for “On Time” transmission outage submission requirements).
- Transmission outage requests submitted “Late” (refer to Section 4.2.1 for transmission outage submission requirements).

Exhibit 5 presents how PJM processes Transmission Outage Requests.

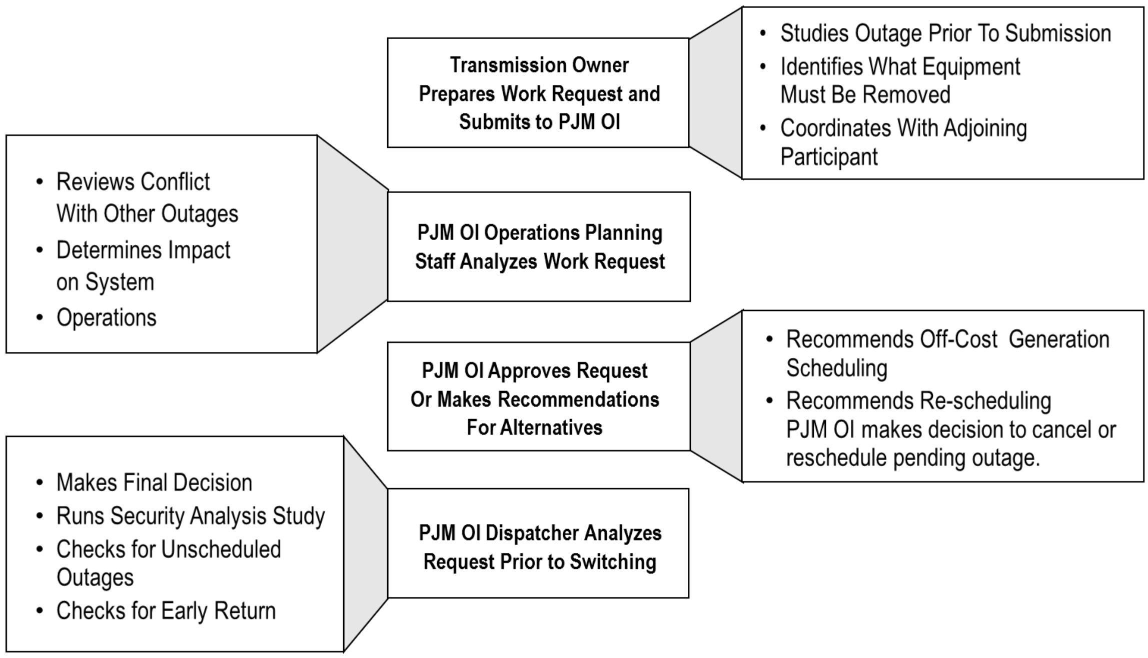


Exhibit 5: Transmission Outage Request Process

PJM Actions:

For all outages exceeding 5 days in duration PJM shall analyze these requests starting the first of the month 6 months in advance of the proposed start date. PJM shall make best efforts to contact the Transmission Owners with the results of this analysis by the end of the month as outlined in the example below.

Example: An outage submitted before January 1, 2009 scheduled for July 10-24, 2009 shall be studied by PJM with other expected July outages starting January 1, 2009. PJM shall make best efforts to contact TO by January 31 with results of analysis. PJM and TO shall work together to resolve any reliability issues.

If it appears that the expected outage will adversely impact system reliability, PJM will determine if a better window of opportunity exists for this work to be scheduled. PJM will coordinate between transmission and generation owners to ensure work will be done with system reliability being maintained.

If conflicting outages that are submitted on-time for the same timeframe from different Transmission Owners are identified, the outage submitted first for that timeframe will have priority.

For outages 5 days or less in duration, PJM shall analyze these requests starting the first of the month preceding the outage start date and make best efforts to contact Transmission Owners with results of the analysis by the 15th of the month.

PJM will inform the Transmission Owners through eDART of the status of all outage requests (either approved or denied) by no later than 1400 hours two days before the requested start of the outage.

In evaluating all Transmission Outage Requests, PJM performs the following activities:

- Studies and approves any emergency outages that do not result in Emergency Procedures. If an emergency outage is expected to result in Emergency Procedures, it will be discussed with the TO to determine the impact and risks associated with taking the outage at that time.
- Studies and approves Transmission Outage Requests that are submitted “On Time” and do not jeopardize the reliability of the PJM System.
- Studies and approves Transmission Outage Requests that are submitted “Late” and do not cause congestion on the PJM System. Determines if a “Late” Request may cause congestion and advises the Transmission Owner of any solutions available to eliminate the congestion. If a generator Planned or Maintenance Outage request is contributing to the congestion, PJM can request the Generation Owner to defer the outage. If no solutions are available, PJM may require the Transmission Owner to reschedule the outage.
- During anticipated emergency conditions, orders all work on Reportable Transmission Facilities that can be returned to service interrupted and the facilities returned to service until the emergency condition is relieved, if possible.

PJM, as system conditions warrant, identifies opportunities for, and encourages, coordination of all generator and transmission maintenance outages. When actual or anticipated system conditions change such that, at the discretion of PJM, the rescheduling of a transmission outage is advisable, PJM informs the Transmission Owner of the conditions and available alternatives. The Transmission Owner involved considers the impacts of proceeding with the outage as advised by PJM and may either proceed knowing the estimated impacts on the remaining facilities or postpone the outage. If the outage is not postponed, PJM determines and records the appropriate impacts or changes to system limits and takes the steps required to maintain established operating reliability criteria as mentioned within Section 1 of this manual.

PJM evaluates planned outages of Reportable Transmission Facilities to determine whether an outage may cause the simultaneous loss of multiple facilities. When non-reportable equipment outages at a station occur, which can lead to the simultaneous loss of more than one reportable transmission or generator facility for any single facility malfunction or failure, PJM must be informed. The Transmission Owners are responsible to report such conditions to PJM as soon as they are recognized.

4.3.1 Notification of Transmission Outages

The Transmission Owners are responsible for reporting outages on facilities contained within the Transmission Facilities List Database (available on the PJM website – www.pjm.com). The eDART reporting system is used to inform PJM and others of the outage according to predefined indexing keys.

Transmission Owners must notify PJM of the unavailability of other transmission components that affect the capability of protection of facilities on the list of Reportable Transmission Facilities. Such unavailability may result in a degradation of protection systems which could result in remote clearing of a transmission faults requiring PJM to modify PJM EMS Network Application Contingencies or switching the impacted facility out-of-service.

Transmission Owners report forced transmission outages of Transmission Facilities to PJM, to directly connected Balancing Authorities that may be affected, and to a jointly-operating PJM

Member as soon as the forced transmission outage occurs or as soon as it is anticipated that forced outage occurs or is imminent.

Transmission Owners must report outages that under expected system conditions may affect system reliability even though these facilities may not be listed as a Reportable Transmission Facility. This includes outages that may result in multiple facility trippings.

PJM dispatcher then informs all other systems that may be affected. PJM dispatcher logs all outages and, as required, reports to and makes necessary arrangements with the appropriate personnel from neighboring RTOs, ISOs, and Balancing Authorities.

4.3.2 Real-Time Switching Notification Procedures

Transmission Owners must request final approval from PJM Transmission Dispatcher one-half hour prior to the expected switching time of any reportable facility. If the switching for the work on the associated outage request has not been completed within 30 minutes from PJM dispatcher's approval, the Transmission Owner must notify the PJM dispatcher of the delay. If the Transmission Owner dispatcher expects the switching to exceed 30 minutes, the TO dispatcher can notify the PJM operator during the initial phone call. No additional notification will be required unless PJM specifically requests to be notified immediately prior to switching.

- PJM considers equipment switched out of service once it has been taken out of network operation, predominately via breakers.
- PJM considers equipment restored when it has been returned to network operation.
- PJM considers relaying disabled/enabled when they've been placed in their intended status.

If for any reason, PJM dispatch approves switching for planned maintenance, and actual or contingency violations are observed, PJM dispatch will direct the facility to be returned to service until system conditions can be adjusted and the outage permitted to continue without violating operating criteria.

When a reportable facility is to be returned to service, the responsible Transmission Owner reports to the PJM Transmission Dispatcher for approval prior to returning the outaged facility to service. This is done so that any generation changes or transmission adjustments can be made to assure reliable operation of the system.

Note:
In general, each neighboring RC, TOP, BA, TO, GO, TSP, and LSE shall use line/equipment terminals and voltage when referring to transmission facilities of an interconnected network, utilizing uniform identifiers as needed to clarify identification and ensure accurate real-time communications.

4.4 Equipment Failure Procedures

Transmission Owners must promptly notify PJM dispatch of any equipment failures involving BES facilities. Transmission Owners promptly conduct investigations of equipment malfunctions and failures and forced transmission outages in a manner consistent with good utility practice and NERC, RFC, and SERC Standards. Causes of failures shall be communicated to PJM dispatch as they are determined. In order to permit other Transmission Owners to take advantage of information leading to possible trends in equipment failures, the Transmission Owners supply the results of such investigation to PJM, other Transmission Owners, and the appropriate entities in NERC, RFC and SERC. Transmission Owners establish guidelines for the level of resources to be applied to restore equipment to service following a failure. The Transmission Owners obtain from PJM the information and support services needed to comply with their obligations.

4.5 Transmission Outage Acceleration Process

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

- A description of the general principles of requesting Transmission Facility Outage Acceleration (see "General Principles").
- A timeline of the process.
- How PJM processes a Transmission Outage Acceleration Request (see "Processing Transmission Outage Acceleration Requests").

4.5.1 General Principles

Transmission Owners provide notice of planned outages to PJM in accordance with the requirements in the Open Access Transmission Tariff and applicable Transmission Owners Agreement as detailed in this Manual (refer to Section 4.2.1 for "On time" transmission outage submission requirements).

Under certain circumstances, it may be beneficial to investigate the possibility of moving or accelerating a transmission facility outage if shortening the overall outage time or moving the start/stop dates can alleviate transmission congestion or revenue inadequacy. To accommodate outages that may be accelerated under this process, PJM will review "on time" outages exceeding 5 days in duration submitted by the Transmission Owners and forced outages projected to last into the month of the analysis window. This analysis will begin on the first of the month 60 days in advance of the outage start dates. If such outage meets the criteria as outlined in the next section, it may be posted for acceleration under this process. The posting is at https://www.pjm.com/markets-and-operations/etools/oasis/outage-accel.aspx. The PJM contact information for Outage Acceleration is outage_acceleration_group2@pjm.com.

If transmission facility outage acceleration is possible, the costs incurred by the Transmission Owner in accelerating the outage will be paid by the PJM Member(s) who requested the outage acceleration. To accommodate a request for the Transmission Owner to move or accelerate an outage, additional costs such as overtime, weekend/holiday, or contractor costs may be incurred.

The decision as to whether an outage can be moved or accelerated would be at the sole discretion of the Transmission Owner. If a Transmission Owner determines in its own reasonable judgement that it cannot move a planned outage or accelerate a planned or forced outage, this decision must be respected by PJM and by participants making the request(s). The Transmission Owner would follow Good Utility Practice, applicable OSHA standards, as well as any and all company safety protocols in determining whether to move or accelerate an outage and by how much, and would also consider any restrictions/requirements contained in collective bargaining agreements.

4.5.2 Criteria for Outage Acceleration

Outages that qualify for this process include the planned outages that will exceed five days and are estimated to cause more than $500,000 in congestion revenue inadequacy. Also qualifying for this process are forced outages projected to last into the month of the analysis window and are estimated to cause more than $500,000 in congestion revenue inadequacy. These outages will be posted to the PJM OASIS approximately four weeks prior to the FTR auction period that would include the outage.

Planned and forced outages affecting the interconnection of a generating unit to the transmission system qualify for outage acceleration regardless of expected congestion revenue inadequacy.

Note: Outages that directly affect a generator's connection to the transmission system will NOT be posted on OASIS because they may reveal the future status of a generating unit.

4.5.3 Timelines for the Outage Acceleration Process

PJM will start reviewing "on time" outages exceeding five days two months before the first of the month in which the outages are scheduled to begin. Outages that meet the acceleration criteria will be posted on OASIS by the 15th of the month. Market participants have one week to express willingness to accelerate an outage. The Transmission Owner then has one week to provide a good faith estimate for acceleration.

Generation Owners can request to accelerate or reschedule outages that affect the interconnection of a generating unit at any time up to two weeks prior to the scheduled start date for planned outages. For forced outages that affect the interconnection of a generating unit, Generation Owners can request to accelerate during the expected outage duration. The Transmission Owner then has one week from the request to provide a good faith estimate for acceleration.

4.5.4 Processing Transmission Outage Acceleration Requests

Participants must make a request for acceleration of an outage within one week of the outage being posted. For an outage affecting the interconnection of a generating unit, Generation Owner must make a request for acceleration up to two weeks prior to the outage's scheduled start date. If one or more requests are received to accelerate an outage, PJM will contact the Transmission Owner and request a revised schedule and cost estimate to accelerate. PJM shall not reveal the identity of the Market Participant(s) making such request(s) to the Transmission Owner.

The Transmission Owner will provide PJM with a response that the outage can or cannot be accelerated within one week of the notification by PJM. If the outage can be accelerated, the Transmission Owner will provide an updated schedule that either moves the outage or shortens the duration of the outage along with the associated costs for acceleration. Either option should result in a projected reduction of revenue inadequacy caused by the outage.

Once the estimate is received from the Transmission Owner, PJM will contact the Market Participant(s)/Generation Owner that made the request to accelerate the outage and has met reasonable creditworthiness standards to provide them with the details of the estimate.

- If only one participant has made a request, that one participant can decide whether to accelerate or not and is then solely responsible for the actual Transmission Owner's acceleration costs.

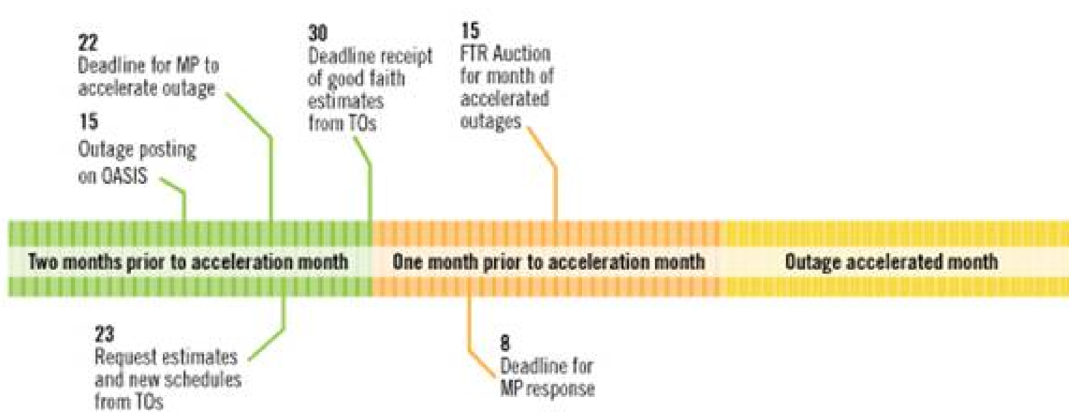
- If multiple participants make requests to accelerate, PJM would (1) provide the TO estimate to each participant; (2) notify the participants that there are multiple request to accelerate without revealing the identity of the other participant(s) making the other requests; and (3) collect a willing to pay amount from each participant. Based on the total amount the participants are willing to pay to accelerate, PJM would make a determination whether to move forward with the acceleration.
- Once it is decided to move forward with the acceleration the Transmission Owner shall update eDART with the new outage schedule.

Determination would be made based on PJM judgment if the committed acceleration request amounts exceed the estimate by a sufficient margin. As a general guideline, for outages outside of a plant or substation, this margin should be a multiple of 2 times the Transmission Owner's estimate for transmission outages. For outages inside the plant, the margin should be a multiple of 5.

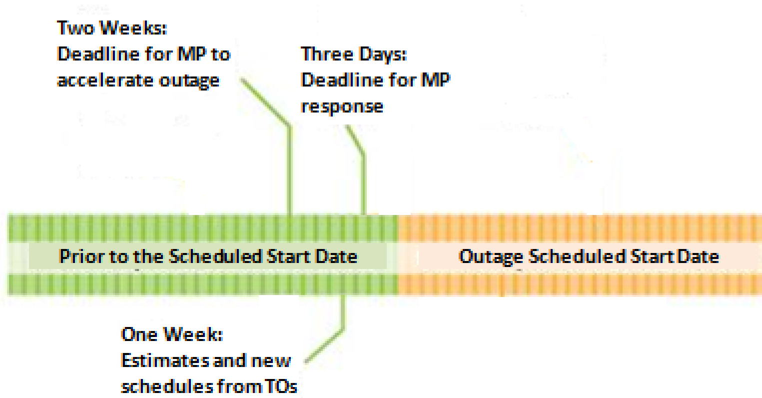
Note:
Inside a substation refers to the substation equipment (including the measurement and metering equipment) to the point of interconnection to the EHV network. The interconnection point may be within the physical limits of the substation perimeter.

1. Actual costs to accelerate would be divided pro-rata across the participants who requested the acceleration, based on the amount they provided with the request.
2. PJM shall give participants only one chance to make a request to accelerate an outage. Meaning, if after the first round of requests there is not enough money to accelerate the outage, the outage would not be accelerated.
3. Participants would only be able to submit an offer for the acceleration quoted by the TO. For example, if the TO says it will cost $50,000 to reduce a two week outage to one week, participants cannot request to accelerate only to 10 days.

Timelines for the Acceleration of Planned and Forced Outages



Timelines for the Acceleration of Planned Outages
Affecting Interconnection of a Generating Unit



If PJM determines that the acceleration should proceed, PJM will then request that the Transmission Owner moves ahead with the acceleration. All of the financial risks associated with the outage acceleration will be borne by those market participants who choose to participate in the specific outage acceleration; the Transmission Owner will not be responsible for any of these additional costs. If, despite the good faith efforts of the Transmission Owner, the acceleration estimated is exceeded, or the Transmission Owner is not able to successfully complete the outage on the accelerated schedule, the market participants will bear the full cost of the acceleration.

It shall be the responsibility of the Transmission Owner to make every reasonable effort to contact PJM prior to exceeding the original estimate by 20% of the cost to accelerate to determine if work should continue at the accelerated schedule or be completed at the original schedule. PJM will then contact the impacted participant. The participant has two business days to decide whether to continue with the revised transmission outage schedule and pay the additional costs. PJM will advise the TO how to proceed based on the feedback from the participant.

Section 5: Index and Operating Procedures for PJM RTO Operation

The operational procedures have been moved into a new PJM Manual-03B: Transmission Operating Procedures. The new Manual-03B and its content can be found in the Critical Energy Infrastructure Information (CEII) page located here:

- http://www.pjm.com/library/manuals/private-m03.aspx

The required access forms are located here:

- http://www.pjm.com/library/request-access.aspx

Attachment A: RAS Listing

TO	RRO	RAS/SPS Name	Planning or Operational	Telem. (Y/N)	Year of Installation	Default Status	Notified Neighbor
Description							
AEP	RFC	Rockport Emergency Unit Tripping	Operational	N	2009	Disarmed	MISO
To improve the voltage and stability performance of the Rockport area, the RAS will turbine trip one unit to achieve rapid reduction in total output for a contingency as defined in the operational procedure.							
AEP	RFC	Rockport Unit Special Protection System	Operational	N	2009	Armed	MISO, TVA
To prevent the tripping of both units by the imbedded safety operating limits, the RAS will trip a unit.							
FE-S	RFC	Belmont RAS	Operational	Y	2011	Disarmed	
To prevent unit instability and the overloading of 138 kV outlets. When armed, the RAS will trip a selected Pleasants unit for a contingency as defined in the operational procedure.							
COMED	RFC	Dresden Unit 2 Trip Scheme[1]	Operational/Non-redundant	N	2004	Armed	MISO
To prevent Dresden Unit 2 from becoming isolated in to Dresden TR81, the scheme will trip Dresden Unit 2 upon the contingency as defined in the operational procedure.							

[1] The RAS is not fully redundant. PJM accounts for the potential failure to operate by monitoring both the scheme operating successfully and the scheme failing to operate. For thermal or voltage issues, PJM will operate the scheme to the LTE limits and the scheme failed to the LD limits.

TO	RRO	RAS/SPS Name	Planning or Operational	Telem. (Y/N)	Year of Installation	Default Status	Notified Neighbor
Description							
COMED	RFC	East Frankfort TR83 Trip Scheme[1]	Operational/Non-redundant	N	2006	Armed	
To prevent overloads on the East Frankfort 345/138 kV TR83 following the contingency as defined in the operational procedure. With the line out of service, if the loading on TR83 exceeds its emergency rating for 10 seconds, the secondary 138 kV CB will open.							
COMED	RFC	Electric Junction – North Aurora L11106 line	Operational	N	2006	Armed	
To prevent low voltages, the scheme will transfer trip of CS 0605 at TSS North Aurora along 138 kV line L11106 upon sensing contingency as defined in the operational procedure.							
COMED	RFC	Elgin Unit Stability Trip Scheme[2]	Operational/Non-redundant	N	2002	Armed	
To isolate the Elgin units by tripping the remote end of the line (Spaulding) and initiating a transfer trip to Elgin Energy Center upon sensing a multi-phase fault on contingencies as defined in the operational procedure. If the 138 kV '2-3' bus tie at 79 Spaulding is operated in the closed position, it is possible for all four Elgin EC units could be tripped for a multi-phase fault with delayed clearing.							
COMED	RFC	Kincaid Unit Stability Trip Scheme[2]	Operational/Non-redundant	N	Pre-1995	Armed	MISO

[2] For stability issues, PJM does not operate to non-redundant RAS and will make pre-contingency generator adjustments to maintain post-contingency security according to PJM operating criteria. When such pre-contingency adjustments are made, the corresponding schemes will be disabled (where possible) to avoid unnecessary generator tripping. If the RAS cannot be disabled, PJM monitors both the scheme operating successfully and the scheme failing to operate as part of PJM stability analysis.

TO	RRO	RAS/SPS Name	Planning or Operational	Telem. (Y/N)	Year of Installation	Default Status	Notified Neighbor
Description							
To prevent first swing and/or oscillatory instability of either unit, a Multi-Phase Fault High-Speed Sectionalizing Scheme and a Multiple Line Outage Scheme are in place at Kincaid. The Multiple Line Outage Scheme is normally disabled when one unit is out of service.							
COMED	RFC	Powerton Unit Stability Trip Schemes[2]	Operational/Non-redundant	N	Pre-1995 & 2017	Armed	MISO
To prevent generator instability, the Multiple line outage trip scheme will trip the Powerton units for the loss of station outlets.							
COMED	RFC	Powerton L0302 and L0304 Unit Trip Schemes	Operational	N	2017	Disarmed	MISO
To prevent first swing instability of the Powerton units as a result of a close-in three-phase faults during certain line outages.							
COMED	RFC	Wolfs Crossing TR 81 RAS	Operational	N	2006	Armed	
To prevent overloads on the Wolfs Crossing 345/138 kV TR81 and 138 kV Wolfs – Frontenac L11102 line, a RAS will open 138 kV CB TR81 low side CB upon sensing the opening of the facility as defined in the operational procedure with TR81 exceeding its emergency rating.							
DOM	SERC	Clover RAS	Operational	Y	2013	Disarmed	VACAR
To mitigate angular stability and thermal issues when there is only one outlet from Clover power station. When armed, the RAS will trip Clover unit #2 when outlets (as defined in the operational procedure) from Clover power station are opened.							
DOM	SERC	Bath County-Valley Stability Trip Scheme	Operational	Y	2014	Disarmed	
To mitigate angular stability issues at Bath County pumped storage facility during a significant outage in the area. Depending on the number of units armed, the contingency loss (as defined in the operational procedure) will trip a predetermined number of units.							

