STITES & HARBISON PLLC
ATTORNEYS

RECEIVED

MAY 0 2 2016

PUBLIC SERVICE
COMMISSION

421 West Main Street
Frankfort, KY 40601
[502] 223-3477
[502] 223-4124 Fax

May 1, 2016

Mark R. Overstreet
(502) 209-1219
(502) 223-4387 FAX
moverstreet@stites.com

HAND DELIVERED

Aaron D. Greenwell
Acting Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RE: Administrative Case No. 345

Dear Mr. Greenwell:

Pursuant to the Commission's March 1, 1993 Order in Administrative Case No. 345, please find enclosed and accept for filing a copy of AEP East/PJM and AEP West/SPP Emergency Operating Plan Version 18. Due to its voluminous nature, and in accordance with past practice, the Company is filing the copy of the Plan in electronic form on a CD.

Also being filed are the original and ten copies of the Company's motion for confidential treatment for those portions of the AEP East/PJM and AEP West/SPP Emergency Operating Plan identified in the enclosed affidavit of Michael R. Richardson as being confidential.

Please do not hesitate to contact me if you have any questions.

Very truly yours,

Mark R. Overstreet

MRO

RECEIVED

MAY 02 2016

PUBLIC SERVICE
COMMISSION

AFFIDAVIT OF MICHAEL R. RICHARDSON

Michael R. Richardson, first being duly sworn, deposes and states:

1. I am employed by American Electric Power Service Corporation ("AEPSC"). AEPSC is a wholly-owned subsidiary of American Electric Power Company, Inc. (AEP) and is an affiliate of Kentucky Power Company (the "Companies"). I am responsible for support of the efficient and reliable operation and coordination of the AEP subsidiaries' transmission network in PJM and SPP; for the development of operational standards, and system studies, normal and emergency operating plans and procedures. I also assist with the development and delivery of training in support of system control center and dispatching activities and in support of operations engineering practices; with providing operational input to the transmission asset management process; with Transmission Operations compliance with all NERC and Regional Reliability Council operational and reliability requirements; with updating the annual revision and improvement of the AEP Transmission Emergency Operating Plan and ensuring the Plan conforms to the latest NERC requirements. I have also been involved in several NERC Standards Authorization Request/Standard Drafting Team.

2. I am of the age of majority and competent to make this Affidavit. The statements in this Affidavit are based on my personal knowledge or knowledge gained through my investigation with other AEPSC and Kentucky Power employees of the matters set forth in this Affidavit.

Description of the Confidential Information for Which Protection is Sought

3. Kentucky Power is requesting that certain confidential Critical Energy Infrastructure Information ("CEII") included in Kentucky Power's Emergency Operation Plan be exempted from public disclosure pursuant to KRS 61.878(1)(k) and KRS 61.878(1)(m).

4. The Confidential Information contained in this emergency response plan (as indicated in the table below) is treated by the Federal Energy Regulatory Commission as CEII and is exempt from public disclosure in accordance with FERC rules. 18 C.F.R. § 388.113(c). All of the information for which confidential treatment is requested constitutes CEII under the FERC rule. The CEII includes specific engineering, vulnerability, and detailed design information about existing critical infrastructure. The information relates details about the production, generation, transportation, and transmission of energy. The CEII is critical to the safety and security of the region. The information does not simply give the general location of critical infrastructure; it is information that could be useful to a person in planning an attack on critical infrastructure. The CEII is exempt from mandatory disclosure under 5 U.S.C. 552.

5. More specifically, Kentucky Power seeks confidential treatment for engineering, vulnerability, and detailed design information about existing critical infrastructure related to the generation and transmission system of the AEP subsidiaries.. The following table details the nature of the information and how it relates to the critical nature of the information in emergency situations.

Vol/Pg #	Confidential Information
VI/11	Description of critical points on the generation and transmission system and describes the dependent engineering relationship.
VI/12	Operations guide relates to the engineering and design of existing infrastructure of a specific portion of the system.
VI/13-14	Description of a SPS system

Vol/Pg #	Confidential Information
VI/15-17	Load shed plan provides information regarding the vulnerability of existing infrastructure.
VI/40-42	Specific description of units equipped with a certain power stabilizer. Damage to these units could affect the reliability of the Bulk Electric System.
Appendix VII/1-7	Contact names and information of personnel involved in the emergency response operations. Public disclosure of this list would provide persons seeking to harm the generation and transmission system a list of individuals both within Kentucky Power and APESC and contacts at other companies who are responsible for securing the system and ensuring its continued operation and could be used to interfere with the performance of their duties.

The Information Contained in Confidential Information is Critical Energy Infrastructure Information and is Not Generally Known, Readily Ascertainable by Proper Means by Other Persons

6. The CEII is not available or ascertainable by other parties through normal or proper means. No reasonable amount of independent research could yield this information to other parties. The information reflects the internal planning efforts of AEPSC and Kentucky Power (the "Companies") and information necessary to ensure a safe and reliable management of the transmission system.

The Information is the Subject of Reasonable Efforts to Maintain Its Secrecy

7. The Confidential Information has been the subject of reasonable efforts to maintain its secrecy. The Companies restrict access to the CEII to those employees and representatives of the Companies who have a need to know such information due to their job and management responsibilities. The Companies limit public access to buildings housing the CEII by use of security guards. Persons not employed by the Companies who are allowed past security guards at buildings where Confidential Information is kept are not permitted to walk within such buildings without an escort. The Companies' files containing the Confidential Information are maintained separately from the Companies' general records and access to those

files is restricted. Within the Companies, access to this information has been and will continue to be disclosed only to those employees and representatives of the Companies who have a need to know about such information due to their job and management responsibilities. Outside the Companies, this information is only provided to certain persons who have a legitimate need to review the information.

Further the Affiant sayeth naught.

Dated: 4/27/2016

Michael R. Richardson

STATE OF OHIO)
) SS:
COUNTY OF FRANKLIN)

Michael R. Richardson appeared before me, a Notary Public in and for this County and State, and swore that the foregoing statements are true.

Cynthia L. Frazier-Keller
Printed

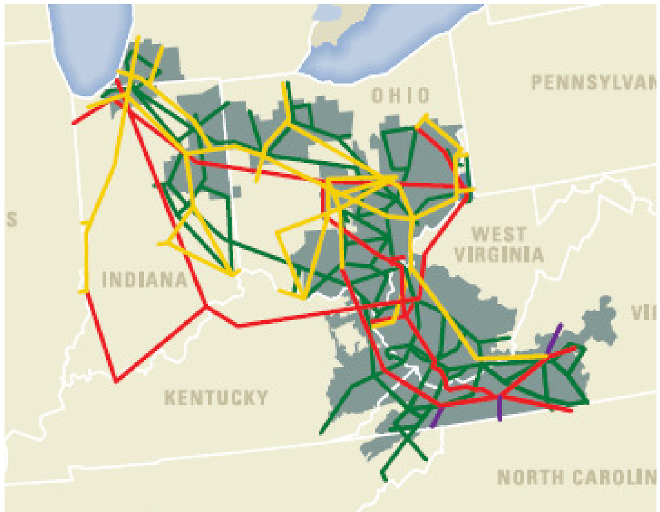
Signature

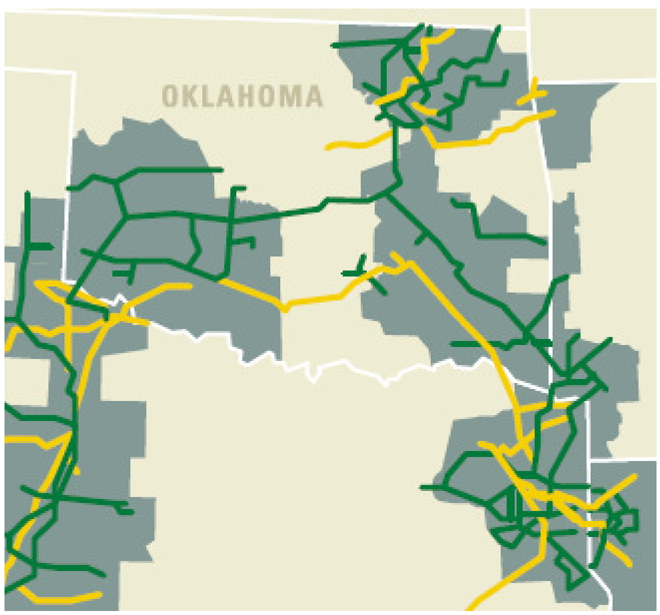
My Commission Expires:
N/A

My County of Residence:
Fairfield

NOTARIAL SEAL STATE OF OHIO
CYNTHIA L. FRAZIER-KELLER
ATTORNEY AT LAW
Notary Public, State of Ohio
My Commission Has No Expiration Date
Section 147.03 ORC

AEP AMERICAN® ELECTRIC POWER





AEP East/PJM and AEP West/SPP

Emergency Operating Plan

Version 18
November, 2015

Prepared By:
Transmission Operations

AEP Confidential Special Handling

Document Control

Preparation

ACTION	NAME(S)	TITLE
Prepared by:	Michael Richardson	Principal Engineer
Reviewed by:	TOPS Engineering	Transmission Operations Engineering Staff

Approvals

Transmission Operations Business Unit

Name: Tim Hostetler **Signature:**

Title: Manager, Transmission Operations Engineering **Date:**

Review Cycle

Quarterly	Semi-annual	Annual √	As Needed √

Retention Period

Six months	One Year	Two Years	Three Years √

Release History

VERSION	DATE	FILE NAME	CHANGE NOTICE
Version 1.0	June, 1999	EOP_V1.pdf	Annual Review
Version 2.0	February, 2001	EOP_V2.pdf	Annual Review
Version 3.0	May, 2001	EOP_V3.pdf	Annual Review
Version 3.1	June, 2001	EOP_V3_1.pdf	Minor Revisions
Version 4.0	June, 2002	EOP_V4.pdf	Annual Review
Version 5.0	June, 2003	EOP_V5.pdf	Annual Review
Version 6.0	March, 2004	EOP_V6.pdf	Annual Review
Version 7.0	October, 2004	EOP_V7.pdf	Major Revisions
Version 8.0	June, 2005	EOP_V8.pdf	Annual Review
Version 9.0	February, 2006	EOP_V9.pdf	Annual Review
Version 9.1	March, 2006	EOP_V9_1.pdf	Minor revisions

Version 9.2	April, 2006	EOP_V9_2.pdf	Minor revisions
Version 9.3	September, 2006	EOP_V9_3.pdf	Minor revisions
Version 10.0	March, 2007	EOP_V10.pdf	Annual Review
Version 10.1	May, 2007	EOP_V10_1.pdf	1. Updated Implementation with some revised names and corrected some phone numbers. 2. Updated the following Sections based on recommendations from the NERC Readiness and RFC audit teams. Section I, II, III, V, VIII, X
Version 11.0	April, 2008	EOP_V11.pdf	Annual Review
Version 11.1	August, 2008	EOP_V11_1.pdf	Minor edits, and classification of document as AEP Confidential Special Handling
Version 12.0	April, 2009	EOP_V12.pdf	Annual Review
Version 12.1	August, 2009	EOP_V12_1.pdf	Added Document Control, updated Section VI-[redacted] and Section VIII-Black Start test dates
Version 12.2	September, 2009	EOP_V12_2.pdf	Updated Implementation phone numbers Updated Section VIII-Black Start - AEPW/SPP test dates and backup agreement with [redacted] for [redacted] Updated Appendix VII Emergency Contact phone numbers
Version 13.0	April, 2010	EOP_V13.pdf	Annual Review • Implementation names/phone numbers • Section III - Capacity Deficiency Program consistent with PJM • Section V - Fuel Limitations added reference to SPP Criteria, update Figure V-1 • Section VI - Transmission

			Emergency Procedures SPS, UVLS, PJM procedures, PSS updates • Section IX -DOE and NERC Reporting clarified reporting times • Section X – Emergency Communications phone numbers • Section XI – Training hours • Appendix III – Under Frequency Guidelines • Appendix V – Manual Load Shedding Guidelines loads • Appendix VII Emergency Contact phone numbers
Version 13.1	December 2010	EOP_V13_1.pdf	Updated 1.) Section III Capacity Deficiency Program • Minor edits to PJM portion 2.) Section VI Transmission Emergency Procedures • Indiana – [redacted] Special Protection System 3.) Section VIII System Restoration • Unit Test dates • TDC Name changes • System Restoration dB 4.) Appendix VII • AEP internal contacts due to reorganization
Version 14.0	June 2011	EOP_V14.pdf	Annual Review
Version 15.0	June 2012	EOP_V15.pdf	Annual Review / Correct Date typo
Version 15.1	December 2012	EOP_V15_1.pdf	Update Section III – Load updates Section VI – Load shedding updates Section VIII – ALR test dates updates Restoration frequency range update

AEP Confidential Special Handling

			Section IX – NERC form update Section X – Satellite phone # update Appendix VI – Added PER-003-1 Appendix VII – Added new contact
Version 16.0	August 2013	EOP_V16.pdf	Annual Review Section III – Update PJM and SPP sections to be consistent with respective RC requirements Section V – Update reference to NERC standards, PJM manuals, and SPP Criteria. Section VI – Updated PJM manual references SPP Criteria references. SPP IROL Relief Guide dated 06/28/13 Rockport Operating Procedure Columbus Southern Under Voltage Load Shed Scheme Added Plant Fault Duty Procedures Operating in an Unknown State Section VIII – This section contains highlights of the AEP System Restoration Plans approved by PJM and SPP RC. Refer to the approved plans on TOps Sharepoint for additional information. Section IX – Update NERC fax #, email address, and links to NERC's reorganized web site.

			Section X – Update NERC, PJM manual references, TDC communication references. Section XI – Update System Operator Training objectives
Version 17.0	September 2014	EOP_V17.pdf	Annual review Section III – Update PJM and SPP sections to be consistent with respective RC requirements Section V – Update SPP section to be consistent with SPP Emergency Operating Plan Section VI – Update to reflect AEP / PJM / SPP Emergency Procedures Section VIII - This section contains highlights of the AEP System Restoration Plans approved by PJM and SPP RC. Refer to the approved plans on TOps Sharepoint for additional information. Section IX – Updated to be consistent with AEP Reporting Operating Plan. Sorted Attachment 1 table by reporting time. Appendix II – Updated high voltage limits in Table AIII-4 to reflect Mike Skidmore's recommendations. Appendix III – Updated AEP East, PSO, SWEPCO peak load

			tables. Appendix IV – Update load relief number Appendix V – Update Tables AV-1, AV-2, PSO, and SWEPCO tables Appendix VI – Added NERC IRO-001-1.1 R8 and IRO-004-2 R1 Appendix VII – Updated contact list and associated phone numbers
Version 18.0	November, 2015	EOP_V18.pdf	Annual Review Implementation – Update contact information Section III – Update PJM and SPP sections to be consistent with respective RC requirements. Updated load management, unit retirements. Section IV – Updated to reflect unit retirements. Section V – Updated to reflect changes in PJM and SPP requirements. Section VI – Updated to reflect changes in PJM m03, m13, m14, m37, and SPP Emergency Operating Plan. Emergency Actions dealing with voltage control. PCLLRW and PCAP additions. Updated UVLS schemes

AEP Confidential Special Handling

			Updated Plant Fault Duty Procedures. Section VII – Updated to align with the AEP Emergency Response Plan. SectionVIII – Refers the reader to the Reliability Coordinator approved system restoration plan for the PJM / SPP areas. Section X – Updated to reflect NERC COM standard, PJM M01, and SPP Criteria 10 changes. Updated phone numbers. Section XI – Updated to reflect NERC PER-005 requirements. Appendix V – Updated load shed MW. Appendix VI – Incorporates updated AEP Operator to Act Policy document. Appendix VII – Updated internal / external contacts

AEP Confidential Special Handling

Purpose

If the AEP/PJM footprint or AEP/SPP footprint experiences a Capacity Deficiency which requires implementation of our Capacity Deficiency plan or if a portion of the PJM or SPP region experiences a wide-spread area outage or becomes separated from the interconnected system, the System Control Center (SCC) and/or Commercial Operations – Market Operations (MO)) will contact their Executive Team representative listed below, explain the system emergency, and begin to take actions to implement the Emergency Operating Plan (EOP).

PJM is the Balancing Authority for AEP East/PJM while SPP BA is the Balancing Authority for AEP West/SPP. The following procedures offer clarification on Section III (Capacity Deficiency) of our plan.

Procedure for implementation of Section III: Capacity Deficiency of the Emergency Operating Plan (EOP):

For the AEP/PJM footprint, PJM is responsible for monitoring the operation of the PJM RTO and declaring the existence of a capacity deficiency, and for directing the operations of the PJM Members as necessary to manage, alleviate, or end a capacity emergency.

For the AEP/SPP footprint the SPP BA is responsible for declaring and communicating the existence of emergencies related to energy and capacity shortages, and for directing the operations of the appropriate entities within the SPP Balancing Authority Area (BAA) as necessary to manage, alleviate, or end an energy or capacity emergency.

Whenever PJM declares a generation alert/warning/action for the AEP/PJM footprint, the System Control Center will contact their Executive Team representative and the Market Operations which will be responsible for notifying their Executive Team representative.

Whenever SPP declares an emergency related to energy and capacity shortages for the AEP/SPP footprint, the System Control Center will contact their Executive Team representative and the Market Operations which will be responsible for notifying their Executive Team representative.

PJM / SPP BA will make the decision as to when to implement the provisions of EOP Section III: Capacity Deficiency and the SCC will make notifications as required.

AEP Confidential Special Handling

Executive Team

Transmission -	Robert W. Bradish[redacted]
	Allan W Smith, [redacted]
Commercial/Market Operations -	Tim Light [redacted]
Energy Supply -	Charles E. Zebula [redacted]
Generation –	Mark C McCullough [redacted]
Fuel, Emissions, Logistics -	Marguerite C. Mills [redacted]
AEP Utilities -	AEP Utilities East: [redacted]
	AEP Utilities West: [redacted]
Corporate Communication -	Dale E Heydlauff [redacted]
Customer Solutions Center -	Robert L Cheripko [redacted]

The Management Group personnel listed below will be responsible for keeping the Executive Team informed and up to date as well as keeping their organizations informed of all the actions taking place. From previous operating experience it would be beneficial for Transmission Operations and Corporate Communications be coordinated from the System Control Center (SCC) location. The other parties could either operate in the SCC or coordinate their efforts by telephone and/or 800 MHz radios.

In an emergency situation, the FERC rules allow for temporary suspension of the affiliate restrictions and standards of conduct in order to preserve the reliability of the grid. A notice will be posted on the OASIS that states: "AEP is in an emergency situation and the separation between the Transmission Reliability and Market functions has been temporarily suspended."

The OASIS posting is on the AEP FERC Standards of Conduct for Transmission Providers. (www.aep.com under About Us/ Required Internet Postings) Ethics and Compliance would coordinate the postings from Transmission. (8-200-6226 or 614-716-6226)

Management Group

Group responsible for directing operational implementations of EOP:

Transmission Operations - Paul B Johnson [redacted]
Timothy Hostetler [redacted]
Market Operations - William R Thompson [redacted]
Energy Trading - Bryan Holland [redacted]
Generation - Jeff LaFleur [redacted]
Daniel V Lee [redacted]
Gary C Knight [redacted]
Paul W Franklin [redacted]
Fuel, Emissions, Logistics Marguerite C Mills [redacted]

Distribution - Thomas L Kirkpatrick [redacted]

Corporate Communication - Thomas Holliday [redacted]
Rachel Hammer [redacted]
Customer Solutions Center - Bradley A Galford [redacted]
Customer Services - Don Nichols [redacted]
Workplace Services - Mike Roman [redacted]
Jerry L Waller [redacted]
Derek L Lindeman [redacted]
Glenda L Staley [redacted]
Regulatory Services - Jon C Walter [redacted]
[redacted] Andrea E Moore [redacted]
Steven H Ferguson [redacted]
Will Castle [redacted]
Lila P Munsey [redacted]
Thomas Brice [redacted]
[redacted] Emily C Shuart [redacted]
[redacted]
Ron K. Ford [redacted]

The Management Group above will provide guidance to the System Control Center regarding implementation of provisions of the Emergency Operating Plan (EOP), but the final decision resides with the System Control Center Operator as per NERC Standards and NERC Certification requirements. The Management Group will also assist in external communication to such agencies as the Public Utilities Commissions, Media Outlets, Homeland Security, State Emergency Management Centers, Nuclear Regulatory Commission (NRC), Department of Energy (DOE), etc.

Table of Contents

I Introduction I-1

II Policies and Guidelines II-1

III Capacity Deficiency Program III-1

Purpose III-1
Criteria III-1
AEP West/SPP Procedures III-2
Responsibility III-2
SPP Communication Methods III-2
Maximum Emergency Generation Alert III-3
Notifying Government Agencies III-3
Energy Emergency Alert 1 ..... III-3
SPP BA issues System Wide Reserve Shortage Alert III-4
Emergency Capacity Shortage Notification III-4
Energy Emergency Alert 2 ..... III-4
Maximizing Generator Output and Availability III-5
Notifying Co-generation and IPP III-5
Load Management Alerts III-5
Public Appeals III-5
Voltage Reduction III-5
Interruptible and Curtailable Loads III-6
Appeals to Customers to Use Alternate Fuels III-6
Miscellaneous III-6
Energy Emergency Alert 3 ..... III-7
Manual Load Curtailment III-7
Real-Time Transmission Reliability Emergency Alarms III-7
CPS and Disturbance Control Standard Deviation III-8
Termination of Capacity Emergency III-8
Capacity Deficiency Summary – AEP/SPP Table III-1 ..... III-10

AEP East/PJM Procedures III-11
Reserve Requirements III-11
Capacity Shortages III-11
Unit Startup Notification Alert III-13
Max. Emergency Generation Alert III-13
Primary Reserve Alert III-15
Voltage Reduction Alert III-15
Step 1 – Pre-Emergency Mandatory Load Management Reduction Action.. .. III-16
Step 2 – Emergency Load Management Reductions III-16
Step 3 - Primary Reserve Warning III-17

Step 4A - Maximum Emergency Generation III-17
Step 4B – Emergency Voluntary Energy Only Demand Response III-19
Step 5 - Voltage Reduction & Reduction of non-critical Plant Load III-19
Step 6 – Curtailment of Non-Essential Building Load III-20
Step 7 - Manual Load Dump Warning III-20
Step 8 - Voltage Reduction III-21
Step 9 - Manual Load Dump III-21
Addendum to Manual Load Dump Procedures III-24
Virginia & Kentucky Curtailment Protocols III-24
Capacity Deficiency Summary – AEP/PJM Table III-2 .... III-28
Severe Weather Conditions III-29
Cold Weather Alert III-29
Hot Weather Alert III-31
Extra Load Capability AEP East/PJM Units Table III-3 .... III-33
Curtailment of Generation Station Use – Table III-4 .... III-33
Notification Procedures III-34
Energy Emergency Alerts III-36
Energy Emergency Alert Report (EEA Report) III-41
Emergency Messages from American Electric Power to the Public III-44

IV Procedures During Abnormal System Frequency IV-1
Introduction IV-1
Under Frequency Procedures IV-1
AEP/PJM IV-1
AEP/SPP IV-5
Isolation of Coal-Fired Steam Turbine Generation Units IV-7
Constant Frequency Operations Guide IV-8
Turbine Off-Frequency Operation IV-13
Introduction IV-13
Turbine Generator Units IV-14
AEP/PJM IV-14
AEP/SPP SWEPCO IV-17
AEP/SPP PSO IV-20

V Fuel Limitations V-1
AEPE/PJM Reporting Procedures V-1
AEPW/SPP Reporting Procedures V-5
Notifications V-9

VI Transmission Emergency Procedures VI-1
NERC, PJM, and SPP Standard Reference VI-1
SOL & IROL Definitions VI-1
Introduction and Conditions VI-4
1. Contingency Thermal Overloads VI-5
2. Contingency System Stability Over Limits VI-5

3. Contingency Voltage Under\Over Limits VI-5
4. Actual Thermal Overloads and/or Actual Voltages Under Limits VI-5
Transmission Reserve Warning (TRW) VI-6
Emergency Actions VI-6
[redacted] VI-11
[redacted] VI-15
Plant Fault Duty Procedures VI-18
Geomagnetic Disturbance Operating Procedure VI-19
Notifications VI-22
PJM - Locational Marginal Pricing - LMP VI-23
SPP – Congestion Management VI-24
NERC Transmission Loading Relief (TLR) Procedure VI-26
PJM – Thermal Operating Guides VI-29
PJM – Voltage Limit Violations VI-31
PJM – Heavy Load Voltage Schedule VI-32
PJM – Post Contingency Local Load Relief Warning VI-34
PJM – Contingency Load Dump Limit Exceedance Analysis VI-38
PJM – Reactive Reserve Check (RRC) VI-39
Units [redacted] VI-40
Conservative Operation VI-43
Emergency Messages from AEP to the Public VI-45

VII Major Storm Restoration VII-1
Introduction VII-1
AEP Emergency Response Plan Overview VII-1
AEP ERP - Declaration of Transmission Emergency VII-2
AEP ERP – Transmission Operations Overview VII-2
AEP ERP – Training Personnel VII-2
Storm Restoration Plan VII--3
Restoration Priority VII-3
Staffing VII-4
Communications VII-5
Storm Organization Responsibilities VII-6
Storm Emergency Communications VII-10

VIII System Restoration VIII-1
Introduction VIII-1

IX DOE and NERC Reporting Requirements IX-1
Introduction DOE and NERC Reporting Requirements IX-1
Process IX-1
Reporting Responsibilities IX-1
Attachment 1 .... IX-3

X Emergency Communications X-1
NERC / PJM / SPP References X-1
Communications Diagram X-2
Types of Communications X-3
Decision Making/Collaboration X-7
Failures X-7
Testing X-8

XI Training XI-1
Requirements XI-1

Appendix I Station Equipment Problems Resulting from Loss of AC **AI-1**
Station Batteries AI-1
Portable Generators AI-1
Operation of Transmission Breakers During a Loss of Auxiliary Power AI-1
Restoration of AC Power to Air Blast and SF6 ..... AI-6

Appendix II High Voltage Limits on Equipment **AII-1**
High Voltage Limits – Off Peak Load AII-2
High Voltage Limits – Peak Load AII-7
Overvoltage Relay Settings AII-11
High Voltage Limits – Circuit Breakers AII-13

Appendix III Under Frequency Guidelines **AIII-1**
AEP/PJM Guidelines AIII-1
AEP/SPP Guidelines AIII-4

Appendix IV Voltage Reduction Guidelines **AIV-1**
AEP/PJM Guidelines AIV-1
AEP/SPP Guidelines AIV-2

Appendix V Manual Load Shedding Guidelines **AV-1**
AEP/PJM Guidelines AV-1
AEP/SPP Guidelines AV-6

Appendix VI Responsibility and Authority **AVI-1**

Appendix VII Emergency Contact Information **AVII-1**
Internal AVII-1
AEP East/PJM Region Neighboring System AVII-3
AEP West/SPP Region Interconection AVII-7

Section I
Introduction

This plan is aimed at maintaining reliable power system operation associated with the bulk power supply system. The main focus is on preventing major power outages of wide extent involving generating plants, transmission lines and bulk power substations that collectively furnish the power to major points of distribution.

While localized power interruptions are considered beyond the scope of this plan, it is important to recognize that some of the plan's features will be of benefit in those situations.

The Emergency Operating Plan (EOP), as outlined in this report, is primarily directed toward providing concepts, recommendations for facilities (communications, displays, alarms, etc.) and basic data which, together with trained personnel, will permit a sound approach to the handling of any emergency situation that may arise. This keeps the plan dynamic and also avoids the impractical approach of trying to define every condition that may arise.

Should conditions arise that are beyond any reasonable expectations, including multiple outages caused by either weather or equipment failures, refer to the NERC Reliability Coordinator approved System Restoration Plans. The System Restoration Plan contains general procedures for restoring the system as quickly as possible. Every effort will be made to avoid the need to use restoration procedures.

DOE form OE-417, which is mandatory pursuant to Section 13(b) of the Federal Energy Administration Act of 1974 (Public Law 93-275), places an added emphasis on the need for formal procedures to be followed in emergencies related to the bulk power system. Reporting procedures related to this form are summarized in Section IX.

Personnel receiving copies of this plan need to become familiar with its contents; furthermore, all employees who would be involved in the various procedures need to have sufficient training to perform the intended tasks. It is intended that the procedures set forth in this plan will be followed in the sequence, and for the reasons, listed. However, due to the dynamic nature of a power delivery system and the unknowns that can accompany certain events, it may become necessary at times to deviate from the standards herein.

AEP considers all elements of EOP-001-2.1b, Attachment 1-EOP-001, EOP-005-2, PJM Manuals, SPP Criteria, SPP Reliability Coordinator Area Restoration Plan, and SPP BA Emergency Operations Plan in the development of AEP's Emergency Operating Plans.

AEP will supply the AEP Emergency Operating Plan to neighboring entities. Information that is designated as FERC Critical Energy Infrastructure Information (CEII) will be removed from the Plan unless a signed confidentiality agreement is returned by the neighboring entity.

This plan will be updated annually.

Section II

Policies and Guidelines

Power systems must be operated within limits that will ensure adequate generation and transmission capacity to avoid cascading. While power system load grows more or less on a continual basis, transmission and generation equipment is added in finite blocks. This results in operating margins that not only are changing, but may result in constraints that alternate in severity both in generation and transmission.

In developing a set of operating limits for the System, it is important to do so within a general framework in order to ensure that the operating objectives are met. Accordingly, a set of general guidelines is presented below.

1. First and foremost in carrying out these emergency procedures is our Environment, Safety & Health Philosophy:

"No aspect of operations is more important than the health and safety of people. Our customers' needs are met in harmony with environmental protection."