TO	RRO	RAS/SPS Name	Planning or Operational	Telem. (Y/N)	Year of Installation	Default Status	Notified Neighbor
Description							
DOM	SERC	North Hampton RAS	Operational	Y	2017	Disarmed	
The North Hampton RAS has been decommissioned for use in operations.							
PE	RFC	Peach Bottom #1 Transformer	Operational	N	Pre-1995	Armed	
To mitigate stability concerns when Muddy Run is generating or pumping, the RAS will trip the Muddy Run 5-8 units. If a contingency as defined in the operational procedure occurs, the Peach Bottom ‘675’ & ‘475’ 230 kV CBs will open and a transfer trip will be issued to the Muddy Run #2 230 kV bus.							
PE	RFC	Planebrook 785 CB & 985 CB	Planning	N	2008	Disarmed	
To mitigate post contingency low voltages at Planebrook 230 kV when the 34 kV load at Planebrook exceeds 225 MVA. The scheme mitigates the voltage depression by isolating only one Planebrook 34 kV bus to be fed from the remaining distribution transformer. A stuck facility event would initiate the scheme and trip all (4) 34 kV Bus Tie CBs. Additionally, the scheme protects the remaining 230/34 kV distribution transformer from a post-contingency emergency overload during peak load conditions. *(NOTE: Non-Operational due to being stuck breaker contingency.)*							
PPL	RFC	Susquehanna 500 kV Caddy Corner Scheme	Planning	N	2014	Armed	
To prevent generator instability, a rejection scheme will trip Susquehanna #2 Unit for specific CB failure conditions during other 500 kV outages at Susquehanna. The scheme is not fully redundant and only operates for CB failure scenarios (non-operational contingency).							
PN-FE	RFC	Homer City #2 & #3 Unit Stability Trip Schemes	Operational	Y	Pre-2008	Disarmed	NYISO

TO	RRO	RAS/SPS Name	Planning or Operational	Telem. (Y/N)	Year of Installation	Default Status	Notified Neighbor
Description							
To mitigate unit instability for potential configurations that would isolate either Homer City Unit #2 or #3 onto one 345 kV line, a Unit Stability Trip Scheme is armed to trip Unit #2 or #3 whenever the facilities as defined in the operational procedure are opened.							

Attachment B: Transmission Outage 'Cut-In' Ticket Guidelines

The following guidelines have been created in order to assist the Transmission Owner (TO) in determining if the 'cut-in' flag should be checked when submitting a transmission outage ticket in eDART. It is critical that this flag be used as intended to ensure all new and/or upgraded facilities/equipment are being accurately monitored and screened for in the PJM EMS.

This attachment will include the high-level criteria for the 'cut-in' tickets, followed by some descriptive examples of tickets that should have the 'cut-in' box checked as well as some that should not have the 'cut-in' box checked. It should be noted, there may be some exceptions and situations that do not fit entirely into the criteria below. In those instances, please contact PJM Transmission Operations Department for clarification.

'Cut-In' Criteria for TO

A. All 'cut-in' tickets should have a very explicit description of work (i.e., "At the completion of this outage, new line xx-xx will be energized"). This is especially important so all PJM users of eDART can have a clear picture of what equipment/facilities need to be updated in the PJM EMS.

B. When possible, future equipment should be included in the 'cut-in' ticket if already in the PJM model. If new equipment is not available in eDART, 'description of work' comments should include this information so PJM staff can enter the new equipment once it is modeled.

C. There should only be one 'cut-in' ticket per facility being energized. The assumption is, at the return of the ticket, the cut-in facility will be in service. Other tickets that support the construction of the final energized facility (i.e., outages supporting intermediate phases of construction) should NOT be marked cut-in. In such cases, it is preferred that each ticket indicate which one is the final cut-in ticket (i.e. ticket 1 of 2, final cut-in occurs on eDART #999999).

D. If any cut-in is associated with a project and/or there are additional 'cut-in' tickets related to it:

1. An outage sequence should be attached to EACH cut-in ticket and a 'project' should be created in eDART for help with tracking the tickets together. This can be coordinated with outage analysis contacts at PJM.
2. When possible all 'cut-in' ticket numbers associated with a project should be listed in the 'description of work' to allow the ability to cross-reference information.

E. PJM 'cut-in' tickets generally DO fall into one of the following categories:

1. Any new branch (line, transformer, series device, phase shifter) or shunt that will affect PJM modeled topology.
2. Any reconfiguration (circuit breakers, disconnects, bus topology changes).
3. Any reconductored/upgraded equipment that ***will*** result in a different rating and/or impedance change when re-energized (i.e., CT/PT, wave trap).
4. Permanently retiring facilities (should be explicitly noted in description of work).

F. PJM 'cut-in' tickets generally DO NOT fall into the following categories:

1. Replace/repair existing equipment that ***will not*** change ratings or topology (i.e., CT/PT, wave trap, distribution transformer).

2. Poles/towers, foundations, any preparation work or sequence of tickets related to energization that will NOT result in energization at the completion of that specific ticket (NOTE: cause type 'Construction: New Equipment' should be used for this, not 'Cut-In').

Examples where 'cut-in' flag is appropriate

- As described in section A above, new line energization with explicit description of work.

Cut-in	Ticket ID	Dates	Description of work	Equipment			
x	A	3/7 – 3/11	Install structures and connect line to new Pine substation. At the end of this outage, new line Apple – Pine will be energized.	Open	CB	138	PINE 'APL'
				Open	CB	138	APPL 'PINE'
				Open	**LINE**	**138**	**PINE-APPL**

- As described in section D (2), tickets that involve bus reconfigurations should be marked as cut-in. Typically, these involve new CBs and contingency changes.

Cut-in	Ticket ID	Dates	Description of work	Equipment			
x	A	5/8 – 5/15	X-1234 SPRUCE - BERRY Needs to come out to relocate the X-1234 to its new position at Spruce	Open	CB	230	SPRUCE '1-2'
				Open	CB	230	SPRUCE '2-3'
				Open	**LINE**	**230**	**SPRU-BERR**

- Each ticket is for energization of a different piece of equipment related to the new transformer (CB's). The last ticket is to energize the transformer. Note that the actual transformer is NOT on any of the preceding tickets because it will not be in service once they are complete.

Cut-in	Ticket ID	Dates	Description of work	Equipment			
x	A	3/7 – 3/11	Tie in new 138 kV (low side of new Grape TX1) to Bus A	Open	CB	138	GRAPE 'LO-T1A'
				Open	CB	138	GRAPE 'A1'
				Open	CB	138	GRAPE 'A2'
x	B	3/12 – 3/16	Tie in new 138 kV (low side of new Grape TX1) to Bus B	Open	CB	138	GRAPE 'LO-T1B'
				Open	CB	138	GRAPE 'B1'
				Open	CB	138	GRAPE 'B2'
x	C	3/17 – 3/21	Tie in new 230 kV (high side of Grape TX1) to 230 kV bus	Open	CB	230	GRAPE 'HI-T1'
				Open	CB	230	GRAPE 'C1'
				Open	CB	230	GRAPE 'C2'
x	D	3/22 – 3/26	Energize new Grape 'TX1' 230/138 kV transformer	Open	CB	138	GRAPE 'LO-T1A'
				Open	CB	138	GRAPE 'LO-T1B'
				Open	CB	230	GRAPE 'HI-T1'
				Open	**Xfmr**	**230/138**	**GRAPE 'TX1'**

Examples where 'cut-in' flag is NOT appropriate

- As described in C above, the following two tickets were submitted for the same facility and with identical descriptions, yet both were marked as 'cut-in'. If final facility energization occurs on 3/21, then Ticket 'A' should NOT be marked 'cut-in'.

Cut-in	Ticket ID	Dates	Description of work	Equipment			
	A	**3/7 – 3/11**	PINE JCT 138KV LINE Tapping line for the new Apple Station	Open	CB	138	PINE 'APL'
				Open	CB	138	APPL 'PINE'
				Open	**LINE**	**138**	**PINE-APPL**
x	**B**	**3/14 – 3/21**	PINE JCT 138KV LINE Tapping line for the new Apple Station	Open	CB	138	PINE 'APL'
				Open	CB	138	APPL 'PINE'
				Open	**LINE**	**138**	**PINE-APPL**

- As described in section E (1) above, description of work states repair/replacement of existing equipment. This should NOT be marked 'cut-in'.

Cut-in	Ticket ID	Dates	Description of work	Equipment			
	A	**3/7 – 3/11**	CT/PT Reliability project to replace CT/PT combo metering units – no change to ratings	Open	CB	138	PINE 'APL'
				Open	CB	138	APPL 'PINE'
				Open	**LINE**	**138**	**PINE-APPL**

- As described in section E (2) above, this is an example of a sequence of tickets on different but related equipment that should not be marked 'cut-in' leading up to the last ticket which is the only one that should be marked 'cut-in'.

Cut-in	Ticket ID	Dates	Description of work	Equipment			
	A	**3/7 – 3/11**	Install foundations for new Grape 'TX1' 230/138 kV transformer	Open	CB	138	GRAPE 'LO-T1A'
				Open	CB	138	GRAPE 'A1'
				Open	CB	138	GRAPE 'A2'
x	**D**	**3/22 – 3/26**	Energize new Grape 'TX1' 230/138 kV transformer	Open	CB	138	GRAPE 'LO-T1A'
				Open	CB	138	GRAPE 'LO-T1B'
				Open	CB	230	GRAPE 'HI-T1'
				Open	**Xfmr**	**230/138**	**GRAPE 'TX1'**

Attachment C: Requesting Voltage Limit Exceptions to the PJM Baseline Voltage Limits

The purpose of this attachment is to provide further explanation on how to request voltage limit exceptions for non-PJM OATT facilities to the PJM Baseline Voltage Limits as discussed in this Manual Section 3: Voltage and Stability Operating Guidelines.

Addressing Generators and other Non- PJM OATT Facilities (including Distribution) (see Exhibit C-1)

1. For a limitation at a Generator or other Non- PJM OATT facility, a PJM Member can request PJM to operate for any requested voltage limits at a specific bus that are identified as more restricting than the PJM Baseline Voltage Limits.
    a. These requested voltage limits are submitted in writing by the PJM Member to the PJM Manager – Transmission Operations Department.
    b. PJM will evaluate these limits for reasonableness and inform the requestor.
2. The PJM Member will be billed for any “Off-cost” operation.

Note:
For NPIR voltage limits, PJM will notify the impacted Transmission Owner and coordinate the implementation.

To: PJM Manager-Transmission Operations Department

From: **PJM Member Company:___________________ Requested By**: __________________

RE: Request to Operate to a Different Voltage Limit than the PJM Baseline Voltage Limits for a Generator or Other Non-PJM Open Access Transmission Tariff Facility.

We request that PJM operate to a voltage limit different from the PJM Baseline Voltage Limits at the specific bus identified below. If this bus limitation results in “off-cost” operation appropriate billing will be made to the PJM Member/Requestor.

Authorized by: ____________________(PJM Member Representative) Date: ____________

Facility Identification	Voltage	LD	EL	NL	NH	% Volt Drop	Target Implementation Date	Comment or Reason for voltage limit exception to the PJM Baseline Limit

Key: LD = Load Dump **EL** = Post Contingency Emergency Low **NL** = Normal Low **NH** = High **% Volt Drop** = Post Contingency Voltage Drop Percentage Limit

Exhibit C-1

Submit this form to the PJM Manager-Transmission Operations Department (transops@pjm.com). Attach other pertinent documentation that would provide a complete understanding of the reason for the request. PJM will contact the requestor with feedback on the status of this request or any questions. If you have any questions, please call the Manager-Transmission Operations Department at (610) 666-8976. PJM will communicate, coordinate analysis, and implementation dates with the impacted Transmission Owners(s).

Attachment D: Post Contingency Congestion Management Program

PJM has historically operated on a pre-contingency basis under which it calls for off-cost generation to be run to alleviate contingency overloads. The amount of off- cost generation can total in excess of millions of dollars per year in congestion. PJM analysis indicates that the probability of contingent facility tripping during an off-cost event is less than .05%.

PJM believes that it is prudent to operate to a higher pre-contingency threshold (i.e., 30-minute rating) in areas where analysis demonstrates that there is ample fast-start generation or switching actions available to eliminate an actual overload should contingent facility tripping occur. This generation must demonstrate a history of adequate availability and response as defined below.

PJM's post-contingency congestion management program is operated for monitored facilities that meet the following criteria:

1. Outage of the contingent facility must not cause a cascading outage or precipitate uncontrolled separation within and external to the PJM Balancing Authority.
2. EHV facilities will not be included in this program. However there are cases in some areas where facilities up to and including 345 kV may be studied for inclusion in the program as long as there is no adverse impact on the transmission system.
3. The Transmission Owner of the facility will have established a short-term emergency rating for the facility (nominally 30 minutes).
4. Facilities must have more than one fast-start combustion turbine or diesel generator in the vicinity (and off-line) to eliminate a contingency should it occur. Normally, availability of 120% of the necessary generation to obtain the required MW relief from the 30-minute rating to normal rating will need to be demonstrated to account for the possibility that some generation will not start.
5. The net area generation has to have a history of being on-line and loaded for control within 30 minutes 85% of the time. (Normally, review of the previous 12 month performance will be sufficient to establish the historical performance.)
6. Where available, condensers will be brought on-line for control once contingency flow reaches the 4-hour emergency rating.
7. This program will be implemented during non-winter months for facilities where fast-start generation is used for control. Switching procedures that demonstrate successful winter implementation may be included under the program year-round.
8. Facilities in transmission systems that were designed to operate on a post-contingency basis as outlined in the next section will be considered on a case by case basis.

Alternative Controlling Options

1. The TO may offer generation run-back schemes to control for these facilities. These will be considered as controlling actions under this program after PJM tests the ramp-rate data as supplied by the generation owner. Further discussion and analysis is needed in this area prior to accepting these options. This document will be revised once these procedures are submitted, tested, and approved.

2. The TO may offer switching and reclosing procedures to control for these facilities in accordance with applicable regional requirements. These procedures must be studied and approved by PJM. These procedures may be implemented once PJM has the capability to properly study the impacts of these options in EMS.

Transmission Owners (TOs) must be capable of implementing the agreed upon post-contingency switching procedures via SCADA control. Additionally, TOs must have the ability to dump sufficient load via SCADA in the event that switching procedures cannot be implemented. Load dump cannot propagate to adjacent zones.

Where feasible, the switching procedures mentioned above may be implemented on a pre-contingency basis once contingency flow exceeds the 30-minute rating and all controlling generation has been called.

Systems Designed for Post-Contingency Switching

1. On a pre-contingency basis off-cost operations will commence once simulated contingency flow, using guide implemented contingency definitions, reaches the long-term emergency (LTE) rating.
2. On a pre-contingency basis off-cost operations will commence once simulated contingency flow, using guide failed contingency definitions, approaches the load dump (LD) rating.
3. In the event of a contingent facility tripping, the appropriate guide scheme will be used to ensure flow drops below the LTE rating on the monitored facility. If the post-contingency operating step does not reduce flow below the normal rating on this facility, generation re-dispatch, where available, will be used to bring flow below the normal rating.

Roles and Responsibilities

1. **PJM**. PJM will be responsible for selecting the facilities for inclusion into the program and performing the required analysis to ensure that the facilities meet the criteria for participation. PJM will consult with and communicate with the appropriate TO, as required, to ensure that the analysis is accurate. PJM will publish the list of facilities in PJM Manual M-03, Transmission Operations and will operate to the short term rating provided by the TO. If the rating is exceeded pre-contingency, PJM will operate off-cost to mitigate the simulated overload.
2. **Transmission Owner**. The TO will review and comment on the facilities proposed under this program. If the TO disagrees with a proposed facility they may take that facility to the PJM Dispute Resolution Process and PJM will delay implementation of that facility into the program until the completion of the process. The TO may offer additional facilities to be studied for inclusion under this program. The TO is responsible for establishing a short term rating for these facilities. These ratings will be submitted to PJM for approval. The TO will provide the necessary information to PJM to enable the appropriate analysis.
3. **Generation Owner**. The owners of the fast-response generation are to operate those units is accordance with the current PJM rules and procedures. When called upon to mitigate a transmission outage on a facility included in the program, the generation owner shall start the unit in accordance with PJM’s instructions.

Process for TO to Request PJM to Change constraints/facilities in the Post-Contingency Congestion Management program

1. By Dec 1 - TO formally submits the request, addressed to the Manager of Transmission Operations, for PJM to change the transmission constraints/facilities in the Program starting June 1 of the following year. TO should provide all necessary information with the request for PJM to perform the required analysis.
2. Shortly after Dec 1 - PJM posts all pending requests (including those selected by PJM and those requested by Transmission Owners) on the PJM website shortly after the Dec 1 submittal deadline.
3. Dec 1 to Feb 15 - PJM System Planning, System Operations, Performance Compliance and Market Monitoring Departments perform various studies to determine if the transmission constraint can be accepted in the Program.
4. Mar 1 - TO will be notified whether the requested transmission constraint can be accepted in the Program.
5. Mar 1 to Mar 8 - PJM posts the changes to the constraint list in the Program effective June 1 on the PJM website. PJM will indicate whether the constraint is accepted for non-Winter months only or for the year-round.
6. Jun 1 - PJM assumes the operation of the transmission constraints under the Program.

Note:
This process has the same timeline as the Process to Change the PJM Congestion Management Control Facilities List as stated in Section 1 of this Manual.

Post-Contingency Congestion Management Program Constraint List

There are no transmission constraints included in the operation of the Post Contingency Congestion Management Program.

Attachment E: Automatic Sectionalizing Schemes

List of currently active Automatic Sectionalizing Schemes is posted on OASIS at this link:

https://www.pjm.com/-/media/etools/oasis/system-information/manual-03-attachment-e-automatic-sectionalizing-schemes.ashx?la=en

Automatic Sectionalizing Schemes pending approval and recent changes are posted on OASIS at this link:

https://www.pjm.com/-/media/etools/oasis/system-information/manual-03-attachment-e-automatic-sectionalizing-schemes-pending-approval-and-recent-changes.ashx?la=en

Attachment F: Short Term Emergency Ratings

The referenced attachment lists facilities with STE Ratings and their appropriate time based durations (30-minutes, 2hrs, etc). The STE ratings are used on a post-contingency basis in conjunction with operating steps listed in Manual-03 Section 5 or Attachment D as special cases to control for an actual overload as defined in Section 2 and Exhibit 1. If no associated operating step exists or the associated operating step does not reduce the loading to below the LTE rating, the duration of the rating is utilized to determine the time to shed load.

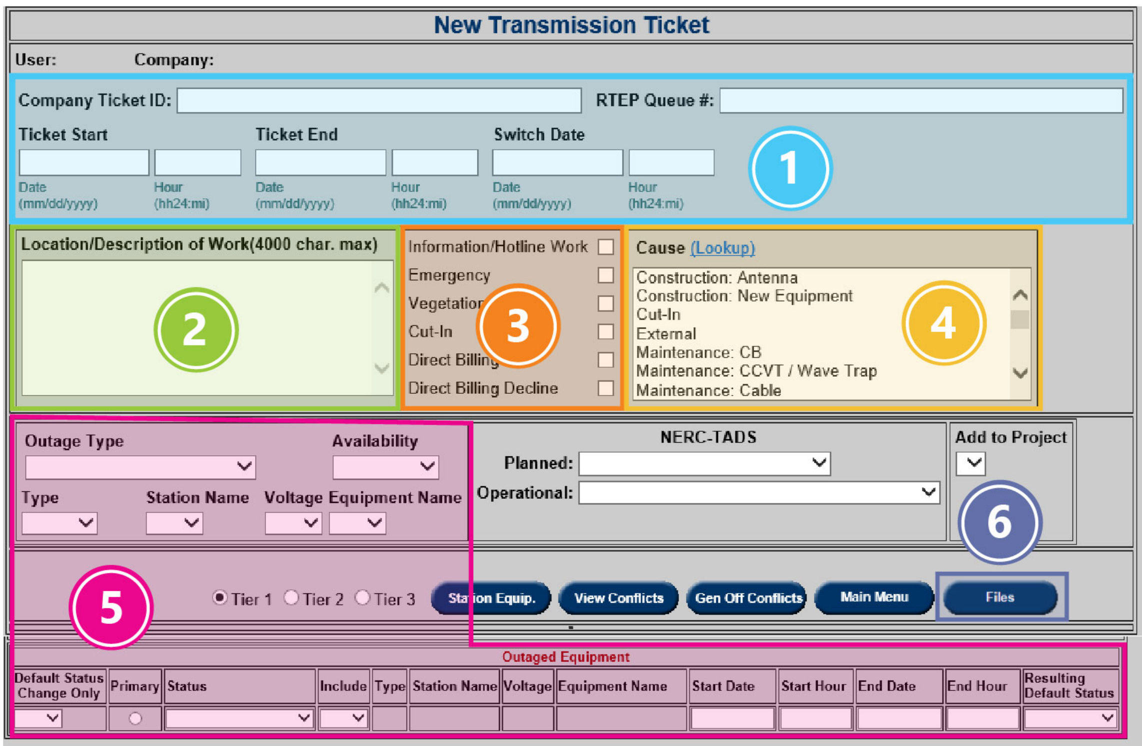
The STE rating list is posted on OASIS at this link:

http://www.pjm.com/~/media/etools/oasis/system-information/m03-attachment-f-ste-rating-list.ashx

Attachment G: Transmission Outage Ticket Best Practices

The following guidelines have been created in order to assist the Transmission Owner (TO) when creating and submitting transmission outage tickets. In order to remain consistent and provide the most accurate information, these guidelines can be used to determine the best way to convey an outage request. Information here will also provide the TO an understanding of all the flags on the eDART ticket and how they relate to specific referenced areas of M-3.