2. Each Transmission Operator has the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies including the shedding of firm load.
3. The integrity of the transmission system will be maintained at all times without planned internal separation. Actual thermal overloads or voltage under limits must be alleviated immediately using identified transmission procedures.
4. The System Control Center Operator (SCCO) shall comply with reliability directives issued by the PJM and/or SPP Reliability Coordinator, and Market Operations (MO) shall comply with reliability directives issued by the System Control Center Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements.
5. The Transmission Dispatch Center (TDC) Transmission Dispatcher shall comply with reliability directives issued by the System Control Center Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements.
6. The Distribution Dispatch Center (DDC) Distribution Dispatcher shall comply with reliability directives issued by the TDC Transmission Dispatcher, unless such actions would violate safety, equipment, regulatory or statutory requirements.
7. The System Control Center Operator (SCCO) shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events
8. Maximum reasonable assistance will be given to adjacent systems experiencing difficulty. However, such assistance will be terminated - without opening

interconnection circuits if possible - when the reliable operation of the AEP System is impaired.

9. The System should be operated so that the occurrence of any single contingency (circuit, unit, or breaker) will not result in a cascading loss of the bulk transmission system. The single contingency is geared to the current state of the System and reflects maintenance and forced outage events as they occur. In addition, when evaluating overload contingencies, the time to relieve the stress must be compared to the permissible degree of overload.
10. Operation of the System should also take into consideration effects on facilities outside of the AEP System. Other systems should be advised of known conditions that may present a hazard to their operation. Events and conditions affecting regional or national bulk power supply reliability must be reported to the U.S. Department of Energy (DOE) and NERC.
11. The principles of sound interconnected operation will be maintained when the System experiences a generation load unbalance by bringing under control an unscheduled tie-line power flow condition as quickly as possible.
12. Generating plant, substation, and transmission equipment maintenance and testing should be held to a minimum prior to and during System emergency conditions. When such conditions are expected to exist, the System Control Center (SCC) will notify each Transmission Dispatching Center (TDC) and Market Operations (MO), so that work that could jeopardize generation or transmission capabilities can be postponed.
13. Some typical acronyms used throughout this plan are:

SCC	AEP System Control Center, New Albany
TDC	Transmission Dispatching Center
	Columbus West
	Columbus East
	Columbus Central
	Roanoke North
	Roanoke South
	Tulsa
	Shreveport
	Corpus Christi
DDC	Distribution Dispatching Center
CC	Corporate Communications
CSC	Customer Solutions Center
MO	Market Operations
RF	Reliability First
SPP	Southwest Power Pool
LCC	Local Control Center (synonymous with SCC)
LSE	Load Serving Entity
FEL	Fuel, Emissions and Logistics

Section III

Capacity Deficiency Program

Purpose

Provide a plan for full utilization of emergency capacity resources and for orderly reduction in the aggregate customer demand on the American Electric Power AEPEast/PJM and AEP West/SPP Systems in the event of a capacity deficiency.

Criteria

The goals of AEP are to safely and reliably operate the interconnected network in order to avoid widespread system outages as a consequence of a major disturbance. Precautionary procedures including maintaining Daily Operating Reserves, as specified in Reliability First Standard BAL-002-RFC-02, SPP Criteria 6, SPP Emergency Operating Plan and PJM Manual M13, will assist in avoiding serious emergency conditions such as system separation and operation at abnormal frequency. BAL-502-RFC-02 establishes common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the Reliability First Corporation (RFC) region.
However, adequate Daily Operating Reserves cannot always be maintained, so the use of additional emergency measures may be required. A Capacity Deficiency is a shortage of generation versus load and can be caused by generating unit outages and/or extreme internal load requirements. In the event that a report needs to be filed with the Department of Energy (DOE), NERC, or a Reliability Coordinator, the Transmission Operations Engineering group can assist in preparing those reports.

NERC EOP 001-2.1b R2.1 requires AEP as a registered Transmission Operator:
R2.1 Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity. AEP fulfills this requirement by following the SPP / PJM capacity deficiency procedures under AEP West/SPP Procedures and AEP East/PJM Procedures sub sections.

AEP West/SPP Procedures

AEP will follow request from the SPP BA as described in the SPP Emergency Operating Plan[1]. There are four Reserve Zones in the SPP Balancing Authority Area. (SPP BAA) AEP is part of SPP Reserve Zone #4 starting March 1, 2014.

Note: The following section contains excerpts from Section VI – Capacity and/or Emergencies of the SPP Emergency Operating Plan dated September 1, 2015. SPP maintains the current version of the SPP Emergency Operating Plan on SPP OPS1.

Responsibility

The SPP BA is responsible for declaring and communicating the existence of emergencies related to energy and capacity shortages, and for directing the operations of the appropriate entities within the SPP BAA as necessary to manage, alleviate, or end an energy or capacity emergency. SPP is responsible for balancing energy and load to resolve a capacity emergency. SPP BA utilizes the SPP RSG and any executed agreements with neighboring Balancing Authorities for the mutual provision of service to meet a capacity and/or energy emergency. If an energy emergency is recognized in the SPP BAA, the BC will request the SPP RC to issue the appropriate level EEA Alert to notify neighboring entities of the Energy situation in the BAA.

If the SPP BA is energy deficient as a whole, SPP entities will jointly implement emergency procedures up to the point of a manual load shed. SPP will determine how much each TOP will shed and communicate its plan to the appropriate entities. Manual load shed will be implemented by the TOP.

If the SPP BAA is deficient, it will only use the assistance provided by the Eastern Interconnection frequency bias for the time needed to implement corrective actions. The SPP BA shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Transaction changes. As such, unilateral adjustment may overload transmission facilities.

SPP Communication Methods

Generally, SPP will initiate normal communications with the Stakeholders within its BA footprint, to properly notify affected areas and coordinate mitigation plans when deemed necessary.

These modes of communications could include:

VOICE
- VOIP Telephone – This device is regularly used by on-shift Operators, no additional testing is performed.
- Blast Call – This is a SPP initiated conference call that can be initiated via internet to any type of phone. Participants are included in pre-defined groups. This system is tested weekly.
- Cell Phones - SPP real-time Operations staff has access to cell phones located in the Operations Center, easily accessible, constantly charged and periodically tested to provide additional means of voice communications.
- Satellite Phone - SPP performs a weekly roll call and test of its Satellite phone and current participant's Satellite phones via a "blast call." An Operating Entity Status report sheet will be completed by the SPP RC with comments recorded during the test and roll call. Results will then be emailed to all participating entities.

SPP Communication Methods

Stakeholders (GOP, TOP, LSE, MP) are required to communicate with SPP certain information, as detailed throughout this document, depending on the type of emergency situation. Stakeholders shall communicate the required information using the following modes, as applicable:
- Telephone the appropriate SPP operations desk
- Email to
  - Shift Supervisor: shiftsupervisordesk@spp.org
  - Balancing Coordinator Desk: BalancingCoordination@spp.org
  - Reliabilility Coordinator Desk: ReliabilityCoordination@spp.org
  - Shift Engineers: ShiftEngs@spp.org
- CROW; updated with the outage and/or de-rates with the appropriate reason for status change
- ICCP
- Markets UI/API; updated to reflect any changes
- Monthly reliability call (restricted to TOPs only)

In this section, the AEP Control Center will be referred to as SCC and the AEP Market Operations will be referred to as MO.

Forecast Minimum Generation Alert

The Forecast Minimum Generation Alert informs Member entities that SPP foresees a possible need to operate resources below their Minimum Economic Capacity Operating limit or de-commit capacity in order to maintain system reliability for the Operating Day in question.

Possible actions the SPP BA will take include, but are not limited to:

- Resources not cleared for Regulation-Down in the Integrated Marketplace that do not have a Dispatch Status of Fixed will be dispatched down to their Minimum Emergency Capacity Operating Limits.
- Any remaining Resources that were Self-Committed following the Day-Ahead Reliability Unit Commitment process will be de-committed.
- Curtail any remaining fixed Import Interchange Transactions pro-rata.
- Reduce Resources with a non-dispatchable status, including Variable Energy Resources down to their Minimum Emergency Capacity Operating Limit.

Expected Actions:

- The SPP BA will notify SCC and MO of the **Forecast Minimum Generation Alert Alert.**
- The SCC to Notify_TOPS West e-mail notifications.

Maximum Emergency Generation Alert

The purpose of the Maximum Emergency Generation Alert is to provide an early alert that the Day Ahead commitment study indicates is needed for emergency capacity to ensure system reliability.. It is implemented when Resources that are not intended for economic commitment are needed, or may be needed, in the SPP BAA to ensure system reliability.

SPP Actions:

- The SPP BA issues a Maximum Emergency Generation Alert to MPs using the SPP Communication Protocols defined above . This will include an estimated end time or duration.

Expected Actions:

- The SPP BA notifies the SCC and MO of the **Maximum Emergency Generation Alert**.
- The SCC to Notify_TOPS West e-mail notifications.

Notifying Government Agencies

In the event the SPP BA is in an emergency situation which requires the reduction of system demand, SPP will instruct its Stakeholders to contact Governmental Agencies, which are their customers, to reduce their use of electricity during the emergency.

Expected Actions:

- SPP BA request SCC to contact Governmental Agencies to reduce the use of electricity.
- SCC request Regulatory Services to contact Governmental Agencies to reduce the use of electricity.

<u>Energy Emergency Alerts</u>

Energy Emergency Alert 1

The SPP BA will request the SPP RC to issue an EEA1 if it foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about meeting required operating reserves. These conditions may manifest themselves in several different ways, and SPP will respond to each situation as listed below. Before requesting EEA1, the SPP BA will have already provided the appropriate internal notifications to its Stakeholders.

As part of requesting EEA1, the SPP BA will take (or have already completed) the following actions (regardless of cost):

- Identify and curtail non-firm external energy sales (including those that are recallable to meet reserve requirements).
- Starting up all available resources that are needed to meet capacity requirements.
- Identifying generation outages that can be postponed, verifying postponement times with generation owners.
- Identifying the pertinent transmission outages that can be recalled, verifying recall times with transmission owners and advising Transmission Owners of potential recall of outages.
- If required, arranging for, but not necessarily executing, external energy purchases in advance.

Expected actions:

- The SPP BA notifies SCC / MO it will request an EEA 1.

The SCC to Notify_TOPS West e-mail notifications.

- SPP BA determines if any generator outages are available for postponement.
- SPP BA verifies the times for potential postponement with MO.

- SPP BA determines what if any pertinent transmission outages can be recalled, and verifies recall times with

SCC.

- SCC works with TDC to see if there are any issues.

- SPP ask MO if units are constrained due to environmental reasons MO conveys to SPP BA any AEP generating units that are constrained due to environmental issues.

- SPP BA identifies available resources that are needed for capacity. MO to start up all available resources requested by SPP BA.

SPP BA issues System Wide Reserve Shortage Alert.

The purpose of the System-Wide Reserve Shortage Alert is to alert members of the anticipated system-wide shortage of operating reserve capacity for a future time period 1 to 24 hours in the future. The Alert is issued when estimated operating reserve capacity for the SPP BA is less than the forecast reserve requirement.

SPP Actions:

- The SPP BA requests the SPP RC to issue a NERC Energy Emergency Alert Level 1.
- The SPP BA issues a System-Wide Reserve Shortage Alert to MP entities using SPP Communication Methods defined above .
- The SPP RC will monitor congestion in the Balancing Area.
- The SPP BA reports significant changes in the estimated operating reserve capacity to the SPP RC and to member entities using the SPP Communication Methods..

Expected actions:

SPP BA notifies SCC and MO of **System Wide Reserve Shortage Alert**.
The SCC to Notify_TOPS West e-mail notifications.

Emergency Capacity Shortage Notification

The purpose of the Emergency Capacity Shortage Notification is to advise the appropriate Member Entities that SPP has, or foresees, the possible need to utilize emergency capacity in order to maintain system reliability for the Operating Day in question. Emergency capacity may come in the form of committing Resources currently offline or utilizing the Maximum Emergency Capacity Operating Limits of Resources currently online. <u>No immediate action</u> is required by the Member entities, but they should take notice that SPP may call on emergency capacity to ensure the reliability of the Bulk Electric System.

SPP Actions:

- The SPP BA requests the SPP RC to issue a NERC Energy Emergency Alert Level 1.
- The SPP BA issues Emergency Capacity Shortage Notification to member entities..
- The SPP BA reports significant changes to the SPP RC and to Stakeholders.
- The SPP BA will request from impacted Stakeholders and receive periodic, but at least hourly, status updates from those impacted entities.

Expected actions:

- SPP BA issues Emergency Capacity Shortage Notification to SCC and MO.
- SPP BA reports significant changes in estimated operating reserve requirement.
- MO / SCC provide SPP BA status updates upon request at least hourly.
- SCC to Notify_TOPS West e-mail notifications.
- SCC issue <u>Voluntary Load Curtailment Alert</u> to TDC and Corporate Communications.

Energy Emergency Alert 2

The SPP BA will request the RC to issue an EEA2 in the event that it is no longer capable of providing its customers' expected Energy requirements and is now an Energy Deficient Entity or the SPP BA foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. The SPP BA is utilizing Operating Reserves such that it is carrying reserves below the required minimum and has initiated assistance through the Reserve Sharing Group. Timely communications to the impacted Shareholders will be made when requesting an EEA2.

As time permits, the SPP BA will take actions including, but not limited to:

- Commit all quick-start resources, regardless of cost.
- Maximize all available online generation in the time frame of the emergency, in accordance with the Integrated Marketplace Market Protocols. SPP may dispatch resources to the Maximum Emergency Operating Limit.
- Make all available external emergency purchases up to the point of solving the Energy Emergency, regardless of cost, which may include invoking assistance from neighboring entities in accordance with standing Seams agreements.
- Recall any transmission outages identified in the EEA1 process above that are adversely impacting the situation.

Expected actions:

- SPP BA will make timely notifications to SCC and MO when requesting an EEA2.
- MO will commit quick start generation resources as requested by SPP BA.
- SCC / TDC recall transmission outages identified in EEA1 process as requested by SPP BA.
- SCC to Notify_TOPS West e-mail notifications.

Maximizing Generator Output and Availability

During an Emergency, SPP may request planned generator outages to be deferred or cancelled (including wind). In the event that an outage is deferred or canceled, CROW schedules and the commitment status in the Markets UI/API shall be updated to reflect the planned outage changes. In addition, SPP should request its GOP to maximize the output of the resources as necessary.

The SPP BA will coordinate with the appropriate GOPs to ensure that the resource will submit market information to properly reflect the maximization of its output.

Expected actions:

- MO defer or cancel planned generator outages requested by SPP BA
- MO maximizes generator output as requested by SPP BA.

Notifying Cogeneration and Independent Power Producers (EEA 2)

SPP will notify cogeneration and independent power producers to maximize output and availability. SPP will order Independent Power Producers to maximize capacity and availability for use by SPP, as needed.

Load Management Alerts

This notification alerts the members that SPP has, or foresees, a time period where SPP may direct the use of load management. For an EEA 2 event, this includes, but not limited to:

- Reducing load through use of public appeals
- Implementing load management systems
- Voltage Reduction
- Interrupt interruptible load and exports

The notifications will be issued to impacted Stakeholders individually.
Please see the detailed actions for Public Appeals, Voltage Reduction, and Interruptible / Curtailable Loads in the sections below.

Public Appeals

Each appropriate TOP within the SPP BAA has a plan to implement Public Appeals in their local area to reduce load to their end-use customers at the request of the SPP BA. The SPP BA will also request the SPP Corporate Communications Department to activate the plan to make public appeals in the Little Rock area. When appropriate, the BA will use the SPP Corporate Communications Department to:

- Make public appeals to reduce demand for the BA Region/BAA in the Little Rock area.
- Notify news wire services of the request to reduce demand using pre-designated messages for appeals on the Little Rock area.
- Request appropriate TOP to implement their plan for public appeals to reduce demand within their local area of the SPP BA.

SPP member TOPs shall implement their plan for public appeals in their local areas upon receiving a request to make public appeals from SPP.

Expected actions:

- SPP BA request SCC to make public appeals.
- TDC Execute Voluntary Load Curtailment when requested by SCC
- Corporate Communications implement public appeal plan when requested by SCC
- SCC to Notify_TOPS West e-mail notifications.
- SCC prepares DOE report

Voltage Reduction

The SPP BA will communicate with the Stakeholder within the SPP BA footprint that are capable of providing Load

Management by means of voltage reduction in a timeframe adequate to allow the respective Stakeholder to implement the desired relief. Any Stakeholder capable of reducing load by means of voltage reduction shall provide SPP a realistic time to implement voltage reduction on their respective systems and the expected effect on load.

- AEP West SPP does not have any voltage reduction capabilities.

Interruptible and Curtailable Loads

Various Stakeholders within the SPP BAA have contracts in place with large industrial customers where load may be interrupted at the Stakeholders request. Since these contracts are unique and have specific notification requirements and conditions associated with them, the SPP BA will rely on the individual Market Participants to maintain real time awareness of what interruptible load is available within their system.

Each SPP Stakeholder, if aaplicable, shall provide the SPP BA a list of the loads and methods they use to manage those loads during real time emergencies.. The Stakeholders shall update the list when management methods or load configurations change substantially and the list shall be reviewed annually.

When EEA 2 conditions exist in the BA, SPP will request its Stakeholder to interrupt their interruptible and curtailable loads within the SPP BA as shown below.

Note: **SPP** Staff will request information on each type of interruptible and curtailable load from the market participants with estimates of how much load is interruptible, how often they can be interrupted and conditions under which it can be interrupted.

- Curtail (or recall) all non-firm external sales transactions.
- Interrupt non-firm end use loads, in accordance with applicable contracts (refer to the section on Interruptible Load for additional information).
- Implement Demand-side management.
- Implement Utility load conservation measures (refer to the section on Utility Load Conservation Measures for additional details).

Expected actions:

- SPP BA provides time, duration, and MW to SCC and MO.

- SCC request TDC initiates curtailment of interruptible loads
- TDC request DSM Coordinator implement Demand Side Management

- TDC implement curtailment non-Essential building load
- TDC implement SWEPCO/SPP ERCOT Load Transfer

- MO implements curtailment generation plant use

Appeals to Customers to Use Alternative Fuels

In a capacity and/or energy emergency (EEA 2), SPP shall make appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply. SPP will request Stakeholders to make appeals to their customers to utilize alternative fuels as long as those fuels are not in short supply and will not impact the ability of generators to get that fuel.

Expected actions:

- SPP BA request SCC to make appeals to customers with generators to utilize alternate fuels not in short supply.
- SCC request TDC to contact customers.
- SCC issue Mandatory Load Curtailment Alert
- SCC to Notify_TOPS West e-mail notifications.

Miscellaneous

The SPP BA will also take the following actions as part of issuing an EEA2:

- As per the Integrated Marketplace Protocols, notifying Market Participants of the hours in which the emergency ranges of any Resources are expected to be required, the hours in which Resources with a Commit Status of Reliability are expected to be committed, and the hours in which non-firm fixed Export Interchange Transactions are expected to be curtailed
- Filing an OEC, as needed to access Reserve Sharing Group energy
- Preparing for potential load shedding, and notifying TOPs to prepare accordingly.

While in EEA2, the SPP BA will communicate its condition and forecasted condition to the SPP RC no less than every hour.

Expected actions:

- SPP BA provide SCC forecasted MW amount.
- SCC prepare for potential load shedding.
- SCC advise TDC to prepare for potential load shedding.
- SCC will issue a Mandatory Load Curtailment Warning to TDC
- SCC to Notify_TOPS West e-mail notifications.

Energy Emergency Alert 3

If time permits, all steps in the previous alert levels will have been executed before proceeding to this level. If the emergency situation occurs suddenly and is severe enough to rise to an EEA 3 level, the RC may proceed directly to issuing an EEA 3 notification before any other EEA notifications are issued. In this case, all applicable steps in EEA 1 and EEA 2 can be executed in coordination with the EEA 3 steps.

The SPP BA will declare EEA3 when it foresees or has implemented firm load obligation interruption. Before declaring EEA3, the SPP BA will have already provided the appropriate internal notifications to its Market Participants..

The SPP BA will notify the SPP RC to issue the alert for EEA3.

As part of EEA3, the SPP BA will:

- Continue all actions listed in previous alert levels and will update the SPP RC of its condition every hour at minimum.
- Provide updates to Transmission Operators regarding load shedding plan.
- Issue directives to shed load if/when needed.
- Filing an OEC, as needed if not already filed
- Upon notification from the SPP RC, take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding.

As part of EEA 3, SPP TOPs may be asked to be involved in load shedding.

Expected actions:

- SPP BA notifies SCC / MO it will request an EEA3. This may require the SCC to shed load as noted below.
- SCC notifies TDC on latest status of load shedding request.
- SCC to Notify_TOPS West e-mail notifications.

Manual Load Curtailment

The purpose of Manual Load Shed is to curtail firm load when all other possible means of supplying internal SPP BA load have been used to address a capacity or energy emergency within the SPP BAA or to maintain ACE so as to not jeopardize the reliability of the Bulk Electric System. Examples of such conditions may include, but not limited to:

- The SPP BA cannot provide adequate capacity to meet the SPP BA load and interchange requirements.
- Overloaded transmission Facilities cannot be relieved by shifting generation or in any other way
- Low frequency operation during an islanding event

Transmission Operators that have connected load within the SPP BAA shall have plans for Operator-controlled manual load shedding to respond to real-time emergencies. These entities shall be capable of implementing the load shedding plan within a timeframe adequate for responding to the emergency.

SPP will instruct the impacted Transmission Operator(s) or Load Serving Entities to shed a specific MW amount of load. SPP will specify the area of the load to be shed if location is a factor in relieving the emergency condition requiring Manual Load Shed.

Expected actions:

- SPP BA instructs SCC to shed a specific MW amount of load and the area if appropriate.
- SPP BA issues directive SCC to shed load
- SCC instructs TDC to shed a specific MW amount of load.
- SCC issue the order Execute Mandatory Load Curtailment
- SCC to Notify_TOPS West e-mail notifications.
- SCC prepares DOE report.

Real-Time Transmission Reliability Emergency Actions

When RC/TOP real-time analysis results or studies identify Transmission Reliability issues such as SOL or IROL overloads that threaten cascading outages or uncontrolled tripping of transmission elements on the BES that cannot be resolved via transmission system reconfiguration, generation adjustments or utilization of Resource Maximum Emergency Operating Capacity Limits, SPP BA shall comply with directives to coordinate firm load shedding with TOPs.

Expected actions:

1. SPP RC or SCC studies shows a Transmission Reliablity issue.
2. SCC issues PCAP to control Transmission Reliability issue and coordinates with SPP RC.

CPS and Disturbance Control Standard Deviation

If the SPP BA cannot comply with the CPS and Disturbance Control Standards as described in the NERC Reliability Standards, then it shall immediately implement remedies to do so. Operators will use tools, including RTGEN (AGC) and operator situational awareness tools, to monitor both real time and long term control performance.

Once the SPP BA has exhausted the steps listed in the EEA 2 notification, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the SPP BA shall perform the following steps:
- Notify the TOP to manually shed firm load without delay to return its ACE to zero.
- Request the SPP RC to declare an Energy Emergency Alert level 3 as defined in NERC Reliability Standards.

Expected actions:
- SPP BA instructs SCC amount of load to shed without delay.
- SCC advises TDC to load shed an additional designated amount of load without delay.
- If not issued previously, SCC issue the order Execute Mandatory Load Curtailment
- SCC to Notify_TOPS West e-mail notifications.
- SCC prepares DOE report.

Termination of Capacity Emergency

SPP BA review status of an EEA at least every 60 minutes

Expected actions:

SPP BA request SPP RC to terminate emergency.
- SCC to cancel Voluntary Load Curtailment and Mandatory Load Curtailment Alerts if previously issued.
- SCC to issue Notify_ TOPS WEST e-mail notifications
- SCC notifies Regulatory Services which notifies Government Agencies, as applicable.

Section VI of the Capacity and / or Energy Emergencies of the SPP Energy Operating Plan is summarized in Table III-1 below. The Communications are the anticipated communications paths initiated by SPP BA[1] to AEP as an "impacted entity

	Activity	Communications	Description		Reference
	Communications	SPP BA – AEP	SPP notifications listed below will use their Communication Protocols which may include VOIP telephone, blast call, cell phones, or satellite phone		**4.7**
	Communications	AEP – SPP	Communicate with SPP using telephone, email, CROW, ICCP as applicable		**4.7.1**
	Forecast Minimum Generation Alert	SPP BA-MO SPP BA-SCC SCC-TDC	**SPP** informs Members SPP foresees need to operate resources below Minimum Economic Capacity Operating Limit to maintain system reliability for Operating Day.		6.2.1[1]
	Maximum Emergency Generation Alert	SPP BA-MO SPP BA-SCC SCC-TDC	**SPP** Day Ahead commitment study indicates Resources not intended for economic commitment are needed to ensure transmission reliability.		6.2.2[1]
	Notifying Government Agencies	SPP BA-SCC	**SCC request Regulatory Services to**contact Government Agencies to reduce their use of electricity		6.2.3[1] (Section 8g. EOP v16)
	Energy Emergency Alert 1	SPP BA-MO	**SPP BA determines if any generator outages are available for postponement. SPP BA verifies the times for potential postponement with the generator owner.**		6.3.1
		SPP BA-SCC SCC-TDC	SPP BA determines what if any pertinent transmission outages can be recalled, and verifies recall times with transmission owners.		6.3.1[1]
		SPP BA-MO	SPP ask MO if units are contrained due to environmental reasons.		5.3
			MO notifies SPP BA of any AEP units constrained due to environmental issues.		5.3
		SPP BA –SCC SPP BA –MO	SPP BA notifies SCC / MO it will request an EEA1		6.3.1
		SPP BA –MO	**SPP BA identifies available resources that are needed for capacity. MO** to start up all available resources requested.	**EEA 1**	
	System-Wide Reserve Shortage Alert	SPP BA-MO SPP BA-SCC SCC-TDC	1. **SPP BA** issues System-Wide Reserve Shortage Alert 2. **SPP BA** reports significant changes in estimated operating reserve capacity		6.3.1.1[1]
	Emergency Capacity Shortage Notification	SPP BA –MO SPP BA –SCC SCC-TDC MO/SCC –SPP BA status updates SCC –TDC SCC –Corporate Communications	1. **SPP BA** issues Emergency Capacity Shortage Notification 2. **SPP BA** reports significant changes in estimated operating reserve requirement. 3. **MO / SCC** provide status updates upon request at least hourly 4. **SCC** issue Voluntary Load Curtailment Alert to TDC and Corporate Communications.	**EEA 1**	6.3.1.2[1] EEA 1, step 7[2]
	Energy Emergency Alert 2	SPP BA – MO SPP BA – SCC	**SPP BA will make timely notifications to SCC and MO when requesting an EEA 2,**		6.3.2[1] (ORW EOP v16)
		SPP BA –MO	**MO** commit all quick start generation resources as requested by SPP BA SPP BA may dispatch resources to Maximum Emergency Operating Limit.	**EEA 2**	
		SPP BA –SCC SCC-TDC	**SCC/TDC** recall transmission outages identified in EEA 1 process.		
	Maximizing Generator Output and Availability	SPP BA – MO	1. **MO** defer or cancel planned generator outages 2. **MO** maximize generator output		6.3.2.1[1] 6.3.2 (ORW EOP v16)
	Notifying IPPs		SPP will notify IPP to maximize output and availability		6.3.2.2
	Load Management Alerts	SPP BA – SCC, SPP BA – Corporate Communications, SPP BA – MO	SPP alert members on Public Appeals, Voltage Reduction, and Interruptible Load as listed below		6.3.2.3[1]

	Activity	Communications	Description		Reference
	Public Appeals	SPP BA-SCC SCC-TDC SCC - AEP Corporate Communications	**TDC** Execute Voluntary Load Curtailment when requested by SCC **Corporate Communications** implement public appeal plan **SCC** prepares DOE report		6.3.2.4[1] (Step 8 EOP v16)
	Voltage Reduction	SPP BA-SCC	Voltage Reduction – N/A AEP West SPP does not have any voltage reduction capabilities		6.3.2.5[1] (Step 7 EOP v16)
	Interruptible / Curtailable Loads	SPP BA-SCC SPP BA-MO SCC-TDC TDC-DSM Coordinator	1. **SPP BA** provide time, duration, and MW to SCC 2. **TDC** initiates curtailment of interruptible loads 3. **DSM Coordinator** implement Demand-Side Management 4. **MO** implement curtailment generation plant use 5. **TDC** implement curtailment non-Essential building load 6. **TDC** implement SWEPCO/SPP ERCOT Load Transfer		6.3.2.6[1] (Step 6 & 10 EOP v16) 5.4
	Appeals to Customers to Use Alternate Fuels	SPP BA –SCC SCC-TDC	TDC make appeals to customers with generators to utilize alternate fuels not in short supply. SCC issue Mandatory Load Curtailment Alert to TDC		6.3.2.7[1] (Section V EOP v16)
	Miscellaneous	SPP BA-SCC SCC-TDC	Prepare for potential load shedding. **SPP BA** provide forecasted MW amount. **SCC** will issue a Mandatory Load Curtailment Warning to TDC.		6.3.2.8[1] EEA 2[2],step 7 (Step 11 EOP v16)
	Energy Emergency Alert 3	SPP BA –SPP RC	a. SPP BA notifies SCC / MO it will request an EEA3	**EEA 3**	6.3.3[1]
	Manual Load Curtailment	SPP BA-SCC SCC-TDC	1. **SPP BA** provide updates on load shedding MW amount and the area if appropriate. 2. **SPP BA** issue directive to shed load 3. **SCC** issue the order Execute Mandatory Load Curtailment 4. **SCC** prepares DOE report		6.4[1] 6.4.1[1] EEA 3[2], steps 3, 4 (Step 13 EOP v16)
	Real Time Transmission Reliability Emergency Actions	SPP RC –SCC	1. SPP RC or SCC studies shows a Transmission Reliablity issue. 2. SCC issues PCAP to control Transmission Reliability issue and coordinates with SPP RC.		6.4.2
	CPS / Disturbance Control Standard Deviation	SPP BA –SCC SCC-TDC	**1. SPP BA notify SCC to Manually shed firm load without delay.** **2. SCC issue order Execute Mandatory Load Curtailment** **3. SCC prepare DOE report.**		6.4.3
	Energy Emergency Alert Level	SPP BA-SPP RC	**SPP BA** review status of an EEA at least every 60 minutes	**EEA 1,2, or 3**	6.5[1]

Table III-1 Capacity Deficiency Summary – AEP/SPP

References:

1. **SPP Emergency Operating Plan Version 4.5 dated September 1, 2015**
2. **SPP Ops: Energy Emergency Alerts Version 1.4 dated February 25,2014**
3. **AEP Emergency Operating Plan v16, plan used prior to SPP Balancing Authority**

AEP East/PJM Procedures

(note: the following section contains excerpts from PJM Manual – M13 Revision 58 . PJM maintains the current version of M13 on the PJM webb site PJM.COM.