In conjunction with these guidelines, if help is needed on how to create and submit tickets, the eDART user guide can be found here: https://pjm.com/markets-and-operations/etools/edart



1. Dates/RTEP Queue #
    a. Start and end date of the scheduled work
    b. RTEP/Interconnection Queue numbers associated with the work being performed
2. Description of Work
    a. The nature of work being performed and the name/number of the equipment being worked. See FAQ for more details that should be in description of work.
3. Flags (as applicable)
    a. The Transmission Company specifies these flags concerning the nature of the work. See FAQ for description of flags.
4. Cause Type

   a. Generic classification of work being performed

5. Equipment/Availability
   a. Tabular list of equipment and facilities to be operated or unavailable during the outage
   b. Switching times (if different from ticket start/end)
   c. Availability of returning the outage before completion (for emergency purposes)
6. Attachments (optional)
   a. Additional files for PJM operators to better understand the nature of the work

FAQ when creating transmission outage tickets:

1. **<u>Dates/RTEP/Queue</u>**
   a. How should I enter times for equipment that will be open for switching only?
      i Please use the equipment status options of 'takeout', 'restore', and 'takeout and restore' for this function.
   b. How should I handle outages that have equipment coming out 'one a time?'
      i Ideally have one ticket with individual times listed *at the equipment level* for each piece of equipment. Please explicitly mention that the work is to be done *one at a time* in the 'Description of Work' field. 'One at a time' tickets should:
         • Have only ONE substation per ticket
         • Not cover more than one day (24 hour period) per ticket
   c. Do I have to enter anything in the RTEP field?
      i This field is reserved for any RTEP/Interconnection Queue numbers associated with the work being performed. If this information is available, it is very helpful for cross-reference/cross-divisional purposes and assistance with modeling of new equipment. RTEP/Interconnection Queue numbers can also be entered in the Description of Work.
2. **<u>Description of Work</u>**
   a. What should be included in the 'Description of Work' field?
      i The information in this field should be clear and concise and should include any or all of the following as they apply:
         • The nature of work being performed
         • The name/number of the equipment being worked on, including any equipment needed for takeout/restore, to ensure that the correct equipment has been selected from the equipment list
         • Any needed contingency switching to account for congestion
         • Any cross-referenced/related tickets that should be noted (i.e. cut-in tickets or other tickets associated with a project sequence)

- Any special procedures that may/will be implemented during the ticket
- Whether any NEW equipment will be energized AND/OR retired upon completion of this ticket (typically the 'cut-in' flag will be checked in this case *Refer to Flags section in this document and Attachment B in this manual for more information.*
- Any additional useful information that cannot be conveyed in other areas of the ticket
- If the equipment is unavailable to select in eDART, there should be a note in the description of work with the specific name of the equipment that should be included on the ticket. Refer to Equipment section in this document for more information.

b. Is all of the information listed above required?

i While these are just guidelines and not required, this field provides the TO the opportunity to convey as much detail as possible in order to ensure the outage is studied appropriately. If this field is not populated sufficiently, the ticket may be flagged as 'potentially incomplete' (see Flags section in this document)

3. **Flags**

a. What is the purpose of each flag available to the transmission company?

i Emergency - This flag should be checked by the TO if the work is emergent and cannot wait for proper on-time submittal. It should be noted that once this flag is checked, the ticket may be open to additional review to ensure the emergency status is being used properly. *Refer to Section 4.2.8 in this manual for additional information.*

ii Cut-in Flag - This flag should be checked by the TO if completion of the ticket will result in any new energization, retired equipment, and/or a change in parameters such as impedance and ratings. *Refer to Attachment B in this manual for additional information*

iii Direct Billing/Direct Billing decline - Use of this flag applies to tickets that are NOT ON TIME for which congestion is expected. Any time this flag is checked, it should be done so in conjunction with coordination with PJM outage coordination contacts. *Refer to Section 4.2.9.1 in this manual for additional information.*

iv Info Hotline Work - This flag should be checked by the TO for in-service work. Refer to Section 4.2.2 in this manual for additional information.

v Veg Trip - This flag should be checked by the TO if the nature of the work is for vegetation. Note that use of the Cause Type – 'Maintenance: Vegetation' will result in this flag being automatically checked.

b. What are the additional flags unavailable to transmission owners?

i Submit On-Time (automatic or PJM Personnel*) - This flag is checked/un-checked using built in logic within eDART based on PJM outage submittal rules. PJM personnel also have a tool which can tell if rescheduling a ticket impacts it's on-time status; contact your PJM outage coordination contact if you want to evaluate if a ticket gains/losses on-time status if you were to reschedule it. *Refer to Section 4.2.1 in this manual for additional information.* *PJM personnel may check the flag at their discretion and in coordination with the TO when circumstances indicate it is warranted.

ii Potentially Incomplete (automatic) - This flag may be checked by eDART if the information in the 'Description of Work' field is insufficient. (See 'Description of Work' section in this document for more information)

iii Market Sensitive (automatic) - This flag may be checked by eDART if any of the equipment selected for the ticket is associated with a generator. The market sensitive equipment will not be publicly posted on OASIS.

iv Congestion Expected (added by PJM personnel) - This flag will be checked by the PJM Outage Analysis Team in conjunction with subsequent information detailed in the 'PJM Comments' field. While the flag is checked if congestion is encountered during analysis, there are additional reasons for which this flag may be used to draw attention to the ticket. Reasons include but are not limited to:

- Contingency activation/de-activation needed
- Contingency switching solution needed
- Modeling issues/concerns with the ticket
- Capacitor switching indicated

v At Risk (added by PJM personnel) - This flag will be checked by the PJM Outage Analysis Team (often during the six month out/one month out analysis timeframe) whenever there is uncertainty on whether the outage can be completed on the dates requested. This can be due to:

- Load Dependent – in this case, typically the flag remains checked until the near-term analysis is completed with more accurate load projections
- Conflicts with other outages submitted during the same timeframe – details will be provided in the PJM comments field and conflicts should be resolved in coordination with the PJM Outage Analysis Team and other affected TO's as necessary.

4. **Cause Type**

a. How do I know what Cause Type to select for my outage?

i Please refer to the following link for a list of Cause Type definitions when entering eDART tickets. https://www.pjm.com/-/media/committees-groups/forums/edart/edart/20161202/20161202-transmission-outage-cause-types.ashx?la=en

5. **Equipment/Availability**

a. What should I choose as primary equipment?

i The TO should choose the main equipment that is being worked on for the outage. (i.e. a transmission line or transformer) Any supporting equipment like circuit breakers/disconnects for clearance should be listed subsequently.

b. Should Transmission Owners enter any default status information for equipment when entering their ticket?

   i NO, default status equipment is entered by PJM personnel ONLY.

c. What equipment should be included for a line I am taking out of service?

   i For a line coming out of service completely, listed equipment should include the line as well as all clearance points. (i.e. any associated circuit breakers/ disconnects that will be out of service for clearance)

d. How should I enter equipment if a line will only be open-ended?

   i Please use the 'open-ended' equipment status option for this function. *Per section 4.2.1 in this manual:* "All line and transformers that will be outaged or open ended as a result of the scheduled maintenance must be included in the outage request. For example, an outage request for CB work that open ends a line must include the line as being out of service in the ticket. This will ensure proper posting of all outages to the PJM OASIS and the NERC System Date Exchange (SDX) site.

e. "What if I have to change/add/delete some of the equipment on my ticket after it has been submitted?

   i Once an outage is submitted, some changes to equipment might be needed. It is important to note that the outage is subject to additional scrutiny if initial equipment is changed/deleted and/or new equipment is added to ensure the scope of work has not been changed. If the changes are so extensive that it will change the scope of work, it is suggested that an additional supporting ticket be created with a cross-referenced note in the 'Description of Work' field.

f. What if I see a message that says 'This ticket has been locked by PJM'?

   i Once a ticket has been moved to 'approved' status and/or if any default status equipment changes have been made to the ticket by PJM personnel, the TO will no longer be able to make changes directly to the ticket. If changes are needed, the TO will have to contact PJM in order to request any changes.

g. What if the 'availability' of return for my outage is variable at different times during the outage?

   i Upon entering the ticket, please select the *initial/starting* availability for the outage. It should be noted in the 'Description of Work' field that the availability for this outage will be variable. This information should also be communicated to the PJM outage analysis contact. Once the outage has begun, the TO should contact their PJM counterpart to request the 'availability' status be updated accordingly throughout the duration of the outage.

h. What if the equipment being worked on is not yet available in eDART?

   i If the equipment coming out of service is not modeled in PJM (not available in eDART), a similar equipment should be chosen and a note should be added to the description stating the equipment is not available in PJM. The actual equipment should be mentioned in the description so that it can be added when available.

6. **Attachments**

   a. What attachments should be included with an eDART ticket?

      i This feature can be used for any outage tickets that are associated with projects and/or ‘cut-in’ tickets to highlight changes being made. Examples of attachments include: one-line diagrams and project sequences. Attachments are not required and are not needed for all eDART tickets, but can be helpful to provide additional information on the outage.

Revision History

Revision 58 (11/19/2020):

- Periodic Review: Updated references to Manual-03B throughout.
- Section 3.3.1: Corrected 138 kV PJM Baseline limit.
- Section 1, 3, and 4: Updated EHV reference by defining EHV and removed duplicate uses.

Revision 57 (05/29/2020):

- Periodic Review
- Corrected typos, removed references to SPS. Updated references to Section 5.
  - Moved the contents of Manual-03 Section 5 to a new Manual-03B: Transmission Operating Procedures.
- Section 1.5: Removed Section 2 reference from Manual 3A.
- Section 1.7: Updated RAS procedure for PRC-012 standard.
- Section 3 and Attachment C: Updated baseline voltage tables and voltage exception request due to new eDART function for voltage limit implementation.
- Section 3.9: Removed language concerning TSA Benchmarking.
- Section 3.11: Effective June 1, 2020, eDART Voltage Schedules is the required method for communicating generator voltage schedules.
- Section 4.5: Added Outage Acceleration posting site and contact email.
- Section 5: Updated RTO Perry and Calvert Cliffs NPIR voltage limits.
- Section 5: Updated NY/NJ PAR Coordination and deleted 5018 Hopatcong – Ramapo PAR Coordination in RTO based on updated Joint Operating Memo (OM 022B Market to Market Redispatch Flowgates and NY NJ PAR Coordination, Rev. 10).
- Section 5: Updated AE directional ratings table.
- Section 5: Updated AEP Jacksons Ferry SVC Procedure.
- Section 5: Removed AEP Cook Stability Restriction Procedure.
- Section 5: Updated FE-S Belmont RAS Procedure.
- Section 5: Updated FE-E Seneca Stability Procedure with updated limits.
- Section 5: Added new FE-E Ironwood Stability Procedure.
- Section 5: Updated FE-E Homer City Stability Trip procedure.
- Section 5: Updated BGE Calvert Cliffs Stability Limit Procedure.
- Section 5: Deleted BGE Westport Breaker Limitations and Gould St. Generation Operations procedure.
- Section 5: Removed ComEd Lisle substation from Normally Open Bus Tie procedures.

- Section 5: Updated language to use RAS for the ComEd Electric Junction – North Aurora procedure and modified location of CS 0605 to be at 11106 line
- Section 5: Updated ComEd Camp Grove Islanding (SPOG 2-40) procedure for new configuration.
- Section 5: Updated the ComEd Powerton Stability Trip Scheme procedure due to the new Nevada substation.
- Section 5: Updated the ComEd Islanding Prevention Scheme for TSS 941 Grand Ridge Generation (SPOG 2-41) procedure.
- Section 5: Updated ComEd Prospect Heights SVC procedure.
- Section 5: Added new Lancaster Automatic Trip Scheme to Prevent Islanding of Ecogrove procedure.
- Section 5: Updated powerflow/SA language for the DOM Northern Virginia High Voltage Control procedure.
- Section 5: Added new DOM Mosby/Mt. Storm SVC procedure and Colington STATCOM procedure.
- Section 5: Added new DOM Ladysmith/Doswell Stability Procedure.
- Section 5: Updated DOM Brunswick/Greensville Stability procedure.
- Section 5: Added new PECO Conowingo stability procedure.
- Section 5: Added new PPL Safe Harbor Relay procedure.
- Section 5: Updated PPL Martins Creek stability procedure.
- Section 5: Updated PSEG Artificial Island procedure due to new substation.
- Attachment A: Updated language for Wolfs Crossing RAS.
- Attachment A: Removed two Lisle schemes due to station reconfiguration.
- Attachment B: Added clarifying language to 'Cut-In' Criteria for TO associated with project work.

Revision 56 (12/05/2019):

- Periodic Review.
- Section 1.1: Updated TOP distinction.
- Section 1.7: Updated PJM Procedure to Review Remedial Action Schemes/Special Protection Systems (RAS/SPS) to remove mention of Special Protection Systems (SPS).
- Section 3.2: Updated voltage drop reference as a percentage of pre kV by removing reference to nominal voltage.
- Section 3.5.3: Updated EHV capacitors in auto mode.
- Section 3.7 – Added additional lines to Dominion area for High Voltage Control.
- Section 4.2.12: Removed Nuclear Generating Station's Circuit Breaker listing table.

- Section 4.3.2: Updated language in Real-Time Switching notification procedure to better align with dispatch switching practices.
- Section 5: Updated the RTO Recognition of Automatic Sectionalizing Schemes procedure.
- Section 5: Updated Dresden NPIR voltage limits and removed EMS bus node names.
- Section 5: Removed TMI NPIR limits due to unit retirement.
- Section 5: Updated Bi-Directional Ratings for AE.
- Section 5: Updated Bi-Directional Ratings for DPL.
- Section 5: Removed reference to Darwin in the header of the AEP Rockport procedure.
- Section 5: Updated AEP Tidd 138 KV switchyard operating guideline for Overduty Circuit Breakers.
- Section 5: Moved Dayton Darby procedure to AEP.
- Section 5: Updated AEP Cook Plant stability procedure.
- Section 5: Added Jacksons Ferry SVC procedure to AEP.
- Section 5: Added description of conditions for the 2345 circuit for the BGE 230 kV Harbor Crossing Cables procedure.
- Section 5: Updated ComEd Burnham – Taylor 345 kV Line Operation (SPOG 3-6).
- Section 5: Updated ComEd Transformer Operations at 138 kV Line Tie Breaker Substations (SPOG 4-30).
- Section 5: Updated ComEd SPOG 2-2-B Marengo procedure.
- Section 5: Updated ComEd SPOG 2-2-C Damen procedure.
- Section 5: Added ComEd Prospect Heights SVC procedure (SPOG 2-45).
- Section 5: Removed ComEd Itasca 138 kV N.O. Bus Tie 2-3 CB SPOG 2-37.
- Section 5: Removed ComEd Quad Cities/Cordova RAS/SPS procedure due to retirement.
- Section 5: Updated DOM Bath County Stability restriction for Valley-Dooms 500kV.
- Section 5: Updated Circuit Breaker name for Gordonsville Bus Tie under South Anna and Louisa CT Islanding Scheme.
- Section 5: Updated Glebe-VirginiaHills-Ox line reference from 2159A to 248 and added line #294 for parallel Braddock-Annandale in the Northern Virginia High Voltage Control procedure.
- Section 5: Removed Lexington Area Loss-of-Load Contingency Mitigation Procedure due to additional Dooms-Lexington 2168 line.
- Section 5: Removed PPL Martins Creek Overdutied breaker procedure.
- Section 5: Added new PPL Wescosville 500/138 kV T3 Transformer Switching procedure.

- Section 5: Updated the UGI/PPL 66 kV Tie Line Operation procedure.
- Section 5: Updated FE EAST Conemaugh/Hunterstown/Fairview Stability Limits procedure.
- Section 5: Updated FE EAST Homer City #2 & #3 Stability Trip (RAS) unit output arming criteria.
- Section 5: Updated FE EAST Homer City Stability Limits single outage damping restrictions.
- Section 5: Updated FE EAST Seneca Stability procedure.
- Section 5: Updated FE EAST Seneca Pumping Notification Procedure (title only).
- Attachment A: Removed the Quad Cities Unit Stability Trip Scheme.
- Attachment A: Removed the Cordova /Quad Cities Multi-Line-Outage Unit Trip Scheme.
- Attachment A: Updated North Hampton RAS description based on future retirement.
- Attachment B: Replaced cause type from ‘New Construction’ to ‘Construction: New Equipment’ to align with eDART.

Revision 55A (10/31/2019):

- Section 5: Deleted Gas-Pipeline Contingency Analysis Procedure

Revision 55 (05/31/2019):

- Cover to cover periodic review. Updated links and terminology throughout.
- Section 3.3: Added NextEra to Voltage Limit table.
- Section 3.9: Added language for TSA real-time monitoring and control for dynamic stability.
- Section 4.2.2: Added on-time criteria for hotline work that may have system impact and a clarification note concerning RTU outages not requiring an eDART ticket.
- Section 5: Updated RTO NPIR Voltage limits for North Anna, Surry, and Peach Bottom. Clarified Susquehanna voltage.
- Section 5: Removed the ComEd Dresden Bus Operation procedure.
- Section 5: Updated the ComEd Powerton Stability procedure.
- Section 5: Updated the ComEd Normally Open Bus Tie procedure.
- Section 5: Removed the ComEd/MISO Pleasant Prairie-Zion Conservative Operation procedure.
- Section 5: Removed the FE West Mansfield Unit 2 Reclosing Restriction.
- Section 5: Updated the FE EAST Hunterstown/Conemaugh stability procedure for the interconnection of the Fairview CC.
- Section 5: Updated the FE East Birdsboro Plant Stability Restriction.
- Section 5: Updated the AEP Rockport operating guide limits.

- Section 5: Removed the AEP Conesville 345 kV plant procedure.
- Section 5: Added new FE East Asylum/Liberty Stability procedure.
- Section 5: Updated the PSEG Artificial Island Stability procedure.
- Section 5: Removed the Dominion North Hampton RAS Procedure.
- Section 5: Updated the Peach Bottom Transformer outage procedure for Muddy Run regulation.
- Section 5: Updated NY/NJ PAR Coordination and NYISO Ramapo Par Operating Instruction for Hudson reconfiguration to Marion.
- Section 5: Updated RTO NY/NJ PAR Coordination General Principles tap change language.
- Attachment A: Updated the Lisle RAS description.

Revision 54 (12/10/2018):

- Cover to cover periodic review. Corrected typos, updated equipment names, and updated terminology throughout.
- Section 1.7: Added external RAS evaluation process.
- Section 2.1.3: Updated note for PCLLRW issuance.
- Section 3.2: Updated language to refer to existing charts for time to control for limit exceedances and added note for PCLLRW issuance.
- Section 3.5.5: Added clarification that PJM will use the Normal High limits for line open-ended condition if the Emergency High voltage limits are not defined by the Transmission Owner.
- Section 3.8: Updated Western reactive interface definition.
- Section 3.11: Updated Generator Voltage Schedules procedure to reflect new eDART functionality for defining, communicating, and acknowledging voltage schedules.
- Section 4.2.12 and Section 5: Removed references to Oyster Creek nuclear plant due to retirement.
- Section 4.5: Updated the Outage Acceleration process.
- Section 5: Removed RTO procedure listing/table.
- Section 5: Removed BGE/PEPCO/Doubs/Northern Virginia (NOVA) operating procedure.
- Section 5: Added AE Cardiff/Cedar/Dennis SVC procedure.
- Section 5: Removed ComEd Mazon-Crescent Ridge 7713 line directional ratings procedure.
- Section 5: Added new AEP Cook Stability Restriction procedure.
- Section 5: Updated AEP Rockport Operating Guide.

- Section 5 and Attachment A: Removed DOM Carolina 54 RAS procedure due to retirement.
- Section 5: Updated DOM Bath County Stability Restrictions procedure.
- Section 5: Updated Dom Brunswick/Greensville Stability Restrictions procedure.
- Section 5: Added new DEOK switching procedure.
- Section 5: Added new FE East Birdsboro Stability Restriction procedure.
- Section 5: Updated FE East Conemaugh/Hunterstown stability procedure.
- Section 5: Updated FE East Keystone-Conemaugh re-closing procedure.
- Section 5: Updated CB names for PPL Martins Creek Overdutied Breakers procedure.
- Section 5: Updated ComEd Wolfs Crossing procedure.
- Section 5: Updated ComEd Transformer Operations at 138 kV Line Tie Breaker Substation procedure.
- Section 5: Updated DLCO Arsenal-Brunot Island 345 kV common trench cable ratings.
- Section 5 and Attachment A: Removed ComEd Davis Creek SPS/RAS procedure.
- Section 5 and Attachment A: Removed ComEd University Park SPS/RAS procedure.
- Section 5 and Attachment A: Removed BGE Mt. Washington RAS procedure.
- Attachment E: Moved table to OASIS.

Administrative Change (06/01/2018):

- Section 5: The changes to the NPIR voltage limits for North Anna and Surry plants were reverted back to their prior limits due to further review.

Revision 53 (06/01/2018):

- Cover to cover periodic review. Corrected grammar and formatting throughout.
- Section 1.7: Updated the RAS Committee review procedure.
- Section 2.1: Updated Note 3 for Thermal Limit corrective action.
- Section 3.3: Added OVEC voltage limits.
- Section 3.8: Updated the Eastern Interface and Cleveland Interface definitions.
- Section 3.12: Updated Note concerning RRC submittal via ICCP.
- Section 5: Updated North Anna, Surry, and Limerick NPIR voltage limits.
- Section 5: Updated ComEd SPOG 2-22 procedure.
- Section 5: Added retirement dates for the ComEd Davis Creek and University Park North schemes.
- Section 5: Updated the ComEd Dresden Bus tie procedure.
- Section 5: Added new section for OVEC without any special operating procedures.

- Section 5: Updated the FE-East West Wharton SVC procedure.
- Section 5: Updated FE-East Homer City procedure.
- Section 5: Updated FE-East Seneca stability procedure.
- Section 5: Updated the FE-East Conemaugh/Hunterstown stability procedure.
- Section 5: Updated FE-South Belmont RAS procedure.
- Section 5: Updated the AEP Cook Unit Isolation procedure.
- Section 5: Updated the AEP Gavin-Rolling Hills procedure.
- Section 5: Updated the AEP Rockport procedure.
- Section 5: Updated the AEP Additional Regional procedure.
- Section 5: Added DLCO new common trench rating for 302, 307, and Z-45 circuits.
- Section 5: Updated AE Directional Rating.
- Section 5: Removed the PSEG Bergen Overdutied Breakers procedure.
- Section 5: Updated the PECO Peach Bottom #1 Transformer RAS procedure.
- Section 5: Added new PPL Martins Creek Overdutied Breakers procedure.
- Section 5: Updated PPL NEPA Stability procedure for new plants in the area.
- Section 5: Added new Dominion Brunswick/Greensville stability procedure.
- Section 5: Added new Dominion Chesapeake, Fentress, Landstown and Lynnhaven STATCOM's procedure.
- Attachment A: Updated RAS descriptions.
- Attachment C: Added note to indicate PJM will notify TO of NPIR voltage changes.
- Attachment E: Added the AEP Huntington-Sorenson 138 kV sectionalizing scheme.
- Attachment E: Added the PPL Frackville #1, #2 and #3 230/69 kV transformer sectionalizing schemes.
- Attachment E: Removed retired schemes and updated other schemes.

Administrative Change (03/14/2018):

- Section 1.5: Added Missing note between Section 1.5.6 and 1.5.7.
- Section 5: Corrected a table formatting issue for PECO Limerick directional ratings.

Revision 52 (12/22/2017):

- Cover to cover periodic review. Updated references and terminology. Designate SPS to RAS or to scheme where applicable.
- Section 1.2: Added notification language for conditions that will result in the loss of multiple generation units.
- Section 1.7: Updated dates for the SPS/RAS review and classification.