Overview

PJM is responsible for determining and declaring that an Emergency is expected to exist, exists, or has ceased to exist in any part of the PJM RTO or in any other Control Area that is interconnected directly or indirectly with the PJM RTO. PJM directs the operations of the PJM Members as necessary to manage, allocate, or alleviate an emergency.

- *PJM RTO Reserve Deficiencies* — If PJM determines that PJM-scheduled resources available for an Operating Day in combination with Capacity Resources operating on a self-scheduled basis are not sufficient to maintain appropriate reserve levels for the PJM RTO, PJM performs the following actions:

- Recalls energy from Capacity Resources that otherwise deliver to loads outside the Control Area and dispatches that energy to serve load in the Control Area.

- Purchases capacity or energy from resources outside the Control Area. PJM uses its best efforts to purchase capacity or energy at the lowest prices available at the time such capacity or energy is needed. The price of any such capacity or energy is eligible to determine Locational Marginal Prices in the PJM Energy Market. The cost of capacity or energy is allocated among the Market Buyers as described in the PJM Manual for Operating Agreement Accounting (M28)..

In this section, the AEP System Control Center will be referred to as SCC and the AEP Market Operations will be referred to as MO.

Reserve Requirements

PJM schedules reserves on a day-ahead basis in order to ensure that differences in forecasted loads and forced generator outages does not negatively impact the reliable operation of the PJM Transmission System. PJM operates in real-time to ensure Contingency/Primary (10 minute) and Synchronized/Spinning reserve requirements are always maintained. Day Ahead Scheduling Reserves (Operating), Contingency (Primary) and Synchronized/Spinning Reserve Requirements for AEP are as follows:

Control Zone	Reliability Region	Day-ahead Scheduling (Operating)	Contingency/ (Primary)	Synchronized Reserve	Regulation
RTO includes AEP	RFC	5.93%	150% Largest Single Contingency	Largest Single Contingency	See Note 4 below.

Note:

1. PJM must schedule sufficient Regulating Reserves to satisfy control standards. Regulating Reserves shall not be less than 75% spinning reserves, and resources allocated to regulating reserves shall not be included as part of Contingency Reserves.
2. PJM must schedule sufficient Contingency Reserves to satisfy the Reliability*First* (RFC) requirements. Contingency Reserves shall not be less than the largest contingency. Contingency Reserves must be made up of at least 50% Spinning Reserves. No more than 25% of Contingency Reserves should be interruptible load. (Standard BAL-002-0, BAL-002-RFC-02)
3. Contingency (Primary) Reserve Requirements for the RFC portion of the PJM footprint is 150% of the largest generators.
4. The Regulation Requirement for the PJM RTO is defined in section 4.4.3 of Manual 12, Balancing Operations.

The PJM RTO's Regulating Requirement is 525 effective MW during off-peak hours (0000 to 0459) and 700 effective MW during on-peak hours (0500 – 2359). PJM dispatch may increase or decrease the regulation requirements as needed to accommodate system conditions. Each LSE is required to provide a share of the PJM Regulating Requirement.

PJM schedules Day-ahead Scheduling reserves on a day-ahead basis as a single market in the RTO. Primary and Synchronized Reserves are maintained in real-time based on the locational requirements identified above, recognizing transmission constraints while scheduling sufficient localized reserves on a control zone basis to satisfy reserve sharing agreements. The cost of capacity or energy is allocated among the Market Buyers as described in the PJM Manual for **Operating Agreement Accounting (M-28)**

PJM commits generation real-time on an economic basis, considering resource characteristics (start-up, min run, starts per day) and anticipated system changes (load curve, interchange, must-run generation) while honoring system constraints.

PJM issues capacity emergencies across the entire PJM RTO except for PJM Load Dump Warnings/Actions, which are solely issued on a Control Zone basis. However, transmission constraints may force Emergency Procedure warnings/actions to be issued on a Control Zone or a subset of a Control Zone. For example, if known transmission constraints would prohibit delivery of Maximum Emergency Generation capacity from one Control Zone to another, a Maximum Generation Alert would not be issued for the Control Zone with undeliverable energy.

.

Capacity Shortages

PJM is responsible for declaring the existence of an Emergency, and for directing the operations of the PJM Members as necessary to manage, alleviate, or end an Emergency. PJM also is responsible for transferring energy on the PJM Members' behalf to resolve an Emergency. PJM is also responsible for executing agreements with other Control Areas interconnected with the PJM RTO for the mutual provision of service to meet an Emergency.

PJM may issue an **Advisory** one or more days in advance of the operating day. General in nature and for elevated awareness only. No preparations required.

Exhibit 1 illustrates that there are three general levels of emergency actions for capacity shortages:

- Advisory – issued one or more days in advance of the operating day. General in nature and for elevated awareness only. No preparations required.
- Alerts – issued in advance of the operating day for elevated awareness and to give time for advanced preparations
- Warnings – issued real time, typically preceding, and with an estimated time/window for a potential future ACTION.
- Actions – issued real time and requires PJM and/or Member response.
    - PJM actions are consistent with NERC and RFC EOP standards.

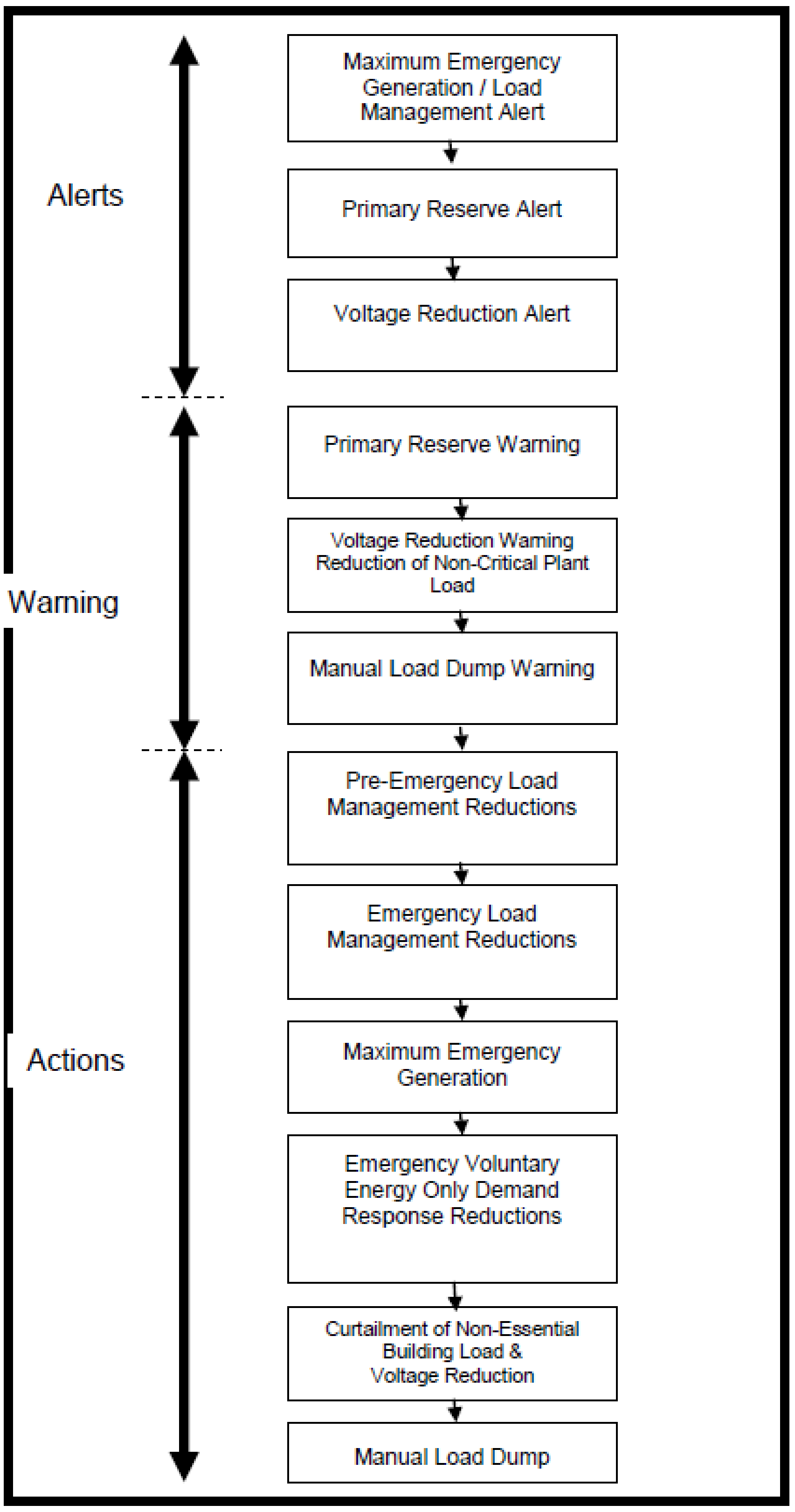


Exhibit 1: Emergency Levels

Exiting emergency procedures is achieved in a controlled, deliberate manner so as to not adversely affect system reliability, while minimizing the impact of these emergency actions on the LSE's customers. PJM members are expected to implement all emergency procedures immediately to achieve the desired relief within 30 minutes unless otherwise directed. PJM dispatchers have the flexibility of implementing the emergency procedures in whatever order is required to ensure overall system reliability. PJM dispatchers have the flexibility to exit the emergency procedures in a different order than they are implemented when conditions necessitate.

PJM strives to meet customer energy demands either through the use of available generating resources, power purchases from PJM Members, or through the use of planned load management programs. If customer demand cannot be met, Emergency actions, such as voltage reductions, and as a last resort, manual load shedding, are used.

During unconstrained operations, PJM Control Zones will jointly implement Emergency Procedures up to the point of a Manual Load Dump Action. Prior to the implementation of a Manual Load Dump Action, PJM dispatch will review each PJM Control Zone energy / reserves calculation to determine their relative level of capacity deficiency (reserves evaluated via PJM EMS system). If all PJM Control Zones are capacity deficient, Manual Load Dump Actions will be implemented proportionally, based on the level of shortage, otherwise only the deficient Control Zones will be required to shed load.

Transmission constraints may result in PJM dispatch implementing emergency procedures, including load dump, on a Control Zone specific basis or a subset of a Control Zone.

Note: All capacity related Alerts / Warnings / Actions are to be communicated via All-Call to local Transmission / Generation owners/ Curtailment Service Providers and posted to selected PJM websites.

Unit Startup Notification Alert

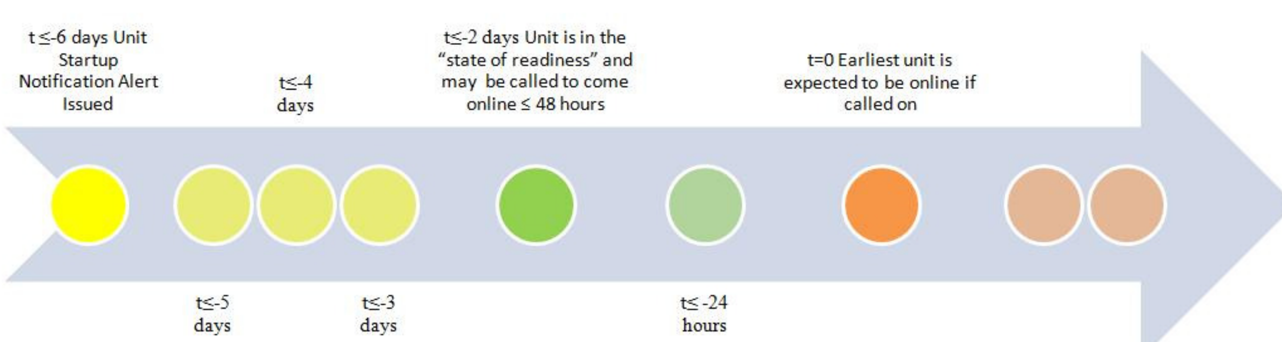
The purpose of the Unit Startup Notification Alert is to alert members to place units in state of readiness so they can be brought online within 48 hours for an anticipated shortage of operating capacity, stability issues or constrained operations for future periods. It is implemented when a reliability assessment determines that long lead time generation is needed for future periods and can be issued for the RTO, specific Control Zone(s) or individual unit basis. The Unit Startup Notification Alert is issued so that units can be ready to come online in 48 hours or less, based on the lesser of submitted notification time + startup time or 6 days. After reaching the state of readiness, if a unit fails to come online within 48 hours when called by PJM, the unit will be considered as forced outage until it can be online or PJM cancels the unit.

PJM Actions:

- PJM dispatch notifies PJM management and members.
- PJM dispatch issues the Alert to members, stating the Alert period(s) and the affected areas. An Alert can be issued for the RTO, specific Control Zone(s) or individual unit basis on the projected location of transmission constraints and should be issued as soon as practicable (typically 6 days or less) prior to the anticipated need for long lead time generation to come online.
- PJM will schedule an amount of long lead time generation anticipated to be needed for the operating day(s) in economic order respecting unit operating parameters. Once a generator is scheduled its offer price is locked for the operating day.
- PJM dispatch will evaluate system conditions daily to determine whether to release units from the Alert, to keep the units in the state of readiness or to call the units online.
- PJM dispatch cancels the Alert, when appropriate.

SCC Actions:

- SCC/MO notifies Transmission/MO management of the alert.
- SCC to issue Notifiy PJM_Emer_Procedures e-mail notification.
- SCC/MO advises all TDC's, Plants and key personnel as needed.
- MO orders unit(s) to be in the state of readiness (i.e. able to be online within 48 hours) in the lesser of (submitted notification time + startup time or 6 days) minus 48 hours.



Advanced Notice Emergency Procedures: Alerts

The intent of the alert(s) is to keep all affected system personnel aware of the forecasted and/or actual status of the PJM RTO. All alerts and cancellation thereof are broadcast on the "ALL-CALL" system and posted to selected PJM websites to assure that all members receive the same information.

Alerts are issued in advance of a scheduled load period to allow sufficient time for members to prepare for anticipated initial capacity shortages.

Maximum Emergency Generation / Load Management Alert

The purpose of the Maximum Emergency Generation / Load Management Alert is to provide an early alert that system conditions may require the use of the PJM emergency procedures. It is implemented when Maximum Emergency Generation is called into the operating capacity or if Demand Response is projected to be implemented.

PJM Actions

- PJM dispatch notifies PJM management
- PJM dispatchers perform a situation analysis and prepare capacity/load/ interchange/reserve projections for that day and appropriate future operating periods considering potential bottled generation based on location of transmission constraints.
- PJM dispatch issues an alert to members, stating the amount of estimated operating reserve capacity and the requirement. Alert can be issued for entire PJM RTO or for specific Control Zones and should be issued 1 or more days prior to the operating day.
- PJM dispatch reports significant changes in the estimated operating reserve capacity.
- PJM dispatch issues a NERC Energy Emergency Alert Level 1 (EEA1 = ALERT LEVEL 1 / THREAT LEVEL = ELEVATED / THREAT COLOR = YELLOW) via the Reliability Coordinator Information System (RCIS) to ensure all Reliability Authorities clearly understand potential and actual PJM system energy emergencies. EEA1 signals that PJM foresees or is

experiencing conditions where all available resources are scheduled to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves.

- PJM dispatch reviews the level of dependency on External Transactions to serve PJM load and contacts PJM support staff if the need to implement Capacity Benefit Margin (CBM) is required (refer to PJM Manual for Transmission Service Request Section 2 for additional details regarding Capacity Benefit Margin). PJM Dispatch shall log occurrences where CBM is implemented base on the results of support staff analysis. PJM shall notify external systems via RCIS, and PJM members via the PJM website and issue appropriate NERC alert levels consistent with NERC EOP-002.
- PJM dispatch determines whether a Supplemental Status Report (SSR) is required and notifies PJM Members via the All-Call. PJM Dispatch may elect not to request an SSR until the operating day for which the Alert is in effect.
    - MO responsible for generation data
    - SCC responsible for:
        - Emergency Load Management Reductions
            - **120 minute lead time – 626.4 Mws**

                - Via CCS

<u>SCC Actions:</u>

- SCC/MO notifies Transmission/MO management of the alert.
- SCC to issue Notify_PJM_Emer Procedures e-mail notifications.
- SCC/MO advises all TDC's, Plants and key personnel as needed.
- SCC/MO reviews plans to determine if any maintenance or testing, scheduled or being performed, on any monitoring, control, transmission, or generating equipment can be deferred or cancelled.
    - MO reports to PJM dispatch any and all fuel / environmental limited facilities as they occur and update PJM dispatch as appropriate.
    - SCC/MO suspends any high risk testing of transmission or generating equipment.
- PJM dispatch cancels the alert, when appropriate.

Primary Reserve Alert

The purpose of the Primary Reserve Alert is to alert members of the anticipated shortage of operating reserve capacity for a future critical period. It is implemented when estimated operating reserve capacity is less than the forecasted primary reserve requirement.

PJM Actions:

- PJM dispatch notifies PJM management and members.
- PJM dispatch issues alert to members, stating the amount of estimated operating reserve capacity and the requirement. An Alert can be issued for the entire PJM RTO or for specific Control Zone(s) based on the projected location of transmission constraints and should be issued 1 or more days prior to the operating day.
- PJM dispatch reports significant changes in the estimated operating reserve capacity.

SCC Actions:

- SCC/MO notifies Transmission/MO management of the alert.
- SCC to issue Notify_PJM_Emer Procedures e-mail notifications.
- SCC/MO advises all TDC's, Plants and key personnel.
- SCC/MO reviews plans to determine if any maintenance or testing, scheduled or being performed, on any generating equipment or critical monitoring, control, or bulk power transmission facility can be deferred or cancelled.
- SCC request MO to evaluate the impact of current environmental constraints and start the process to possibly lift those constraints identified.
- MO is to inform PJM of any environmentally restricted units and may consider the need to obtain a temporary variance form environmental regulators for specific generators in accordance with PJM Attachment M to assist in preventing load shed. PJM is not responsible for obtaining a temporary variance from environmental regulations but will assist the member company if requested.
- PJM dispatcher cancels the alert, when appropriate.

Voltage Reduction Alert

The purpose of the Voltage Reduction Alert is to alert members that a voltage reduction may be required during a future critical period. It is implemented when the estimated operating reserve capacity is less than the forecasted synchronized reserve requirement.

PJM Actions:

- PJM dispatch notifies PJM management.
- PJM dispatch issues an alert to members, stating the amount of estimated operating reserve capacity and the requirement. An Alert can be issued for the entire PJM RTO or for specific Control Zone(s) based on the projected location of transmission constraints and should be issued 1 or more days prior to the operating day.
- PJM dispatch advises members that a possibility exists that a voltage reduction will be issued and the estimated hour of implementation.

SCC Actions:

- SCC/MO notifies Transmission/MO management of the alert.
- SCC to issue Notify_PJM_Emer Procedures e-mail notifications.
- SCC to issue Notify_TOPS_East e-mail notifications.
- SCC advises all TDC's, and key personnel.
- SCC/TDC proceed on the basis that a voltage reduction warning will be issued during this future period and take steps that could expedite implementation of a voltage reduction, should one become necessary; i.e. identify stations for voltage reduction.
    - Voltage reduction takes approx. 8 hours to implement, so this alert would need to be received at least a day ahead of the event
- SCC/ PJM Management consider issuing the appropriate system-wide or Control Zone-specific Public/Media Notification Message
- PJM dispatcher cancels the alert, when appropriate.

Note: Substations without SCADA control will be expected to be staffed in order to implement a Voltage Reduction Action if needed

Real Time Emergency Procedures (Warnings and Actions)

All warning and actions are issued in real-time. Warnings are issued during present operations to inform members of actual capacity shortages or contingencies that may jeopardize the reliable operation of the PJM RTO. Disturbance control actions per NERC standard BAL-002 are described in PJM Manual 12, "Balancing Operations" section 4, "Providing Ancillary Services". Generally, a warning precedes an associated action. The intent of warnings is to keep all affected system personnel aware of the forecast and/or actual status of the PJM RTO.

The PJM RTO is normally loaded according to bid prices; however, during periods of reserve deficiencies, other measures must be taken to maintain system reliability. These measures involve:

- loading generation that is restricted for reasons other than cost
- recalling non-capacity backed off-system sales
- purchasing emergency energy from participants / surrounding pools
- load relief measures

Due to system conditions and the time required to obtain results, PJM dispatcher may find it necessary to vary the order of application to achieve the best overall system reliability. Issuance and cancellation of emergency procedures are broadcast over the "ALL-CALL" and posted to selected PJM websites. Only affected systems take action. PJM dispatcher broadcasts the current and projected PJM RTO status periodically using the "ALL-CALL" during the extent of the implementation of the emergency procedures.

Note: The Real-Time Emergency Procedures section combines Warnings and Actions in their most probable sequence based on notification requirements during extreme peak conditions. Depending on the severity of the capacity deficiency, it is unlikely that some Steps would be implemented. Attachment G, entitled Capacity Emergency Matrix, is a tabular summary of PJM and Member Company Actions during Real-time Emergency Procedures.

Step 1: Pre-Emergency Load Management Reduction Action (30, 60 or 120-minute)

PJM Actions:

- PJM dispatch notifies PJM management, PJM public information personnel, and members. PJM dispatcher advises members to consider the use of public appeals to conserve electricity usage. PJM dispatcher notifies other Control Areas through the RCIS.
- PJM dispatch, via the eLRS System and Emergency Procedures website, will post detailed instructions to the Curtailment Service Providers (CSP) to dispatch 30, 60 and/or 120 minute Pre-Emergency Load Management Reductions. An Action can be issued for the entire PJM RTO, specific Transmission Zone(s) or a Transmission Sub-zone(s) if transmission limitations exist. PJM dispatcher will also issue an All-Call informing the Members and CSPs to check the eLRS and Emergency Procedures postings for the detailed information pertaining to the Pre-Emergency Load Management that has been called.

PJM Member Actions:

- Member Curtailment Service Providers implement load management reductions as requested by PJM dispatchers.

<u>Step 2: Emergency Load Management Reductions - (30, 60, or 120 minute)</u>

The purpose of the Load Management Curtailments is to provide additional load relief by using PJM controllable load management programs. Load relief is expected to be required after initiating Maximum Emergency Generation.

<u>PJM Actions:</u>

- PJM dispatch notifies PJM management, PJM public information personnel, and members. PJM dispatch advises members to consider the use of public appeals to conserve electricity usage. PJM dispatch notifies other Control Areas through the RCIS.
- PJM dispatcher, via eLRS System and Emergency website, , will post detailed instructions to the Curtailment Service Providers (CSP) to implement dispatch 30, 60, and/or 120 minute Emergency Load Management Reductions (Long Lead Time). An Action can be issued for the entire PJM RTO, specific Control Zone(s) or a subset of a Control Zone if transmission limitations exist. PJM will also issue an All-Call informing the Members and CSPs to check the eLRS and Emergency Procedures posting for the detailed information pertaining to the Emergency Load Management that has been called.
- PJM dispatch issues a NERC Energy Emergency Alert Level 2 (EEA2 = ALERT LEVEL 2) via the RCIS to ensure all Reliability Authorities clearly understand potential and actual PJM system emergencies if one has not already been issued concurrent with the issuance of Emergency Load Management Reductions. **NERC EEA2 is issued when the following has occurred: Public appeals to reduce demand, voltage reduction, and interruption of non-firm load** in accordance with applicable contracts, demand side management, or utility load conservation measures.

<u>SCC Actions:</u>

- SCC notify management of emergency procedure.
- SCC to issue Notify_PJM_Emer Procedures e-mail notifications.
- SCC to issue Notify_TOP_East e-mail notifications.
- SCC contact Corporate Communications to consider the use of Public Appeals to conserve electricity usage.
- SCC notifies Regulatory Services which notifies Government Agencies, as applicable.
- SCC implements load management programs, as requested by PJM dispatchers.
    - **626.4 Mws**
        - Available upon request. via Customer Communication System (CCS)
- PJM dispatcher cancels, when appropriate.

Note 1: Load management programs, whether under PJM control and directed by PJM dispatcher or solely under the Local Control Center's direction, have various names including, but not limited to Active Load Management, interruptibles, curtailables, or load management. To simplify operations during these emergency situations, all PJM issued reductions are referred to as Emergency Load Management Reductions.

Note 2: PJM RTO Load Management Reductions are not to be used to provide assistance to adjacent Control Areas beyond PJM. Restoration of Load Management Reductions is undertaken in a stepped approach, as necessary. PJM Control Zones implement Emergency Procedures concurrently until a Manual Load Dump Action, which will only occur in the deficient Control Area.

Note 3: Pre-Emergency and Emergency Load Management Reductions are available for Limited, Extended Summer and Annual Demand Resources as defined in the Reliability Assurance Agreement (RAA).

Note 4, EEA Levels: PJM dispatcher issue a NERC Energy Emergency Alert Level 2 (EEA2 = ALERT LEVEL 2) via the Reliability Coordinator Information System (RCIS) to ensure all Reliability Authorities clearly understand potential and actual PJM system emergencies if one has not already been issued concurrent with the issuance of Emergency Load Management Reductions. NERC EEA2 is issued when the following has occurred: Public appeals to reduce demand, voltage reduction, interruption of non-firm load in accordance with applicable contracts, demand side management/active load management, or utility load conservation measures.

Note 5, Demand Resource Curtailment: If PJM needs to dispatch Demand Resources (DR) during the Limited DR availability Period then PJM will dispatch all DR products simultaneously unless all products have been dispatched frequently during the current delivery year. Frequent dispatch of DR during the delivery year is defined as:

- 2 times prior to July 1st,

- 4 times prior to August 1st, or,

- 7 times prior to September 1st.

Should PJM frequently dispatch DR during a delivery based on the criteria above PJM may elect to dispatch only the Extended Summer and Annual DR, to preserve Limited DR for the remainder of the delivery year.

Note 6, Capacity Benefit Margin (CBM): Under NERC Energy Emergency Alert Level 2, the PJM dispatcher may request import energy over firm transfer capability set aside as CBM. If so, dispatch will waive any real-time operating timing and ramp requirements and document such actions in compliance with MOD-004-1.

<u>Step 3 (Real-time): Primary Reserve Warning</u>

The purpose of the Primary Reserve Warning is to warn members that the available primary reserve is less than required and present operations are becoming critical. It is implemented when available primary reserve capacity is less than the primary reserve requirement, but greater than the synchronized reserve requirement.

<u>PJM Actions:</u>

- PJM dispatch issues a warning to members and PJM management stating the amount of adjusted primary reserve capacity and the requirement. A Warning can be issued for the entire PJM RTO or for specific Control Zone(s) based on the projected location of transmission constraints.
- PJM dispatch notifies PJM public information personnel.
- PJM dispatch rechecks with members to assure that all available equipment is scheduled and that requested secondary reserve is brought to primary reserve status.
- PJM dispatch ensures that all deferrable maintenance or testing on the control and communications systems has halted at PJM Control Center. PJM dispatcher should provide as much advance notification as possible to ensure maintenance/testing does not impact operations. This notification may occur prior to declaration of Primary Reserve Warning.
-

<u>SCC Actions:</u>

- SCC/MO notifies Transmission/MO management of the warning.
- SCC to issue Notify_PJM_Emer Procedures e-mail notifications.
- SCC to issue Notify_TOP_East e-mail notifications.
- SCC/MO advises all TDC's, Plants and key personnel as needed.
- MO prepares to load all available primary reserve, if requested.
- MO inform PJM of any environmentally restricted units and may consider the need to obtaina temporary variance from environmental regulators for specific generators in accordance with Attachment M in PJM Manaul 13 to assist in preventing load shed. PJM is not responsible for obtaining a temporary variance from environmental regulators but will assist the member company if requested.
- SCC contacts MO to determine the status of any requests to alleviate environmental constraints on generating units.
- SCC/MO ensures that all deferrable maintenance or testing affecting critical transmission or capacity is halted. Any monitoring or control maintenance work that may impact operation of the system is halted.
- PJM dispatcher cancels the warning, when appropriate.

<u>Step 4 A (Real-time): Maximum Emergency Generation</u>

The purpose of the Maximum Emergency Generation is to increase the PJM RTO generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the highest incremental cost level.

Note: Maximum Emergency Generation can only be included in the daily operating capacity when requested by PJM dispatch.