- Section 3.5.3: Added Montgomery and Damascus 230 kV capacitors. Removed Black Oak, Meadow Brook, and Doubs #2 capacitors.
- Section 3.9: Added NERC TPL standard references for stability analysis criteria.
- Section 3.9.1: Removed reference to Out of Management Control for stability restrictions.
- Section 3.11: Added notification language for the Generator Voltage Schedules updates.
- Section 3.12: Clarifications and additional information added with respect to the Reactive Reserve Check RRC process.
- Section 5: Updated nuclear voltage (NPIR) limits and reorganized procedure.
- Section 5: Updated the Automatic Remedial Action Scheme (RAS) Operating Criteria section.
- Section 5: Updated AEP Rockport Operating guide.
- Section 5: Updated the Dayton Darby Plant procedure.
- Section 5: Updated BGE Mt. Washington RAS procedure.
- Section 5: Updated the AEP Rockport Operating procedure.
- Section 5: Removed PJM/NY-ISO PAR Operation procedure.
- Section 5: Updated Oscillation Mitigation Procedure.
- Section 5: Updated the PECO Peach Bottom Transformer Outage procedure.
- Section 5: Updated the ComEd Kincaid Stability Trip Schemes procedure.
- Section 5: Updated the ComEd Powerton Stability Trip Schemes procedure.
- Section 5: Updated the ComEd Quad Cities and Cordova Limitations procedure.
- Section 5: Updated the ComEd East Frankfort TR83 345/138 kV Transformer Scheme procedure.
- Section 5: Updated the ComEd University Park North Energy Center Stability Trip Schemes procedure.
- Section 5: Updated the ComEd Elgin Energy Center Stability Bus Tie Scheme procedure.
- Section 5: Updated the ComEd Wolfs TR 81 Scheme procedure.
- Section 5: Updated the ComEd Dresden Unit 2 Trip Scheme procedure.
- Section 5: Updated the Dominion Clover Gen Shed Scheme procedure.
- Section 5: Updated the Dominion Bath County-Valley Stability RAS procedure.
- Section 5: Updated the Dominion Carolina RAS procedure.
- Section 5: Updated the FE-W Mansfield reclosing procedure.
- Section 5: Added the FE-S West Moreland/Ronco/South Bend stability procedure.
- Section 5: Added the FE-S Squab Hollow SVC procedure.

- Section 5: Updated the FE-S Belmont RAS procedure.
- Section 5: Updated the FE-E Warren-Falconer procedure by removing SPS designation.
- Section 5: Updated the FE-E E.Sayre-N.Waverly procedure by removing SPS designation.
- Section 5: Updated FE-E Seneca's pumping procedure.
- Section 5: Removed DUQU Crescent #1 or #3 345/138 kV Autotransformer Relief procedure.
- Section 5: Removed the FE-E Yards Creek SPS procedure due to retirement. Tentative effective date of December 31, 2017.
- Section 5: Removed FE-S Willow Island Area thermal overload procedure.
- Section 5: Added new procedure for gas-pipeline contingency analysis in RTO section.
- Attachment A: Removed Rockport Fast Valving SPS.
- Attachment A: Removed Aurora SPS.
- Attachment A: Removed Warren-Falconer SPS.
- Attachment A: Removed N. Waverly-E.Sayre SPS.
- Attachment A: Modified RAS/SPS descriptions.
- Attachment A: Remove the Yards Creek SPS.
- Attachment E: Added Jenkins #1 TX scheme with effective date.
- Attachment E: Added Elko #1 transformer scheme with effective date.
- Attachment E: Removed retired schemes and updated effective dates.

Revision 51 (6/1/2017):

- Cover to cover periodic review. Changed formatting, updated references. Updated terminology for Constraint Logger, SmartLog, etc.
- Section 1.3: Added contingency verification step to the modeling issue investigation process.
- Section 1.5.6: Added note to indicate PJM EMS has the capability to monitor flow on devices such a circuit breakers (Flow Device). Transmission Owners can submit device/ circuit breaker ratings following the same process as other facilities.
- Section 3.3, Exhibit 3, and Exhibit 5: Updated section and combined exhibits with new tables for PJM Baseline Voltage Limits and Transmission Owners' Voltage Limits.
- Section 3.3.3: Moved Generator Voltage Schedules from Section 3.3.3 to new Section 3.11 and clarified language
- Section 3.5.3: Updated Bulk Electric System Capacitors Operation at Erie South, Four Mile, and West Wharton.
- Section 3.7: Removed TMI-Hosensack as a high voltage control switching option due to system upgrade.

- Section 3.8: Changed one Eastern interface definition line from TMI-Hosensack to Lauschtown-Hosensack. Reformatted interface definition table to “from-to” format.
- Section 3.12: Added new section Reactive Reserve Check (RRC). Previously located in Manual-14D.
- Section 4.1: Added paragraph highlighting need for Transmission Owners to enter outages for transmission equipment owned by Generation Owners
- Section 4.2.2: Updated the relay outage and degradation reporting criteria. Changed note text from “Hotline” to “automatic reclosing”.
- Section 4.2.6: Revised Peak Period Outage Scheduling Guidelines to add clarity on denial under certain projected conditions.
- Section 4.2.13: Updated title and added Transmission Owner notification to impacted unit owner.
- Section 5: Updated procedure types throughout in various procedure table listings.
- Section 5: Updated the NPIR voltage limit table.
- Section 5: Replaced PS/ConEd Wheel procedure with NY/NJ PAR Coordination procedure.
- Section 5: Updated reference for MISO Pleasant Prairie – Zion E.C procedure.
- Section 5: Updated the ComEd Quad Cities / Cordova procedure.
- Section 5 and Attachment A: Removed the ComEd Byron/Lee County operating procedure and SPS due to upgrades.
- Section 5: Updated the ComEd Powerton Stability/SPS procedure.
- Section 5: Updated the ComEd Normally Open Bus Tie CB procedure by removing the Wayne CBs.
- Section 5: Removed Single breaker de-rate section for BC, DOM, DLCO, DEOK, FE-South, PPL, and PS.
- Section 5: Updated AEP Smith Mountain 138 kV Station Stability.
- Section 5: Updated AEP Conesville 345 kV Plant Operating Guidelines.
- Section 5: Updated AEP Cook Unit Isolation on Select Circuits.
- Section 5 and Attachment A: Added new Dominion North Hampton Remedial Action Scheme procedure.
- Section 5: Updated UGI Mountain 23030 Bus Tie Operation procedure.
- Section 5: Updated the PECO Peach Bottom Transformer RAS/SPS procedure.
- Section 5: Updated the BGE Calvert Cliffs procedure.
- Section 5: Updated the DLCO Cresent 345/138 transformer relief procedure by removing a single breaker derate reference.
- Section 5: Added the FE East West Wharton SVC procedure.

- Section 5: Added the FE East Erie South SVC procedure.
- Section 5: Updated the FE East Altoona SVC procedure.
- Section 5: Renamed the ATSI Mansfield procedure.
- Section 5 and Attachment A: Removed the BGE Concord Street RAS/SPS procedure due to retirement on 5/31/17.
- Section 5 and Table of Contents: Renamed the PSEG Bergen Overdutied Breaker procedure (previously Bergen Normally Open Equipment procedure) and edited procedure for clarity.
- Section 5: Reformatted tables in PE Limerick 4A and 4B 500/230 kV Transformer Banks procedure.
- Section 5: Updated and renamed the PE Muddy Run Restrictions procedure.
- Section 5 and Attachment A: Removed the Linwood SPS procedure.
- Section 5: Changed projected retirement date for BGE Mt. Washington RAS/SPS procedure from June 2018 to December 2018.
- Section 5: Updated reference title for Bath County – Valley Stability RAS/SPS.
- Section 5 and Attachment A: Removed the PPL Jenkins SPS procedure due to retirement.
- Section 5: Updated AEP Tidd 138 kV Switchyard Operating Guidelines for overduty circuit breakers.
- Section 5: Deleted AEP Tidd 345 kV Station Voltage Concerns procedure.
- Section 5: Added PPL Susquehanna CB switching procedure.
- Section 5: Added PPL Martins Creek stability procedure.
- Section 5: Updated name to PPL Northeast PA (NEPA) Stability Limit. Updated line names and added stability restriction table for Transmission Outage with impact to Sunbury CC.

Attachment E: Updated the list of sectionalizing schemes by removing schemes no longer needed due to upgrades. Added new sectionalizing schemes in Dominion with effective dates of 7/27/17.

Revision 50 (12/1/2016):

- Cover to cover periodic review. Corrected typos and grammar. Revised terms for consistency. Updated graphics, tables, and exhibits. Updated cited NERC standard(s).
- References: Added NYISO PJM Joint Operating Agreement.
- Section 1.1: Listed ITCI as TOP for its facilities.
- Section 1.4: Clarified language.
- Section 1.7: Revised RAS/SPS review process. Added RAS term throughout.

- Sections 2 and 3: Replaced 'Load Shed Operating Instruction' to 'Load Shed Directive' to align with terminology in M-13.
- Section 2.1.3: Revised language in table - "PJM Actual Overload Thermal Operating Policy" on limit exceedance.
- Section 3, Exhibit 5: Updated SMECO integration date to Q1 2017 and voltage limits. Corrected PJM baseline voltage limits to one decimal place and the corresponding TO limits.
- Section 3.3.3: Clarified generator voltage exemption basis and updated baseline voltage table notes.
- Section 3.4: Removed PCLLRW pertaining to NPIR voltages.
- Section 3.5.3: Updated Juniata capacitor bank.
- Section 3.8: Updated the Cleveland Interface definition by adding the new Lake Avenue #1 and #2 345/138 kV transformers and changing the Black River-Lorain 138 kV to Charleston-Lorain 138 kV. Updated CE-East Interface from Olive-University Park to Olive-University Park North 345 kV line. Updated the AP South Interface definition from Mt. Storm-Doubs to Bismark-Doubs. Updated the BC/PEPCO Interface definition from Pleasant View-Dickerson to Edwards Ferry-Dickerson.
- Section 4: Clarified language and distinguished between transmission outage denial and cancellation.
- Section 4, removed reference to outages submitted after 0800 three days prior to requested start date
- Section 4.2.2: Updated relay work reporting to include 230 kV and other facilities near generating plants and timeline.
- Section 4.2.9: Revised language on rescheduling outages for clarity and added information about modifying equipment list on tickets.
- Section 4.2.11: Updated Nuclear circuit breaker table.
- Section 5: Added table for Cook nuclear voltage limits after regular nuclear voltage limits table (removed cook references from regular table). Added a note to indicate the voltage drop criteria is only applicable for the loss of a unit.
- Section 5 and Attachment A: Updated the PSEG Artificial Island procedure due to the Cross Trip SPS retirement.
- Updated the PSEG Bergen procedure.
- Section 5: Updated the AE directional ratings.
- Section 5: Updated the AEP Smith Mountain procedure.
- Section 5: Updated the AEP Gavin – Rolling Hills Stability procedure.
- Section 5: Updated the AEP Rockport procedure.
- Section 5: Updated Voltage Control at Nuclear Stations procedure.
- Section 5: Added action for TO/GO to notify PJM of SPS/RAS unavailability.

- Section 5: Added action for TO to notify PJM of Sectionalizing scheme unavailability or degradation.
- Section 5: Updated the ComEd Kincaid stability procedure.
- Section 5: Updated the ComEd East Frankfort SPS procedure.
- Section 5: Updated the ComEd Byron SPS procedure.
- Section 5 and Attachment A: Removed the ComEd Northbrook/Highland Park Transfer Trip SPS due to retirement.
- Section 5: Added retirement dates for the ComEd Quad Cities/Cordova SPS.
- Section 5: Updated the BC/PEPCO operating procedure.
- Section 5: Updated the FE East Conemaugh/Hunterstown and Homer City procedures.
- Section 5 and Attachment A: Removed Bath County Thermal SPS and all references.
- Section 5: Removed outage timeframe from Bath County - Valley Stability SPS.
- Section 5: Removed references from table to both Cloverdale 500/345kV transformers and updated Mt.Storm-Doubs for Bismark in Bath County Stability Restrictions procedure.
- Section 5: Added temperature set for Carolina 54 SPS.
- Section 5: Updated Clover SPS/RAS Procedure.
- Section 5: Added the PJM Actions to the PPL Steel City – Hosensack 500 kV Reclosing procedure.
- Attachment A: Modified the PECO Planebrook SPS description.
- Attachment A: Modified the PECO Linwood SPS description.
- Attachment A: Rename title of Clover Generator Shed Scheme to Clover RAS/SPS Scheme.
- Attachment B: Added new attachment (to replace 'deleted') called Transmission Outage 'Cut-In' Ticket Guidelines
- Revision History, V49: Corrected history to add "removal of Load Shed Directive Procedure and placement in M-13".

Revision 49 (06/01/2016):

- Periodic Review: Updated terms throughout document for consistency
- Introduction – Modified intended audience for this manual
- Section 2.1.3 and 3.2 – Clarify time to correct in table columns and add reference to Load Shed Operating Procedure
- Section 3.2 and 3.5.3 – Clarified Normal and Emergency High voltage limits
- Section 3.2 and 3.3.2 – Remove references to specific voltage levels
- Section 3.3.1 – Changed 34 kV LD baseline voltage limit to n/a instead of 0.0

- Section 3.3.3 - specified email address for generator voltage exemption requests (instead of requests through SOS chair)
- Section 3.5.5 – Clarified language on high voltage limits
- Section 3.5.3: Updated Bulk Electric System Capacitor/SVC Operation, as a resulst of new SVC's placed in-service.
- Section 3.7: Updated High Voltage Operation techniques; added STATCOM
- Section 3.7 – Removed opening of Homer City – Stolle Road as an option to control high voltage
- Section 3.8 – Added reference to steady state voltage collapse point and post-contingency low voltage in reactive interface limit determination
- Section 3.8 – Removed prior ComEd interface definition
- Section 3 Exhibit 5 - Added SMECO (effective 7/1/16) and ITCI (effective 6/1/16) companies to table.
- Section 3 Exhibit 5 - Added ATSI 500 kV voltage limits
- Section 3 Exhibit 5 – Updated ITCI Normal Limit and Normal High Limit (effective 6/1/16)
- Section 3 Exhibit 5 – Updated EKPC voltage drop limit and emergency low voltage limit.
- Section 3 Exhibit 5 – Updated Dominion and UGI normal high voltage limits.
- Section 4.2.1 – Renamed section to "Outage Submittal Rules" and modified language for ease of understanding. Removed 'past deadline' section of table on outages <= five calendar days
- Section 4.2.6 – Condensed language on "Peak Period Outage Scheduling Guidelines" to make Summer Peak Period June 15 – September 15 and recommend all outages scheduled during peak periods have < 72 hour restoration time
- Section 4.2.7 – Modified language on "Outage Scheduling Exceptions" for clarity
- Section 4.2.9 – Added note on Rescheduling Outages for clarity
- Section 4.2.11 – Revised language for "Coordinating Outage Requests With Other RTO's"
- Section 4.2.13 – Modified language on Coordinating Transmission Outage Requests that will make a generation facility unavailable.
- Section 5: Removed Load Shed Directive Procedure from M-03 and put in M-13: Emergency Procedures
- Section 5: Updated language to include time delay for Carolina 54 SPS and added company reference to SPS
- Section 5 and Attachment A: Removed Carolina 22 SPS due to retirement
- Section 5: Removed Note 2 from Bath County Stability Restriction
- Section 5: Updated wording in Note 5 for Bath County-Valley Stability SPS

- Section 5: Added references to DOM company documents for: Bath County – Valley Thermal Trip Scheme; Bath County – Valley Stability Trip Scheme; Clover Generator Shed Scheme; and Carolina '54' line SPS
- Section 5: Added references to BGE company documents for: Concord Street and Mt. Washington SPS
- Section 5: Modified BGE Concord Street SPS to reflect summer load dump ratings
- Section 5 and Attachment A: Removed Black Oak SPS due to retirement
- Section 5: Updated Homer City #2 and #3 stability trip scheme language.
- Section 5: Added Company references for Homer City #2 and #3 stability trip scheme (STS-1 – language new to manual, STS-2, STS-3)
- Section 5: Added references to FE company documents and default status for: Belmont SPS; Yards Creek Pumping, East Sayre – North Waverly 115 kV Relay; and Warren – Falconer 115 kV RelaySection 5: Added reference to PPL company document for Jenkins SPS
- Section 5: Updated UGI/PL 66kV Tie Line Operation based on new line clearance point
- Section 5: Updated references for C-3403 line termination from Hudson to Marion
- Section 5: Revised PS/ConEd wheel procedure with updated line names and designations
- Section 5 and Attachment A: Updated Linwood SPS procedure based on the new Post substation
- Section 5: Added reference to PECO documentation for the Peach Bottom SPS
- Section 5: Updated PS Normally Open Bus Tie procedure due to Bergen-Linden Corridor system upgrades
- Section 5: Removed Kammer operating procedure due to system upgrade
- Section 5: Removed reference about UPFC at Inez substation due to retirement
- Section 5: Updated Rockport operating guide due to the retirement of Breed substation and added reference to AEP company document Section 5: Updated Twin Branch – Argenta (Conservative Operations) due to system upgrade
- Section 5: Added Washington plant stability restriction
- Section 5: Added projected retirement dates to applicable SPS procedures
- Section 5: Updated the ComEd East Frankfort SPS procedure
- Section 5 and Attachment A: Added SPS designation for the Lisle SPS scheme
- Section 5: Updated the Dresden 345 kV bus operation procedure
- Section 5: Added the ComEd Crawford SVC procedure
- Section 5: Updated the ISO-NE Contingencies procedure

- Attachment A: Modified BGE Concord Street SPS to reflect summer load dump ratings and 'armed' period of 6/1-8/31 annually
- Attachment A: Modified BGE Mt. Washington SPS to show 'armed' period of 6/1-8/31 annually
- Attachment A: Removed Susquehanna #1 Unit SPS due to retirement
- Attachment A: Updated Planebrook SPS description to clarify stuck breaker triggers
- Attachment C: Updated notes and exhibit numbers
- Attachment D: Removed constrains that are no longer part of the Post Contingency Congestion Management Progam and added note that there are no constraints that are currently part of the program.
- Attachment E: Removed retired sectionalizing schemes at Hosensack and updated description of Jenkins 4 xfmr sectionalizing scheme.

Revision 48 (12/01/2015):

- Throughout: Revised/clarified language around use of the term SOL.
- Throughout: Replaced term "eData" with "Data Viewer".
- Section 1.2: Added full name for Manual-01.
- Section 1.5.2: Revised DMWG to DMS to reflect current name and subcommittee.
- Section 1.7 and Attachment A: Added language to indicate the terms SPS and RAS are used interchangeably.
- Section 3.3.1 Exhibit 3: Revised the PJM baseline voltage limits to 1 decimal point.
- Section 3.3.3: Updated the generator voltage schedule coordination among TOs, GOs, and PJM. Added voltage deviation criteria for GO notification to the TO and PJM.
- Sections 3.5 to 3.7: Reorganized sections for better clarity.
- Section 3.5.3 - Updated Bulk Electric System Capacitor/SVC Operation, included the Shingletown capacitor bank #3 logic.
- Section 3.7: Modified note for on-site personnel for switching.
- Section 3.8: Added the new COMED interface definition and new name to be effective on 3/1/16. Added note that the existing interface definition will be retired on the same date.
- Section 3.9: Added additional language on the use of the real-time Transient Stability Assessment (TSA) Tool.
- Section 3.9.1: Revised the title of the section/process.
- Section 3: Exhibit 5: Clarified PSE&G 230 kV prevailing voltage limits.
- Section 3 Exhibit 5: Updated FE-West (ATSI) 138 kV equipment voltage drop limit.
- Section 3 Exhibit 5: Updated FE-South (APS) voltage drop limits for 500 kV, 230 kV and 115 kV voltage class equipment.

- Section 4.2.9: Reformatted for clarification and grammatical corrections
- Section 5: Added new Oscillation Mitigation procedure.
- Section 5 and Attachment A: Removed Montour Runback Scheme (SPS).
- Section 5: Updated Cook nuclear voltage limit.
- Section 5: Added North Anna nuclear high voltage limit.
- Section 5: Added Surry nuclear high voltage limit.
- Section 5: Updated Beaver Valley nuclear voltage limit.
- Section 5: Updated Limerick nuclear voltage limit.
- Section 5: Updated Peach Bottom Valley nuclear voltage limit.
- Section 5: Modified Gavin Mountaineer–Rolling Hills Stability guide to reflect updates due to new lines in area.
- Section 5: Updated Rockport Operating procedure.
- Section 5: Revised PSEG N.O. Bus Section Breakers procedure based on transmission upgrades.
- Section 5: Removed PSEG Breaker Derate Table and added OASIS link for the PSEG single breaker de-rates posting
- Section 5: Removed PPL Sunbury 500/230 kV Transformer Ratings table and added OASIS link for the PPL single breaker de-rates posting.
- Section 5 and Attachment A: Revised PPL Jenkins SPS to include Stanton-Jenkins #2 230 kV line and new CBs.
- Section 5: Updated the NEPA stability limit procedure.
- Section 5: Added the Mainesburg switching under the PJM/NY-ISO Transfers section.
- Section 5: Updated Seneca stability restrictions and pumping procedure.
- Section 5: Deleted Burma-Piney 138 kV line from a list of FE East/South border facilities that may be opened for an actual or post contingency control.
- Section 5: Updated a list of facilities impacting PSE&G/ConEd Wheel deliverability.
- Section 5: Deleted DEOK Dimmick-Port Union 138 kV line relief procedure.
- Section 5: Removed DEOK single breaker de-rates table and added OASIS link for the DEOK single breaker de-rates posting.
- Section 5: Updated Clover Generator Shed Scheme [SPS] to clarify operation.
- Section 5: Revised Bath County Stability SPS procedure to reflect the use during the Cloverdale-Lexington outage.
- Section 5: Updated Bath County Stability Restrictions procedure to reflect new outage.
- Section 5: Updated Bath County Thermal SPS procedure.
- Section 5: Updated Crescent #1 and #3 345/138 kV autotransformer relief procedure.

- Section 5: Removed DLCO single breaker de-rates table and added OASIS link for the DLCO single breaker de-rates posting.
- Section 5 and Attachment A: Removed SPS designation for the Lisle Auto Sectionalizing Scheme and Auto Closing Scheme.
- Section 5: Updated the Byron Operating Guide due to bus upgrade.
- Section 5: Updated the Black Oak SVC settings.
- Section 5: Updated Title for FE-S Single Breaker Derates procedure.
- Section 5: Updated Chalk Point transformer procedure
- Section 5: Updated Title for BG&E Single Breaker Derates procedure.
- Section 5: Updated BGE/PEPCO/NOVA/Doubs Area Operating Procedure to remove import capability
- Section 5: Removed Nottingham – Cooper 230 kV Line Limitations section
- Section 5 and Attachment A: Consolidated Peach Bottom SPS sections
- Section 5: Revised Linwood SPS procedure to clarify monitoring on non-SPS contingencies
- Attachment A: Revised description for Susquehanna 1 SPS to specify line outages
- Attachment A: Revised description for Bath County Stability SPS.
- Attachment B: Removed Attachment B and references to it within the manual: replaced with references to EMS try-back displays.
- Attachment E: Removed the following sectionalizing schemes: Chancellor TX#1, Clover #9, Carson-Clover 556 line, Midlothian TX#2, Midlothian-North Anna 576 line, Pleasant View TX#3, Pleasant View-Loudoun 558 line, Yadkin TX#1, and Yadkin TX#2.
- Attachment E: Updated the Clifton TX#1 sectionalizing scheme.
- Attachment E: Added the Clifton TX#2 Sectionalizing scheme
- Attachment E: Added the Guilford #1 138/34.5 kV sectionalizing scheme
- Attachment E: Added the Guilford #2 138/69 kV sectionalizing scheme
- Attachment E: Added the Monocacy #4 230/138 kV sectionalizing scheme
- Prevision Revision History: Added the missing revision 45 list of revisions (listing only).
- Periodic Review: Updated/corrected web links and typos throughout document.

Revision 47A (07/01/2015):

- Section 2.1.1: Added requirement that Load Dump rating be at least 3% higher than Emergency rating.

Revision 47 (06/01/2015):

- Section 2.1.3, Exhibit 1: Modified language in Note 1.

- Section 3.3.3: Removed Note 1 in reference to GPM.
- Section 3.5.2 and Exhibit 5: Added voltage exception language and Sullivan bus voltage to Exhibit 5.
- Section 3.8: Changed Eastern Transfer Interface definition from Wescosville-Alburtis to Breinigsville-Alburtis.
- Section 3.8: Changed Cleveland Transfer Interface definition by adding Mansfield-Glen Willow 345 kV line, removing Greenfield-Beaver 138kV line, and changing West Akron-Hickory to West Akron-Bath.
- Section 3 Exhitbit 5: Changed FE-PN 500 kV voltage limits to PJM default limits.
- Section 4.2.3: Clarified the languages of energizing new facilities
- Section 5: Removed the Millstone Point Contingency Procedure.
- Section 5: Updated the Rockport Operating procedure by adding a note to indicate the SPSs will only be armed when the plant output exceeds 2100 MW.
- Section 5: Removed the N-2266, M-2239, L-2238, and V-2222 lines from the PJM/NY-ISO PAR Operation procedure.
- Section 5: Updated the PSEG 5024 line single CB derates.
- Section 5: Added Cook nuclear voltage limits.
- Section 5: Updated ComEd Dresden nuclear voltage limits.
- Section 5: Updated/Added ComEd Quad Cities nuclear voltage limits.
- Section 5: Updated Dominion North Anna nuclear voltage limits.
- Section 5: Updated Dominion Surry nuclear voltage limits.
- Section 5: Updated FE-West Davis-Besse nuclear voltage limit.
- Section 5: Updated the AEP Rockport Operating procedure by adding a note to indicate the SPSs will only be armed when the plant output exceeds 2100 MW.
- Section 5 and Attachment A: Removed ComEd Zion Stability SPS procedure.
- Section 5 and Attachment A: Removed PPL 5043/5044 Transfer Trip Scheme procedure.
- Section 5: Removed the PPL Montour Single CB Stability Restriction procedure.
- Section 5: Revised the PPL NEPA Stability procedure.
- Section 5: Removed the PPL/PSEG Double Circuit Tower Line Contingencies (DCTL) Associate with Susquehanna-Roseland Delay procedure.
- Section 5: Remove PS Sewaren 138kV 5-6 breaker from the breaker derate table.
- Section 5: Updated UGI Mountain Bus Tie procedure.
- Section 5: Updated the Linwood SPS procedure.
- Section 5: Updated the Dominion Bath County Stability table to remove retired lines and to add new lines.

- Section 5: Added a TLC note to the Bath County stability SPS procedure.
- Section 5: Added Dominion North Anna Stability Limit procedure.
- Section 5: Updated the Dominion South Anna and Louisa CT Islanding Scheme.
- Attachment A: Removed PPL Susquehanna #2 scheme.
- Attachment A: Added PPL Susquehanna Cattycorner scheme.
- Attachment B: Added Alburtis-Breinigsville and Hopatcong-Lackawanna to table.
- Attachment B: Revised Wescosville-Alburtis to new line Breinigsville-Wescosville.
- Attachment B: Added Hopatcong-Roseland and Hopatcong-Branchburg to table.
- Attachment B: Added Front Royal-Morrisville, Goose Creek-Brambleton, Loudoun-Mosby, Brambleton-Mosby, Goose Creek-Pleasant View, Doubs-Goose Creek, and Meadowbrook-Front Royal.
- Attachment B: Removed Pleasant View- Loudoun, Doubs-Pleasant View, and Meadowbrook-Morrisville.
- Attachment E: Revised AEP Benton Harbor sectionalizing scheme for T1.
- Attachment E: Revised AEP Robison Park sectionalizing schemes for T5 and Allen.
- Attachment E: Revised AEP Wyoming T1 and T2 sectionalizing schemes.
- Attachment E: Removed AEP Cloverdale sectionalizing scheme for T10.
- Attachment E: Removed AEP Sporn sectionalizing scheme for T4.

Revision 46 (12/01/2014):

- Throughout document replaced LCC with TO
- Throughout document replaced Eastern Kentucky Power Cooperative with East Kentucky Power Cooperative
- Throughout document replaced Midwest with Midcontinent or MISO
- Section 1.4.2: Revised T.O. name from AP to FE South
- Section 2.1.2: Changed title and language from ‘short-time’ to ‘short-term’ and referenced Attachment F which contains the STE ratings list
- Section 3.2: Added language to clarify timing to shed load for post-contingency voltage collapse for consistency with M-13
- Section 3.5.3: Updated section on opening EHV lines for voltage control
- Section 3.7 and Exhibit 4: Updated section to include new SVC’s and changes in capacitors switching logic
- Section 3.7.1: Changed AEP 30 minute Emergency voltage limit from 920 kV to 840 kV
- Section 3.8: Added Hopatcong – Lackawanna 500 kV line to the Eastern transfer interface definition
- Section 3.9.1: Added a procedure for handling stability issues

- Section 3.9 Exhibit 5: Changed Dayton voltage drop limit from 8% to 10%
- Section 4.2.6: Added guideline language to avoid scheduling impactful long-duration outages before September 15th.
- Section 5: Removed Peach Bottom 500kV Normal High Voltage Limit
- Section 5: Updated AE Directional Ratings table
- Section 5: Updated AEP Kammer Operating procedure
- Section 5: Updated AEP Conesville 345kV plant Operating Guideline stability limitation table
- Section 5: Updated AEP Rockport Operating Guide Emergency Unit Tripping (EUT) (SPS) and generation output tables
- Section 5: Updated AEP Gavin Mountaineer - Rolling Hills Stability
- Section 5: Updated AEP Additional Regional Procedures
- Section 5: Removed AEP Single Breaker Derates
- Section 5: Updated AEP Index table to include Tidd 138 kV procedure
- Section 5: Updated FE South Belmont SPS
- Section 5: Updated FE South Black Oak SVC
- Section 5: Added new FE South Meadow Brook SVC procedure
- Section 5 and Attachment A: Removed FE East Conemaugh #2 Stability Trip SPS.
- Section 5: Added new FE East Hunterstown SVC procedure
- Section 5: Added new FE East Altoona SVC procedure
- Section 5: Updated FE East Conemaugh and Hunterstown stability limits
- Section 5: Updated FE East Keystone-Conemaugh 5003 Re-Close procedure
- Section 5: Updated FE East/South Tie Lines Switching Procedure
- Section 5: Updated FE East Warren-Falconer 115 kV relay procedure
- Section 5: Updated FE East East Sayre-North Waverly 115 kV relay procedure
- Section 5: Updated DEOK normally open Red Bank CB 920 138kV auto closing scheme
- Section 5: Updated DEOK's Breaker Derate Table for Todhunter-Foster
- Section 5: Updated DLCO Crescent #1 345/138 kV autotransformer relief procedure
- Section 5: Updated DLCO Breaker Derate Table
- Section 5 and Attachment A: Updated the PSEG Artificial Island procedure to remove the 5038 line outage and the cross trip on the 5015 line.
- Section 5: Revised language for ComEd 123 Marengo CB procedure (SPOG 2-2-B)
- Section 5: Removed ComEd 154 Libertyville bus tie scheme (SPOG 2-13) from the Normally Open Bus Tie table.

- Section 5: Added ComEd 7 State Line bus tie scheme to the Normally Open Bus Tie table.
- Section 5: Added MISO Pleasant Prairie – Zion E.C (Conservative Operations) procedure
- Section 5 and Attachment A: Removed the ComEd Waukegan 138 kV Bus Tie procedure
- Section 5 and Attachment A: Removed the ComEd Wolfs Crossing-Sandwich 138kV 14302 line procedure
- Section 5 and Attachment A: Added new PPL Jenkins SPS procedure
- Section 5: Removed PPL Sunbury Trans 22 & 23 Operating Restrictions
- Section 5 and Attachment A: Added new DVP Bath County-Valley Stability SPS procedure
- Section 5: Updated the DVP Bath County Thermal SPS procedure
- Section 5: Updated DVP Bath County Stability Restriction procedure
- Section 5: Updated the BGE Westport Breaker Limitations section
- Section 5: Added header title for NYISO procedure section
- Section 5: Added header for Dayton procedure section
- Section 5: Added header title and name change for MISO procedure section
- Section 5: Changed reference of ISO-NE Millstone #1 unit to #2 unit and reference of three units to two units
- Attachment A: Revised SPS descriptions to removed specific mention of contingency names.
- Attachment A: Updated Belmont SPS description
- Attachment A: Updated Clover Unit 2 SPS description
- Attachment A: Added installation year for Dominion SPSs
- Attachment A: Changed table header from ERO to RRO
- Attachment A: Added Bath County Thermal SPS to the list (existing procedure).
- Attachment B: Added open ended voltages for the Lackawanna-Susquehanna 500 kV line.
- Attachment E: Removed AEP Ohio Central T1 from the list
- Attachment E: Removed AEP Galion-Ohio Central from the list
- Attachment E: Removed AEP Kammer T300 from the list
- Attachment E: Removed AEP Kammer T100A/100B from the list
- Attachment E: Removed AEP Tanners Creek T A/B from the list
- Attachment E: Removed AEP Fall Creek T1 from the list

- Attachment E: Removed AEP Fall Creek-Noblesville from the list
- Attachment E: Removed AEP Benton Harbor-Cook from the list
- Attachment E: Removed AEP Benton Harbor-Palisade from the list
- Attachment E: Removed AEP Fostoria Central-South Berwick from the list
- Attachment E: Removed AEP Galion-South Berwick from the list
- Attachment E: Removed AEP Kanawha River T B from the list
- Attachment E: Removed AEP Kanawha River-Sporn from the list
- Attachment E: Removed AEP Fall Creek T1 from the list
- Attachment E: Updated line name for the AEP Maliszewski T1 scheme
- Attachment E: Updated the AEP Benton Harbor transformer scheme
- Attachment E: Updated the transformer name for the AEP Baker T200 scheme
- Attachment E: Updated note for the DVP Lexington TX3 scheme
- Attachment E: Removed the DVP Winfall-Suffolk from the list
- Attachment E: Removed the DVP Fentress TX1 from the list
- Attachment E: Removed the DVP Fentress TX3 from the list

Revision 45 (06/01/2014):

- Section 1.7: Added Relay Subcommittee for SPS review.
- Section 2.1 and throughout: Replaced 'Data Management Department' with 'Real Time Data Management Department' and updated M-03A Appendix title.
- Section 3.7 and throughout: Updated Allegheny Power (AP) to First Energy South
- Section 3.7 and Section 5: Updated Black Oak SVC settings
- Section 3.8: Added the new Zion EC-Pleasant Prairie 345 kV tie line to the ComEd interface.
- Section 3.8: Added the new Hayes-Beaver 345 kV line to the Cleveland interface.
- Section 3.9 Exhibit 5: Updated FE South (AP) Voltage Limits
- Section 4.2.12: Updated the nuclear plant circuit breaker list
- Section 5: Added note to Load Shed Directive section indicating PJM will post load shed directive to Emergency Procedures Website
- Section 5: Added note for TO and GO to notify PJM of SPS status, degradation or potential failure to operate.
- Section 5: Removed the MISO owned Zion-Lakeview SPS
- Section 5: Removed L10805 study requirement from Powerton stability procedure
- Section 5: Removed Prospect Heights bus tie schemes (SPOG 2-15)

- Section 5: Revised and added new Calumet inductor banks to L17723 & L17724 procedure
- Section 5: Revised Dresden #2 Voltage Limits
- Section 5: Revised Davis-Besse Voltage Limits
- Section 5: Revised nuclear voltage note for trending in the EMS
- Section 5: Updated Belmont SPS Procedure
- Section 5: Updated Seneca pumping procedure
- Section 5: Updated Conemaugh/Hunterstown stability limits table
- Section 5: Updated outage condition for which Conemaugh SPS can be activated to allow full plant output.
- Section 5: Updated Homer City stability limits table
- Section 5: Removed Ronco stability procedure
- Section 5: Removed FE South (AP) Bus Voltage Exceptions procedure
- Section 5: Updated DEOK single breaker derate table
- Section 5: Updated DLCO single breaker derates table
- Section 5: Removed Smith Mountain High Speed Reclosing procedure
- Section 5: Removed Branchburg – Deans 500 kV Substation Contingency Procedure
- Section 5: Changed Branchburg – Ramapo 5018 references to Hopatcong – Rampo 5018
- Section 5: Added a step to notify MISO of status change for University Park North SPS.
- Section 5: Added a step to notify MISO of status change for Davis Crk SPS.
- Section 5: Added a step to notify MISO of status change for Dresden SPS.
- Section 5: Added a step to notify MISO of status change for Zion SPS.
- Section 5: Added a step to notify MISO of status change for Byron SPS.
- Section 5: Added a step to notify MISO of status change for Kincaid SPS.
- Section 5: Added a step to notify MISO of status change for Powerton SPS.
- Section 5: Added a step to notify VACAR of status change for Clover SPS.
- Section 5: Added a step to notify NYISO of status change for East Sayre-North Waverly SPS.
- Section 5: Added a step to notify MISO and TVA of status change for Rockport SPS.
- Section 5: Added a step to notify NYISO of status change for Warren-Falconer SPS.
- Section 5: Added a step to notify NYISO of status change for Salem SPS.
- Section 5 and Attachment A: Removed Brandon Shores-Riverside SPS.

- Section 5 and Attachment A: Added Concord Street and Mt. Washington SPS proceduresSection 5: Removed BGE single breaker derate table, Cross Town common trench circuit ratings table, and 230kV Harbor Crossing Cables ratings table. Added hyperlinks to the OASIS system information page for all tables.
- Section 5: Removed note #2 from the Bath County Stability Restriction Table
- Section 5: Added South Anna / Louisa CT Islanding Scheme
- Section 5: Added the Virginia Hills reactor to the Northern Virginia High Voltage control section
- Attachment A: Added a column to the SPS listing to notify impacted neighbors.
- Attachment B: Updated open-ended voltage table.
- Attachment E: Added Dravosburg 138/69 kV transformer #1 sectionalizing scheme list.
- Attachment E: Removed PPL Juniata #1 and #2 transformer from sectionalizing scheme list.

Revision 44 (11/01/2013):

- Section 2.1.1 and 2.1.3: Added language regarding emergency rating change approval
- Section 3.3.3: Added applicability for individual generating units greater than 20 MVA, added 161 kV default voltage schedule, and added GO/GOPs voltage schedule performance monitoring to Note 1.
- Section 3.5.1: Clarified that the voltage coordination pertains to generator voltage schedules.
- Sections 3.5.2 and 3.5.3: Added variable reactor tap adjustment.
- Section 3.7: Added variable reactors language.
- Section 3.8: Added BC/PEPCO interface definition.
- Sections 3, 5, and Attachment A: Removed Powerton/Joliet SPS procedure and references.
- Section 4.2.9.1: Added “reductions in demand” option for Direct Billing for Late Outages.
- Section 4.2.11: Deleted a reference to tie line list.
- Section 4.3: Replaced outage submittal language with references to the appropriate section for the actual requirements.
- Section 4.5.1: Replaced outage submittal language with references to the appropriate section for the actual requirements
- Section 5: Changed references of Power Team to Exelon/Constellation.
- Section 5: Added purpose statement for the 5043 and 5044 procedure.
- Section 5: Revised Note for Artificial Island to indicate it is not the only place limited by dynamic stability.

- Section 5: Added a note about lack of redundancy for the Quad Cities/Cordova SPS procedure.
- Section 5: Added the note for Conesville 345 kV Plant Operating Guidelines
- Section 5: Added Tidd 138kV Switchyard Operating Guidelines for Overduty Circuit Breakers
- Section 5: Added the note in Fast Valving Scheme for Rockport Plant Operating Guidelines
- Section 5: Added the note in Emergency Unit Tripping for Rockport Plant Operating Guidelines
- Section 5: Clarified language for Twin Branch-Argenta operation procedure
- Section 5: Updated Cook Unit Isolation on Select Circuits procedure
- Section 5: Updated Gavin Mountaineer-Rolling Hills Stability proceedure
- Section 5: Updated Seneca Plant Stability procedure
- Section 5: Added Darby Plant Stability procedure
- Section 5: Removed Elrama and Mitchell Area Operating Procedure
- Section 5: Updated Sunbury transformer single breaker rating
- Section 5 and Attachment A: Removed the West Shore SPS.
- Section 5 and Attachment A: Removed the Virginia Beach SPS.
- Section 5 and Attachment A: Removed the Harmony Village SPS.
- Section 5: Updated Bath County Stabilty Guide table
- Section 5: Updated switching actions for Dresden L1223 line outage
- Section 5: Removed Pepco common trench cable ratings table and added a link to the PJM system information page
- Attachment A: Removed the Crawford 1-8 Bus Tie Scheme.
- Attachment A: Clarified Susquehanna Unit 1 & 2 SPS operation.
- Attachment E: Added Round Top-Newberry 115 kV sectionalizing scheme
- Attachment F: Replaced the STE rating list with a link to an OASIS posting of the STE rating list.

Revision 43 (06/01/2013):

- Sections 1-5: Changed Bulk Electric System (BES) to System Operating Limit (SOL) facilities wherever applicable to reflect recent change to SOL definition in M-37.
- Section 1.5.6: Clarified language to include all BES facilities.
- Section 3 Exhibit 5: Updated AE and DPL 500 kV voltage limits.
- Section 3.3.1: Reformatted voltage limit tables for consistency.

- Section 3.3.3: Updated the voltage coordination language in Note #4.
- Section 3.5.3: Corrected hyperlink to Powerton/Joliet SPS.
- Section 3.8: Added ComEd Interface to the list.
- Section 3.8: Updated Cleveland Interface definition.
- Section 3.9: Added Transient Stability Assessment (TSA) tool for real-time use.
- Section 4.2.1: Clarified language for Transmission Outage Request requirements.
- Section 4.2.2: Added additional Notes on relay change notification and PJM actions.
- Section 4.2.4: Updated language for Protection System Coordination.
- Section 4.3.2: Clarified real-time tie-line communication requirements.
- Section 5: Removed Transmission Overuse (re:5018 Line Flow).
- Section 5: Added 5018 Branchburg – Ramapo PAR Coordination.
- Section 5: Updated the PSE&G/ConED Wheel procedure.
- Section 5: Increased Byron 1 and 2 low voltage limits Voltage Control at Nuclear Stations.
- Section 5: Revised Beaver Valley Normal Low, Normal High, and Emergency Low voltage limits, Voltage Control at Nuclear Stations.
- Section 5: Updated the Lee Country Byron Trip Scheme Table.
- Section 5: Revised the Powerton/Joliet SPS and added CBs.
- Section 5: Updated Elmhurst SVC control modes.
- Section 5: Updated Kincaid Stability procedure.
- Section 5: Updated Powerton Stability procedure.
- Section 5: Updated Quad Cities Limitations procedure.
- Section 5: Updated East Frankfort Transformer SPS procedure.
- Section 5: Updated University Park SPS procedure.
- Section 5: Updated Lakeview SPS procedure.
- Section 5: Updated the ComEd Normally Open Bus Tie Circuit Breakers table.
- Section 5: Updated Electric Junction – North Aurora 1106 line SPS procedure.
- Section 5: Removed Powerton Jct-1352 line from directional rating list.
- Section 5: Updated the Montour Runback SPS.
- Section 5: Removed the Branchburg 1-2 and 2-3 CB single breaker derate on the 5016 line.
- Section 5: Added Marion 1-4 138 kV CB to the Closing Normally Open Bus Section breakers.
- Section 5: Deleted Sewaren Y-2251 from the single breaker derate table.

- Section 5: Revised wording for East Sayre-North Waverly overcurrent relay protection scheme.
- Section 5: Revised Warren-Falconer overcurrent relay protection scheme.
- Section 5: Updated Kammer Operating Procedures.
- Section 5: Updated single breaker derate table for AEP's Kammer T100 transformer.
- Section 5: Removed AEP Sunnyside-Torrey operating procedure.
- Section 5: Removed AEP Marysville 765kV Reactor Guidelines.
- Section 5: Removed AEP Tanners Creek 345kV Station concern.
- Section 5: Updated Gavin-Mountaineer-Rolling Hills Stability operating procedure.
- Section 5: Added, removed, and updated several AEP Regional Procedures.
- Section 5: Added Ft. Slocum-Takoma 69054 & 69167 to common trench cable rating table.
- Section 5: Updated Buzzard Point - Ritchie 23016 common trench cable rating table.
- Section 5: Added Bells Mill – Bethesda 13801 and 13802 lines to common trench cable rating table.
- Section 5: Removed Doubs-Dickerson Line contingency section.
- Section 5: Updated single breaker limit table for Waugh Chapel 230-1, 230-2, 230-3 transformer.
- Section 5: Extracted Harbor Crossing Cables (2344 & 2345 circuits) special ratings from BGE common trench cable section and updated the ratings.
- Section 5: Added Westport-Center 110552 ratings to BGE common trench cable section.
- Section 5: Removed Green Street to Concord Street 110559 and 110562 Cables rating tables in BGE common trench cable section.
- Section 5: Updated Concord Street to Monument Street 110563 and 110564 Cables rating tables in BGE common trench cable section.
- Section 5: Updated single breaker limits table for Pumphrey-Wagner 115032 line.
- Section 5: Added the note for single breaker limits table for Conastone-Peach Bottom 5012 line.
- Section 5: Removed footnote from Bath County Stability restriction table.
- Section 5: Removed the Mt. Storm Single Breaker Derates section and replaced it with a hyperlink for all of Dominions single breaker ratings. Table of contents updated to reflect changes made.
- Section 5 and Attachment A: Removed Carlls Corner CT #2 SPS.
- Section 5: Removed the Corson – Union 1402 Directional Rating.
- Section 5: Updated single breaker limit for the Doubs-Pleasant View 514 line.
- Section 5: Updated table of contents and hyperlinks.