PJM Actions:

- PJM dispatch issues Maximum Emergency Generation. An Action can be issued for the entire PJM RTO, specific Control Zone(s) or a subset of a Control Zone if transmission limitations exist.
- PJM dispatch notifies PJM management, PJM public information personnel, and member dispatchers.
- PJM dispatch implements the Emergency Bid-Process, requesting Emergency bids by posting messages to selected PJM websites, RCIS, and contacting the neighboring control areas.
- PJM dispatch instructs members to suspend Regulation on all resources, except hydro generation.
- PJM dispatch recalls off-system capacity sales that are recallable (network resources).
    - PJM dispatch will determine any limiting transmission constraints internal to PJM that would impact the ability to cut transactions to a specific interface.
    - PJM dispatch will identify off-system capacity sales associated with the identified interfaces.
    - PJM dispatch will identify off-system capacity sales associated with the identified interfaces.
    - PJM dispatch will contact the sink Balancing Authority to determine the impact of transaction curtailment.
        - If the net result of cutting off-system capacity sales would put the sink Balancing Authority into load shed then PJM will not curtail the transactions unless it would prevent load shedding within PJM.
        - If the net result of cutting off-system capacity sales would put PJM in a more severe capacity emergency than it is in currently in due to reciprocal transaction curtailments from the sink Balancing Authority, PJM will not initiate curtailing the transactions.
- PJM dispatch declares Maximum Emergency Generation and begins to load Maximum Emergency Generation or purchase available emergency energy from PJM Members (Emergency Bid Process) and from neighboring Control Areas based on economics and availability.
- PJM dispatch loads Maximum Emergency Generation incrementally as required, if the entire amount of Maximum Emergency Generation is not needed. PJM dispatchers generally load Maximum Emergency CTs prior to loading Maximum Emergency Steam in order to preserve synchronized reserve.

Note 1: Emergency Bid-Process: Following issuance of Maximum Emergency Generation, PJM may purchase available energy from any PJM Member (as emergency) that is available up to the amount required or until there is no more available, recognizing the impact on transmission constraints. The following rules are used to provide an orderly operation.
Note 2: PJM should consider loading of shared reserves with neighboring systems prior to implementing voltage reduction, while recognizing the impact on transmission limits.

Emergency Bid Process

- The PJM Member is responsible for delivering (i.e., securing all transmission service) of the energy to one of PJM's borders with a neighboring control area. To ensure deliverability, firm transmission service may be required if external Reliability Authorities have issued TLRs.
- PJM attempts to provide 60-minutes notice before the energy is required by posting on selected PJM websites an emergency procedure message stating that PJM anticipates requiring emergency energy purchases beginning at a specific time.
- Once PJM posts the request for emergency purchases all PJM Members can submit "bids" to make emergency energy sales to PJM. PJM Members should use email as primary means of submitting bids with fax as secondary means if email is unavailable and call PJM to confirm receipt. The Emergency Bid form is found in Attachment D in manual 13 along with the rules for submitting. Bids may also be called into a pre-assigned, recorded voice line. They should be structured as follows:
    - time – of energy available
    - amount – of energy available
    - price of energy
    - duration (hours) energy is available and limits on minimum time required to take
    - notification time to cancel/accept
    - PJM Member identification
    - interface and contract path

PJM accepts the offers and schedules the energy using the following guidelines:

- Energy is accepted based on economics (least cost offers will be accepted first based on energy price and minimum hours) if more energy is offered than required.
- Energy is accepted as required based on economics from the available bids (i.e., if PJM requires 500 MW immediately it takes the cheapest 500 MW bid at the time). PJM adjusts current schedules to correct economics if time permits (i.e., if a cheaper schedule is bid after a more expensive schedule is loaded PJM only cancels the first if reasonable time exists to cancel one and load the other).
- Similarly priced offers are selected based on timestamps (i.e., first in first selected).

Bids accepted by PJM are Emergency Purchases by PJM and will set the Locational Marginal Price. The energy received is accounted for according to the current Emergency Energy accounting procedures. See the *PJM Manual for Operating Agreement Accounting (M28)* for more details.

PJM reserves the right to load maximum emergency equipment as required to control the system regardless of whether any bids were/were not accepted (i.e., sudden unit loss may not allow time to accept bids).

PJM implements and curtails emergency purchase transactions with as much notice as practical to allow for a reliable transition into and out of emergency conditions.

PJM requests emergency energy from neighboring Control Areas (under current Control Area agreements) after all energy offered by the PJM Members is accepted, unless there is an immediate need for the energy.

PJM can deviate from or change the order of the above actions as/if necessary.

<u>**SCC Actions:**</u>

- SCC/MO notifies Transmission/MO management.
- SCC to issue Notify_PJM_Emer Procedures e-mail notifications.
- SCC to issue Notify_TOP_East e-mail notifications
- MO suspends regulation, as requested and loads all units to the Maximum Emergency Generation level, as required.
- MO notifies PJM dispatching of any Maximum Emergency (ME) generation loaded prior to PJM requesting ME generation is loaded. .
- TDC to poll co-generation and independent power producers (IPP's) to determine if any units are available for supplying power, and provide that information to SCC. SCC to provide information to PJM. (EOP 001-2.1b and Attachment 1-EOP-001 item 11)
- PJM dispatcher cancels, when appropriate.

<u>Step 4 B (Real-time): Emergency Voluntary Energy Only Demand Response Reductions</u>

The purpose of this Load Reduction Action is to request end-use customers, who participate in the Emergency Voluntary Energy Only Demand Response Program, to reduce load during emergency conditions.

<u>***PJM Actions:***</u>

- PJM dispatch issues Action via the PJM All-call and post message to selected PJM Websites. An Action can be issued for the entire PJM RTO, specific Control Zone(s) or a subset of a Control Zone if transmission limitations exist.
- PJM dispatch notifies PJM management, PJM public information personnel, and PJM Markets personnel who notify Emergency Load Response Program participants.

<u>**SCC Actions:**</u>

- SCC/MO notifies Transmission/MO management.
- SCC to issue Notify_PJM_Emer Procedures e-mail notifications.
- SCC to issue Notify_TOP_East e-mail notifications.
- SCC implements load reduction programs, as requested by PJM dispatchers.
    - **AEP presently does not have any programs in this category.**

<u>Step 5 (Real-time): Voltage Reduction Warning & Reduction of Non-Critical Plant Load</u>

The purpose of the Voltage Reduction Warning & Reduction of Non-Critical Plant Load is to warn members that the available synchronized reserve is less than the Synchronized Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required. It is implemented when the available synchronized reserve capacity is less than the synchronized reserve requirement, after all available secondary and primary reserve capacity (except restricted maximum emergency capacity) is brought to a synchronized reserve status and emergency operating capacity is scheduled from adjacent systems.

<u>PJM Actions:</u>

- PJM dispatch issues a warning to members and PJM management, stating the amount of adjusted synchronized reserve capacity and the requirement. A Warning can be issued for the entire PJM RTO or for specific Control Zone(s) based on the projected location of transmission constraints.
- PJM dispatch notifies PJM public information personnel.
- PJM notifies the Department of Energy (DOE).

<u>SCC Actions:</u>

- SCC/MO notifies Transmission/MO management of the warnings that impact AEP Zone or entire Control Area.
- SCC to issue Notify_PJM_Emer Procedures e-mail notifications.
- SCC to issue Notify_TOP_East e-mail notifications.
- SCC/MO advises all TDC's, Plants and key personnel.
- SCC notifies Regulatory Services which notifies Government Agencies, as applicable.
- SCC/TDC prepares to reduce voltage, if requested, and dispatches station personnel to voltage reduction station locations.
- MO orders all generating stations to curtail non-essential station light and power. (see Table III-4)
- Transmission dispatchers / LSEs and Curtailment Service Providers notify appropriate personnel that there is a potential need to implement load management programs, in addition to interrupting their interruptible/curtailable customers in the manner prescribed by each policy, if it has not already been implemented previously.PJM marketers remain on heightened awareness regarding PJM system conditions and the potential need for Emergency Energy Purchases
- SCC notifies neighboring TO's, BA's.
- PJM dispatcher cancels the warning, when appropriate.

Step 6 (Real time): Curtailment of Non-Essential Building Load

The purpose of the Curtailment of Non-Essential Building Load is to provide additional load relief, to be expedited prior to, but no later than the same time as a voltage reduction.

PJM Actions:

- PJM dispatch notifies PJM management, PJM public information personnel, and members. PJM dispatcher advises members to consider the use of public appeals to conserve electricity usage. PJM dispatcher notifies outside systems through the RCIS.
- PJM dispatch issues a request to curtail non-essential building load. An Action can be issued for the entire PJM RTO, specific Control Zone(s) or a subset of a Control Zone if transmission limitations exist.

SCC Actions:

- SCC/MO notifies Transmission/MO management of the warnings that impact AEP Zone or entire Control Area.
- SCC to issue Notify_PJM_Emer Procedures e-mail notifications.
- SCC to issue Notify_TOP_East e-mail notifications.
- SCC advises all TDC's, and key personnel
- SCC notifies Regulatory Services which notifies Government Agencies, as applicable.
- At the request of PJM, Corporate Communications consider use of public appeals to conserve electricity usage.
- SCC notifies Workplace Services to switch off all non-essential light and power in commercial, operations, and administration offices.
- PJM dispatcher cancels the warning, when appropriate.

Note: Curtailment of non-essential building load may be implemented prior to, but no later than the same time as a voltage reduction.

Step 7 (Real-time): Manual Load Dump Warning

The purpose of the Manual Load Dump Warning is to warn members of the increasingly critical condition of present operations that may require manually dumping load. It is issued when available primary reserve capacity is less than the largest operating generator or the loss of a transmission facility jeopardizes reliable operations after all other possible measures are taken to increase reserve. The amount of load and the location of areas(s) are specified.

PJM Actions:

- PJM dispatch issues the warning to members and PJM management, stating the estimated amount of load relief that is required (if applicable). A Warning can be issued for the entire PJM RTO or for specific Control Zone(s) based on the projected location of transmission constraints.
- PJM dispatch notifies PJM public information personnel.
- PJM dispatch notifies FERC via the FERC Division of Reliability's electronic pager system, consistent with FERC Order No. 659.
- PJM dispatch establishes a mutual awareness with the appropriate member dispatchers of the need to address the occurrence of a serious contingency with minimum delay.
- PJM dispatch examines bulk power bus voltages and alerts the appropriate member dispatchers of the situation.

SCC Actions

- SCC/MO notifies Transmission/MO management of the warnings that impact AEP Zone or entire Control Area.
- SCC to issue Notify_PJM_Emer Procedures e-mail notifications.
- SCC to issue Notify_TOP_East e-mail notifications.
- SCC advises all TDC's, and key personnel as needed.
- SCC notifies Regulatory Services which notifies Government Agencies, as applicable.
- MO/Environmental Services obtains any permission to lift environmental restrictions.
- SCC/TDC/DDC reviews local computer procedures and dispatches switching personnel to manual load shedding station locations.
- SCC/TDC/DDC reinforce internal communications so that load dumping can occur with minimum of delay.
- SCC notifies MO of possible impact to Units.
- SCC notifies neighboring TO's, BA's.
- PJM dispatcher cancels the warning, when appropriate.

Step 8(Real-time): Voltage Reduction

The purpose of Voltage Reduction during capacity deficient conditions is to reduce load to provide a sufficient amount of reserve to maintain tie flow schedules and preserve limited energy sources. A curtailment of non-essential building load is implemented prior to or at this same time as a Voltage Reduction Action. It is implemented when load relief is still needed to maintain tie schedules.

Note: Voltage reductions can also be implemented to increase transmission system voltages.

PJM Actions:

- PJM dispatch notifies PJM management, PJM public information personnel, and members. PJM dispatcher advises members to consider the use of public appeals to conserve electricity usage. PJM dispatcher notifies outside systems through the RCIS. PJM dispatch notifies DOE. An Action can be issued for the entire PJM RTO, specific Control Zone(s) or a subset of a Control Zone if transmission limitations exist.
- PJM Management may issue system-wide or Control Zone-specific Public/Media Notification Message W2. See Manual 13 - Attachment A.
- PJM dispatch investigates loading of shared reserves with neighboring systems prior to implementation of a voltage reduction, recognizing the impact on transmission limits.
- PJM dispatch issues the order for a 5% voltage reduction.
    - AEP is either a 2.5% or 5% depending on controls
    - Station or P&C personnel may be required to change settings.
- PJM dispatch issues a NERC Energy Emergency Alert Level 2 (EEA2 = ALERT LEVEL 2) via the RCIS to ensure all Reliability Authorities clearly understand potential and actual PJM system emergencies if one has not already been issued concurrent with the issuance of Active Load Management Curtailables / Full Emergency Load Response (formerly known as ALM). NERC EEA2 is issued when the following has occurred: Public appeals to reduce demand, voltage reduction, and interruption of non-firm load in accordance with applicable contracts, demand side management/active load management, or utility load conservation measures.
- If it has not already begun, the PJM dispatch will initiate Shortage Pricing if the region where the voltage reduction action has been initiated corresponds with an entire Synchronized Reserve Zone or Sub-Zone.

SCC Actions:

- SCC/MO notifies Transmission/MO management of the warnings that impact AEP Zone or entire Control Area.
- SCC to consider the use of Public Appeals to conserve electricity usage.
- SCC to issue Notify_PJM_Emer Procedures e-mail notifications.
- SCC to issue Notify_TOP_East e-mail notifications.
- SCC notifies MO of possible impact on Units Mvar response.
- SCC advises all TDC's, and key personnel
- SCC notifies Regulatory Services which notifies Government Agencies, as applicable.
- SCC/TDC/DDC take steps to implement the voltage reduction.
    - Voltage reduction takes approx. 8 hours to implement, so this would need to be received at least a day ahead of the event. Issue updated DOE report.
- MO must ensure generators (connected below 230kv) participate in a voltage reduction declared by PJM and operate the facility at the voltage level requested by the Local Control Center. Unless PJM requests a manual adjustment, the Generator must maintain the facility's automatic voltage regulator(s) in service during an Emergency.
- SCC notifies neighboring TO's, BA's.
- PJM dispatcher cancels the reduction, when appropriate.

Note: Curtailment of non-essential building load may be implemented prior to, but no later than, the same time as a voltage reduction.

Step 9 (Real-time): Manual Load Dump

The purpose of the Manual Load Dump is to provide load relief when all other possible means of supplying internal PJM RTO load have been used to prevent a catastrophe within the PJM RTO or to maintain tie schedules so as not to jeopardize the reliability of the other interconnected regions. It is implemented when the PJM RTO cannot provide adequate capacity to meet the PJM RTO's load or critically overloaded transmission lines or equipment cannot be relieved in any other way and/or low frequency operation occurs in the PJM RTO, parts of the PJM RTO, or PJM RTO and adjacent Control Areas that may be separated as an island.

Under capacity deficient conditions, the PJM EMS load dump calculator was modified to institute changes to the Operating Agreement set forth in Schedule 1, Section 1.7.11 that states that "…the Office of Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone."

The load dump calculation determines which Control Zone(s) is short based on real-time load and energy values from EMS and capacity values received daily from the Capacity Adequacy Planning Department. Real-time energy values are used as a surrogate for available capacity, because in a capacity shortage situation all available generation should be loaded to full capacity. Since most of the values used in the load dump calculation are real-time dynamic numbers, the calculation is performed in the PJM EMS. Load Serving Entities will be able to designate within eCapacity that capacity resources are being used to serve load in a specific Control Zone. Similarly ExSchedule users will be able to specify that an external energy schedule is designated for a specific Control Zone. Resources that are not designated for a specific Control Zone will be considered an RTO resource for load dump calculation purposes and allocated across all Control Zones according to load ratio share. Only Control Zones that are determined to be deficient will be assigned a share of a load dump request initiated due to RTO capacity deficiencies. If the PJM Mid-Atlantic Region is determined to be deficient, its share will be further allocated according to Manual 13 - Attachment E.

PJM Actions:

- PJM dispatch verifies that separations have not occurred and that load dumping is desirable on the system being controlled (i.e., make sure that a load dump will help, not aggravate the condition).
- PJM dispatch instructs members to suspend all remaining regulation, if not already suspended previously.
- PJM dispatch determines which Control Zone (s) are capacity deficient and the relative proportion of deficiency. PJM dispatcher estimates the total amount of load to be dumped and utilizes the PJM EMS to determine deficient Control Zones and their share of load dump required.
- PJM dispatch orders the appropriate member dispatchers to dump load according to PJM EMS calculations. The PJM Mid-Atlantic Region share will be further allocated according to Manual 13 - Attachment E. PJM dispatch will implement load shedding in controlled step sizes to minimize system impact and further uncontrolled separation.
- PJM dispatch notifies PJM management, PJM public information personnel, and members. PJM dispatcher advises members to consider the use of public appeals to conserve electricity usage and public announcements of the emergency. PJM dispatcher notifies other Control Areas through the RCIS, and notifies DOE, FEMA, and NERC offices, using established procedures.
- PJM dispatch notifies FERC via the FERC Division of Reliability's electronic pager system, consistent with FERC Order No. 659.
- PJM dispatch issues a NERC Energy Emergency Alert Level 3 (EEA3 = ALERT LEVEL 3) via the RCIS to ensure all Reliability Authorities clearly understand potential and actual level of PJM System Emergencies.
- PJM Management issues a system-wide or Control Zone specific Public/Media Notification Message W2. Typically, this would be issued prior to a Manual Load Dump. See Manual 13 - Attachment A.
- If it has not already begun, the PJM dispatch will initiate Shortage Pricing if the region where the manual load dump action has been initiated corresponds with an entire Synchronized Reserve Zone or Sub-Zone.

Note 1: If partial restoration of the load dumped is requested by PJM dispatcher, confirmation of the load restored by each member must be made prior to further restoration requests by PJM dispatcher.
Note 2: If step 1 of UFLS is insufficient to return frequency to acceptable ranges and if emergency procedures cannot be implemented in a timely fashion then PJM dispatch shall dump sufficient load to restore system frequency.

<u>SCC Actions:</u>

- MO suspend remaining regulation, when directed by PJM prior to dumping load.
- SCC dump an amount of load equal to or in excess of the amount requested by PJM dispatcher within 5 minutes of the issued directive.
  - SCC/MO/Environmental Services lift environmental restrictions on units to regain curtailed generation. (count as part of load dump allocation)
  - SCC notifies MO of possible impact on Units.
  - SCC/TDC/DDC promptly dump an amount of load equal to or in excess of the amount requested by PJM dispatcher taking into account the amount of regained curtailed generation.
- SCC/MO notifies Transmission/MO management of the Manual Load Dump orders that impact AEP Zone or entire Control Area.
- SCC to issue Notify_PJM_Emer Procedures e-mail notifications.
- SCC to issue Notify_TOP_East e-mail notifications.
- SCC advises TDC's, and key personnel as needed.
- SCC notifies Regulatory Services which notifies Government Agencies, as applicable.
- SCC notifies Corporate Communications.
  - Corporate Communications notifies Customer Solutions Center.
- Corporate Communications considers the continued use of public appeals to conserve electricity usage and consider the use of public announcements of the emergency.
- SCC/TDC/DDC maintains the requested amount of load relief until PJM dispatcher cancels the load dump order.
- SCC reports the amount of load curtailed / restored upon implementation to the PJM Power Dispatcher.
- SCC notifies neighboring TO's, BA's.

Note: PJM dispatch should take necessary actions to support system frequency, consistent with good utility practices. These actions may include emergency procedures to arrest frequency decline, but PJM will not violate BAAL (Balancing Authority ACE Limit) limits by overgenerating to correct for a low frequency. PJM shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. PJM will not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. In general, emergency procedures are preserved to ensure PJM net tie deviation is not adversely impacting system frequency after all economic options have been exhausted. However, Emergency Procedures should be exhausted, including Manual Load Dump, to arrest frequency decline once Under Frequency Load Shedding Schemes (UFLS) have triggered but prior to generating stations tripping off-line (57.5 Hz). Underfrequency Load Shedding Plan settings are defined in Manual 13 - Attachment F, "PJM Manual Load Dump Capacity."

Addendum to Manual Load Dump Procedures

AEP understands that PJM intends to implement these curtailment protocols consistent with the agreements that PJM entered into in Kentucky and Virginia, in Stipulations approved by the Kentucky Public Service Commission and Virginia State Corporation Commission (with modifications) in Case No. 2002-00475 and Case No. PUE-2000-00550, respectively.

Capacity Deficiency Summary Table

A summary of the Capacity Deficiency Emergency alerts, warning and actions, together with the typical sequence and the method of communication, are presented in the following Table III-2.

		Communications	Description		Time Estimate
Alerts	Unit Startup Notification Alert	PJM-MO PJM-SCC SCC-TDC	SCC/MO notify management TDC advise station MO orders units to be in a state of readiness		
	Maximum Emergency Generation / Load Management Alert	PJM-MO via All-Call PJM-SCC via All-Call SCC-TDC	SCC/MO review scheduled or actual maintenance / testing of transmission / generation affecting capacity or critical transmission to determine if it can be deferred or cancelled MO report any fuel / environmental issues to PJM	**EEA 1**	< 1 hr.
	Primary Reserve Alert	PJM-MO via All-Call PJM-SCC via All-Call SCC-TDC SCC-MO	SCC/MO reviews plans to determine if any maintenance or testing, scheduled or being performed, on any generating equipment or critical monitoring, control, or bulk power transmission facility can be deferred or cancelled. SCC request MO to evaluate the impact of current environmental constraints and start the process to possibly lift those constraints identified. MO inform PJM of any environmentally restricted units		< 1hr.
	Voltage Reduction Alert	PJM-SCC via All-Call SCC-TDC	SCC/TDC to identify stations for Voltage Reduction		< 1 hr.; however, alert needs to be issued day ahead
Warnings & Action Items					
Step 1	Pre-Emergency Load Management Reductions (30,60, or 120 minute)	PJM-SCC via All-Call SCC - MO	626.4 MW via CCS		2 hrs
Step 2	Emergency Load Management Reductions ((30,60, or 120 minute)	PJM-SCC via All-Call SCC – MO	Not Applicable for 30 or 60 minute 626.4 MW via CCS if not implemented in Step 1	**EEA 2 (DOE Report see note 1)**	2 hrs
	Public Appeal (PJM may issue at other Steps)	PJM –SCC SCC-Corporate Communications	a. Radio and TV alert to general public		1-2 hrs.
		SCC – Customer Services SCC –MO & Regulatory Services	b. Call to Industrial and Commercial Customers, Government Agencies		1-2 hrs.

		Communications	Description		Time Estimate
Step 3	Primary Reserve Warning	PJM-MO via All-Call PJM-SCC via All-Call SCC-TDC SCC -MO	SCC/MO ensures that all deferrable maintenance or testing affecting capacity or critical transmission is halted. SCC/MO advises all TDC's, Plants, and key personnel as needed MO inform PJM of any environmentally restricted units. MO prepares to load all available primary reserve if requested by PJM SCC contacts MO to determine the status of any requests to alleviate environmental constraints on generating units.		< 1 hr.
Step 4A	Maximum Emergency Generation Action	PJM-MO via All-Call PJM-SCC via All-Call SCC-PJM SCC-TDC	Supplemental Oil & Gas Firing; Operate Generator Peakers; Emergency Hydro ;Extra Load Capability, Emergency Bid Process, TDC contact IPP's	See Table III-3	< 1hr.
Step 4B	<u>Emergency Voluntary Energy Only Demand Response Reductions</u>	PJM-SCC via All-Call	Not Applicable		N/A
Step 5	Voltage Reduction Warning & Reduction of Non-Critical Plant Load	PJM-MO via All-Call PJM-SCC via All-Call SCC-TDC	SCC to inform TDC to man Voltage Reduction Stations & prepare for Voltage Reduction	MO to reduce plant load. (See Table III-4)	6-8 hrs. – VR < 1 hr. – plant load
		SCC-Regulatory Services	Notify Government Agencies as applicable		
Step 6	Curtailment of Non-Essential Building Load (Action)	PJM-SCC via All Call SCC-Workplace Services	Initiate curtailment of AEP building load – 4.4 Mws		< 1 hr
		SCC-Regulatory Services	Notify Government Agencies as applicable		
		PJM –SCC SCC-Corporate Communications	Radio and TV alert to general public		
Step 7	(Real-time): Manual Load Dump Warning	PJM-SCC via All-Call SCC– MO-Environmental Services SCC-TDC-DDC	Lifting of Environmental Restrictions	Manual & Automatic Load Shedding	
		Make preparations for a Public Appeal if one becomes necessary.	a. Obtain permission to exceed opacity limits b. Obtain permission to exceed heat input limits c. Obtain permission to exceed river temperature limits	SCC/TDC will review local computer procedures and man manual load shedding stations	1-2 hrs.

		Communications	Description		Time Estimate
		MO/Environmental Services	Obtains permission to lift environmental restrictions		
		SCC-Regulatory Services	Notify Government Agencies as applicable		
		SCC-TDC-DDC	Review local computer procedures / dispatch switching personnel to manual load shed		
		SCC-TDC-DDC	Reinforce internal communications to allow load dumping to occur with minimum of delay		
Step 8	(Real-time): Voltage Reduction Action	PJM-SCC via All-Call SCC –TDC & SCC -MO	Initiate Voltage Reduction - AEP/PJM – 64 Mws	**(DOE Report)**	< 1 hr.
		PJM-MO	Must ensure generators connected below 230kV participate in a voltage reduction declared by PJM.		
				2% of AEP Internal Load (DOE Report)	Need to make Noon broadcast
				.	.
Step 9	(Real-time): Manual Load Dump	PJM-SCC via All-Call SCC-MO-Environmental Services SCC-TDC-DDC	PJM Allocation based on deficient zones and their share of load to dump	**EEA3 (DOE & EEA-3 Report required)**	
		SCC – Corporate Communications Corporate Comm.-CSC SCC – Customer Services SCC – Regulatory Services	a. Lift Environmental Restrictions on units	(Regains curtailed generation)	< 1 hr.
			b. Selected distribution customers (manual load curtailment)	Execute ALS	< 1 hr.
		PJM-MO	Suspend remaining regulation when directed by PJM		
		PJM-SCC-TDC	Dump load equal to or in excess of the amount requested by PJM dispatcher		5 minutes
		SCC-Regulatory Services	Notify Government Agencies as applicable		
		PJM-Corporate Commuications	Public Appeals		

		Communications	Description		Time Estimate
		SCC-TDC	Maintain requested load dump relief until PJM cancels		
		SCC-PJM	Report Mw amount to PJM		

Table III -2 Capacity Deficiency Summary – AEP/PJM

Notes:

1. DOE Report required for Public Appeals / Voltage Reduction called in an EEA 2. See NERC EOP-002-3.1 Attachment 1-EOP-002

Severe Weather Conditions (reference PJM Manual M13)

Cold Weather Alert

The purpose of the Cold Weather Alert is to prepare personnel and facilities for expected extreme cold weather conditions. As a general guide, PJM can initiate a Cold Weather Alert across the RTO or on a Control Zone basis when the forecasted weather conditions approach minimum or actual temperatures of 10 degrees Fahrenheit or below. PJM can initiate a Cold Weather Alert at higher temperatures if PJM anticipates increased winds or if PJM projects a portion of gas-fired capacity is unable to obtain spot market gas during load pick-up periods. PJM will initiate the Cold Weather Alert for the appropriate region(s) in advanced of the operating day.

PJM Actions:

- PJM dispatcher issues an Alert and provides the following information:
  - Control Zone
  - Forecasted low temperature
  - Duration of the condition
  - Amount of estimated operating reserve and reserve requirement
- PJM Dispatch communicates whether fuel limited resources are required to be placed into Maximum Emergency Category.

Note1: Since a Cold Weather Alert may only be issued on a portion of the PJM footprint, and since PJM schedules and operates the footprint as a single Balancing Authority, PJM may elect not to automatically place Fuel Limited Resources into the Maximum Emergency Category.
Note2: There may be times when Gas-fired Fuel Limited Combustion Turbines are placed into the Maximum Emergency Generation Category with a daily availability < 8 hours per day (i.e. 5 hours of gas per day). Considering the daily nature of gas limitations, the PJM Dispatcher has the option of requesting the generator owner, with daily gas limitations, to remove the fuel limited resource from the Maximum Emergency Category to ensure PJM tools economically schedule the gas fired CTs.

PJM utilizes the following weather locations and approximate unavailability rates to declare a Cold Weather Alerts on a PJM Control Area or Control Zone basis.

Control Zone	Region	Weather	Unavailability
Mid Atlantic	Mid-Atlantic	Philadelphia	4000 - 5000 MW
FE -South	Western	Pittsburgh	500 – 1000 MW
AEP	Western	Columbus	1000 – 1500 MW
Dayton	Western	Dayton	500 – 1000 MW
ComEd	Western	Chicago	2000 – 3000 MW
Dominion	Southern	Richmond	1000 – 2000 MW
FE West	Western	Cleveland	500 – 1000 MW
DEOK	Western	Cincinnati	200 – 300 MW
EKPC	Western	Winchester	200 – 300 MW

> **Note:** Unavailability numbers are conservative estimates and are not necessarily additive. During the start of extreme cold weather unavailability rates are typically higher. Values can be adjusted based on the duration of cold weather, actual unity performance during cold weather, the impact on fuel sources (i.e., frozen coal, gas interruptions, etc.), the projected level of combined cycle/combustion turbine usage, and level of scheduled long-lead/seldom-run generation.

- When scheduling for a period covered by a Cold Weather Alert, PJM dispatch may assume an unavailability factor for scheduled interchange that could range from 25% to 75% of the pre-scheduled interchange. Dispatch will make this decision based on the severity of the conditions, recent interchange curtailment experience, and the current/projected impact of the weather system on other Control Areas. This decrease may require the commitment of additional steam units and/or the purchase of emergency power from external systems.
- When in PJM's judgment combustion turbines in excess of 2000 MW are needed within a control zone, PJM will notify the respective combustion turbine that PJM expects these units to be run. If the predicted minimum temperature is -5 degrees Fahrenheit or less or if recent unit performance has sufficient increase in unit unavailability, an additional level of unavailability is to the amount of CTs expected to operate. PJM will notify these additional station turbine owners that PJM expects these units to be run.
- PJM confers with generator owners and if appropriate, directs them to call in or schedule personnel in sufficient time to ensure that all combustion turbines and diesel generators that are expected to operate are started and available for loading when needed for the morning pick up. This includes operations, maintenance, and technical personnel that are necessary to gradually start all equipment during the midnight period. Directions may also be given to bring units on at engine idle, or loaded as necessary to maintain reliability. Once units are started, they remain on-line until PJM dispatcher requests the units be shut down. Running CTs to provide for Synchronized Reserve is monitored closely for units where fuel and delivery may be hampered. Most troublesome or unreliable units should be started first. PJM dispatch should make this notification on afternoon shift the day prior, paying particular attention to weekend staffing levels.
- PJM dispatch should poll large combined cycle units regarding projected availability during reserve adequacy run.
- PJM dispatch reports significant changes in the estimated operating reserve capacity.
- PJM dispatch cancels the alert if the weather forecast is changed or when the alert period is over.

<u>SCC Actions:</u>

- SCC/MO notifies Transmission/MO management of the alerts that impact AEP Zone or entire Control Area.
- SCC to issue Notify_PJM_Emer Procedures e-mail notifications.
- MO coordinates with AEP generation based on direction received from PJM call in or schedule personnel in sufficient time to ensure that all combustion turbines and diesel generators that are expected to operate are started and available for loading when needed for the morning pick up. This includes operations, maintenance, and technical personnel that are necessary to gradually start all equipment during the midnight period. The units are brought on at engine idle, where possible, and loaded as necessary to maintain reliability. Once units are started, they remain on-line until PJM dispatcher requests the units be shut down. Running CTs to provide for Spinning Reserve is monitored closely for units where fuel and delivery may be hampered. Each generator owner attempts to start their most troublesome or unreliable units first.
- MO reviews their combustion turbine capacities, specifically units burning No. 2 fuel oil that do not have sufficient additive to protect them from the predicted low temperature.
- MO/FEL review fuel supply/delivery schedules in anticipation of greater than normal operation of units.
- MO/FEL monitors and reports projected fuel limitations to PJM dispatcher
- MO/FEL contacts PJM dispatcher if it is anticipated that spot market gas is unavailable, resulting in unavailability of bid-in generation.
- MO/FEL contacts PJM dispatch to inform them of gas-fired CTs placed in Maximum Emergency Generation due to daily gas limitations of less than 8 hours (i.e. 5 hours of gas per day)
- SCC/MO/FEL review plans to determine if any maintenance or testing, scheduled or being performed, on any monitoring, control, transmission, or generating equipment can be deferred or cancelled.

Hot Weather Alert

The purpose of the Hot Weather Alert is to prepare personnel and facilities for extreme hot and/or humid weather conditions which may cause capacity requirements/unit unavailability to be substantially higher than forecast are expected to persist for an extended period. In general, a Hot Weather alert can be issued on a Control Zone basis, if projected temperatures are to exceed 90 degrees with high humidity for multiple days.

<u>PJM Actions:</u>

- PJM utilizes the following weather locations and approximate unavailability rates to declare a Hot Weather Alerts on a PJM Control Area or Control Zone basis.

Control Zone	Region	Weather	Unavailability
Mid-Atlantic	Mid-Atlantic	Philadelphia	2000 - 2500 MW
FE South	Western	Pittsburgh	300 – 500 MW
AEP	Western	Columbus	500 – 1000 MW
Dayton	Western	Dayton	300 – 500 MW
ComEd	Western	Chicago	1000 – 1500 MW
Dominion	Southern	Richmond	500 - 1000 MW

FE West	Western	Cleveland	300 – 500 MW
DEOK	Western	Cincinnati	100 – 200 MW
EKPC	Western	Winchester	100 – 200 MW

- PJM dispatch notifies PJM management and member dispatchers.
- PJM dispatch issues an Alert stating the amount of estimated operating reserve capacity and the reserve requirement.
- PJM Dispatch communicates whether fuel limited resources are required to be placed into Maximum Emergency Category for Hot Weather/Cold Weather Alerts.
    - **Note1:** Since a Hot Weather Alert may only be issued on a portion of the PJM footprint, and since PJM schedules and operates the footprint as a single Balancing Authority, PJM may elect not to automatically place Fuel Limited Resources into the Maximum Emergency Category.
    - **Note2**: There may be times when Gas-fired Fuel Limited Combustion Turbines are placed into the Maximum Emergency Generation Category with a daily availability < 8 hours per day (i.e. 5 hours of gas per day). Considering the daily nature of gas limitations, the PJM Dispatcher has the option of requesting the generator owner, with daily gas limitations, to remove the fuel limited resource from the Maximum Emergency Category to ensure PJM tools economically schedule the gas fired CTs.
- PJM dispatch reports significant changes in the estimated operating reserve capacity.

<u>SCC Actions:</u>

- SCC/MO notifies Transmission/MO management of the alerts that impact AEP Zone or entire Control Area.
- SCC to issue Notify_PJM_Emer Procedures e-mail notifications.
- SCC/MO advises all generating stations and key personnel.
- SCC/MO reviews plans to determine if any maintenance or testing, scheduled or being performed, on any monitoring, control, transmission, or generating equipment can be deferred or cancelled.
- MO/FEL reports to PJM all fuel-limited facilities as they occur and update PJM dispatcher as appropriate.
- MO/FEL contacts PJM dispatch to inform them of gas-fired CTs placed in Maximum Emergency Generation due to daily gas limitations of less than 8 hours (i.e. 5 hours of gas per day).
- PJM dispatcher cancels the alert, when appropriate.

AEP West/SPP and AEP East/PJM

Unit	MW (Summer/Winter)
Amos #1	20/40
Amos #2	20/40
Cardinal #1	5/15
Cardinal #2	5/15
Cardinal #3	0/5
Rockport #1	0/5
Rockport #2	5/10
Kammer #1	0/10
Kammer #2	0/10
Mitchell #1	10/30
Mitchell #2	20/40
Total System	**85/220**

Table III-3
AEP System - Details of Emergency Capacity Resources Extra Load Capability

Plant	MW	Plant	MW
Amos	2		
Big Sandy	2		
Clinch River	1	Mitchell	1
Cardinal	1	Mountaineer	2
Conesville	6		
D. C. Cook	0		
Gavin	5	Rockport	0
		Total AEP/PJM System	**20**
Flintcreek	1	Northeastern	3
Welsh	1	Pirkey	2
		Total AEP/SPP System	**7**

Table III-4
AEP System - Details of Emergency Capacity Resources Curtailment of Generating Station Use

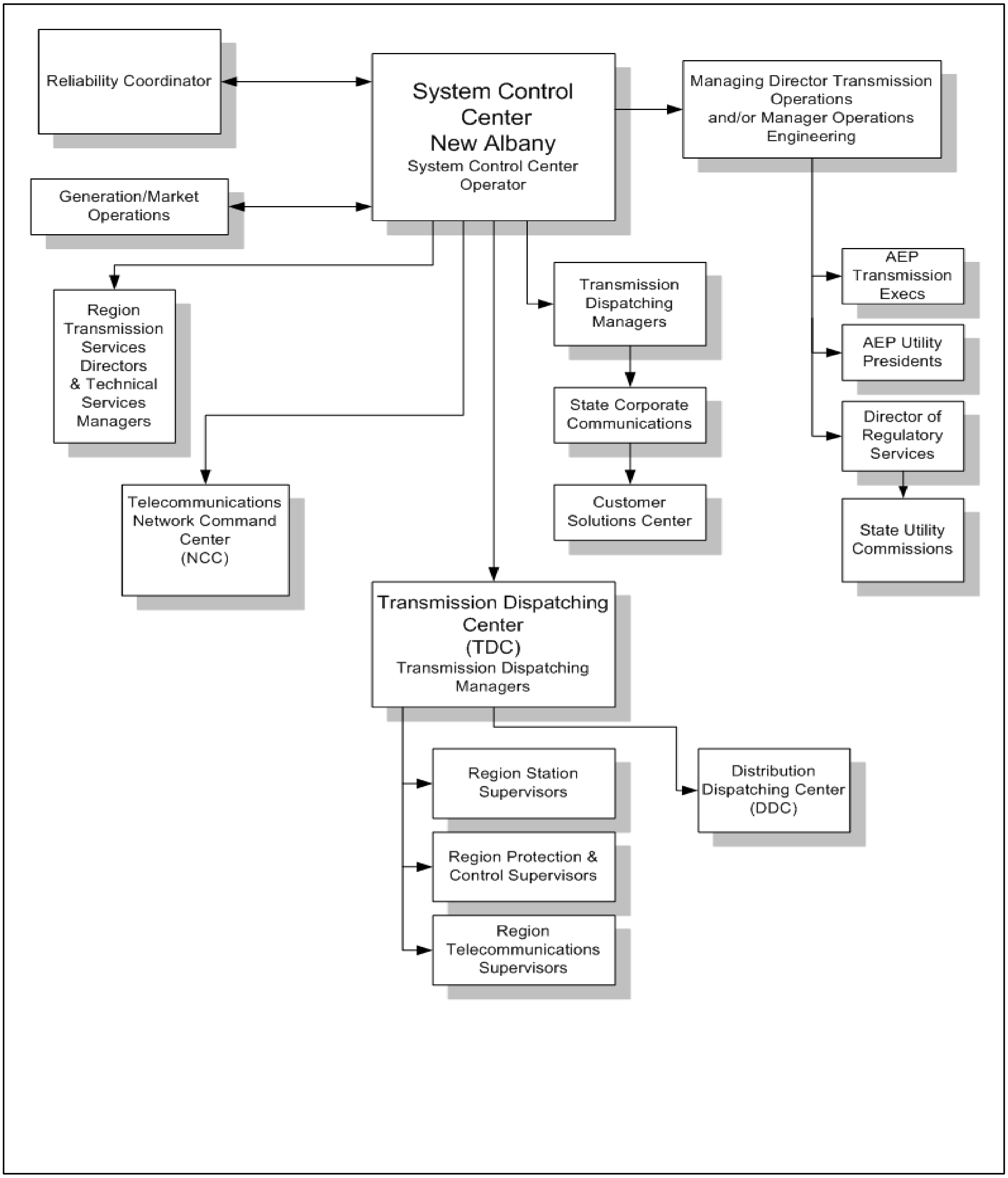


Figure III-1
Capacity Deficiency Warning Notifications

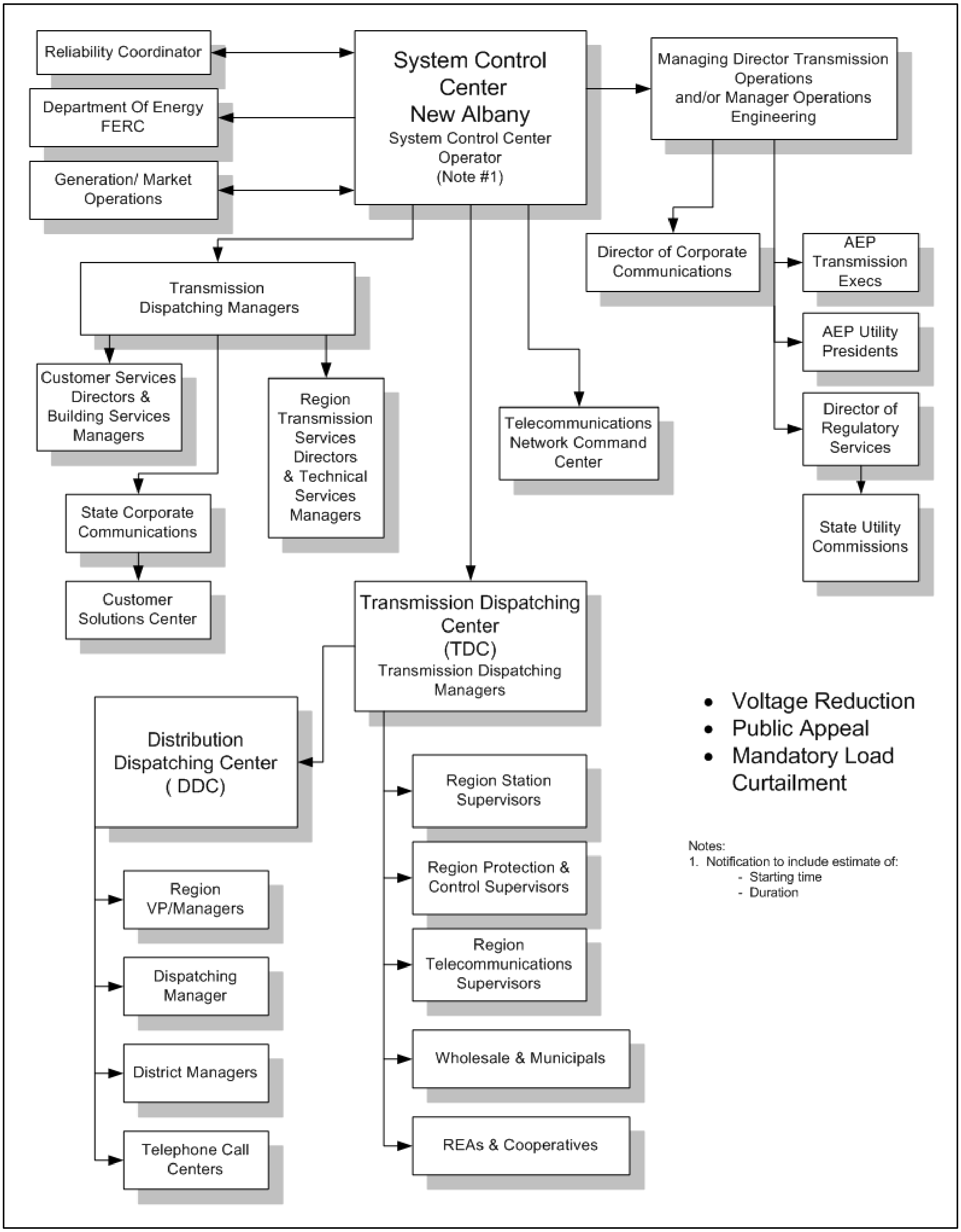


Figure III-2
Capacity Deficiency Action Notifications

Energy Emergency Alerts (Applies to both AEP West/SPP and AEP East/PJM)

Introduction

This Attachment provides the procedures by which a Load Serving Entity can obtain capacity and energy when it has exhausted all other options and can no longer provide its customers' expected energy requirements. NERC defines this situation as an "Energy Emergency." NERC assumes that a capacity deficiency will manifest itself as an energy emergency.

The Energy Emergency Alert Procedure is initiated by the Load Serving Entity's Reliability Coordinator, who declares various Energy Emergency Alert levels as defined in Section B, "Energy Emergency Alert Levels," to provide assistance to the Load Serving Entity.

The Load Serving Entity who requests this assistance is referred to as an "Energy Deficient Entity."

NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements, and nothing in these procedures should be interpreted as changing those obligations.

A. General Requirements

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of a Balancing Authority, or 3) upon the request of a Load Serving Entity.

   1.1. **Situations for initiating alert.** An Energy Emergency Alert may be initiated for the following reasons:

   - When the Load Serving Entity is, or expects to be, unable to provide its customers' energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or
   - The Load Serving Entity cannot schedule the resources due to, for example, Available Transfer Capability (ATC) limitations or transmission loading relief limitations.

2. **Notification.** A Reliability Coordinator who declares an Energy Emergency Alert shall notify all Balancing Authorities and Transmission Providers in its Reliability Area. The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify the other Reliability Coordinators when the alert has ended.

B. Energy Emergency Alert Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual energy emergencies in the Interconnection, NERC has established three levels of Energy Emergency Alerts. The Reliability Coordinators will use these terms when explaining energy emergencies to each other. An Energy Emergency Alert is an emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standards or power supply contracts.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **Alert 1 — All available resources in use.**
   Circumstances:
   - Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **Alert 2 — Load management procedures in effect**.
   Circumstances:
   - Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
   - Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
     - Public appeals to reduce demand.
     - Voltage reduction.
     - Interruption of non-firm end use loads in accordance with applicable contracts[1].
     - Demand-side management.
     - Utility load conservation measures.

   During Alert 2, Reliability Coordinators, Balancing Authorities, and Energy Deficient Entities have the following responsibilities:

   2.1 Notifying other Balancing Authorities and market participants. The Energy Deficient Entity shall communicate its needs to other Balancing Authorities and market participants. Upon request from the Energy Deficient Entity, the respective Reliability Coordinator shall post the declaration of the alert level along with the name of the Energy Deficient Entity and, if applicable, it's Balancing Authority on the NERC website.

2.2 Declaration period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators, Balancing Authority, and Transmission Providers**.**

2.3 Sharing information on resource availability. A Balancing Authority and market participants with available resources shall immediately contact the Energy Deficient Entity. This should include the possibility of selling non-firm (recallable) energy out of available Operating Reserves. The Energy Deficient Entity shall notify the Reliability Coordinators of the results.

2.4 Evaluating and mitigating transmission limitations. The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may limit the Energy Deficient Entity's scheduling capabilities. Where appropriate, the Reliability Coordinators shall inform the Transmission Providers under their purview of the pending Energy Emergency and request that they increase their ATC by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures, and reviewing generation re-dispatch options.

2.4.1 Notification of ATC adjustments. Resulting increases in ATCs shall be simultaneously communicated to the Energy Deficient Entity and the market via posting on the appropriate OASIS websites by the Transmission Providers.

2.4.2 Availability of generation re-dispatch options. Available generation re-dispatch options shall be immediately communicated to the Energy Deficient Entity by its Reliability Coordinator.

2.4.3 Evaluating impact of current transmission loading relief events. The Reliability Coordinators shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the Energy Deficient Entity. This evaluation shall include analysis of system reliability and involve close communication among Reliability Coordinators and the Energy Deficient Entity.

2.4.4 Initiating inquiries on reevaluating SOLs and IROLs. The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of reevaluating and revising SOLs or IROLs.

2.5 Coordination of emergency responses. The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.

2.6 Energy Deficient Entity actions. Before declaring an Alert 3, the Energy Deficient Entity must make use of all available resources. This includes but is not limited to:

2.6.1 All available generation units are on line. All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.

2.6.2 Purchases made regardless of cost. All firm and non-firm purchases have been made, regardless of cost.

2.6.3 Non-firm sales recalled and contractually interruptible loads and demand-side management curtailed. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and demand-side management activated within provisions of the agreements.

2.6.4 Operating Reserves. Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

3. Alert 3 — Firm load interruption imminent or in progress.
Circumstances:

- Balancing Authority or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 Continue actions from Alert 2. The Reliability Coordinators and the Energy Deficient Entity shall continue to take all actions initiated during Alert 2. If the emergency has not already been posted on the NERC website (see paragraph 2.1), the respective Reliability Coordinators will, at this time, post on the website information concerning the emergency.

3.2 Declaration Period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers.

3.3 Use of Transmission short-time limits. The Reliability Coordinators shall request the appropriate Transmission Providers within their Reliability Area to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities into the Energy Deficient Entity.

3.4 Re-evaluating and revising SOLs and IROLs. The Reliability Coordinator of the Energy Deficient Entity shall evaluate the risks of revising SOLs and IROLs on the reliability of the overall transmission system. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Balancing Authority or Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the Energy Deficient Entity who has requested an Energy

Emergency Alert 3 condition. SOLs and IROLs shall only be revised as long as an Alert 3 condition exists or as allowed by the Balancing Authority or Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.4.1 **Energy Deficient Entity obligations.** The deficient Balancing Authority or Load Serving Entity must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding.

3.4.2 **Mitigation of cascading failures**. The Reliability Coordinator shall use its best efforts to ensure that revising SOLs or IROLs would not result in any cascading failures within the Interconnection.

3.5 **Returning to pre-emergency Operating Security Limits**. Whenever energy is made available to an Energy Deficient Entity such that the transmission systems can be returned to their pre-emergency SOLs or IROLs, the Energy Deficient Entity shall notify its respective Reliability Coordinator and downgrade the alert.

3.5.1 **Notification of other parties.** Upon notification from the Energy Deficient Entity that an alert has been downgraded, the Reliability Coordinator shall notify the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers that their systems can be returned to their normal limits.

3.6 **Reporting.** Any time an Alert 3 is declared, the Energy Deficient Entity shall submit the report enclosed in this Attachment to its respective Reliability Coordinator within two business days of downgrading or termination of the alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC website. The Reliability Coordinator shall present this report to the Reliability Coordinator Working Group at its next scheduled meeting.

4. **Alert 0 - Termination.** When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of its Reliability Coordinator that the EEA be terminated.

4.1. **Notification.** The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the affected Balancing Authorities and Transmission Operators. The Alert 0 shall also be posted on the NERC website if the original alert was so posted.

C. Energy Emergency Alert 3 Report

A Deficient Balancing Authority or Load Serving Entity declaring an Energy Emergency Alert 3 must complete the following report. Upon completion of this report, it is to be sent to the Reliability Coordinator for review within two business days of the incident.

Requesting Balancing Authority:

____

Entity experiencing energy deficiency (if different from Balancing Authority):

____

Date/Time Implemented:

____

Date/Time Released:

____

Declared Deficiency Amount (MW):

____

Total energy supplied by other Balancing Authority during the Alert 3 period:

____

Conditions that precipitated call for "Energy Deficiency Alert 3":

____

____

____

If "Energy Deficiency Alert 3" had not been called, would firm load be cut? If no, explain:

____

____

____

Explain what action was taken in each step to avoid calling for "Energy Deficiency Alert 3":

1. **All generation capable of being on line in the time frame of the energy deficiency was on line (including quick start and peaking units) without regard to cost.**

____

____

____

2. **All firm and nonfirm purchases were made regardless of cost.**

____

____

____

3. **All nonfirm sales were recalled within provisions of the sale agreement.**

____

____

____

4. **Interruptible load was curtailed where either advance notice restrictions were met or the interruptible load was considered part of spinning reserve.**

____

____

____

5. **Available load reduction programs were exercised (public appeals, voltage reductions, etc.).**

____

____

____

6. Operating Reserves being utilized.

Comments:

Reported By: **Organization:**

Title:

Emergency Messages from American Electric Power to the Public

This is an Emergency Message from American Electric Power Company.

Demand for electricity is expected to increase as the (*excessive heat and humidity, excessive cold*) continues. AEP asks customers to conserve electricity, if health permits – especially between (*3 p.m .to 7 p.m. - summer, 6 a.m.-9 a.m. and 3 p.m. to 7 p.m. - winter*)

Electricity customers can take simple electricity conservation steps:
- Close curtains and blinds to keep out the sun (*summer*), and
- Postpone using major electric household appliances such as stoves, dishwashers and clothes dryers until the evening hours, and
- If health permits, set air conditioner thermostats higher than usual (summer), or set heating thermostats lower than usual (winter), and
- Turn off electric appliances and equipment that you do not need or are not using.

Conserving electricity will help ensure adequate power supplies. AEP continues to carefully monitor the power supply conditions. It will do everything possible to keep power flowing in the region.

AEP will keep you informed by radio and television announcements until the problem eases.

AEP thanks you for your cooperation.

Figure III-3
Voluntary Load Curtailment Request to the Public

This is a Further Emergency Message from American Electric Power Company.

The power supply problem announced earlier has become critical.

To avoid widespread blackouts it has become necessary to interrupt electric service to customers for periods ranging from 30 minutes to two hours. To minimize inconvenience, the interruptions will take place on a rotating basis: while some areas will be off, others will be on. Later, the areas of outages will be reversed, so that no group of customers will have to bear all of the inconvenience.

Even while your electric service is on, you can help in this emergency by turning off all appliances, lights, radios, and television sets that are not essential. We recommend that you leave at least one electric light in the "on" position so that you'll know when the power is “on” or “off.”

AEP thanks you for your cooperation in helping us to get through this critical time.

Figure III-4
Mandatory Load Curtailment Initiation Announcement to the Public

This is an Emergency Message from American Electric Power Company.

The power curtailment to AEP's customers is continuing. In an effort to lessen the impact of this emergency on all of our customers, the company is alternating the power cut-off among groups of customers for periods ranging from 30 minutes to two hours. Make sure that all appliances are turned off so that, when the power is restored, it will not cause an overload and create further problems. If you are receiving power, please keep your usage to a bare minimum. Full service will be restored just as soon as conditions permit.

AEP regrets that the critical problem it now faces has made these drastic steps necessary, and thanks all of its customers for their cooperation and understanding.

Further announcements will follow as the situation continues to develop.

Figure III-5
Mandatory Load Curtailment Information Statement to the Public

This is a Message from American Electric Power Company.

AEP reports that the critical electric power shortage has now eased, and full-time electric service has been restored to its customers.

If your electric service is still interrupted, please call the appropriate AEP Customer Solutions Center.

AEP thanks you for your cooperation and understanding. We realize the importance of your electric service.

Figure III-6
Capacity Deficiency Termination Statement to the Public

Section IV

Procedures During Abnormal System Frequency

(DOE Report Required if Load is Shed)

Under-frequency Program

Introduction

Precautionary procedures are required to meet emergency conditions such as system separation and operation at subnormal frequency. In addition, the coordination of these emergency procedures with neighboring companies is essential. The AEP program, which is in accordance with SPP Criteria 7, and NERC Standard EOP-002 and EOP-003, is noted below. In the event that a report needs to be filed with the Department of Energy (DOE), NERC, or a Reliability Coordinator, the Security Control Center will prepare those reports and the Transmission Operations Engineering group will review it.

Procedures AEP/PJM

1. From 59.8 - 60.2 Hz to the extent practicable utilize all operating and emergency reserves. The manner of utilization of these reserves will depend greatly on the behavior of the System during the emergency. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.
2. At 59.75 Hz
    a. Suspend Automatic Generation Control (AGC)
    b. Notify Interruptible Customers to drop load
3. At 59.5 Hz automatically shed 5 % System internal load by relay action. (25 cycle, .42 sec. delay)
4. At 59.3 Hz automatically shed an additional 5 % of System internal load by relay action. (25 cycle, .42 sec. delay)
5. At 59.1 Hz automatically shed an additional 5 % of System internal load by relay action. (25 cycle, .42 sec. delay)
6. At 58.9 Hz automatically shed an additional 5 % of System internal load by relay action. (25 cycle, .42 sec. delay)
7. At 58.7 Hz automatically shed an additional 5 % of System internal load by relay action. (25 cycle, .42 sec. delay)
8. At 58.2 Hz automatically trip the D.C. Cook Nuclear Units 1 and 2.
9. At 58.0 Hz or at generator minimum turbine off-frequency value, isolate generating unit without time delay.

Automatic Load Shedding Program Specifications

A. Load shedding relays should be accurate to +/- .01 Hz with contact provisions for tripping and automatic restoration. They can be static relays or digital devices and the automatic restoration can be by timer or supervisory control.

B. General guidelines for relay installation are:
   1. A feeder load of 3 MWs or a total station load of 6 MW should be controlled by each static relay or digital device.
   2. Total load to be controlled by load shedding relays should equal 25 % of System internal load.
   3. Under-frequency relays should only be installed on generators or tie lines where necessary; such as, at the D.C. Cook Nuclear Plant.

C. The System is to be designed to provide for manually directed or automatic restoration as follows:
   1. Frequency is to be manually directed to return to 60 Hz by the SCC in conjunction with the MO and interconnections.
   2. Load should be restored only when spinning reserve equals three times the restoration block and due consideration is given to possible automatic reclosing of interconnections by check synchronizing schemes.
   3. Restoration blocks will be determined by:
      a. Automatic Restoration - time delay elements in series with relay reclose contact settings
         i. Both the straight time and integrating timers must complete their sequences before a load block will be restored.
      b. Supervisory Control
         i. UF trip only, no automatic restoration
   4. Each restoration block should represent one percent of system internal load. If a station does not have supervisory control but is located in a metropolitan area, the automatic restoration feature can be disabled and the feeder can be set for a UF trip only.
   5. The restoration frequency should be 59.95 Hz. The time delay settings are shown in the table below:

Load Restored	**Integrated Time at or above 59.95 Hz**	**Straight Time at 59.95 Hz**
1st Block - 1%	4 minutes	1 seconds
2nd Block - 1%	4 minutes	2 seconds
3rd Block - 1%	4 minutes	3 seconds
4th Block - 1%	6 minutes	4 seconds
5th Block - 1%	6 minutes	5 seconds
6th Block - 1%	6 minutes	6 seconds
7th Block - 1%	8 minutes	7 seconds
8th Block - 1%	8 minutes	8 seconds
9th Block - 1%	8 minutes	9 seconds
10th Block - 1%	8 minutes	10 seconds
11th Block - 1%	10 minutes	11 seconds
12th Block - 1%	10 minutes	12 seconds
13th Block - 1%	10 minutes	13 seconds
14th Block - 1%	10 minutes	14 seconds
15th Block - 1%	10 minutes	15 seconds
16th Block - 1%	12 minutes	16 seconds
17th Block - 1%	12 minutes	17 seconds
18th Block - 1%	12 minutes	18 seconds
19th Block - 1%	12 minutes	19 seconds
20th Block - 1%	12 minutes	20 seconds
21st Block - 1%	14 minutes	21 seconds
22nd Block - 1%	14 minutes	22 seconds
23rd Block - 1%	14 minutes	23 seconds
24th Block - 1%	14 minutes	24 seconds
25th Block - 1%	14 minutes	25 seconds

Table IV-1
Restoration Blocks - Time Delay Settings

Note: An additional 30 second integrated timer setting is normally applied to the older style mechanical relays.

D. Management of the data and information system relative to the continuing status of the load shedding program is the responsibility of Transmission Operations.

If at any time in the above procedure the decline in area frequency is arrested below 59.5 Hz, an evaluation will be made as to whether the area should manually shed an additional 5 % of its initial load. If, after five minutes, this action has not returned the area frequency to 59.5 Hz or above, the area shall manually shed an additional 5 % of its remaining load and continue to repeat in five-minute intervals until 59.5 Hz is reached. These steps must be completed within the time constraints imposed upon the operation of generating units that are discussed in the subsection: Isolation of Coal-fired Generating Units.