- Attachment A: Removed Mays Chapel SPS listing.
- Attachment A: Removed MISO owned Lakeview SPS from listing.
- Attachment A: Added Carolina “22” SPS to listing.
- Attachment D: Removed several ComEd facilities from the list.
- Attachment E: Removed minor note for PPL and UGI schemes.
- Attachment E: Removed Red Bank “TB 27” and “TB 28” 345/138 kV Sectionalized Schemes.

Revision 42 (04/01/2013):

- Section 3.3.3: Updated language for voltage schedule.

Revision 41 (12/01/2012):

- Section 2.1.1: Removed language concerning the default LD rating to be 115% of the Emergency rating.
- Section 3: Added EKPC 161 kV to Exhibit 5 Deviations from PJM baseline voltages.
- Section 3.3.1: Added 161 kV to PJM baseline voltage schedule.
- Section 3.3.3: Modified generator voltage schedules language for compliance clarification.
- Section 3.7: Added 230kV Cardiff Cap under automatic control of Cardiff SVC.
- Section 3.7: Added additional conditions for the manual operation of the Elroy capacitor.
- Section 4.2.1: Changed submittal date example.
- Section 4.2.9 Added language regarding eDART transmission outage ticket revision rules.
- Section 5: Added additional ComEd facilities to the Normally Open Bus tie CB table.
- Section 5: Update the Sewaren derate table.
- Section 5: Corrected exhibit number for the Sunbury T24.
- Section 5: Updated the Quad Cities and Cordova SPS procedure.
- Section 5: Added minor revision to the Powerton/Joliet SPS.
- Section 5: Revised ratings of Sunbury 500/230kV transformer in PPL.
- Section 5 and Attachment A: Added new ATC owned Lakeview SPS incorporated into SPOG 3-10 section in ComEd.
- Section 5: Revised the West Shore SPS in PPL.
- Section 5 and Attachment A: Added the Montour SPS in PPL.
- Section 5: Added summer and winter single breaker derates for BGE’s Waugh Chapel 230-1, 230-2, 230-3, and 230-4 transformers.

- Section 5: Added temperature set points for SPS at Virginia Beach and Carolina stations.
- Section 5: Changed operating procedures for Chalk Point #5 transformer operation.
- Section 5: Updated common trench cable ratings for PEPCO.
- Section 5: Removed Potomac River Station Operation procedures.
- Section 5: Renamed First Energy companies into regions.
- Section 5: Changed the Marsh Run and Remington Ct stability restrictions guide.
- Section 5 and Attachment A: Deleted Richland SPS, due to SPS deactivation as a result of Richland substation reconfiguration.
- Section 5: Updated Belmont SPS, due to Willow Island units deactivation.
- Section5: Updated Contingency Overloads in the Willow Island Area procedure, due to Willow Island unit's deactivation.
- Section 5: Updated Yards Creek SPS to incorporate new relay settings on the Portland-Kittatinny V1010 230 kV line.
- Section 5: Updated First Energy South single breaker derate table.
- Section 5: Update Seneca stability language to include equipment that is in-series with the Glade-Lewis Run 230 kV line, and hence imposes the same set of stability restrictions.
- Section 5: Updated Homer City stability language to include instruction dealing with the event that any portion of the 230 kV Homer City-Keystone line is open or if the tie between the 230 kV South Bus and the 345 kV South Bus is open and all 345 kV breakers are closed.
- Section 5: Updated Rockport Op guide language to clarify FV scheme and unit SPS initiation description. Also removed language in SPS section per AEP's request.
- Section 5: Updated Gavin-Mountaineer stability limits and organized limits in table format. Also added language to HSR section.
- Section 5: Updated Kammer Op guide bus configuration table by replacing Brues-Kammer 138kV circuit references with Wayman-Kammer 138kV.
- Section 5: Changed terminal station names for the X-2224 line.
- Section 5: Updated the Powerton Stability Limit according to the most recent CE procedure.
- Section 5: Updated the Ridgeland Bus Tie procedure according to the most recent CE procedure.
- Section 5: Updated the Byron Operating Procedure according to the most recent CE procedure.
- Section 5: Added EKPC.
- Section 5: Added Dayton.

- Section 5: Added RECO.
- Section 5: Updated the Limerick 4A &4B transformer ratings.
- Section 5 and Throughout: Changed PP&L to PPL.
- Section 5: Removed the Branchburg single breaker derate on the 5016 line for 1-2 and 2-3 CB.
- Section 5: Removed Transmission Overuse (re:5018 Line Flow) and Added 5018 Branchburg – Ramapo PAR Coordination
- Section 5: Add Marion under PSE&G Closing Normally Open Bus Section Breakers
- Section 5: Removed the Corson – Union 1402 Directional Rating
- Attachment A: Added Brandon Shores – Riverside SPS to the list.
- Attachment B: Corrected line designation for the circuit 5038, East Windsor-New Freedom 500 kV line.
- Attachment E: Added and modified several sectionalizing schemes to the Dominion zone.
- Attachment E: Removed ‘Canton Central – SE Canton 345kV’ and ‘SE Canton 345/138kV T-1’ sectionalizing schemes (AEP) due to installation of new high-side breaker on SE Canton 345/138kV transformer.
- Attachment E: Removed ‘Jefferson 765/345kV T-1’ sectionalizing scheme (AEP) due to installation of new high-side breaker on Jefferson 765/345kV transformer.
- Attachment E: Removed PEPCO sectionalizing schemes Benning T8, T9 & Benning U16, Bowie T1, Bowie T2, Burchess Hill T2.
- Attachment F: Added and removed several COMED facilities.

Revision 40 (06/01/2012):

- Annual Review
- Manual-wide, replaced ‘Unit Dispatch System (UDS)’ with ‘Security Constrained Economic Dispatch (SCED)’
- Section 1.1, Note 2 – added more detail related to PJM and AEP coordination of AEP 138kV facility control.
- Section 1.4.2, updated to include DEOK reclosing philosophy.
- Section 2.1.1, added Note 2, 3, and 4 to reflect PJM TSS recommendation regarding determination of Load Dump Limits.
- Section 3.5.1 – Voltage Coordination – added clarity regarding coordination of capacitor operations on 230kV and above vs. 138kV and below facilities.
- Section 3.6 and 3.5.3 – High Voltage – deleted the sections in 3.6 referring to opening approved EHV facilities for voltage control and moved them to section 3.5.3. Also updated and expanded upon the facilities to open.

- Section 3.7 – BES Capacitor Operation – removed language for consistency.
- Section 3.8 – Added 138 kV lines to interface description.
- Section 3.9 Exhibit 5 – added 69 kV voltage limits for PL.
- Section 4.2.1 – Outage Scheduling Requirements – Included 30 day outage duration requirement in table and made changes for clarity.
- Section 4.2.9.1 – Direct Billing – added section to outline process for T.O. to request the ability to pay for late outage rather than have outage denied by PJM.
- Section 5-Voltage Control at Nuclear Station-Updated the high voltage limits at N. Anna & Surry stations
- Section 5-Voltage Control at Nuclear Station-Updated voltage drop limits at Peach Bottom
- Section 5: PJM RTO Operating Procedures – Updated nuclear facility voltage limits.
- Section 5 – Updated Carlls Corner SPS rating from 54 to 56 MVA.
- Section 5 – CE Operating Procedures – removed PJM Actions from 138kV Phase Shifting Transformer Ops (SPOG 3-22). Three shift dispatcher communications are not required since telemetry exists.
- Section 5 – CE Operating Procedures – Updated Zion Generating Stability Trip Scheme (SPOG 1-3-K) to reference Unit 12 and removal of fiber communication.
- Section 5 – CE Operating Procedures – Added directional relay ratings for Mazon, Crescent Ridge, and Powerton Jct.
- Section 5 – Deleted Whitpain 500-1 or 500-2 Transformer Outages section from PECO Operating Procedures, due to Whitpain 500 kV bus reconfiguration.
- Section 5 – Updated Powerton/Joliet Trip Scheme [SPS].
- Section 5 – DEOK Operating Procedures – Updated Breaker Derate Table for Foster-Sugar Creek, Foster-Pierce and Miami Fort-West Milton Lines.
- Section 5 – APS Operating Procedures – Updated Breaker Derate Table, as a result of new APS rating methodology.
- Section 5 – Revised language for the 5043 and 5044 (Alburtis-Wescosville-Susquehanna) Transfer Trip Scheme [SPS].
- Section 5 – GPU Operating Procedures – Revised Yards Creek 230 kV Relay (Pumping) [SPS] ratings from old values of 1158 MVA (Winter) / 1068 MVA (Summer) to new values of 1195 MVA (Winter) / 1147 MVA (Summer).
- Section 5 – Deleted Sunbury normal condition ratings from chart.
- Section 5 – Added Sunbury Transformer 22 & 23 operating restrictions.
- Section 5 – Added West Shore Special Protection Scheme in PP&L zone.
- Section 5 – Updated Bath County Stability Restrictions. Multiple changes to number of units allowed to pump/generate. Added 2 contingencies to list (Greenland Gap-

Meadowbrook and Loudoun-Pleasant View 500kV; Lexington-Dooms and Loudoun-Pleasant View 500kV). Removed Bath-Lexington and Mt Storm 500kV Bus #1 or Bus #2 contingency.

- Section 5 – Added breaker derate table for Wagner-Lipins Corner 110534 115kV. Updated breaker names to reflect Wagner terminal for Pumphrey-Wagner 110532 115kV breaker derate table.
- Section 5 – Replaced Tables in the Rockport operating guide section and added Communication protocol and additional details for alarming EUT SPS to match AEP's version 7 of the Rockport Operating Guide.
- Section 5: AEP Operating Procedures – Updated MISO Standing Op Guide Reference for the Twin Branch-Argenta procedure
- Section 5 - Update to Kammer Operating Procedures and change in how PJM recognizes Kammer post-contingency switching.
- Section 5 – Revised Seneca Stability limits in FE zone, due to Forest Glade Tap reconfiguration.
- Section 5 – Added 'DCTL Contingencies Associated with Susquehanna-Roseland Delay' section to both PS and PPL procedures.
- Section 5 – Updated PEPCO common trench cable ratings and added Benning – Ritchie 23003 & 23004 to the table of common trench cable ratings.
- Section 5 – Updated DLCO common trench cable rating for the Arsenal – Brunot Island 345 kV circuits 305 and 306.
- Attachment A: SPS Listing – added West Shore to list.
- Attachment A – Added Powerton/Joliet Trip Scheme to SPS list.
- Attachment B – Updated Open Circuit Terminal Voltage Control, due to construction of the TRAIL project, Suffolk substation, Cranberry substation, and Centerpoint substation.
- Attachment D – Post-Contingency Congestion Management Constraints – Removed Dupont-Seaford, Cheswold-Kent, Wye Mills xfmr, Hallwood-Oak Hall due to upgrades making previous ratings obsolete.
- Attachment E - Removed Harwood #4 from sectionalizing scheme list due to retirement.
- Attachment E - Addition of two new sectionalizing schemes at Cabot station, due to installation of new #3 500/138 kV transformer.
- Attachment E - Addition of new Collins-Middletwon Junction 115 kV Sectionalizing scheme.
- Attachment E – Deletion of the East Towanda #4 230/115 kV sectionalizing scheme, due to upgrades at East Towanda station.
- Attachment E - Addition of Midlothian – North Anna 500kV line sectionalizing scheme
- Attachment E - Addition of Pleasant View – Loudoun 500kV line sectionalizing scheme
- Attachment E: Removed "S Canton – S.E. Canton 345kV Sectionalized"

- Attachment E: Removed “Twin Branch 345/138 kV T-6 Sectionalized”
- Attachment E: Added West Millersport 345/138 kV T-2 Sectionalized
- Attachment E: Added Kammer 345/138 kV T300 Sectionalized
- Attachment E: Added Kammer 345/138 kV Transformer 100A/100B Sectionalized
- Attachment E: Added East Lima-Southwest Lima 345 kV Sectionalized
- Attachment E: Added East Lima-Maddox Creek 345 kV Sectionalized
- Attachment E: Added East Danville T4 Sectionalized
- Attachment E: Added East Danville T5 Sectionalized
- Attachment E: Added East Danville-East Monument 138 kV Sectionalized
- Attachment E: Added Jackson Road-Twin Branch 345 kV Sectionalized
- Attachment E: Revised West Millersport 345/138 kV T-1
- Attachment E: Revised Canton Central-SE Canton 345 kV
- Attachment E: Revised Maliszewski 765/138 kV T-1
- Attachment E: Revised Kirk 345/138 kV T4
- Attachment E: Revised South Berwick 345/69 kV T-1
- Attachment E: Revised Jefferson 765/345 kV T-1
- Attachment E: Revised Tanners Creek 345/138 kV T-A/B
- Attachment E: Revised Desoto 345/138 kV T-1
- Attachment E: Revised Sorenson 345/138 kV T-1
- Attachment E: Revised Sorenson 345/138 kV T-2
- Attachment E: Revised Cook-East Elkhart 345 kV
- Attachment E: Revised East Elkhart-Hiple 345 kV
- Attachment E: Revised Benton Harbor-Palisades 345 kV
- Attachment E: Revised Cook-Jackson Road 345 kV

Revision 39 (11/16/2011):

- Section 1.3 – Changed to notify PJM within 15 minutes when TO analysis package is unavailable.
- Section 2.1.1 – Included language to clarify use of LTE and STE ratings consistent with M-3A, section 3.3.
- Section 2.1.3 – Modified Exhibit 1 to replace LTE/STE with Emergency Rating, modified Note 2 to describe use of STE by exception and eliminated Note 3.
- Section 3.3.3 – Modify language to better align with M-14D.

- Section 3.9 – Added entries for DEOK for upcoming integration, effective 1/1/2012 with in Exhibit 5: Bus and Zone Specific Variations to PJM Base Line Voltage Limits to appropriate voltage limits.
- Section 5 – Updated PJM/NYISO PAR Operation section. Also eliminated Attachment A dealing with Waldwick area ratings.
- Section 5 – Removed Operating Procedure for Controlling the Doubs 500/230 kV Transformer Loadings for the Allegheny Power Transmission Zone and applicable index tables.
- Section 5 – Added DEOK Transmission Zone section within the Operating Procedures with an Effective Date of the PJM-DEOK Integration, 1/1/2012. Added to all applicable index tables.
- Section 5 – Added Dimmick-Port Union, Red Bank and Todd Hunter Switching, and Breaker Derate Table within the Operating Procedures for the DEOK Transmission Zone and applicable index tables.
- Section 5 – Revised the Common Trench Cable Ratings within the Operating Procedures for the DLCO Transmission Zone.
- Section 5 – Delete the Seneca Generation For FE/PJM Constrains section within the Operating Procedures for the First Energy Transmission Zone, due to ATSI integration.
- Section 5 – Homer City Stability Limits – Changed Homer City #1 and #2 Transformer references to Homer City North Auto and South Auto Transformer, respectively.
- Section 5 – Revised North Anna nuclear station voltage limits in Nuclear Voltage Limits table to appropriate voltage limits under Voltage Control at Nuclear Station section.
- Section 5 – Added Brandon Shores – Riverside SPS [SPS] for the BC Transmission Zone
- Section 5 – Updated to classify different temperature settings as part of the overall SPS at Carolina line 22 and 54 within the Operating Procedures for the DVP Transmission Zone.
- Section 5 – Revised the Common Trench Cable Ratings within the Operating Procedures for the PEPCO Transmission Zone.
- Section 5 – Powerton/Joliet Trip Scheme: added new scheme
- Section 5 – Revised Dresden Nuclear Voltage limits and communication of LTC change protocol.
- Section 5 – SPOG 2-41: Renamed Grand Ridge from SPS to Load Rejection Scheme
- Section 5 – SPOG 1-3-A: Updated current guidelines
- Section 5 – SPOGs 1-3-B, SPOG 1-3-B-1: Updated scenarios for Powerton trip and additional guidance for high Top Crop WF output during outage of L0302 & L93505
- Section 5 – SPOG 1-3-J: Added Multi-phase fault unit trip scheme for stability
- Section 5 – SPOG 2-29: Corrected bus-tie name

- Section 5 – SPOG 2-39: Minor clarifications
- Section 5 – SPOG 3-27: Added additional detail
- Section 5 – SPOG 3-31: Added additional detail
- Section 5 – SPOG 3-32: Contingency triggering SPS revised. Additional detail added
- Section 5 – Updated contingency name for “Operation of 23030 Tie at Mountain” Procedure
- Attachment A – Waldwick Microprocessor rating operations updated under section 5. This Attachment is obsolete. Replaced with SPS Listing.
- Attachment A – updated Planebrook title and description.
- Attachment E – Added Automatic Sectionalizing Schemes for the DEOK Transmission Zone for upcoming integration, effective 1/1/2012.
- Attachment E – Revised Burches Hill Automatic Sectionalizing Schemes for the PEPCO Transmission Zone due to upgrades
- Attachment E – Corrected the title of Benning 230/69kV T9 Sectionalized for the PEPCO Transmission Zone
- Added new Attachment F – STE ratings by zone.
- Section 5 – Updated AEP Smith Mountain 138 kV Station Stability Limits

Revision 38 (04/27/2011):

- Throughout – Formatting changes to tables to meet with current PJM style set.
- Throughout – Replaced references to “Conectiv” with “PHI – Pepco Holdings, Inc.” or “AE-PHI” where appropriate.
- Throughout – Replaced references to “Orange” with “Maliszewski” wherever the reference was to the former “Orange” 765/138kV substation within AEP.
- Section 1.3 – Note added regarding TO requirements for real-time network analysis within *Transmission Operations Guidelines*.
- Section 2.1 – Revised wording for *Note1* from “may operator” to “may operate” within *Thermal Operating Criteria* section.
- Section 2, end – Revised wording for Exhibit 1 *PJM Actual Overload Thermal Operating Policy* table from a Guideline to a Policy and revised text within said table to correspond with *Load Shed Determination Procedure*.
- Section 3.2 – Revised section title from *Voltage Operating Criteria & Guidelines* to *Voltage Operating Criteria & Policy* and relevant wording within section from “Guideline” to “Policy”.
- Section 3.3.3 – Clarified the Voltage *Schedule* and *Bandwidth* rows as being ‘kV’ values within the *Generator Voltage Schedules* table.
- Section 3.8 – Reformatted the Interface line definitions for clarity within the *Transfer Limits* section. Added the future Mt Storm – Meadowbrook 500kV line to the AP South

definition, and added the CLVLND reactive interface both with an effective date of 6/1/2011.

- Section 3.9 – Revised UGI's 69kV voltage limits within *Exhibit 5: Bus and Zone Specific Variations to PJM Base Line Voltage Limits* to appropriate voltage limits for their 66kV network. Added entries for ATSI and CPP for upcoming integration, effective 6/1/2011.
- Section 4.2 – Inserted subsection *4.2.6 Peak Period Outage Scheduling Guidelines*. To accommodate, former subsections 4.2.6 through 4.2.12 all advanced by one and are now 4.2.7 through 4.2.13.
- Section 4.2.9 – Revised wording from ' … may loose its priority … ' to 'may lose its priority' within the *Rescheduling Outages* subsection.
- Section 4.5 – Updated the *Transmission Outage Acceleration Process* to provide clarifications, aligning manual with tariff language.
- Section 5 – Revised all Single Breaker Derate tables to utilize standardized 'NL', 'EM', 'LT', 'ST' and/or 'LD' limit titles where appropriate within the Operating Procedures for all Transmission Zones with applicable Single Breaker Derate tables.
- Section 5 – Added *Load Shed Determination Procedure* and *Load Shed Directive* within the Operating Procedures for the PJM RTO and applicable index tables.
- Section 5 – Corrected wording in reference to the "J" and "K" lines in the *PSEG/ConEd Wheel* within the Operating Procedure for the PJM RTO.
- Section 5 – Revised NL & EL voltage limits for the Dresden units 2 & 3 in *Voltage Control at Nuclear Stations* within the Operating Procedures for the PJM RTO. Added Davis-Besse and Perry in same section effective upon ATSI integration, 6/1/2011.
- Section 5 – Added a *Directional Ratings* procedure within the Operating Procedures for the AE Transmission Zone and applicable index tables.
- Section 5 – Added *AEP Single Breaker Derates* within the Operating Procedures for the AEP Transmission Zone and applicable index tables.
- Section 5 – Updated the *Smith Mountain 138kV Station Stability* procedure within the Operating Procedures for the AEP Transmission Zone.
- Section 5 – Updated to classify Fast Valving and Emergency Unit Tripping as part of the overall SPS at Rockport in the *Rockport Operating Guide* within the Operating Procedures for the AEP Transmission Zone.
- Section 5 – Revised the *Twin Branch – Argenta (Conservative Operations)* procedure to clearly identify the potential IROL limits within the Operating Procedures for the AEP Transmission Zone.
- Section 5 – Renamed/Revised the *Pleasants and Oak Grove Operating Restrictions* to the *Belmont SPS* within the Operating Procedures for the AP Transmission Zone and applicable index tables to reflect the redundancy added to the preexisting relay scheme.
- Section 5 – Added *Bus Voltage Exceptions* within the Operating Procedures for the AP Transmission Zone and applicable index tables.

- Section 5 – Added/Revised rating sets for Bedington, Belmont, Black Oak, Cabot, Doubs, Ft Martin, Harrison, Hatfield, Meadowbrook, Pruntytown, South Bend, Wylie Ridge & Yukon 500kV CBs in the *Breaker Derate Table* within the Operating Procedures for the AP Transmission Zone.
- Section 5 – Revised the ratings with one breaker in service for the Waugh Chapel – Calvert Cliffs '5052' 500kV line in the *Breaker Derate Table* within the Operating Procedures for the BC Transmission Zone.
- Section 5 – Added a DPL Transmission Zone section within the Operating Procedures and applicable index tables.
- Section 5 – Added a *Directional Ratings* procedure within the Operating Procedures for the DPL Transmission Zone and applicable index tables.
- Section 5 – Added Note, explaining limitation of one pump per GSU for a duel pump trip, to *Bath County SPS* procedure within the Operating Procedures for the DOM Transmission Zone.
- Section 5 – Added an FE-ATSI Transmission Zone section within the Operating Procedures with an Effective Date of the PJM-ATSI/CPP Integration, 6/1/2011. Added to all applicable index tables.
- Section 5 – Added *Mansfield Unit Stability Restrictions* and *Richland Substation SPS* within the Operating Procedures for the FE-ATSI Transmission Zone and applicable index tables.
- Section 5 – Removed *TMI Voltage Notification Procedures*, as the limits for 1 Auxiliary Transformer and 2 Auxiliary Transformers are now the same, within the Operating Procedures for the FE Transmission Zone and applicable index tables.
- Section 5 – Renamed/Reordered Operating Procedures and associated index tables for FE Transmission Zones.
- Section 5 – Added the *Homer City Stability Limits* within the Operating Procedures for the FE Transmission Zone and applicable index tables.
- Section 5 – Revised the table and procedure based upon most recent study results in the *Conemaugh/Hunterstown Stability Limits* within the Operating Procedures for the FE Transmission Zone.
- Section 5 – Revised wording from "500 Conemaugh – Keystone 500kV line" to "5003 Conemaugh – Keystone 500kV line" in the *Conemaugh #2 Stability Trip* within the Operating Procedures for the FE Transmission Zone.
- Section 5 – Clarified control modes for the 138kV Capacitor Banks for the *Elmhurst SVC* within the Operating Procedures for the ComEd Transmission Zone.
- Section 5 – Removed reference to retired SPOGs 1-3-I-1 and 1-8 within the Operating Procedures for the ComEd Transmission Zone.
- Section 5 – Removed reference to retired SPOG 1-3-C-1 from *Quad Cities and Cordova Stability Limitations [SPS]* within the Operating Procedures for the ComEd Transmission Zone.

- Section 5 – Removed retired SPOG 3-21 *107_Dixon 'L15621' 138 kV CB Operation* within the Operating Procedures for the ComEd Transmission Zone and applicable index tables.
- Section 5 – Added *Wolfs TR81 [SPS]* within the Operating Procedures for the ComEd Transmission Zone and applicable index tables.
- Section 5 – Revised and renamed the former *Sandwich 138kV Bus Tie Circuit Breaker [SPS]* to *Wolfs Crossing-Sandwich 138kV 14302 line [SPS]* due to changes associated with the SPS and the applicable ComEd SPOG 3-31 within the Operating Procedures for the ComEd Transmission Zone and applicable index tables.
- Section 5 – Added *Electric Junction – North Aurora 138kV 11106 line [SPS]* due to changes associated with SPOG 3-27 within the Operating Procedures for the ComEd Transmission Zone and applicable index tables.
- Section 5 – Added *Highland Park Transfer Trip [SPS]* within the Operating Procedures for the ComEd Transmission Zone and applicable index tables.
- Section 5 – Added *Zion Generation Stability Trip [SPS]* within the Operating Procedures for the ComEd Transmission Zone and applicable index tables.
- Section 5 – Added *Camp Grove Islanding* within the Operating Procedures for the ComEd Transmission Zone and applicable index tables.
- Section 5 – Removed the *Elrama 138/69kV Auto Transformer Operation* procedure within the Operating Procedures for the DLCO Transmission Zone and applicable index tables due to transformer replacement.
- Section 5 – Revised the *Common Trench Cable Ratings* within the Operating Procedures for the PEPCO Transmission Zone.
- Section 5 – Revised status to normally 'Disabled; And, Enabled as needed' for the *Peach Bottom '45' 500kV CB SPS* and the *Peach Bottom '35' 500kV CB SPS* within the Operating Procedures for the PE Transmission Zone
- Section 5 – Removed 2 lines pertaining to North & South bus outage restrictions and applicable Note from the *Montour Stability Restrictions* within the Operating Procedures for the PL Transmission Zone.
- Section 5 – Removed the *Hosensack – Buxmont 230kV Line Contingency* procedure within the Operating Procedures for the PL Transmission Zone and applicable index tables as the scheme is no longer required and has been disabled.
- Section 5 – Associated the *PSE&G Artificial Island Stability* procedure with the *A.I. (Salem) Cross Trip Scheme* and designated it as an [SPS] within the Operating Procedures for the PS Transmission Zone.
- Section 5 – Removed the 500kV '3-4' & '4-4A' CBs @ Branchburg, the New Freedom 500kV '2-6', '2-8' & '9-10' CB, the 138kV '4-5' & '5-6' CB @ Trenton and the 230kV '1-5' & '5-6' CBs @ Linden; Added the 500kV '2-6' & '5-6' CBs @ Deans; Revised the 500kV '1-3' CB @ Hope Creek; All within the *Breaker Derate Table* for the PS Transmission Zone.

- Section 5 – Revised to reflect area upgrades the *Operation of 23030 Tie at Mountain* and *UGI/PL 66kV Tie Line Operation* procedures within the Operating Procedures for the UGI Transmission Zone Removed the *Hunlock Outlet Overloads* procedure from same.
- Section 5 – Properly identified the *Clover Generation Shed Scheme* as an "[SPS]" within the Operating Procedures for the VP Transmission Zone.
- Attachment B – *Open Circuit Terminal Voltage Control* table updated to reflect present PJM EHV lines.
- Attachment E – Added Automatic Sectionalizing Schemes for the PPL & UGI Transmission Zone which are effective as of March 1, 2011. Removed three Automatic Sectionalizing Schemes related to the Matt Funk 345kV for the AEP Transmission Zone due to upgrades .
- Exhibits – Added wording to indicate the Juniata PLC trip for high voltage is currently off within *Exhibit 4: Capacitor Installations with PLCs*.

Revision 37 (06/18/2010):

- Annual Review
- Section 3.5 – Clarified verbiage with regard to the section pertaining to Voltage Coordination.
- Section 5 – Formatting, corrections and additions where appropriate within Index Tables.
- Section 5 – Clear designation via '[SPS]' denotation of Special Protection Schemes within PJM.
- Section 5 – Revised naming of First Energy East Tie Lines (aka, PJM/AP Tie Lines via First Energy) operating procedure to FE East/AP Tie Lines throughout Operating Procedures.
- Section 5 – Removed separate Voltage Setpoints based upon LTC's being in Auto or Manual mode for Dresden Nuclear Voltage Limits. Added distinct Voltage Drop %'s and Limits for Susquehanna when only one start-up transformer is in service or when both are in service. Added 138kV Voltage limits for Beaver Valley #1 & #2. All within the Voltage Control at Nuclear Stations section of Operating Procedures for PJM RTO.
- Section 5 – Retired the Deptford 230kV Breaker Relay within the Operating Procedures for AE Transmission Zone due to system upgrades.
- Section 5 – Additional Regional Procedures revision within the Operating Procedures for the AEP Transmission Zone. Indicate that opening the 138kV 'B' CB at Hinton is an accepted practice for alleviating loading on Kanawha River – Bradley 138kV lines. Indicate that opening the Layman 138kV CB at Corner is an accepted practice for alleviating loading on the Muskingum River – Wolf Creek – Corner 138kV line.
- Section 5 – Updated Kammer Operating Procedures to reflect current revision (rev. 5) of AEP's Kammer Operating Procedures within the Operating Procedures for the AEP Transmission Zone.

- Section 5 – Revised Rockport Operating Guide, including the removal of references to the Rapid Unit Runback procedure, to correlate with AEP's Revision 5 of the Rockport Operating Guidelines within the Operating Procedures for the AEP Transmission Zone.
- Section 5 -- Nottingham - Cooper 230 kV Line Limitations. Due to relay changes, revised "does not" to "will" in regard to contingency changes at Conowingo upon opening Bus Tie CB within the Operating Procedures for the BC Transmission Zone.
- Section 5 – Clarified applicable circuit breakers in the Single Breaker Derate section for the BC Transmission Zone.
- Section 5 – Equipment associated with cancelled ComEd SPOG 2-19 were removed from the Normally Opened Circuit Breaker Table within the Operating Procedures for the ComEd Transmission Zone.
- Section 5 – Added Islanding Prevention Scheme for TSS 941 Grand Ridge Generation within the Operating Procedures for the ComEd Transmission Zone.
- Section 5 – Added procedure for Davis Creek 345kV Bus Tie 2-3 Auto-Closing [SPS] within the Operating Procedures for ComEd Transmission Zone.
- Section 5 – Added procedure for the Dresden Unit 2 Trip Scheme [SPS] within the Operating Procedures for ComEd Transmission Zone.
- Section 5 – Added language regarding to MISO notification to the Quad City/Cordova Stability Procedure within the Operating Procedures for ComEd Transmission Zone.
- Section 5 – Added Marsh Run and Remington CT Stability Restrictions to Operating Procedures for DVP Transmission Zone and associated index tables.
- Section 5 – Changed name from 'Bath County Contingency Restrictions' to 'Bath County Stability Restrictions'. Changed type from Contingency to Stability. Added reference to Fluvanna where Cunningham generation was noted. All in the Bath County Stability Restrictions section within the Operating Procedures for the DVP Transmission Zone.
- Section 5 – Clarified line/cb labeling and tripping sequence of the Virginia Beach SPS within the Operating Procedures for DVP Transmission Zone.
- Section 5 – Clarified line/cb labeling and tripping sequence of the Harmony Village SPS within the Operating Procedures for DVP Transmission Zone.
- Section 5 – Clarified line labeling and tripping sequence of the Carolina Substation 22 Line SPS within the Operating Procedures for DVP Transmission Zone.
- Section 5 – Clarified line labeling and tripping sequence of the Carolina Substation 54 Line SPS within the Operating Procedures for DVP Transmission Zone.
- Section 5 – Added Mt Storm Single Breaker Derates within the Operating Procedures for the DVP Transmission Zone.
- Section 5 – Added Crescent TR1 345/138kV Autotransformer Relief Procedure within the Operating Procedures for the DLCO Transmission Zone.
- Section 5 – Added DLCO Single Breaker Derates to Operating Procedures for DLCO Transmission Zone.

- Section 5 – Removed ratings table for Erie West #1 345/115kV Xfrmr in the Seneca Pump Operations section within the Operating Procedures for FE Transmission Zone.
- Section 5 – Corrected line voltage for the Erie South – Warren 230kV line within the Seneca Stability Procedures of the Operating Procedures for FE Transmission Zone. Previously designated as a 345kV line.
- Section 5 – Added Muddy Run Restrictions within the Operating Procedures for the PECO Transmission Zone.
- Section 5 – Revised naming of ‘Nottingham – Graceton 230kV Line Limitations’ to ‘Nottingham – Cooper 230kV Line Limitations’ due to addition of Cooper Substation within the Operating Procedures for the PECO Transmission Zone. For any reference to the ‘220-08’ 230kV line, replaced any reference to “Graceton” with “Cooper” due to substation addition along that path within the PECO Transmission Zone.
- Section 5 – Steel City – Hosensack 500kV Line Reclosing Limitation. Clarified description of reclosing limitation and associated procedure within the Operating Procedures for the PPL Transmission Zone.
- Section 5 – Added Montour Stability Restrictions within the Operating Procedures for the PPL Transmission Zone.
- Section 5 – Removed 500kV CB Derate for the ‘5020’ 500kV line CB Derate Table due to breaker replacement within the Operating Procedures for PSE&G Transmission Zone. Removed the 500kV CB Derate for the New Freedom ‘7-8’ 500kV CB due to breaker replacement within same procedure.
- Section 5 – Removed section pertaining to Deans Single Breaker Derates on the Breaker Derate Table within the Operating Procedures for PSE&G Transmission Zone.
- Section 5 – Revised the Closing Normally Open Breakers section within the Operating Procedures for PSE&G Transmission Zone. Removed reference to Athenia 138kV bus due to breaker replacements the Athenia 138kV bus is now solid. Revised the Linden section due to breaker replacements on the Linden 138kV bus.
- Section 5 – Revised Single Breaker Derate Table within the Operating Procedures for APS Transmission Zone. Added ratings for North Longview substation. Corrected ratings for the Cabot ‘CL6’ 500kV CB. Revised Ft Martin section to reflect system upgrages.
- Section 5 – Revised name of Pleasants and Willow Island Operating Restrictions within the Operating Procedures for the APS Transmission Zone to Pleasants and Oak Grove Operating Restrictions as it pertains to schemes to trip Pleasants and Oak Grove units. Clarified output restrictions, arming conditions, contingency control and Oak Grove circuit breakers
- Section 5 – Added Black Oak 500/138kV Transformer SPS within the Operating Procedures for the APS Transmission Zone.
- Section 5 – Added ‘Note1’ and ‘Note2’ box to the MISO Safe Operating Mode Procedure within the Operating Procedures for the MISO.

- Attachment D – Removed Yorkana #1 & #4 230/115kV transformers I/o Jackson-Yorkana 230kV line and Yorkana #3 230/115kV transformer from Congestion Management Program due to substation upgrades at Yorkana in the ME Transmission Zone.
- Attachment E – Added Automatic Sectionalizing Schemes at Burches Hill, Bowie & Benning for the PEPCO Transmission Zone and are effective as of August 1, 2010.
- Attachment E – Added Automatic Sectionalizing Schemes at Bristers, Suffolk, Surry, Morrisville & Valley for the DVP Transmission Zone and are effective as of June 1, 2010.
- Attachment E – Corrected numbering within the APS Transmission Zone.

Revision 36 (01/01/2010):

- Section 2.1: Thermal Operating Guidelines: Provided clarity regarding operator timeline to control thermal overloads.
- Section 3.2 Voltage Operating Criteria and Guidelines: Provided clarity on controlling simulate post-contingency high voltage limit violations.
- Section 3.7: Bulk Electric System Capacitor/SVC Operations: Updated table of AP 500kV relay automatic trip settings.
- Section 4.2: Scheduling Transmission Outage Requirements: Provided clarity on TO/GO reporting requirements for protective relay outages/failures.
- Section 5: Index of Operating Procedures for PJM RTO Operations: Updated Voltage Control at Nuclear Station limits for Peach Bottom Station.
- Section 5: Index of Operating Procedures for AE Transmission Zone: Added Logan Runback Special Protection Scheme.
- Section5: Index of Operating Procedures for First Energy Transmission Zone: Updated Keystone-Conemaugh 5003 Line / Re-Close Procedure.
- Section 5: Index of Operating Procedures for PECO Transmission Zone: Modified Peach Bottom Xfmr, Peach Bottom #35, and Peach Bottom #45 SPS.
- Section5: Index of Operating Procedures for BGE Transmission Zone: Deleted switching procedure to control Conastone Xfmr due to increased ratings resulting from transformer replacement. Updated Breaker Derate Table.
- Section 5: Index of Operating Procedures for PPL Transmission Zone: Updated Sunbury 500/230kV Xmfr rating with 1 CB out-of-service.
- Section 5: Index of Operating Procedures for ComEd Transmission Zone: Updated Powerton Stability Limit (ComEd SPOG 1-3-B, 1-3-B-1) and Quad City/Cordova Stability Limit Procedure (ComEd SPOG 1-3-C, 1-3-C-1, 1-3-G).
- Section 5: Index of Operating Procedures for PSE&G Transmission Zone: Inserted Breaker Derate Table. Updated Closing Normally Open Breakers (Bus Sections) to remove Roseland, Marion and Metuchen as a result of CB replacements.
- Attachment E: Automatic Sectionalizing Schemes: Added FE-E (PN) and Dayton Auto sectionalizing Schemes effective 2/1/10 and 3/1/10.

Revision 35 (10/05/2009):

- Section 5 – Voltage Control at Nuclear Stations: Updated TMI voltage limits.
- Section 5 – Index of Operating Procedures for Baltimore Gas and Electric (BGE) Transmission Zone: Updated Single Breaker/Double Breaker Ratings limitations table to include Conastone 500-3 transformer
- Section 5 – Index of Operating Procedures for First Energy Transmission Zone: Updated 5003 Reclosing procedure to include studying of Keystone/Conemaugh generation redispatch to reduce phase angle to 10 degrees.
- Section 5 – Index of Operating Procedure for Commonwealth Edison (ComEd) Transmission Zone: Added SPOG 4-30, Transformer Operations at 138 kV Tie Line Breaker Substations. Updated Byron SPOG
- Section 5 – Index of Operating Procedures for PECO Transmission Zone: Changed wording to Phillips Island in Linwood Special Protection Scheme
- Section 5 – Index of Operating Procedures for FE Transmission Zone: Updated Seneca Pump Operations procedure, updates include renaming of FERD to FE TSO and correction to second pump operation
- Section 5 – Index of Operating Procedures for American Electric Power (AEP) Transmission Zone: Updated Rockport Operating Guide to include Special Protection Scheme (SPS) and section for Carrier Communication Failure. Renamed Section for Single Phase Operation to (SPO). Updated Conesville 345kV Plant Operating Guidelines based on installation of 345/138kV autotransformer T-7.
- Attachment E: Automatic Sectionalizing Schemes: Included Belmont, Bedington, Cabot, Yukon and Wylie schemes that were left out of Attachment E in error. PJM has been operating to AP automatic sectionalizing schemes since the 2002 AP integration.

Revision 34 (5/22/2009):

- Annual Review
- Modified to change thermal constraint control 15 minute threshold to 30 minutes. Changed PCLLRW issuance from 30 minute to 60 minutes. Timing changes based on controlling non-IROL constraints to 100% LTE.
- Section 3.7 - Bulk Electric System Capacitor/SVC Operation: Included operations of Elroy 500kV Capacitors (600 MVAR total).
- Section4 – Reportable Transmission Facility Outages: Eliminated use of “working” and “business” days to provide clarity and consistency to documentation of outage approval process.
- Section 5 – Index of Operating Procedure for Commonwealth Edison (ComEd) Transmission Zone: Updated Kincaid Stability Trip Scheme section.
- Updated Powerton Stability Limitations section
- Updated Byron and Lee County Operating Guides section
- Updated Quad Cities and Cordova Stability Limitations section

- Updated Normally Open Bus Tie Circuit Breakers section
- Updated Burnham – Taylor (L17723) 345 kV line Operation section
- Updated 107 Dixon ‘L15621’ 138 kV CB Operation section
- Added Sandwich Bus Tie Operation section
- Section 5 – Index of Operating Procedures for Potomac Electric Company (PEPCO) Transmission Zone: Added Potomac River Operating Procedure for Overdutied Circuit Breakers Potomac River Operations as part of existing Potomac River Station Operation during Abnormal Conditions, Island Operations, Restoration and Resynchronization procedures.
- Section 5 – Index of Operating Procedures for PECO Transmission Zone: Renamed Muddy Run Protective Relay to Peach Bottom 1 Transformer Operation
- Section 5 – Index of Operating Procedure for Public Service Electric & Gas Company (PSE&G) Transmission Zone: Updated section entitled “Closing Normally Open Breakers (Bus Sections).
- Section 5 – Index of Operating Procedures for American Electric Power (AEP) Transmission Zone: Updated Rockport Special Controls - removed Rapid Unit Runback
- Section 5 – Index of Operating Procedures for Baltimore Gas and Electric (BGE) Transmission Zone:
- Added Cross Town, Cross Harbor Cable Circuit Ratings Changes section
- Updated BGE Single Breaker/Double Breaker Ratings section
- Section 5 – Index of Operating Procedures for Duquesne Light Company (DLCO) Transmission Zone:
- Removed Procedure to relieve loading on Z-87 and Z-88 lines
- Section 5 – Index of Operating Procedures for Dominion Virginia Power (DVP) Transmission Zone – Updated Bath County Contingency Restrictions
- Section 5 – Index of Operating Procedures for Dominion Virginia Power (DVP) Transmission Zone: New Bath County Special Protection Scheme (SPS)
- Section 5 - Index of Operating Procedures for ISO New England (ISO-NE) Balancing Authority: Modified ISO-NE contingency set.
- Section 5 – Index of Operating Procedures for Midwest Independent System Operator (MISO): Modified PJM and MISO Manual Shadow Price Override Procedure.
- Attachment E: Autosectionalizing Schemes:
- Deleted Mount Storm 500kV #1 Bus Sectionalized scheme due to replacement of transformer high-side disconnect with Mt Storm RSS2.
- Deleted Cook 765/345kV transformer autosectionalizing scheme due to installation of L2 345kV CB at Cook.

Revision 33 (11/26/2008):

- Updated Section 1: Transmission Operations Requirements, clarifying AEP as registered TOP for AEP system 138kV and below.
- Updated Section 3: Generator Voltage Schedules, to provide guidance regarding actions generator should take when they are unable to meet the specified voltage schedule.
- Updated Section 5: Index of Operating Procedures for PJM RTO Operations, Voltage Control at Nuclear Stations to include Limerick Tap 69kV Power Source.
- Updated Section 5: Index of Operating Procedures for AEP to include modified Rockport schemes and removed Rockport Operations at Extended Capability section, updated Kammer Operating Procedures, and update the Gavin and Mountaineer Stability sections.
- Updated Section 5: Index of Operating Procedures for First Energy, Homer City Stability Trip Scheme and Seneca Pump Operations.
- Updated Section 5: Index of Operating Procedure for PSE&G, Artificial Island Stability procedure revised based upon new station topology.
- Updated Attachment B: Open Circuit Terminal Voltages, to reflect topology changes near Salem.
- Updated Section 5: Index of Operating Procedure for BG&G to include modified Circuit Breaker Derate table.

Revision 32 (October 3, 2008):

- Updated Section 5: Index of Operating Procedures for First Energy, TMI Voltage Notification Procedure.
- Updated Section 5: Index of Operating Procedures for New York ISO to include Ramapo PAR Operating Instructions
- Updated Attachment B to include 5021, 5038, and 5039 reconfiguration.

Revision 31 (09/15/2008):

- Section 1:
    - o Provided clarification regarding congestion management for Monitored “Reliability and Market” versus “Reliability” Facilities.
    - o Deleted detailed Process to Change the PJM Congestion Management Control Facilities List, since the information is contained within Manual 3A.
    - o Incorporated Procedure for naming new facilities 500kV and above.
- Section 3:
    - o Modified AP South Reactive Interface definition to include Mt. Storm – Valley 500kV line.
    - o Eliminated Exhibit 5.
- Section 4:

- Updated section regarding rescheduling outages.
- Updated requirement to restore “automatic reclosing” to provide clarity.

- Section 5:
  - Update BGE Section to include Breaker Derate Table
  - Updated BGE Section to include Gould Street Procedure
  - Updated BGE Section to modify Conastone Xfmr Thermal Limitations procedure based on upgrade to Conastone Xfmr.
  - Updated AP Section to include updated setting on Black Oak SVC.
  - Updated AP Section to correct contingencies in the Pleasants and Willow Island Operating Restrictions Procedure.
  - Updated AP Section to modify ratings in Breaker Derate Table.
  - Updated Doubs procedure to include option to switch Dickerson – Quince Orchard (23032) below certain load levels
  - Updated PPL Section to provide clarity when using adders under a multiple outage conditions.
  - Updated PPL Section to include reclosing restriction on Steel City – Hosensack 500kV line.
  - Updated PN Section to include Seneca Stability conditions.
  - Updated PN Section to include Homer City Stability conditions.
  - Updated PN Section to correct Conemaugh Stability limitations when reclosing Conemaugh – Keystone (5003) 500kV outage.
  - Attachment E
- Deleted Hunterstown #4 230/115kV Sectionalized scheme due to new configuration.

Revision 30 (5/01/2008):

- General:
  - Annual PJM System Operations Subcommittee (Transmission) Review.
  - BES Implementation
- Section 1:
  - BES implementation.
- Section 3:
  - Updated Reactive Transfer Interfaces
- Section 4:
  - Scheduling Transmission Outage Requests: Modified section to align tariff/manual for outage approval and outage acceleration processes.