If the recommended limits are exceeded, the subcritical units capable of load rejection should be disconnected by the operation of each unit's generator circuit breaker control switches. The operation should then be continued on a self-supporting basis with the unit carrying its own auxiliaries until such time as it can be reloaded or circumstances suggest that the unit be shut down. The generator voltage regulator must be in service before attempting load rejection; otherwise turbine trip and not load rejection should be applied.

Units not capable of load rejection (supercritical units) should be tripped by operation of the turbine trip switch, which would both avoid the possibility of overspeed as well as result in a transfer of auxiliaries (even at depressed frequencies) which will allow a more orderly shutdown of that unit.

It is important that units not be tripped prematurely when the frequency is declining, as such action will cause the system frequency to decline further.

During any System disturbance involving a declining frequency, the power plant operator should establish communication with the Market Operations (MO). The intent of this recommendation is to assure coordinated restoration procedures. If this attempt with the MO is not successful, communication with the assigned TDC (Transmission Dispatch Center) should be established or, if this fails, with the SCC.

Nothing in the above noted points is intended to alter normal safe operating procedures and good operating judgment.

Procedures AEP/SPP

1. From 59.8 - 60.2 Hz to the extent practicable utilize all operating and emergency reserves. The manner of utilization of these reserves will depend greatly on the behavior of the System during the emergency. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.
2. At 59.75 Hz
   a. Suspend Automatic Generation Control (AGC)
   b. Notify Interruptible Customers to drop load
3. At 59.4 Hz Tulsa unit #3 (3C, 3D, 3E – total 78 Mw) will automatically trip off-line in 180 seconds. This is a 1926 vintage unit that is seldom run, and consequently will not have a significant impact on our plan.
4. At 59.3 Hz automatically shed 10 % of System internal load by relay action. (15 cycle, .25 sec. delay)
5. At 59.0 Hz automatically shed 10 % of System internal load by relay action. (15 cycle, .25 sec. delay)
6. At 58.7 Hz automatically shed 10 % of System internal load by relay action. (15 cycle, .25 sec. delay)
7. At 58.5 Hz isolate into islands in both PSO and SWEPCO (15 cycle, .25 sec. delay)
   c. PSO - 3 Islands, Refer to PSO UF plan for island boundaries
   d. SWEPCO – 3 Islands, Refer to SWEPCO UF plan for island boundaries.
8. At 58.0 Hz or at generator minimum turbine off-frequency value, isolate generating unit without time delay.

Step 7 has been developed to isolate systems into islands by opening predetermined interconnect tie lines. The intention of this step is to stabilize generating units, prevent there cascading shut down, and speed restoration of service after frequency has returned to normal. Each of these islands contains multiple generating units belonging to AEP and/or adjacent companies and loads of one or both companies to ensure an island with natural boundaries and a high probability of successful islanding. The probability of successfully maintaining generation stability greatly depends upon the proper matching of the load within each particular island to the attached generator outputs. With the fluctuation of system load varying from maximum summer peak value to 30% of this value at minimum load, the challenge of maintaining unit stability under these load conditions is complicated. Therefore, the following maximum and minimum criteria should be applied to each island:

- The load, at its maximum peak, within an island shall not exceed the total maximum output ratings of the generating units likely to be operating during that time within that island.
- The load, at its minimum level, within an island shall not be less than the minimum output of the smallest unit likely to be operating during that time within that island.

Additionally, the following objectives should be targeted for each island:

- Minimize the percent of time the total load within an island exceeds the maximum total of the ratings of all generating units except the largest within that island.
- Minimize the percent of time the total load within an island is less than the minimum rating of the next to smallest generating unit within that island.
- When both targets above cannot be met, the plan should favor the maximum load conditions in recognition that an underfrequency condition is more likely to occur and the consequences are more serious at maximum load conditions.

Load flow simulations are used to determine that after each step of the plan has operated, the electric system remaining in service will perform successfully within normal and emergency criteria until normal service can be restored to all loads.

Isolation of Coal-Fired Steam Turbine Generation Units

The basic approach to handling sustained frequency deviations on the System is:

1. Utilize emergency capacity resources. (Refer to Section III.)
2. Maintain generating units in service, while attempting to restore the balance between generation and load, until the system frequency excursion exceeds the allowable limits for safe turbine operation as listed in the following subsection: Turbine Off-Frequency Operation.
3. Load-reject subcritical units and trip supercritical units if the system frequency exceeds the allowable limits for the turbine, and be prepared for restoration procedures.

   Since any significant frequency deviation would be accompanied by system separation, it is not possible for any one-control center to direct unit isolation. It is the responsibility of each unit operator to prevent or minimize potential damage to the unit by disconnecting the unit from the System should the frequency excursions exceed the recommended limits noted in the following subsections.

.

Constant Frequency Operations Guide For Fossil Generating Units

Purpose

The purpose of this guide is to describe the AEP System strategy for fossil generating unit operation during a system frequency disturbance.

In most cases, the Market Operations (MO) would direct the response of the generating units to a system frequency disturbance by contacting unit control room operators and requesting the appropriate action**. As long as communications exists with the MO and/or the SCC or TDC, the unit operators should not take individual action.** This guide, however, assumes that a frequency disturbance is experienced in combination with a total loss of communications between the power plants and the MO, and the SCC and TDC. Under these conditions, a predetermined operating strategy is required which coordinates generating unit responses, without integrated instructions from the MO, in order to allow the bulk power system to continue operating in a stable mode.

This guide describes a strategy for fossil generating units to provide a staged, gradual response to frequency deviations without the power plant operators receiving any instructions from MO. This strategy is designed to keep system frequency within reasonable limits while minimizing oscillations that could be caused by individual generating units attempting to operate in a constant frequency mode without centralized guidance.

This guide is not intended to prevent generating unit operators from taking whatever actions are necessary to protect their equipment from potential damage due to off-frequency operation. Limits for allowable off-frequency operation of fossil generating units should be strictly followed to prevent equipment damage. Short term instabilities and power grid outages can only be made worse if permanent damage is allowed to occur to system equipment. The procedures in this guide apply to fossil generating units only. Where possible, hydro units should maintain load during a system frequency disturbance.

Assumptions

The basic assumptions made in the development of this guide are:

Loss of Communications – all primary and backup data and voice communication channels are lost between the generating units and the MO, and the SCC and TDC..

Generating Unit Status – sufficient generating capacity remains in service to serve the load over the period of lost communications.

Transmission System Status – transmission system congestion does not impose significant constraints on generation unit maneuvering or on providing load service.

Instrumentation – generating units are equipped with frequency metering devices capable of displaying the local system frequency on a wide range (roughly 58.0 Hz to 62.0 Hz).

Constant Frequency Operations

General

If communications are lost between a generating unit and the MO and the SCC and TDC, the only information available to the generating unit operator will be frequency as measured locally by plant instrumentation. Under these conditions, the generating unit operator may not be able to determine if the entire grid is still intact or if he is operating as part of a local island. Therefore, any constant frequency operating strategy must function equally well with either an intact grid or with conditions where the grid has broken into islands of generation and load.

In order to restore system frequency and maintain stable system operations, it may be necessary to maneuver generation to match load. During a System disturbance which results in a frequency deviation, the generating units will automatically provide an immediate and sustained response to increase or decrease unit output based upon the settings of the turbine governor and unit controls. Depending upon the cause and magnitude of the frequency deviation, the initial automatic response of the units may not be sufficient to restore System frequency to 60 Hz. By design, turbine governors provide a proportional action only and therefore may steady out at some frequency other than 60 Hz if the load to generation match is not restored. If frequency is not restored by the initial governor action, additional changes in unit generation may be required and should be initiated by the unit operator in accordance with the procedures listed below.

Procedures

Use these procedures only when AGC and all voice communications with the MO and the SCC and TDC have been lost. All means of backup communications should be utilized to reach the MO, SCC and TDC before proceeding with the following actions. As long as communications exists with the MO, the SCC or TDC, the unit operators should not take individual action.

1. As long as frequency remains within a dead band around 60.00 Hz, no control actions should be taken by the generating unit operator to change unit generation beyond sustaining the initial response of the turbine governor and unit controls. For the AEP System, this frequency dead band will be from 59.80 Hz to 60.20 Hz, as shown on Chart 1. When frequency is within this dead band, the unit operator should allow the governor to control unit output and should make no additional corrections to the unit that will affect generation.

2. As frequency moves outside the dead band, the unit operator should manually load or unload the unit in gradual increments in order to avoid overcorrecting and possibly initiating a frequency oscillation. The approximate total generation change required can be given by the formula:

   Mws = 10 ß (F_A – F_S) where ß = - 218 AEP/PJM,

   and ß = - 94 AEP/SPP

   ß = Frequency Bias, **F_A** = Frequency Actual, and **F_S** = Frequency Scheduled

   As an example, if the AEP/PJM System frequency declines to 59.7 Hz, and the frequency needs to be increased to 59.85 Hz (within dead band)

   Mws = 10 * (-218)(59.7-59.85) = -2180 * -.15 = 327
   Therefore, the AEP/PJM generation would need to increase 327 Mws to cause a .15 Hz increase in frequency.

   While making the appropriate load change, the unit operator should carefully observe frequency and should cease maneuvering the unit when frequency enters the dead band. Stopping within the dead band for some period of time will prevent overshooting or hunting for 60 Hz since the response time of various units to change output will be different and thus, not all units may simultaneously be affecting frequency. Operators should understand that it is not necessary to reach exactly 60.00 Hz but only to attempt to remain in the dead band.

3. After providing the initial manual response, the unit operator should maintain a steady unit output and should continue to closely monitor System frequency. If frequency remains outside the dead band, unit generation should continue to be adjusted in accordance with Table 1 approximately every 5 minutes until frequency enters the dead band.

4. Following the above steps, if frequency still remains outside of the dead band, the generating unit should continue to be maneuvered until reaching its appropriate limit, either fully loaded in the case of a low frequency deviation or at minimum load in the case of a high frequency deviation.

5. If frequency conditions continue to deteriorate, it may be necessary for the unit operator to separate from the grid in order to protect generating unit equipment. Limits for allowable off-frequency operation of fossil generating units should be strictly followed to prevent equipment damage.

   While it is desirable to maintain service continuity, it is imprudent to allow generating unit equipment to suffer major damage that would impede the restoration of service after a major disturbance. However, it is important that the unit not be prematurely tripped when the frequency is declining, as such action will cause the system frequency to decline further. If the system frequency excursion exceeds allowable off-frequency limits, corrective action should be taken as follows.

   - For subcritical units that are capable of load rejection, load reject and secure the unit in an islanded mode until communications are restored and further instructions are received from the SCC and/or MO. Turbine speed should be adjusted back to near 3600 rpm (60 Hz) after separating from the grid.

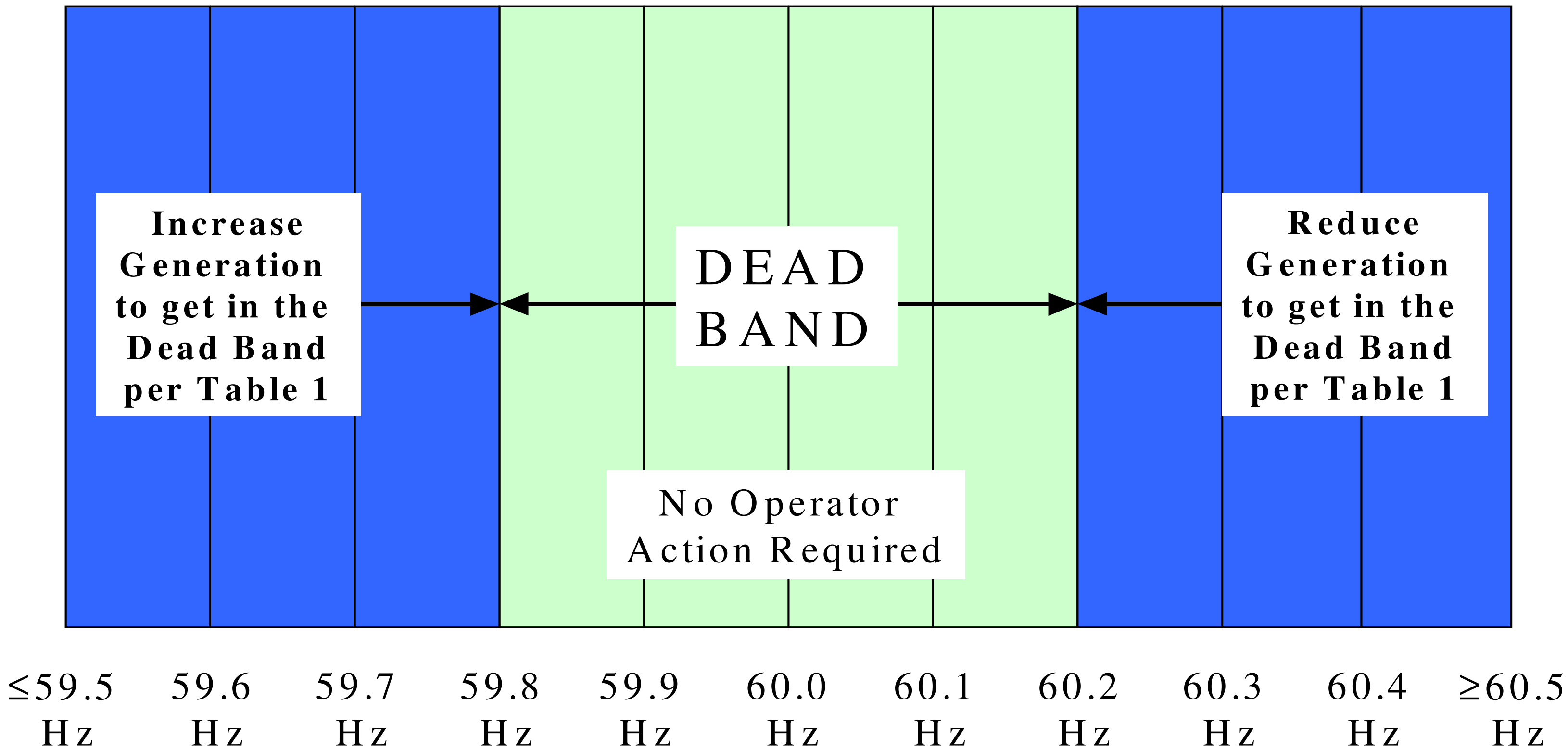
   - For subcritical units incapable of load rejection and for all supercritical units, trip and secure the unit on turning gear until system restoration procedures can be implemented.

6. Units which have been successfully load rejected should not be resynchronized to the grid to address frequency deviation except as directed by the SCC after communications have been restored. It is a higher priority that these units are maintained in an islanded condition in order to support system restoration (Black Start) procedures.

	Turbine Speed (RPM)	
Freq. (Hz)	2-poles	4-poles
59.5	3570	1785
59.6	3576	1788
59.7	3582	1791
59.8	3588	1794
59.9	3594	1797
60.0	3600	1800
60.1	3606	1803
60.2	3612	1806
60.3	3618	1809
60.4	3624	1812
60.5	3630	1815

Chart 1
AEP System
Constant Frequency Operations Guide

1. Use this guide only when all communications have been lost with the SCC
2. Refer to Section IV of the AEP Emergency Operating Plan for allowable off-frequency operating limits



Turbine Off-Frequency Operation

Introduction

The primary consideration for operating a steam turbine generator under loaded condition at other than rated frequency (60 Hz) is protection of the tuned rotating blading at the exhaust end of the low-pressure turbine. In most fossil applications, this may include the last two to three stages (L-0, L-1, and L-2 stages) of blading. Operation with these stages under load at a speed that results in the coincidence of a blading natural frequency and a multiple of actual turbine running speed frequency will lead to blading fatigue damage. Fatigue damage is cumulative over blading service life and will ultimately lead to failure and unit forced outages.

In order to prevent blading fatigue damage, turbine operation at other than rated frequency (hereafter referred to as off-frequency) should be limited. Typically, turbine blading will have an off-frequency range that allows for continuous operation without the potential for blading fatigue damage. Additionally, another off-frequency range or ranges is defined where total accumulated time is limited such that blading fatigue damage is not sufficient to initiate a failure.

The purpose of this subsection is to provide plant operators with recommendations that establish allowable deviation from rated frequency for steam turbine generators under loaded conditions. It is the responsibility of each fossil unit operator to monitor and respond to system frequency excursions in order to prevent blading fatigue damage. .

Recommendations for turbine off-frequency operation contained in this subsection are provided for each of the AEP system units, listed under their respective original equipment manufacturer. Operating parameters defined in the text on the following pages take into account that frequency limitations are applicable to the turbine generator equipment during load operation only and as such do not apply to no-load operation during startup. However, these instructions do apply to units that are operating in a load rejected or islanded mode, and action should be taken to restore and maintain turbine speed at 3600 rpm for these units after separating from the grid.

AEP/PJM - Turbine Generator Units

The following pages provide listings of AEP/PJM Region units and recommendations for each group of units, based on their original equipment manufacturer. The original equipment manufacturers are:

- ABB
- General Electric
- Westinghouse

ABB Turbine Generator Units

These units use the ABB Turbine Generators:

- Cardinal 3
- Amos 3
- Gavin 1 and 2
- Mountaineer 1
- Rockport 1 and 2

Allowable Turbine Speed Range	Allowable Frequency Range	Comments
3420 rpm - 3816 rpm	57 Hz - 63.6 Hz	Unlimited (continuous) operation permitted.
Below 3420 rpm	Below 57 Hz	Operation in this speed (frequency) range not to exceed 10 seconds per occurrence.

Table IV-3
Recommendations for ABB Turbine Generators

General Electric Turbine Generator Units

These units use the General Electric Turbine Generators:

- 600 MW Series
  - Cardinal 1 and 2
  -
- 800 MW Series
  - Amos 1 and 2
  - Mitchell 2

Westinghouse Turbine Generator Units

There are two separate sets of recommended turbine off-frequency operating parameters applicable to the Westinghouse turbine-generator sets on the AEP system. These recommended operating limitations are a function of LP turbine last stage blade length and design. This subsection separates recommendations for applicable units according to last stage blade design.

These units use the Westinghouse Turbine Generators with 18, 20, 23, 25 and 26 Inch LP Ends and 32 Inch Ruggedized LP Ends:

- Big Sandy 1
- Conesville 4, 5 and 6

Allowable Turbine Speed Range	Allowable Frequency Range	Comments
3510 rpm – 3690 rpm	58.5 Hz - 61.5 Hz	Continuous operation in this speed (frequency) range permitted.
3360 rpm – 3510 rpm	56 Hz – 58.5 Hz	Operation in this speed (frequency) range not to exceed 10 minutes cumulative time over the life of the LP blading.

Table IV-5
Recommendations for Westinghouse Turbine Generators
18, 20, 23, 25 and 26 Inch LP Ends and 32 Inch Ruggedized LP Ends

These units use the Westinghouse Turbine Generators with 28.5 through 44 Inch LP Ends:

- Mitchell 1

Allowable Turbine Speed Range	Allowable Frequency Range	Comments
3570 rpm - 3630 rpm	59.5 Hz - 60.5 Hz	Continuous operation in this speed (frequency) range permitted.
3510 rpm - 3570 rpm	58.5 Hz - 59.5 Hz	Operation in this speed (frequency) range not to exceed 60 minutes cumulative time over life of the unit.
3360 rpm - 3510 rpm	56 Hz - 58.5 Hz	Operation in this speed (frequency) range not to exceed 10 minutes cumulative time over life of the unit.

Table IV-6
Recommendations for Westinghouse Turbine Generators
28.5 Through 44 Inch LP Ends

AEP/SPP - SWEPCO Region Turbine Generator Units

The following pages provide listings of AEP/SPP SWEPCO Region units and recommendations for each group of units, based on their original equipment manufacturer. The original equipment manufacturers are:

- General Electric
- Westinghouse

General Electric Turbine Generator Units

These units use the General Electric Turbine Generators:

- Arsenal Hill 5
- Flint Creek 1
- Knox Lee 4
- Knox Lee 5
- Lieberman 1
- Lieberman 2
- Lone Star 1
- Wilkes 1
- Wilkes 2
- Wilkes 3

Allowable Turbine Speed Range	Allowable Frequency Range	Comments
3564 rpm - 3636 rpm	59.4 Hz – 60.6 Hz	Unlimited (continuous) operation permitted.
3528 rpm - 3564 rpm 3636 rpm - 3672 rpm	58.8 Hz – 59.4 Hz 60.6 Hz - 61.2 Hz	Operation in this speed (frequency) range to be less than 90 minutes cumulative time over the life of the LP blading.
3492 rpm - 3528 rpm 3672 rpm - 3708 rpm	58.2 Hz – 58.8 Hz 61.2 Hz – 61.8 Hz	Operation in this speed (frequency) range to be less than 10 minutes cumulative time over the life of the LP blading.
3456 rpm - 3492 rpm 3708 rpm - 3744 rpm	57.6 Hz – 58.2 Hz 61.8 Hz - 62.4 Hz	Operation in this speed (frequency) range to be less than 1 minute cumulative time over the life of the LP blading.

Table IV-7
Recommendations for SWEPCO Region General Electric Turbine Generators

Westinghouse Turbine Generator Units

There are two separate sets of recommended turbine off-frequency operating parameters applicable to the Westinghouse turbine-generator sets in SPP Region 5. These recommended operating limitations are a function of LP turbine last stage blade length and design. This subsection separates recommendations for applicable units according to last stage blade design.

These units use the Westinghouse Turbine Generators with 20, 23, or 25 Inch LP Ends.

- Knox Lee 2
- Knox Lee 3
- Lieberman 3
- Lieberman 4
- Welsh 1
- Welsh 2
- Welsh 3

Allowable Turbine Speed Range	Allowable Frequency Range	Comments
3510 rpm – 3690 rpm	58.5 Hz - 61.5 Hz	Continuous operation in this speed (frequency) range permitted.
3360 rpm – 3510 rpm	56.0 Hz – 58.5 Hz	Operation in this speed (frequency) range not to exceed 10 minutes cumulative time over the life of the LP blading.
<3360 rpm - >3690 rpm	<56.0 Hz or > 61.5 Hz	Trip Unit Immediately

Table IV-8
Recommendations for SWEPCO Region Westinghouse Turbine Generators
20, 23, or 25 Inch LP Ends

These units use the Westinghouse Turbine Generators with 28.5 Inch LP Ends:

- Pirkey 1
- Dolet Hills 1

Allowable Turbine Speed Range	Allowable Frequency Range	Comments
3570 rpm - 3630 rpm	59.5 Hz - 60.5 Hz	Continuous operation in this speed (frequency) range permitted.
3510 rpm - 3570 rpm	58.5 Hz - 59.5 Hz	Operation in this speed (frequency) range not to exceed 60 minutes cumulative time over life of the unit.
3360 rpm - 3510 rpm	56.0 Hz - 58.5 Hz	Operation in this speed (frequency) range not to exceed 10 minutes cumulative time over life of the unit.
<3360 rpm - >3690 rpm	<56.0 Hz or > 61.5 Hz	Trip Unit Immediately

Table IV-9
Recommendations for SWEPCO Region Westinghouse Turbine Generators
28.54 Inch LP Ends

AEP/SPP - PSO Region Turbine Generator Units

The following pages provide listings of AEP/SPP PSO Region units and recommendations for each group of units, based on their original equipment manufacturer. The original equipment manufacturers are:

- ABB
- General Electric
- Westinghouse

<u>General Electric Turbine Generator Units</u>

These units use the General Electric Turbine Generators.

- Northeastern 2
- Northeastern 3
- Northeastern 4
- Riverside 2

Allowable Turbine Speed Range	Allowable Frequency Range	Comments
3564 RPM - 3636 RPM	59.4 Hz - 60.6 Hz	Continuous Operation
3636 RPM - 3672 RPM 3564 RPM - 3528 RPM	60.6 Hz - 61.2 HZ 59.4 Hz - 58.8 Hz	Operation in this speed (frequency) range not to exceed 100 minutes cumulative time over the life of the machine
3672 RPM - 3708 RPM 3528 RPM - 3492 RPM	61.2 Hz - 61.8 Hz 58.8 Hz - 58.2 Hz	Operation in this speed (frequency) range not to exceed 10 minutes cumulative time over the life of the machine
3708 RPM - 3744 RPM 3492 RPM - 3456 RPM	61.8 Hz - 62.4 Hz 58.2 Hz - 57.6 Hz	Operation in this speed (frequency) range not to exceed 1 minutes cumulative time over the life of the machine
More than 3744 RPM Less than 3456 RPM	More than 62.4 Hz Less than 57.6 Hz	Trip Unit Immediately

Table IV-10
Recommendations for PSO General Electric Turbine Generators

<u>Westinghouse and ABB Turbine Generator Units</u>

These units use the Westinghouse Electric Steam Turbine Generators.

- Northeastern 1
- Southwestern 1
- Southwestern 2
- Tulsa 2
- Tulsa 3
- Tulsa 4

Allowable Turbine Speed Range	**Allowable Frequency Range**	**Comments**
3510 rpm - 3690 rpm	58.5 Hz - 61.5 Hz	Continuous Operation
3690 rpm - 3780 rpm 3510 rpm - 3420 rpm	61.5 Hz - 63.0 HZ 58.5 Hz - 57.0 Hz	Operation in this speed (frequency) range not to exceed 10 minutes cumulative time over the life of the machine
More than 3780 rpm Less than 3420 rpm	More than 63.0 Hz Less than 57.0 Hz	Trip Unit Immediately

Table IV – 11
Recommendations for PSO Westinghouse Steam Turbine Generators

These units use the Westinghouse Electric Turbine Generators.

- Comanche Steam Turbine (ST-1)
- Riverside 1
- Southwestern 3

Allowable Turbine Speed Range	Allowable Frequency Range	Comments
3570 rpm - 3630 rpm	59.5 Hz - 60.5 Hz	Continuous Operation
3630 rpm - 3690 rpm 3570 rpm - 3510 rpm	60.5 Hz - 61.5 HZ 59.5 Hz - 58.5 Hz	Operation in this speed (frequency) range not to exceed 60 minutes cumulative time over the life of the machine
3690 rpm - 3780 rpm 3510 rpm - 3420 rpm	58.5 Hz - 57.0 Hz 58.5 Hz - 57.0 Hz	Operation in this speed (frequency) range not to exceed 10 minutes cumulative time over the life of the machine
More than 3780 rpm Less than 3420 rpm	More than 63.0 Hz Less than 57.0 Hz	Trip Unit Immediately

Table IV – 12
Recommendations for PSO Westinghouse Turbine Generators

These units use the Westinghouse Electric and ABB Gas Turbine Generators.

- Comanche GT 1
- Comanche GT 2
- Weleetka GT 4
- Weleetka GT 5
- Weleetka GT 6

Allowable Turbine Speed Range	**Allowable Frequency Range**	**Comments**
3480 rpm - 3720 rpm	58.0 Hz - 62.0 Hz	Continuous Operation
3720 rpm - 3840 rpm 3480 rpm - 3360 rpm	62.0 Hz - 64.0 HZ 58.0 Hz - 56.0 Hz	Operation in this speed (frequency) range not to exceed 10 minutes cumulative time over the life of the machine
More than 3840 rpm Less than 3360 rpm	More than 64.0 Hz Less than 57.0 Hz	Trip Unit Immediately

Table IV – 13
Recommendations for PSO Westinghouse and ABB Gas Turbines

Section V

Fuel Limitations

Introduction

The purpose of this plan is to provide information on fuel limitations so that decisions can be made to manage fuel inventories in the event of a fuel shortage, such as might result from a general strike, or severe weather. In addition, fuel switching is considered for certain operating conditions. Fuel supply emergencies having an impact on the Bulk Electric System require an OE-417 report to DOE. Refer to section IX of the EOP for details. In the event that a report needs to be filed with the Department of Energy (DOE), NERC, or a Reliability Authority, the Transmission Operations Engineering group can assist in preparing these reports.

NERC EOP-001-2.1b requires an emergency plan for fuel supply and inventory.

AEPE/PJM Reporting Procedures

(Excerpts from PJM manual M13 rev58 §6.4**, M14D rev35** §7.3, and M36 rev22 §6.1.4**)**

Seasonal Reporting

Prior to going into the winter season, PJM will notify and request from all members with capacity resources, by unit report of fuel information. Additionally this information may be requested at other intervals as deemed necessary such as a fuel crisis (i.e., embargo, strike) or forecasted period of severe cold weather.

An electronic spreadsheet will be sent to participants indicating required data (see Sample Fuel Baseline Data exhibit below). The required data will include information such as each unit's:

- Available primary fuel
- Available secondary fuel
- Projected fuel inventory (in terms of MWh)
- Typical fuel inventory (in terms of MWh)
- Average amounts of fuel per delivery
- Delivery frequency
- Amount of firm gas schedules

While some of this data may represent broad projections, it will assist in providing a baseline that can be compared to data submitted in the real-time reporting process to assist in determining the severity of specific emergency conditions.

Fuel Baseline Data DATE: 1/30/01

Company	Plant Name	Unit Type	Winter (kW)	Primary Fuel		Alternate Fuel		Primary Fuel Availability (MW-Hours)	Primary Average Fuel Availability (MW-Hours)	Alternate Fuel Availability (MW-Hours)	Alternate Average Fuel Availability (MW-Hours)	Gas Schedules (% of Firm)	Average Delivery Amount	Delivery Frequency	Comments
				Fuel Type	Transport Method	Fuel Type	Transport Method								
Company A	Unit 1	GT	7,000	NG	PL	KER	TK	1200	1400	670	470	97%	35	3DAY	
Company A	Unit 2	ST	10,000	FO6	RR			2000	1800				60	5DAY	

Sample Data

Real-Time Reporting

When PJM receives a severe cold weather forecast or foresees a potential fuel crisis (i.e. embargo, strike), real-time updates of fuel limited units will be requested of members via Part G of the Supplementary Status Report (see *Attachment C* of ***PJM Manual for Emergency Operations-M13***). This data will also be reported in other situations when a Supplementary Status Reports is requested, such as Capacity Shortage emergencies. Contact the PJM Master Coordinator (610-666-8809) with questions or concerns. Real-time reporting of fuel deficiencies (outside of a SSR request) can be reported directly to the PJM Master Coordinator.

A unit is considered fuel limited when it is not capable at running at its maximum capacity for the next 72 hours. If a unit has an alternate fuel which would allow it to run at its maximum capacity for more then 72 hours, it does not need to be reported. However, if switching fuels involves a shut down and introduces the risk of the unit not being able to re-start after the switch, the unit should be reported if its primary fuel supply would produce less then 72 hours of runtime at maximum capacity. Besides fuel, the limitation of other resources, such as water, may also restrict the amount of time a unit will be able to operate. If a unit has less then 72 hours of run time at maximum capacity due to any resource limitation, it along with any fuel limited units should be reported in Part G, "Resource Limited Units," of the Supplementary Status Report (see Attachment C of ***PJM Manual for Emergency Operations-M13***). The following information should be included:

- Unit Name - The name of the unit(s) (units with shared resource supplies should be listed together) that are considered resource limited.
- Fuel type
- Maximum Capacity - The current maximum capacity of the unit(s).
- Emergency Minimum - If a unit cannot cycle due to uncertainty of starting up again, Emergency Minimum must be included with a note in the Comments section.
- Current Energy - Current MW output.
- Total Burn Hours Remaining - Total burn hours remaining with unit at max capacity.
- Comments - If a unit is limited for a resource other the fuel, this should be noted in this column as well as any other pertinent information on the unit.

In addition to unit information submitted to PJM via Part G of the SSR, members should also monitor fuel inventories for the following minimum levels:

- Diesels - Less then or equal to 16 hours at maximum capacity
- Gas CT – Less then or equal to 8 hours at maximum capacity.
  - Generation dispatchers should inform PJM dispatch if gas limitation is daily.
- Steam - Less then or equal to 32 hours at maximum capacity

In the event the above levels are reached, generation owners must immediately report this to the PJM Master Coordinator (610) 666-8809

PJM's use of Fuels Data

PJM uses the fuel data in conjunction with the other data reported in the SSR to evaluate system conditions. Reports such as the PJM System Status Report (see Attachment C of the ***PJM Manual for Emergency Operations-M13***) are compiled. Some portions of the reports are posted electronically via the internet or faxed to members so all members can assess the severity of the impending weather and available generation capacity. Additionally reports derived from this information are used to lead strategy discussions among SOS members about the criticality of the situation and to determine the timing of various emergency procedures that may be used.

An invitation may also be posted to other members to attend a PJM SOS conference call to discuss the meaning of this data and how it may result in various emergency procedures.

PJM treats confidential the information on individual units or company data in accordance with PJM's OATT and Operating Agreement. Discussions on individual units or company's fuel status will only occur between PJM and the generation owners who provided the data. During group discussions, PJM will only discuss what possible emergency actions are foreseen or what aggregate fuel crisis exists.

Unit specific Fuel Limitation Information is considered proprietary and confidential, and will not be distributed amongst participants. Only aggregate information will be discussed for the sole purpose of developing reliable operating strategies during projected capacity deficient conditions.

Operation of Fuel Limited Units

PJM requests companies that have units classified as fuel or resource limited units to bid these units in the Max Emergency category. This will serve to preserve these resources for the times when they are needed most. If a unit bid into PJM has resources of less than 32 hours (at maximum capacity) for a steam unit, 16 hours (at maximum capacity) for a Oil, Kerosene, or Diesel CT, or 8 hours (at maximum capacity) for a gas fired CT, and PJM has issued Conservative Operations, a Cold or Hot Weather Alert, then the unit **must** be bid in the Max Emergency category, unless directed not to do so by PJM Dispatch.

PJM will continue to schedule system generation based upon the Two Pass methodology and generator owner's individual bids. If PJM has particular concerns over units deemed critical to current or future system conditions, then PJM will initiate individual communications with the members responsible for those units.

If PJM asks a unit to operate differently then what was accepted in the day-ahead market (in order to conserve the unit's current fuel), then this unit would be paid its lost opportunity cost for the accepted hours that it was not run. (Reference Operating Agreement, section 3.2.3, (e), (f)).

<u>Fuel Switching</u>

1. For the purpose of this document, boiler fuel oil (AEP/PJM Units) is not considered a primary or secondary fuel and consequently, fuel switching is not an option. For the AEP/PJM units #2 fuel oil is used for the following purposes.
    a. Unit Start Up
    b. Unit Shut Down
    c. Placing into service and removing from service primary fuel equipment, i.e. pulverizers and cyclones.
    d. Flame stabilization during periods of extreme low load operation.
    e. Flame stabilization as required for the combustion of low quality fuels.
2. Inventory targets have been developed on a per plant basis for the above purposes based upon historical consumption, plant/unit specific characteristics, delivery method (truck or barge) and seasonal supply constraints (road/river conditions). Additional fuel oil supplies will be purchased to supplement currently available fuel oil inventories at the respective generating stations for the duration of the fuel oil burning period.
3. In the event of a potential fuel shortage, which may be caused by extreme weather conditions or other emergencies, appeals will be made to large industrial and commercial customers, as well as, government agencies to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

<u>System Restoration</u>

PJM System Restortion Manual 36 rev 22 Attachment A: Minimum Critical Black Start Requirement – Generation Owners must notify PJM and Transmission Owners if a critical blackstart fuel resource at maximum stated output falls below 10 hours.

AEPW/SPP Reporting Procedures

(Excerpts from §5 of **SPP Emergency Operating Plan dated September 1, 2015 and** SPP CRITERIA 5.2.1.1)

As mentioned previously, the purpose of this plan is to provide information on fuel limitations so that decisions can be made to manage fuel inventories in the event of a fuel shortage, such as might result from a general strike, or severe weather.

Fuel Supply and Inventory (SPP Emergency Operating Plan section 5.1)

SPP requires adequate and reliable Resource fuel supply and inventory in order to reliably operate the SPP BA. SPP needs data related to limited fuel supplies, including those for switchable dual fuel generation resources.

SPP requires that data regarding fuel supply impacted by seasonal changes be submitted for all Resources in the Balancing Authority. On a forecasted and real-time basis, GOPs within the SPP BAA shall notify SPP via CROW and the Markets UI/API of any generation de-rates. The parties submitting the information shall indicate when the de-rate is a result of an OFO, Critical Notices, or fuel delivery constraint and indicate which pipeline(s) or delivery constraints are impacting them.

Operations of Fuel-Limited Resources (SPP Emergency Operating Plan section 5.1.4)

Resources offered into the SPP Integrated Marketplace that are experiencing a limited fuel situation are to adhere to the following guidelines if SPP BA is operating in conservative operartions:

- Combustion Turbines units in Reliability Status are reserved for emergency conditions when their medium term (48 hour) fuel supply is expected to last less than 16 hours at rated output or there are other known limitations that may restrict these units from operating within their reliable resource limitations.
    - The concept of 16 hours is predicated on the fuel being available during the two day period and operating the resource equal to four 4-hour peak load periods over a 2-day period. Depending on the situation, Resources may be forced out of service (full or partial) prior to these guidelines in order to protect plant equipment or for future system needs.
- Oil-fired steam units in Reliability Status are removed from economic dispatch and reserved for emergency conditions when their fuel inventory is less than 32 hours at rated output.
    - The concept is that 32 hours at rated output equals two 16-hour periods over a 2-day period. Depending on the situation, Resources may be forced out of service (full or partial) prior to these guidelines in order to protect

plant equipment or for future system needs.

- As coal-fired steam units generally have considerable fuel reserves on site, placement of coal units in Reliability Status will be considered if coal reserves are less than 20 days at minimum generating capacity. The ultimate decision will be handled on a case-by-case basis based on system conditions and with appropriate coordination between SPP BA and GOP or Market Participant..

- Gas-fired Steam units in Reliability Status are reserved for emergency conditions when their fuel supply is expected to last less than 16 hours at rated output. .
    - The concept of 16 hours is predicated on the fuel being available during the two day period and operating the resource equal to four 4-hour peak load periods over a 2-day period. Depending on the situation, Resources may be forced out of service (full or partial) prior to these guidelines in order to protect plant equipment or for future system needs.

Although a Resource may fulfill the requirement of being fuel-limited, the SPP BC may elect not to operate the Resource as a Fuel-limited Resource if it is determined to not impact the reliability of either the BAA or Bulk Electric System. This will be handled on a case by case basis between the appropriate GOP and the SPP BC.

Forecasted Fuel Limitation (SPP Emergency Operating Plan section 5.1.2)

In the event that a Generation Operator has concerns regarding a fuel limitation for some future point in time, the following actions will be taken:

SPP Member Actions:

1. GOP contacts SPP Generation Dispatch desk with the status of units and fuel. This discussion includes the max generation levels and needs or requirements.
2. GOP update CROW with outage and/or de-rates with the appropriate reason for status change.

Real-Time Fuel Limitations (SPP Emergency Operating Plan section 5.1.3)

In the event that a Generation Operator has concerns regarding a fuel limitation with real-time impact, the following actions will be taken.

SPP GOP Actions:

1. Contacts SPP RUC to inform that a unit can no longer provide cleared energy or reserves, due to fuel limitations.
2. .
3. If Applicable, updates CROW and Market UI/API with outage and/or de-rates with the appropriate reason for status change.

SPP CRITERIA 5.2.1.1 Outage Reporting and Coordination states:

- Generator Operators shall notify SPP of any generation derates resulting from Operational Flow Orders (OFOs) or Critical Notices or any other type of fuel delivery constraint. The parties submitting the information shall indicate that the derate is a result of an OFO, Critical Notices, or fuel delivery constraint and indicate which pipeline(s) or delivery constraints are impacting them.
- Whenever an OFO, Critical Notices, or fuel delivery constraint causes an inability for the Generator Operator to meet its firm obligations, GOP must use the normal established communication protocols to notify the SPP Balancing Authority.

Appendix 7 in SPP Criteria notes the Generator Operator needs to notify SPP via the CROW Outage Scheduler of Generator Derates or Risk due to a generation facility that is restricted from normal operation due to a fuel related issue.

- Notification of expected time of reduced real power production capability and associated return to service time of full real power production capability. Also, the amount of capability lost shall be provided along with an explanation (OFO, fuel supply issues, mechanical problems, outlet constraints, etc.) of the reason for the derate. As information is updated, the outage shall be updated as appropriate (ex. expected return to service time, reason for the outage, etc.)

- Notification of expected or known risks to or removal of service time and associated expected return to service time of all Generation units as required in the SPP Membership Agreement. As information is updated, the outage shall be updated as appropriate (ex. expected return to service time, reason for the outage, etc.) (Risks may include fuel supply issues)

Fuel Switching (SPP Emergency Operating Plan section 5.2)

Many of AEPW/SPP gas-fired generating units have the ability to burn fuel oil as an alternate fuel. AEP maintains a limited quantity of fuel oil inventory at its gas-fired generating stations that are capable of burning fuel oil as an emergency back-up fuel supply. In the event of a potential severe natural gas shortage, such as one resulting from extreme winter weather conditions, pipeline curtailments or other emergencies, the following steps will be implemented:

1. AEP's gas and fuel oil buyers will monitor national and local weather conditions and maintain constant communication with gas and fuel oil suppliers and transporters.
2. GOP will routinely monitor the web sites of interstate pipelines to determine if any Operational Flow Orders or Operational Alerts have been issued.

3. Communication and coordination will be maintained between fuel procurement, GOP (or their designee), and SPP operations personnel to determine when to switch generation from primary to secondary fuels to ensure reliability of the SPP System.
4. Once the fuel switch occurs, the GOP (or their designee) shall communicate with SPP any updates to its operational limits. These changes in operational limits must also be reflected correctly in the Markets UI/API. Any de-rates as a result of the fuel switching should be communicated through CROW.
5. Additional secondary fuel supplies will be purchased by the GOP (or their designee) to supplement currently available secondary fuel inventories at the respective generating stations for the duration of the expected shortage of the primary fuel.
6. Appeals to large industrial and commercial customers, as well as, government agencies to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.
7. Fuel oil inventories will be replenished once the emergency burning period has ceased to ensure a back-up emergency supply is always available.
8. If secondary fuel supplies are not available, GOP (or their designee) should notify SPP as soon as possible

The GOP is expected to notify SPP in a timely manner if these conditions are not being met.

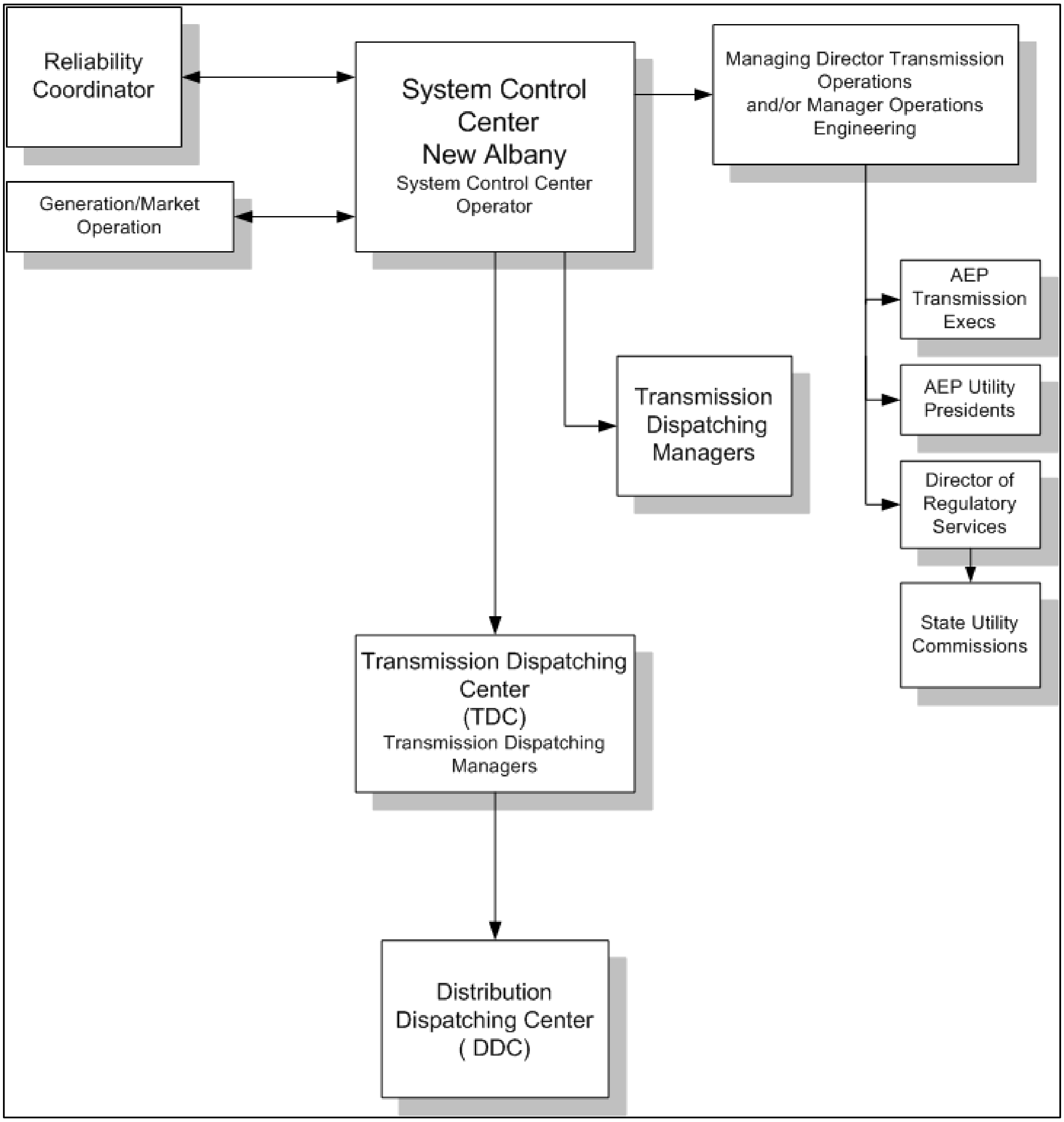


Figure V-1
Fuel Limitation Notifications

Section VI

Transmission Emergency Procedures

References

PJM Transmission Operations Manual M03 rev 47A
Emergency Manual M13 rev 58
Generation Operational Requirements M14D rev 35
Reliability Coordination M37 rev 12
SPP Criteria dated April 2015
SPP Emergency Operating Plan v4.5
SPP Integrated Marketplace rev 33
SPP IROL Relief Guides dated 03/12/2015
NERC Transmission Operations Standards
TOP-002-2.1b Normal Operations Planning
TOP-004-2 Transmission Operations
TOP-006-2 Monitoring System Conditions
TOP-007-0 Reporting SOL and IROL violations
TOP-008-1 Response to Transmission Limit Violations
IRO-001-1.1 Responsibilities and Authorities
IRO-004-2 Operations Planning
IRO-006-EAST-1 Transmission Loading Relief
IRO-009-1 Reliability Coordinator Actions to Operate Within IROLs

SOL/IROL Definitions

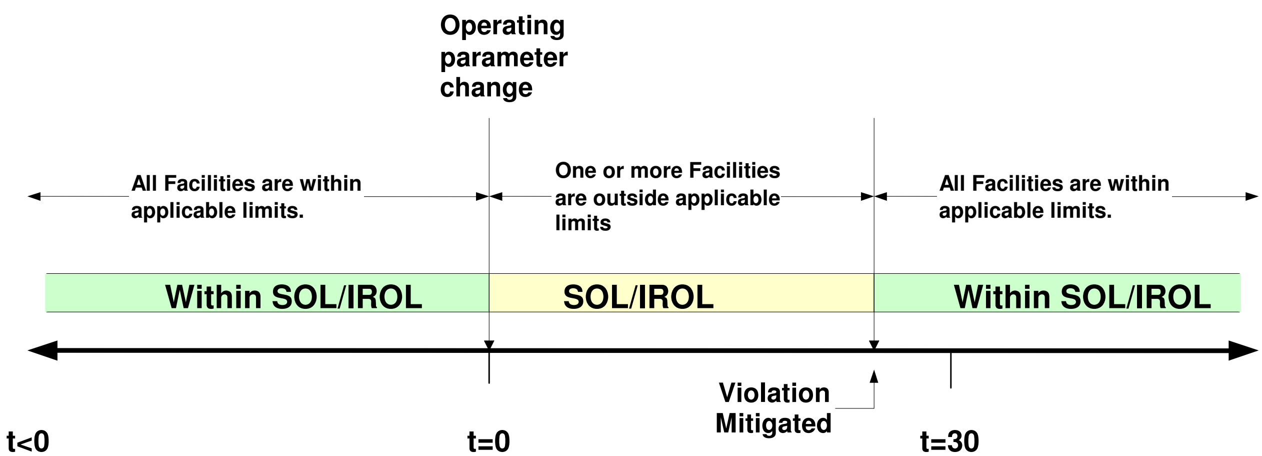
NERC Standard TOP-007 and TOP-008 outlines specific requirements and identifies accountability for developing and implementing transmission emergency procedures to alleviate System Operating Limits (SOL) and Interconnected Reliability Operating Limits (IROL). The definitions of a SOL and IROL are as follows:

System Operating Limit (SOL). The value (such as MW, MVar, Amperes, Frequency, or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SYSTEM OPERATING LIMITS are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post-CONTINGENCY equipment or facility ratings)
- Transient Stability Limits (Applicable pre- and post-CONTINGENCY Stability Limits)
- Voltage Stability Limits (Applicable pre- and post-CONTINGENCY Voltage Stability)
- System Voltage Limits (Applicable pre- and post-CONTINGENCY Voltage Limits)

AEP Confidential Special Handling-CEII

Interconnected Reliability Operating Limit (IROL). A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System.



Limit Violation. The operating state during which one or more FACILITIES are outside SYSTEM OPERATING LIMIT or INTERCONNECTED RELIABILITY OPERATING LIMIT. A violation occurs at the instant the established limit is exceeded (see diagram above). This could be a result of a change in one or more operating parameters (i.e. bulk electrical system configuration changes or any change in the distribution of flows).

Limit Compliance Violation. An INTERCONNECTED RELIABILITY OPERATING LIMIT VIOLATION that has occurred for more than 30 consecutive minutes. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.

NERC Standard TOP-004-2 requirements are as follows:

Requirements:

R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).

R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.

R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.

R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.

R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission
Operator may take such actions, as it deems necessary, to protect its area.

R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:

R6.1. Monitoring and controlling voltage levels and real and reactive power flows.
R6.2. Switching transmission elements.
R6.3. Planned outages of transmission elements.
R6.4. Responding to IROL and SOL violations.

NERC Standard TOP-007-0 requirements are as follows:

Requirements:

R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.

R2. <u>Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.</u>

R3. <u>A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.</u>

R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.

NERC Standard TOP-008-1 requirements are as follows:

Requirements:

R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.

R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. <u>In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.</u>

R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.

R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The

Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.

NERC Standard IRO-001-1.1 requirements are as follows:

Requirements:

R8. Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.

NERC Standard IRO-004-2 requirements are as follows:

Requirements:

R1. Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.

NERC Standard IRO-009-1 requirements are as follows:

Requirements:

R1. For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those IROLs.

R2 For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) to mitigate the magnitude and duration of exceeding that IROL such that the IROL is relieved within the IROL's T_v.

Introduction and Conditions

The AEP transmission system may be subject to transmission overloads or excessively low voltages during abnormal conditions. Internal loads can exceed forecasts during very hot or very cold conditions when load growth exceeds system design and new facilities are not yet in place. Capacity deficiencies in one part of the eastern interconnected network can stress AEP transmission facilities between the deficient areas and areas of excess generation. Likewise, economic interconnected operation can result in AEP transmission facilities being overloaded between available economic generation and high cost generation areas. The result of any one of these conditions or other reasons, separately or in combination, could cause unacceptable operating conditions for the AEP transmission system. With these variables in mind, AEP must operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. AEP will work in conjunction with the applicable Reliability Coordinator to mitigate any transmission emergencies on the AEP system and, should an emergency occur, will make every effort to remain connected to the Interconnection unless such actions would violate safety, equipment, regulatory or statutory requirements. The AEP Transmission System Control Center (SCC) shall comply with all Reliability Directives or Operating Instructions issued by the applicable Reliability Coordinator as outlined in Appendix VI – Responsibility and Authority. In instances where there is a difference in derived operating limits, the AEP transmission system shall always be operated to the most limiting parameter. An overview of the mechanisms to mitigate transmission emergencies is outlined below.

Should an event occur that requires filing a report with the Department of Energy (DOE), NERC, or a Reliability Coordinator, Real Time Operations will prepare those reports with assistance from the Transmission Operations Engineering group and/or the applicable Transmission Dispatch Center personnel.

There are four general types of conditions that will require action:

1. **Contingency Thermal Overloads**
   The outage of one facility will load a transmission element to or above its emergency capability. Loadings must be controlled to no more than the emergency ratings in advance of the contingency occurring unless the overload can be controlled within a short time after the contingency. Additional measures may need to be taken upon the loss of a critical facility.

2. **Contingency System Stability Over Limits**
   The system is transmitting power at a level at which a critical outage of one facility will cause a virtually instantaneous separation across the path over which the power is being transmitted, possibly resulting in cascading outages. Path flows must be reduced immediately to safe levels, or maintained below the stability limits.

3. **Contingency Voltage Under/Over Limits**
   The voltage level is at a level at which the loss of a critical facility will result in unacceptably low voltages. If the voltage is not increased within a matter of a few seconds to a few minutes after the contingency occurs, cascading facility outages, equipment damage for customers and AEP, and/or loss of customer load will occur. Loading levels must be reduced or other measures must be taken to immediately raise voltages before a critical contingency occurs. Also, during light load conditions, system voltages may become unacceptably high.

4. **Actual Thermal Overloads and/or Actual Voltage Under/Over Limits**
   Transmission thermal loadings are above rated capabilities and/or voltage levels are at, below or above levels that will result in equipment damage and/or cascading outages. Action must be taken immediately to reduce facility loadings and/or raise or lower voltages.

AEP Confidential Special Handling-CEII

Transmission Reserve Warning (TRW)

If a transmission emergency exists or is anticipated, a Transmission Reserve Warning (TRW) will be issued by the SCC for the area affected. When a TRW is issued, all station or transmission maintenance, testing, or construction work scheduled or in progress in the affected area will be reviewed to determine if such work should be cancelled or deferred to safeguard system transfer capability and reliability. Also, transmission facilities scheduled out of service will be reviewed and be returned to service if it is determined that returning the facility will alleviate the emergency condition. Generation scheduled/opportunity outages and maintenance work will also be reviewed to determine if returning the units will alleviate the emergency condition.

Emergency Actions

This plan reflects these basic principles:

1. All possible actions will be taken before load shedding is implemented.
2. Load shedding will be used under emergency conditions to prevent cascading outages, and the spread of customer outages.
3. The transmission and generation system must be maintained as intact as possible in order to restore the system and customer loads as quickly as possible.
4. Load shedding will be targeted to minimize the amount shed by choosing loads that will effectively help the emergency condition(s).

When action is required because of transmission overloads or low voltages, a variety of measures can be used for relief. The order of application of transmission relief measures will depend upon the specific problem that exists and the time required to implement each measure. The SCC will work with the Reliability Coordinator, and under NERC guidelines, to achieve an effective and timely resolution of each problem. The following key points relate to TLR's and voltage criteria.

- The NERC Transmission Loading Relief (TLR) Procedures can be found in Table VI-2.
- It is important to maintain adequate pre-contingency voltage levels on the transmission system to prevent loss of load due to low voltage conditions, maximize the amount of power that can be transmitted over the power system, and prevent high voltage conditions.
    - AEP East and West Baseline Voltage Limits are provided below.

AEP East Baseline Voltage Limits*			
Limit	765 kV	500 kV	345 kV to 69 kV
High	1.05 pu (803.2 kV)	1.10 pu (550 kV)	1.05 pu
Normal Low	.95 pu (726.8 kV)	1.00 pu (500 kV)	.95 pu
Emergency Low	.92 pu (703.8 kV)	.97 pu (485 kV)	.92 pu
Load Dump	.90 pu (688.5 kV)	.95 pu (475 kV)	.90 pu
Voltage Drop	10%	8%	8%

AEP West Baseline Voltage Limits*

Limit	345 kV to 69 kV
High	1.05 pu
Normal Low	.95 pu
Emergency Low	.90 pu**

*Exceptions to the High voltage baseline limits can be found in the Appendix II.

**SPP Criteria states voltages shall be maintained above 0.90 pu under single contingency conditions. For conservatism and improved situational awareness, AEP Transmission Operations monitors at 0.92 pu under contingency conditions.

- Voltage Control – AEP/PJM
  - Typically try to maintain voltage levels from 96.0 to 102.0 % on the 765 kV transmission systems.
  - Typically try to maintain voltage levels from 101.0 to 105.0 % on the 500kV transmission system.
  - Typically try to maintain voltage levels from 95.0 to 105.0 % on the 345 kV to 69 kV transmission systems.
  - Maintain schedules at Generating Plants
    - Voltage ± 0.5% (unless specified otherwise by TOPS)
    - Power Factor ± 2% (unless specified otherwise by TOPS)
  - Avoid high voltage limits at the EHV and Transmission levels. AEP's 765kV circuits have overvoltage relay settings that will automatically trip the line circuit breakers if triggered on an individual phase. Refer to Appendix II.

- Voltage Control – AEP/SPP
  - Typically try to maintain voltage levels from 95.0 to 105.0 % on the 345 kV,161 kV, 138 kV & 69 kV transmission systems.
    - 345 ± 17 kV, 161 ± 8 kV, 138 ± 7 kV, 69 ± 4 kV
  - Maintain schedules at Generating Plants
    - Voltage ± 0.5% (unless otherwise specified by TOPS)
    - Power Factor ± 2% (unless otherwise specified by TOPS)
  - Avoid high voltage limits at the EHV and Transmission levels

Minimize the reactive loading on units by balancing reactive loading among units closely connected to the same electrical bus.

All generators connected to the interconnected transmission system shall be operated with their excitation system in the automatic voltage control mode, maintaining network voltage and/ or reactive power as required. All generators connected to the AEP transmission system shall operate with their automatic voltage regulators in service controlling voltage and shall not use reactive power or power factor controllers, unless otherwise authorized by TOPS.

AEP Confidential Special Handling-CEII

The Voltage_and_Reactive_Guide_AEPE_AEPW-SPP lists specific actions to be taken by the System Control Center Operator, Reliability Coordinator, and Transmission Dispatchers to control voltage. The document is stored on the AEP TOPS Sharepoint at Engineering>Operating Guidelines>AEP System Wide Guides and Information.

The transmission measures that will be used for transmission emergencies will include any or all of the following:

1. Any available shunt or bridge capacitors not already in service in a low voltage area will be placed in service and any 765 kV or 345 kV shunt reactors not already out of service in the low voltage area will be removed from service if they can be removed without switching circuits and causing a high voltage condition.
2. Adjusting set point of static VAR compensators (SVC).
3. Operating synchronous condensers.
4. AEP generators will be requested to maximize MVAR output to improve voltage profiles and alleviate transmission system low voltage conditions. Typically a 1-2 % increase in voltage schedule will be requested.
5. On-line IPP's and Co-generators should be contacted to supply maximum available MVARs to the transmission system in order to improve voltage profiles and reactive reserves in accordance with contracts and/or agreements.
6. Series capacitors and reactors whose insertion or removal from service will divert power from a loaded facility and/or increase voltage in a low voltage area will be used to improve system conditions.
7. Capacity resources that may be useful will be used. These may include:
    a. Curtailment of generating station use
    b. Curtailment of unessential building use
8. Reconfigure the transmission system by removing (or returning to service if possible) facilities that will make a significant improvement to the problem area without causing uncontrollable problems elsewhere.
9. PJM Locational Marginal Pricing (LMP) to control congestion.
10. SPP Locational Imbalance Pricing (LIP) to control congestion.
11. Curtailment of Non-Firm transmission service, beginning with the lowest priority reservation, in accordance with NERC Standard IRO-006. Transactions will be curtailed that have a response factor of at least 5% on the overloaded facility or have a significant impact on the voltage problem. Coordination with adjacent systems will ensure that all transactions that meet these criteria will be cancelled, whether or not AEP is directly involved in a given transaction.
12. Re-dispatch generation by reducing units that have large response factors that load the overloaded facility and increasing units with large response factors to unload the overloaded facility.
13. Contact major industrial/commercial customers to reduce load in specific regional areas that will help alleviate the emergency condition.
14. Voluntary load curtailment in the specific regional areas that will alleviate the emergency condition.
15. Purchase power from IPP's, Co-Gen's, or other Market Entities, regardless of cost, and in a direction that will help alleviate the emergency condition.