  - Provided instructions as to when "Automatic Reclosing" can remained out-of-service during multiple day "daily outages".
- Section 5:
  - Automatic Sectionalizing Schemes: updated section to align with SPS notification requirements, specifically the ability to implement immediately in operations under specified conditions.
  - Nuclear Voltage Control: Corrected Surry Voltage Drop Limits, included TMI and Oyster Creek.
  - ComEd SPOG 1-2-E, 2-19, and 2-30 Retired
  - AEP: Eliminated Galion 345kV Bypass switch procedure. Updated Kammer and Conesville procedures.
  - DLCO: Added Elrama (DLCO) and Mitchell (AP) Area Operating Procedure and Elrama 138/69kV switching procedures.
  - FE:
  - Eliminated 5013 cross-trip relay scheme
  - Combined FE subsections (JC, MetEd, and PN) into a common FE section.
  - PEPCO
  - Updated Potomac River Procedure based on 23108 and 23109 topology changes.
  - PS:
  - Modified Artificial Island cross-trip relay scheme based on commissioning of Orchard Substation and splitting of Salem – East Windsor (5021) 500kV into Salem – Orchard (5021) and Orchard – East Windsor (5038) 500kV lines.
- Incorporated normally open CBs.

Revision 29 (1/18/2008):

- General:
  - Replaced MAAC/ECAR with RFC
- Introduction:
  - Added additional related manuals as references
- Section 3:
  - Generator Voltage Schedule: provided clarification regarding generators following PJM default voltage schedules.
  - Bulk Power Capacitor/SVC Operations – provided details regarding Black Oak SVC.
  - Returning EHV Lines That Were Open for Voltage Control: Added ability to use STE High Voltage Limits for switching/open-ended voltage studies.
- Section 5:

- Index of Operating Procedures for PJM RTO
  - Added Procedure for Voltage Control at Nuclear Station
- Index of Operating Procedures for ComEd
  - Deleted Procedure for Voltage Control at ComEd Nuclear Stations
  - Provided clarification to “Ratings associated with Cooling System Operating Modes”.
  - Deleted Minnesota – Eastern Wisconsin Phase Angle Reduction (ComEd CAOP 2-16).
  - Index of Operating Procedures for AP
  - Added Greenland Gap to Breaker Table Derate
  - Deleted Wylie Ridge Special Protection Scheme
  - Added Black Oak SVC
- Index for Operating Procedures for DPL(Conectiv)
  - Deleted 5025 Keeney – Rock Springs
  - Deleted Cecil Xfmr. Scheme
  - Index for Operating Procedures for First Energy (Pennelec)
  - Conemaugh Unit Stability: Added stability restriction for Hunterstown combined cycle units during an outage of the Hunterstown – Conastone (5013) 500kV line and Hunterstown 500/230kV Xfmr.
- Index for Operating Procedure for PS&G
  - Deleted Branchburg Special Protection Scheme (Somerville 1-2 CB)
- Index of Operating Procedures for AEP
  - Deleted South Canton 765/345 kV Transformer (AEP Operating Memo T-020), Conesville 138 kV Bus Configuration (AEP Operating Memo T030) and the Canton Central-Southeast Canton 138 kV line and the Harrison-Poston 138kv line procedures from the Columbus Transmission Region procedures.
- Index of Operating Procedures for MISO
  - Added MISO and PJM Manual Shadow Price Override Procedure

- Attachment B: Updated Open Circuit Terminal Voltage Control
  - Modified to include additional facilities
- Attachment E: Automatic Sectionalizing Schemes
  - Added list of Sectionalizing Schemes by Transmission Zone

Revision 28 (08/28/2007):

- Section 3: Voltage & Stability Operating Guidelines: Added section entitled “Generator Voltage Schedules”, which defines PJM Default Generator Voltage Schedules.

- Section 3: Voltage & Stability Operating Guidelines: Added bullet to Voltage Control Actions / Voltage Coordination section, which requires Generator Owners to notify PJM and Transmission Owners if Power System Stabilizer (PSS) status.
- Section 5: Index & Operating Procedures for PJM RTO Operations: Added section entitled "Automatic Special Protection Scheme (SPS) Operating Criteria, explaining how PJM dispatch activates and controls for enabled SPS schemes.
- Section5: Index & Operating Procedures for PJM RTO Operations: Modified Dominion - Carolina Substation 54 and 22 SPS sections to provide clarity.
- Section5: Index & Operating Procedures for PJM RTO Operations: Added section entitled "Midwest ISO", and included MISO – PJM Safe Operating Mode procedure.

Revision 27 (7/03/2007):

- Section 1: Transmission Operations Requirements, Transmission Operating Guidelines: Added paragraphs providing guidelines for PJM/TO staff to resolve modeling discrepancies.
- Section 3: Voltage & Stability Operating Guidelines, Returning EHV Lines that were opened for voltage control: Added paragraph providing guidance for return EHV lines to service when open-ended voltage violations are projected during switching
- Section 4: Reportable Transmission Facility Outages, Transmission Outage Acceleration Process: Multiple changes throughout section to provide increased clarity
- Section 5: Index and Operating Procedures for PJM RTO Operations:
    - o Modified Calvert Cliffs voltage limits, added Conastone Xfmr Procedure, updated ComEd Spogs (Normally Open Bus-tie Circuit Breakers, Zion TDC 282 – Lakeview (L28201) 138kV Tieline Operation, Sandwich 138kV Bus Tie 2-3 Operation, Ridgeland 138kV Bus Tie 4-14 Operation), added Neptune Regional Transmission System to FE-E_Jersey Central Section, modified PEPCO Common Trench Cable Ratings, modified communication requirements in Attachment C: Requesting Voltage Limit Exceptions to the PJM Base-Line Voltage Limits.

Revision 26 (5/24/2007):

- Changed several references to "Transmission Operator" to "Transmission Owner."
- Added a sentence in Section 5 (page 124)

Revision 25 (5/15/2007):

- Document: Updated titles to reflect NERC Functional Model terminology
- Eliminated redundancy between M-01, M-03 and M-03a, deleting portions of Section 1: Transmission Operations Requirements, providing references where appropriate.
- Section 3:
    - o Updated Exhibits 3 and 6
    - o Modified Transfer Limit section to include additional reactive transfer limits.

- Section 5:
  - o Added Overuse Section (inadvertently deleted in a past update).
  - o Added Twin Branch – Argenta 345kV Conservative Operations section.
  - o Removal of Indian River 4 SPS Scheme based on Indian River 230kV reconfiguration.
  - o Deleted PJM/VAP Voltage Coordination Plan
  - o Added Dominion SPS schemes at Harmony Village, Carolina Substation 22 line, Carolina Substation 54 line, and Virginia Beach.
- Attachments:
  - o Eliminated Attachment B: Controlling PSE&G Con-Ed Wheel
  - o Eliminated Attachment D: Voltage Coordination Plan
  - o Retitled remaining attachments A through D.
  - o Modified Attachment entitled “Requesting Voltage Limit Exceptions to the PJM Base-Line Voltage Limits.
  - o Added post-contingency congestion management program additions which become effective June 1, 2007

Revision 24 (3/22/2007):

- Section 1: Transmission Operating Guidelines – System Operating Limits

Revision 23 (03/22/2007):

- Overview: Updated titles to reflect NERC Functional Model terminology
- Section 1: Provided additional detail regarding EMS Network Applications
- Section 4: Added discussion regarding transmission line identifiers
- Section 5: Updated Calvert Cliffs kV limits
- Introduction trimmed to eliminate redundant information.
- List of PJM Manuals exhibit removed, with directions given to PJM Web site where all the manuals can be found.
- Revision History permanently moved to the end of the manual

Revision 22 (10/25/2006):

- Exhibit 1: Updated to include the new Manual 30: Alternative Collateral Program.
- Section 1: Revised PJM Procedure to Review Special Protection Systems (SPS) and moved from Section 5 to Section 1.
- Section 3: Added Interconnection Reliability Operating Limit (IROL).
- Revised Voltage and Stability Limits chart (PECO limits corrected).

- Section 4: Revised Scheduling Transmission Outage Requests.
- Revised table under Coordinating Outage Requests with Planned Nuclear Generation Outages.
- Revised Processing Transmission Outage Requests.
- Section 5: Added DLCO and UGI back into full table of Index and Operating Procedures for PJM RTO Operation.
- Added Recognition of Automatic Sectionalizing Schemes.
- Added Carlls Corner #2 CT SPS.
- Revised AEP Additional Regional Procedures.
- Added the East Frankfort TR83 345/138 kV Transformer SPS under ComEd.
- Revised the Bath County Contingency Restrictions.
- Revised Muddy Run Protective Relay.
- Revised Peach Bottom ‘45’ 500 kV CB Outage.
- Added Peach Bottom ‘35’ 500 kV CB Outage.
- Updated the Breaker Derate Table under Allegheny Power.
- Removed Attachment A: Definitions and Acronyms (Information available in PJM Manual 35: Definitions and Acronyms).
- Additions made to Post-Contingency Congestion Management Program Constraint List in Attachment F.

Revision 21 (3/13/2006):

- Added Peach Bottom Off-Site Power Supply Voltage Limits under Section 5
- Corrected Exhibit 7: Reactive Transfer Interface Locations under Section 3

Revision 20 (02/10/2006):

- Revised the Notification and Mitigation Protocols for Nuclear Plant Voltage Limits under Section 3
- Revisions on page 17
- Added the Single Breaker Failure Mitigation Procedure under Section 5
- Added the BGE/PEPCO/NOVA/Doubs Area Operating Procedure under Section 5
- Revisions were made on the following pages: 17, 39-44, 72, 77 and 82-85.

Revision 19 (02/02/2006):

- Revised the Post-Contingency Congestion Management Program Constraint List under Attachment G
- Added Process for TO to Request PJM to Change constraints/facilities in the Post-Contingency Congestion Management program under Attachment G

- Revised Bath County Contingency Restrictions under Section 5
- Revised 30-Minute Rating tables under Attachment B
- Added the Transmission Outage Acceleration Process under Section 4
- Revisions were made on the following pages: 27, 29, 55, 64-67, 271-272, 282 and 284-286.

Revision 18 (12/12/2005):

- Corrected Breaker Derate Table in Section 5 AP
- Corrected EHV definition in Section 1
- Added a Bath County contingency restriction under Section 5 DVP
- Added PJM Procedure to Review Special Protection Systems (SPS) under Section 5
- Edited introduction for Section 5
- Edited Reportable Transmission Facility under Section 1
- Updated Exhibit 2 in Section 1

Revision 17 (8/1/2005):

- Added 500X Reactive Limit in Section 3
- Added Post-contingency Congestion Management Program document
- Added Linwood Special Protection Scheme under Section 5
- Revised Processing Transmission Outage Requests under Section 4
- Corrected PECO stability limits under Section 3
- Replaced Wylie Ridge Operating Procedure with Wylie Ridge Special Protection Scheme under Section 5
- Revised Quad City and Cordova Stability Limits under Section 5
- Added Waukegan 138 kV Bus Tie 4-14 Operation (ComEd SPOG 2-29) under Section 5
- Revised PSE&G/ConED Wheel under Section 5
- Deleted PJM/NYPP Joint Operating Procedure under Section 5
- Deleted Transmission Overuse under Section 5
- Deleted 5018 Branchburg- Ramapo Out-of-Service under Section 5
- Added Branchburg Special Protection Scheme (Bridgewater ‘1-2’ CB) under Section 5
- Deleted Brunner Island #2 Master Fuel Trip Relay under Section 5
- Revised Powerton Stability Limitations (ComEd SPOG 1-3-B and 1-3-B-1) under Section 5

Revision 16 (5/1/2005):

- Added Dominion Procedures to Section 5
- Added PJM Southern Region under Section 1 – Reclosing 500 kV Lines That Have Tripped
- Added SERC under Section 1 – Equipment Failure Procedures

Revision 15 (03/01/2005):

- Deleted Sand Point Relay Procedure under Section 5 - AE
- Deleted Collins 345 kV Operating Guide under Section 5 – ComEd
- Revised Artificial Island Procedure in Section 5 – PSE&G
- Added Branchburg Special Protection Scheme in Section 5 – PSE&G
- Revised the Rockport Operating Guide under Section 5 - AEP
- Added Voltage Limit Exception Request Templates to Attachment F
- Added Reportable Facility Code Information Under Section 1 – Reportable Facilities
- Added additional comments to Real-time Switching Notifications Procedure under Section 4

Revision 14 (01/01/2005):

- Added the DQE procedures to Section 5
- Added Attachment F – Requesting Voltage Limit Exceptions to the PJM Base – Line Voltage Limits
- Added Hyperlinks to all the tables in Section 5

Revision 13 (11/17/2004):

- Revised Susquehanna 1 and 2 Double Contingency to clarify reporting requirements and PJM dispatch actions.

Revision 12 (10/01/2004):

- Added document containing the AEP procedures added to Section 5

Revision 11 (05/08/2004):

- Added document containing the UGI procedures added to Section 5

Revision 10 (05/01/2004):

- Revised to include ComEd Procedures
- Added a new table reflecting ComEd's voltage exceptions

Revision 09 (01/12/2004):

- Section 4, "Reportable Transmission Facility Outages" on Page 54 omitted Peach Bottom Unit 3 output breaker CB65 and Limerick Unit 2 output breaker CB235. This revision corrects that omission

Revision 08 (11/17/2003):

- Modified Entire Document
- Changed all references of PJM IA to PJM
- Included guidelines on how to modify facilities in the Transmission Facilities List
- Changed the central location of the Transmission Facilities List to www.pjm.com
- Included both the PJM Eastern and Western philosophies on re-closing EHV lines that have tripped
- Included information on how to change facility ratings
- Updated list of PJM Manuals
- Included charts to explain the thermal and voltage operating criteria
- Added the Bedington – Black Oak and AP South interfaces to the explanation of PJM Transfer Interfaces
- Added a clear explanation of the submittal requirements for transmission outages
- Added all the relevant Operating Procedures of Allegheny Power into Section 5
- Added and/or changed various procedures for several different Transmission Owners in Section 5
- Removed Attachment B: Reportable Transmission Facilities. Changed the central location of the Transmission Facilities List to www.pjm.com
- Remove Attachment E.

Revision 07 (06/01/2002):

- Section 3: Voltage & Stability Operating Guidelines
    - Added description of new procedures for reporting generating unit reactive capability via eDART.
- Attachment J: PJM Generating Unit Reactive Capability Curve Specification and Reporting Procedures
    - Added description of new procedures for reporting generating unit reactive capability via eDART.

Revision 06 (01/24/2001):

- Section 1: Coordination & Direction of Transmission Operations
    - Added description of PJM's Real-Time Reliability Model. Removed description of Designated Transmission Facilities. Added description of PJM Transmission Facilities.

- Section 2: Thermal Operating Guidelines
  - o Revised Thermal Limit Operations. Added Thermal Operating Criteria. Relocated operating procedures to new Section 5: Operating Procedures.
- Section 3: Voltage & Stability Operating Guidelines
  - o Revised Voltage Operation and Voltage Limits. Added Voltage Operating Limits. Relocated operating procedures to new Section 5: Operating Procedures. Revised Voltage Control Actions- Low Voltage Operation and Voltage Control Actions- High Voltage Operation. Added Generating Unit Reactive Capability.
- Section 4: Reportable Transmission Facility Outages
  - o Revised this section for notifications and references to eDART.
- Section 5: Operating Procedures
  - o Added this section which contains operating procedures from sections 2 and 3. Operating procedures are identified by Transmission Zone. Removed Keeney 500/230 kV Transformer Contingency, Keeney-Basin Road 138 kV Special Purpose Relay, Burma-Piney 115 kV Relay, Balt-Wash Scheduling Import Limit, BC/PEPCO Reactive Import Limit. Revised Transmission Overuse Calculation, Muddy Run Protective Relay (Pumping/Generation Mode). Added Constraint Management Mitigation, Cedar Special Purpose Relay Scheme, Seneca Pump Operations, Procedure to Run Seneca Generation For Constraints, Potomac River Limerick Ratings 4A &4B.
- Attachment B Reportable Transmission Facilities
  - o Revised to include references to eDART. Removed multiple Exhibits which were replaced by eDART.
- Attachment H: Transmission Facilities Database
  - o Added this new section. Includes Transmission Facility List for each Transmission Zone. (This continues to be a work in progress).
- Attachment I: Requesting Voltage Limit Exceptions to PJM Base-Line Limits
  - o Added this new section to complement descriptions given in Section 3.
- Attachment J: PJM Generating Unit Reactive Capability Curve Specifications and Reporting Procedures
  - o Added this new section to complement descriptions given in Section 3.

Revision 05 (04/01/2000):

- Section 2: Coordination & Direction of Transmission Operations
  - o Revised Keeney 500/230 kV Transformer Contingency, PJM Actions. Removed step 4, Maximum Scheduled Generation is loaded.
- Section 3: Voltage & Stability Operating Guidelines

- o Revised NEPEX Emergencies. Replaced reference to Max Schedule Generation with ‘highest incremental cost of generation’.

Revision 04 (08/23/1999):

- Section 3: Voltage & Stability Operating Guidelines
    - o Removed “Simultaneous loss of all Hydro Quebec (HQ) HVDC interconnections linked to the HQ AC system” listed under subsection: NEPEX Contingencies.

Revision 03 (06/15/1999):

- Section 2: Thermal Operating Guidelines
    - o Added contingency operations for the Doubs-Dickerson 230 kV Line.

Revision 02 (01/28/98):

- Section 4: Designated Transmission Facility Outages
- Changed:

“The Transmission Owners have the right and obligation to maintain or repair their portion of the transmission system. PJM approves all Designated Transmission Facility outages prior to removal of the equipment from service. PJM will coordinate scheduled outages of all Designated Transmission Facilities with planned generation outages that are submitted to PJM and may affect PJM RTO operations. For purposes of scheduling, Designated Transmission Facilities include, but are not limited to, lines, transformers, phase angle regulators, buses, breakers, disconnects, Bulk Electric System capacitors, reactors, and all related equipment.”

“PJM maintains a list of Designated Transmission Facilities. Each Transmission Owner submits the tentative dates of all transmission outages of Designated Transmission Facilities to PJM as far in advance as possible.”

From:

“The Transmission Owners have the right and obligation to maintain or repair their portion of the transmission system. The Transmission Owners rely upon PJM to coordinate scheduled outages of all Designated Transmission Facilities with planned generation outages that are submitted to PJM and may affect PJM RTO operations. For purposes of scheduling, Designated Transmission Facilities include, but are not limited to, lines, transformers, phase angle regulators, buses, breakers, disconnects, Bulk Electric System capacitors, reactors, and all related equipment.”

“PJM maintains a list of Designated Transmission Facilities. Each Transmission Owner submits the tentative dates of all transmission outages of Designated Transmission Facilities to PJM as far in advance as possible. Under certain operating conditions, reportable outages are not limited to the facilities listed in the Designated Transmission Facility List (See Attachment B).”

under “General Principles.”

- Changed

"A planned transmission outage that is rescheduled or canceled because of inclement weather or at the direction or request of PJM retains its status and priority as a planned transmission outage with PJM approved rescheduled date. If an outage request is rescheduled or canceled for reasons other than inclement weather or at the direction of PJM, the rescheduled or canceled and resubmitted outage is treated as an unplanned outage request. PJM coordinates outage rescheduling with the PJM Members to minimize impacts on system operations."

From:

"A planned transmission outage that is rescheduled or canceled because of inclement weather or at the direction or request of PJM retains its status and priority as a planned transmission outage. If an outage request is rescheduled or canceled for reasons other than inclement weather or at the direction of PJM, the rescheduled or canceled and resubmitted outage is treated as an unplanned outage request. PJM coordinates outage rescheduling with the PJM Members to minimize impacts on system operations."

under "Scheduling Transmission Outages."

- Changed:

"When a thermal or reactive violation is recognized to have above average impact to system operation, PJM will communicate the projected PJM RTO impacts and offer available alternatives that reduce or eliminate the detected condition, to the affected PJM Transmission Owners. Any alternatives offered and the resultant choice will be documented by PJM. In actual operations line loading relief procedures are utilized to control Bulk Electric System transmission facility loadings and reactive constraints. The use of cost effective generation shift procedures are employed after all available zero cost options are exhausted. No outage that is determined to result in potentially unreliable operations is approved by PJM."

From:

"When thermal or reactive violations are recognized, PJM communicates the projected PJM RTO impacts to the affected PJM Members. An appropriate plan to control constraints is agreed upon by affected PJM Members. Line loading relief procedures are utilized to control Bulk Electric System transmission facility loadings and reactive constraints. The use of cost effective generation shift procedures are employed after all available zero cost options are exhausted. No outage that is determined to result in potentially unreliable operations is approved by PJM."

under "Studying Projected System Conditions."

- Changed:

"PJM, as system conditions warrant, identifies opportunities for, and encourages, coordination of all generator and transmission maintenance outages. When actual or anticipated system conditions change such that, at the discretion of PJM, the rescheduling of a transmission outage is advisable, PJM informs the Transmission Owner of the conditions and available alternatives. The Transmission Owner involved considers the impacts of proceeding with the outage as advised by PJM and may either proceed knowing the estimated impacts on the remaining facilities or postpone the outage. If the outage is not postponed, PJM determines and records the appropriate impacts or changes to system limits and takes the steps required to maintain established operating reliability criteria as mentioned within Section 1 of this manual."

From:

“PJM, as system conditions warrant, identifies opportunities for, and encourages, coordination of all generator and transmission maintenance outages. When actual or anticipated system conditions change such that, at the discretion of PJM, the rescheduling of a transmission outage is advisable, PJM informs the Transmission Owner of the conditions. The Transmission Owner involved considers the impacts of proceeding with the outage as advised by PJM and may either proceed knowing the estimated impacts on the remaining facilities or postpone the outage. If the outage is not postponed, PJM determines the appropriate impacts or changes to system limits and takes the steps required to maintain established operating reliability criteria as mentioned within section 1 of this manual.” under “Approving Transmission Outage Requests.”

Revision 01 (06/13/1997):

- Attachment B: Reportable Transmission Facilities (Correction made 09/12/97)
  - Exhibit B.1: Reportable Transmission Facilities - EHV Lines
    - Corrected Designations for Red Lion-Hope Creek (5015) and Keeney-Red Lion (5036)
- Attachment B: Reportable Transmission Facilities
  - Exhibit B.1: Reportable Transmission Facilities - EHV Lines
    - Added 5036 Red Lion - Hope Creek
    - Added 5015 Keeney - Red Lion
    - Deleted 5015 Hope Creek - Keeney
  - Exhibit B.2: Reportable Transmission Facilities - Transformers
    - Added AT-50 Red Lion 500/230
  - Exhibit B.3: Reportable Transmission Facilities - Busses and Breakers
    - Added Red Lion
  - Exhibit B.10: Reportable Transmission Facilities - AE
    - Added Sands Pt – Cedar

Revision 00 (05/06/1997):

- This revision is the preliminary draft of the **PJM Manual for *Transmission Operations***.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Mechanicsville Solar, LLC	)	Docket No. ER21-2091-000
	)	

DECLARATION

JOSEPH E. BOWRING states that I prepared the testimony to which this affidavit is attached with the assistance of the staff of Monitoring Analytics, LLC, and that the statements contained therein are true and correct to the best of my knowledge and belief. Monitoring Analytics, LLC, is acting in its capacity as the Independent Market Monitor for PJM.

Pursuant to Rule 2005(b)(3) (18 CFR § 385.2005(b)(3), citing 28 U.S.C. § 1746), I further state under penalty of perjury that the foregoing is true and correct.

Executed on April 25, 2022.

Joseph E. Bowring