AEP Confidential Special Handling-CEII

16. Curtailment of Firm transmission service in accordance with NERC Standard IRO-006, on a pro-rata basis with native and network loads, that have a response factor of 5% or more on the overloaded facility or a significant positive impact on the low voltage area will be curtailed after preceding steps have been implemented or if the preceding steps are not anticipated to provide adequate relief.
17. If an overload or abnormal voltage or reactive condition persists on a transmission facility and equipment is endangered, the affected facility shall be disconnected. In doing so, AEP shall notify the applicable Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.
18. If the above steps prove to be inadequate then all other available emergency procedures will be implemented including load shedding.

Additionally, some customer loads connected to AEP's transmission and sub-transmission network, such as municipalities and various Co-ops, are served in whole or in part by non-AEP generation and have transmission service agreements with AEP. FERC open transmission access regulations require that AEP treat these transmission customers in a manner comparable to the service provided to AEP's own internal customers. In addition, a few large industrial customers cannot be shed at AEP supply points without fractionalizing the transmission or sub-transmission network and reducing reliability. AEP will request that these municipalities, Co-ops, and industrial customers develop plans for shedding of their load when directed by the SCC. Supervisory controlled loads will be capable of shedding load within 15 minutes of a critical contingency unless otherwise noted. While it is recognized that municipalities, Co-ops, and large industrials do not have this capability, they will be requested and expected to shed load within 15 minutes of notification that a critical contingency has occurred. A DOE report is required for voluntary load curtailment and manual load shedding.

Copies of the Transmission Emergency Plans and Memo's for specific transmission emergency procedures are located on the TOPS Sharepoint as noted below.

The TOPS AEPE Congestion Management Guidelines and PCLLRW Process Document have specific actions to be taken by the System Control Center Operator and Reliability Coordinator for congestion events.

1. The AEPE Congestion Management Guidelines document is located on the AEP TOPS Sharepoint at **Engineering>Operating Guidelines>AEP East>General**.
2. The PCLLRW Process Document is located on the AEP TOPS Sharepoint at **SCC>SCCO East** and outlines processes for Post Contingency Load Relief, including local load shedding.

Refer to the PJM pull down menu under the Switching tab on the AEP URL http://topsweb/PCLLRW/Default.aspx documents the switching / load shed solutions for potential PCLLRW contingencies.

The Transmission Operations AEPW Congestion Management Guidelines provide general guidelines for relieving thermally overloaded AEP transmission facilities within the AEP West/SPP footprint. This document is located on AEP TOPS Sharepoint at **Engineering>Operating Guidelines>AEP West>General.**

Refer to the SPP pull down menu under the Switching tab on the AEP URL http://topsweb/PCLLRW/Default.aspx documents the switching / load shed solutions for potential PCAP contingencies.

TOPS_IROL_Relief_Procedures_AEPE_PJM and IROL_Relief_Procedures AEPW_SPP contain specific actions to be taken by the System Control Center Operator and Reliability Coordinator for IROL events. The documents are on the AEP TOPS Sharepoint at: **Engineering>Operating Guidelines>AEP East>General** for the East area, and **Engineering>Operating Guidelines>AEP West>General** for the West area.

PJM manual 37 Section 3 lists the IROL facilities in the PJM area. In addition, PJM indicates in this manual that all BES facilities and "Reliability and Markets" sub-BES facilities as listed on the PJM Transmission Facilities pages are considered System Operating Limits (SOL).

PJM manual 03 - Section 1, Note 2 states:

> **Note 2**: AEP is the registered Transmission Operator (TOP) for the AEP 138kV and below 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 138kV and below monitored facilities. In an Emergency, AEP will notify PJM of any unilateral actions it has taken with respect to the re-dispatch of generation as soon as practicable, but no later than 30 minutes, so that PJM can coordinate with the impacted parties.

The SPP IROL Relief Guide, as posted on the SPP OPS1 website dated 03/12/2015 , lists the IROL facilities in the SPP area. In addition SPP Criteria 12.3 dated July 29, 2014 utilizes the flowgate limits as the SPP System Operating Limits. SPP utilizes these flowgates to ensure the system is operating within acceptable reliability criteria.

AEP is the registered Transmission Operator (TOP) for AEP facilities in the AEP West/SPP footprint. SPP is not registered as a TOP.

[redacted] in AEP/SPP and AEP/PJM Area

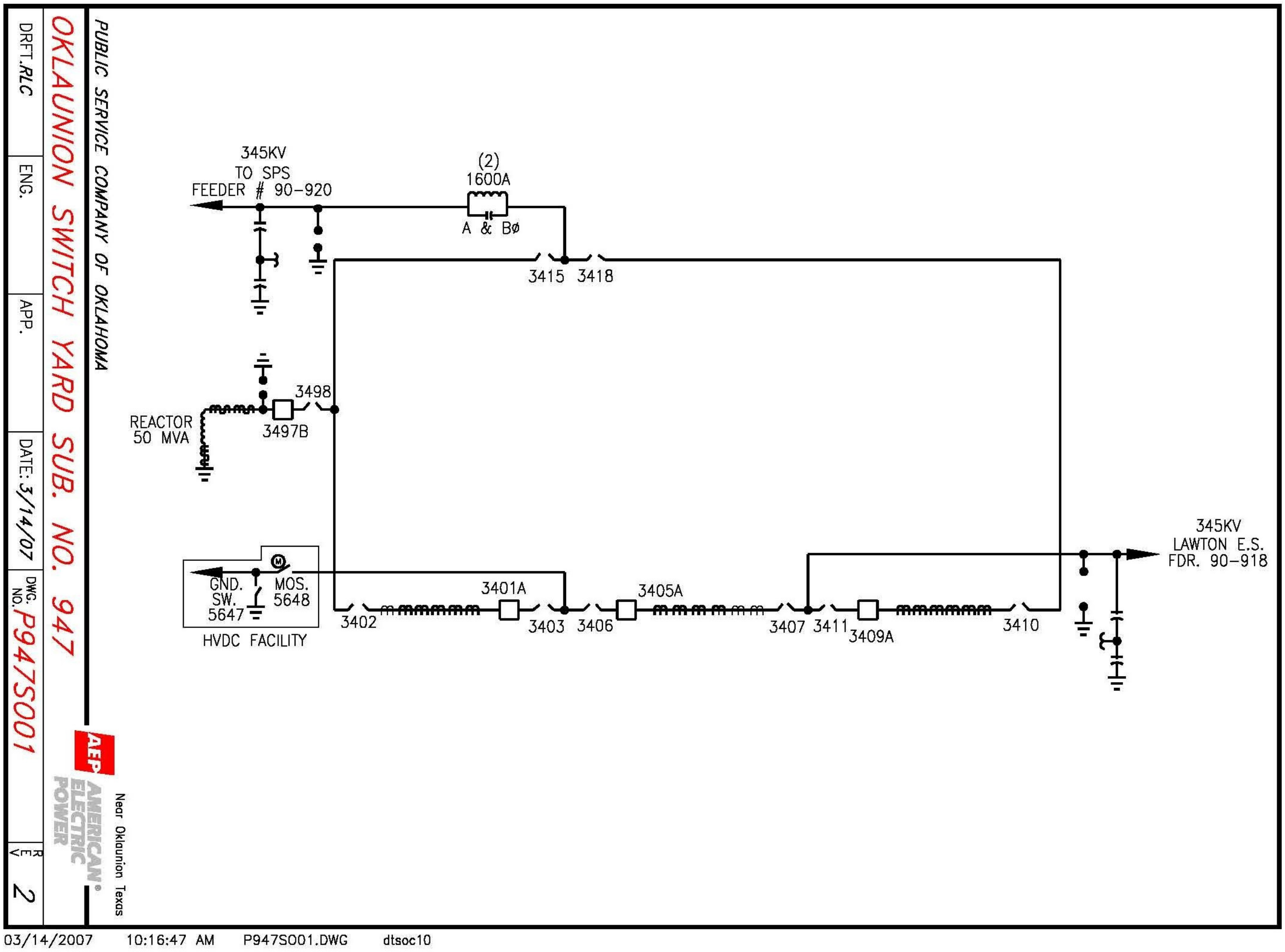
A. AEP/SPP – [redacted]

The AEP/Public Service Co. of Oklahoma (PSO) [redacted] Station [redacted] the electric power systems of the [redacted] and the [redacted] The [redacted] line exiting to the east connects to [redacted] substation. The [redacted] line exiting to the west connects to [redacted] substation [redacted] is a PSO substation. [redacted] is a [redacted] substation. The [redacted] substation was constructed in the mid-1980's.

[redacted] description and summary of functionality:

At [redacted] substation, any time both breakers [redacted] and [redacted] are tripped [redacted] that is line [redacted] is taken out, [redacted] of breaker auxiliary contacts from these breakers will [redacted] through [redacted], which drops the [redacted] and isolates the [redacted]. This mode of operation is necessary to avoid (1) potential transmission overload problems and possible isolation of the [redacted], (2) potential low voltage problems due to heavy power flows and (3) potential high voltage problems that can result in equipment damage if the [redacted] leaving the [redacted] and [redacted] in-service. Utilizing [redacted] sets of [redacted] indication auxiliary contacts, the [redacted] will be simple, reliable and redundant.

AEP Confidential Special Handling-CEII



NERC PRC-016-0.[redacted]: [redacted]

B. AEP/PJM – [redacted]

System Description

[redacted] Special Protection System

On August 4, 2007, an unusual series of electrical faults caused the loss of [redacted] and several non-AEP units in the area. NERC investigated this event and developed recommendations documented in the report "[redacted]. In response to recommendations from NERC related to the [redacted], AEP made enhancements to the Fast Valve controls to cover multiple, random faults resulting in multiple fast valve initiates. The enhancements in the Fast Valve scheme introduced the need for a Special Protection System (SPS). The enhancements to the Fast Valving Controls and the addition of the SPS is designed to address the type of unusual series of sequential faults experienced during the [redacted] disturbance and provides coordination between plant and transmission line protection equipment.

As part of an additional investigation, initiated by RFC in 2010, regarding the [redacted] described above, AEP has concluded that the Fast Valving (FV) and Emergency Unit Trip (EUT) special controls shall be included as part of the [redacted] Protection System definition. The existing functionality of these controls has not changed; however, all Transmission and Generation operation, relay and maintenance activities associated with these controls will be modified to conform with the requirements of a Special Protection System as defined by NERC.

The [redacted] is defined as:

[redacted]

The following is a description of each component of the [redacted] and corresponding Transmission Operator actions should an SPS event occur:

Fast Valving SPS

Fast Valving is defined as part of the [redacted] SPS. Fast Valving enhances the stability performance of the plant through temporary, rapid closure of both the control and the intercept valves to pre-determined set points for contingencies on the [redacted]. Electrical power is reduced by about 50% within one second after initiation. The turbine valves then automatically return to their original positions, restoring the electrical power to the pre-disturbance level within 10 seconds

NERC PRC-016-0.1 R3 states: The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).

Unit SPS Trip

The Unit SPS Trip is required due to the impact that a Fast Valve operation has on the units. Both the boiler & throttle pressures in the turbine increase during each Fast Valve operation. There are imbedded safe operating limits that trip the units for excessive boiler or the throttle pressures. Exceeding either of these safety limits requires the unit to be tripped. Since both [redacted] Fast Valve and respond similarly when at the same MVA output levels, there is the potential that both units will trip simultaneously. To prevent the tripping of both units by the imbedded safety operating limits systems the Unit SPS Trip was installed.

NERC PRC-016-0.1 R3 states: The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).

Emergency Unit Tripping SPS

Emergency Unit Tripping (EUT) is now defined as part of the [redacted] SPS. In order to allow higher pre-contingency unit output, this scheme is utilized by operators such that a unit can be selected to be tripped upon a multi-phase fault or loss of load (current falls below 450 amps or 600 MVA) on the [redacted] line (three-phase fault will trigger the loss of load condition). EUT SPS alarm points, indicating the status of each unit and the current trip condition are available for monitoring on the **LRSR** and **PI** displays.

NERC PRC-016-0.1 R3 states: The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).

Refer to [redacted] located on the TOPS Sharepoint Engineering>Operating Guidelines>AEP East>IM for further details.

Under [redacted] in AEP/SPP and AEP/PJM Area

SWEPCO [redacted] – Springdale Area Distribution

	Station	Breaker	UV Setting	Time Delay	Trip kV	est. 2015 PEAK MW
1	[redacted]	[redacted]	84.4%	3 sec.	10,525	17.6
2		[redacted]				10.57
3	[redacted]	[redacted]	88.0%	3 sec.	60,720	8.75
4		[redacted]				1.44
5	[redacted]	[redacted]	88.0%	3 sec.	141,680	7.04
6	[redacted]	[redacted]	88.0%	3 sec.	60,720	2.15
7		[redacted]				8.36
8	[redacted]	[redacted]	88.0%	3 sec.	60,720	3.44
9		[redacted]				15.56
10	[redacted]	[redacted]	87.7%	3 sec.	10,524	2.84
11		[redacted]				10.75
12		[redacted]				11.81
13		[redacted]				4.15
14	[redacted]	[redacted]	88.0%	3 sec.	60,720	11.83
15		[redacted]				13.99
16	[redacted]	[redacted]	88.0%	3 sec.	10,560	5.92
17	[redacted]	[redacted]	88.0%	3 sec.	10,560	9.39
18		[redacted]				13.88
19		[redacted]				8.50
				Total-		167.97

AEP Confidential Special Handling-CEII

A. SWEPCO Under Voltage Load Shed Scheme – Texarkana Area Distribution

						est. 2015
	Station	**Breaker**	**UV Setting**	**Time Delay**	**Trip kV**	**PEAK MW**
1	[redacted]	[redacted]	88.0%	3 sec.	60,720	4.2
2	[redacted]	[redacted]	88.0%	3 sec.	60,720	6.31
3	[redacted]	[redacted]	88.0%	3 sec.	10,974	6.92
4	[redacted]	[redacted]	88.0%	3 sec.	10,974	2.80
				Total-		20.23

[redacted]> for further details.

AEP Confidential Special Handling-CEII

B. Columbus Southern Power [redacted] – Southern Area

	[redacted]	[redacted]	Feeder	CB	Relaying	Priority	Voltage Setpoint	Relay Time Delay	Circuit Breaker Interrupting Time	Overall Scheme Clearing Time	2015 Summer MWs Interrupted
Adams/Seaman Area	[redacted]	[redacted]	[redacted]	22	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	3.38
	[redacted]	[redacted]	[redacted]	2	DPU2003	2	0.88 pu	180 cycles	3 cycles	183 cycles	3.69
		[redacted]	[redacted]	6	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	1.89
	[redacted]	[redacted]	[redacted]	8	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	2.92
		[redacted]	[redacted]	1	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	1.39
	[redacted]	[redacted]	[redacted]	2	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	3.73
		[redacted]	[redacted]	5	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	3.08
	[redacted]	[redacted]	[redacted]	3	SEL351S	2	0.88 pu	180 cycles	3 cycles	183 cycles	2.22
		[redacted]	[redacted]	2	SEL351S	3	0.88 pu	180 cycles	2.7 cycles	182.7 cycles	1.90
	[redacted]	[redacted]	[redacted]	4	SEL351S	3	0.88 pu	180 cycles	2.7 cycles	182.7 cycles	3.86
		[redacted]	[redacted]	41	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	7.24
	[redacted]	[redacted]	[redacted]	42	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	5.60
	Total [redacted]										40.89

	[redacted]	[redacted]	[redacted]	CB	Relaying	Priority	Voltage Setpoint	Relay Time Delay	Circuit Breaker Interrupting Time	Overall Scheme Clearing Time	2015 Summer MWs Interrupted
Chillicothe Area			[redacted]	K	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	3.20
	[redacted]	[redacted]	[redacted]	F	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	2.88
			[redacted]	N	DPU2000R	3	0.88 pu	180 cycles	3 cycles	183 cycles	9.66
			[redacted]	M	DPU2000R	3	0.88 pu	180 cycles	3 cycles	183 cycles	9.68
			[redacted]	P	DPU2000R	3	0.88 pu	180 cycles	3 cycles	183 cycles	7.24
	[redacted]	[redacted]	[redacted]	H	DPU2000R	3	0.88 pu	180 cycles	3 cycles	183 cycles	4.38
			[redacted]	C	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	3.18
	[redacted]	[redacted]	[redacted]	B	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	2.96
			[redacted]	1	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	4.32
	[redacted]	[redacted]	[redacted]	2	SEL351S	3	0.88 pu	180 cycles	3 cycles	183 cycles	5.07
	Total [redacted]										52.56

Refer to [redacted] guide located on the TOPS Sharepoint Engineering>Operating Guidelines>AEP East>CSP for further details.

Plant Fault Duty Procedures

A. PSO – Riverside Power Station

a. If Riverside Power Station large units (1 and 2) are both running AND one (or both) of the Riverside Station small peaker units (3 and/or 4) is running then open the 138 kV side of one of the two 345/138 kV autotransformers (via breaker 1301A or 1305A) to prevent the breaker(s) over duty issues. Reclose the breaker once the condition above ends**.**

B. OHIO - Cardinal 1

a. To prevent exceeding the fault duty current capability on the 138kV bus circuit breakers at Tidd whenever Cardinal Unit 1 is on line, the Tidd 138kv series reactor needs to be in service (R1 open) and

i. The Tidd 345/138kV TrB bypassed to Sunnyside –Tidd 138kV, or

ii. Operate Tidd 345/138kV TrB open on 138kV and close 138kV CB M2 at Tidd.

iii. Refer to the TiddOperatingMemo.pdf on the TOPS Sharepoint at Engineering>Operating Guidelines>AEP East>OPCO for additional information.

C. OHIO – Kammer 138kV

The Kammer Operating Procedures purpose is to avoid an overduty condition in the Kammer 138kV station. Due to the evolving complexity associated with construction, the user needs to access the latest Kammer_Operating_Procedure located on the TOPS Sharepoint at Engineering>Operating Guidelines>AEP East>OPCO which addresses numerous Kammer configurations to mitigate overduty / contingency issues.

AEP Confidential Special Handling-CEII

Geomagnetic Disturbance Operating Procedure

Geomagnetic storms can cause large fluctuations in the earth's magnetic field. During these storms, geomagnetic induced current (GIC) is produced in the electric power system. The GIC flow through the power system via the neutral grounding points of the wye connected transformers, which can result in saturation of the transformer cores. Transformer saturation causes the excitation current to rise sharply. An increase in the excitation current usage of a transformer may be noticed as an increase in the lagging VAR usage of the transformer. This increase in lagging VAR usage can lead to system reactive power deficiencies and voltage problems.

Highlights of Procedures:

In this procedure, the SCC interacts with the PJM / SPP Reliability Coordinators while the Corpus TDC interacts with the ERCOT Reliability Coordinator.

AEP's GMD procedure:

1. Ensures the SCC and Corpus TDC are aware of GMD space weather forecast information
2. Provides guidance on a response to the potential GMD event;
3. Includes voltage monitoring which is a proxy for the Loss of Reactive Power Support;
4. Provides options to reduce the risk of damage to transformers with DC neutral current monitoring;
5. Has procedures addressing PJM member actions requirements;
6. Has procedures addressing SPP requirements;
7. Has procedures addressing ERCOT requirements; and
8. Conditions for terminating the GMD procedure.

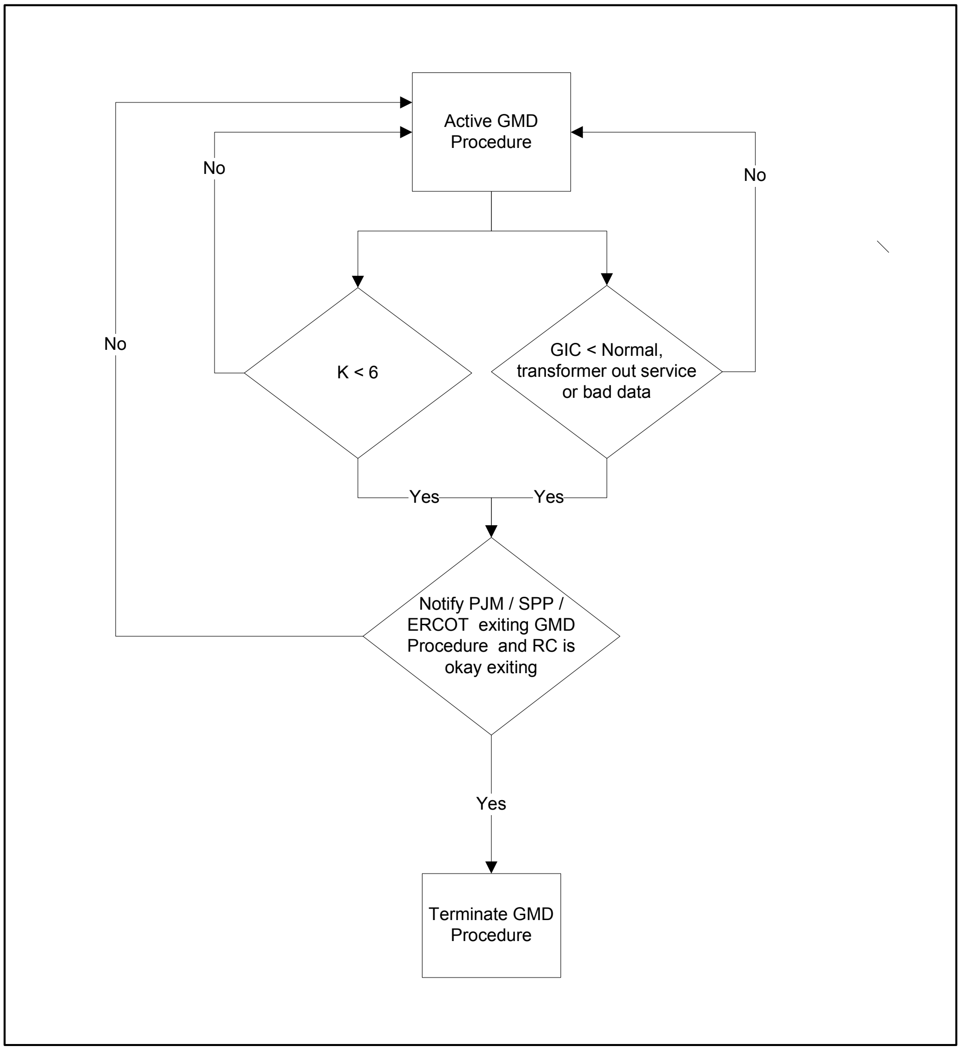
Typically when the K-index reaches a value of 7 or higher, there may be noticeable effects of the power system, such as:

- Unusual noises from power transformers
- Overheating in transformers
- Real and reactive power swings
- Tripping of capacitor banks
- Voltage fluctuations
- Large reactive consumption from transformers with saturated cores
- Operation or the non-operation of protective relays
- Negative sequence relays alarmed (Rockport)
- Communication system problems
- Large reactive consumption from transformers with saturated cores.

The SCC/Corpus Christi TDC receives K-index Alerts and Warnings from PJM, SPP, ERCOT, RCIS, or the Space Weather Prediction Center at the National Oceanic and Atmospheric Administration (NOAA). The TDISPATCHCCR, TOPSEAST and TOPSWEST inbox has been signed up to receive K-index Alerts and Warnings of 6 or higher. The GMD procedure specifies actions to follow for K-index Events.

The SCC monitors the transformer DC neutral Amps at select locations on the PI display board. If the transformers DC neutral Amps reach a threshold value for 10 minutes or more that could jeopardizes the transformer, the GMD procedure specifies actions to mitigate the risk to the transformer. SCC communicates to the Corpus Christi TDC any locations that have reached the threshold level on a similar parallel of any portion of the AEP ERCOT region.

The SCC and / or Corpus Christi TDC will terminate the active GMD Operating Procedure when the following have occurred.



Refer to "GMD Operating Procedure" guide located on the TOPS Sharepoint at Engineering>Operating Guidelines> AEP System Wide Guidelines and Information for specific details.

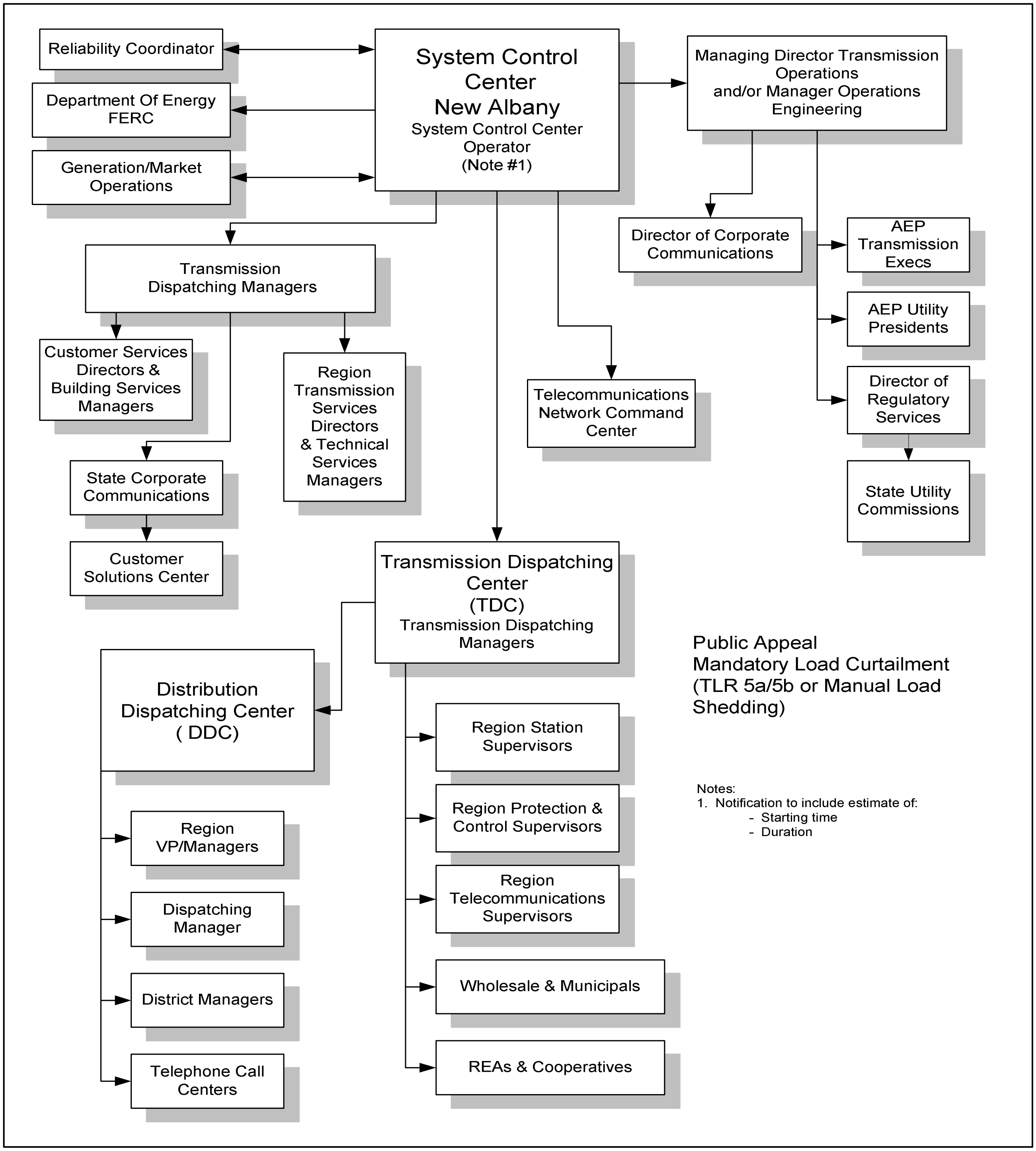


Figure VI-1
Transmission Emergency Notifications

PJM LMP Market Relief Actions

The general procedure is for PJM to first apply corrective actions that can be taken for little or no cost, such as:

- Capacitor/reactor switching
- Pre-studied line switching
- Curtailment of non-firm transactions not willing to pay for congestion relief.

PJM will initiate off-cost controlling actions (generation redispatch) if non-cost controlling actions are not available. This is accomplished by setting Locational Marginal Prices (LMP) that encourage participating generators to ramp up or down. PJM will utilize their RT-SCED tools to redispatch any generation that has at least a 5% Generation Shift Factor (GSF) for projected post-contingency loadings, or any generation with at least a 1% GSF for actual overloads. RT-SCED will also take into account the cost of redispatch per generator and favor cheaper generation changes; for example, if two units have identical GSFs for a particular constraint, the "cheaper" unit would be more heavily redispatched.

MP1 Facilities

Only facilities categorized as MP1 by PJM are eligible for LMP Market Relief Actions. In essence, the cost of congestion on these facilities is socialized across the entire PJM market, unless the congestion is caused by an outage not meeting PJM's approved on-time requirements (See PJM Manual-03 PJM Manual-03: Transmission Operations or AEP Transmission Operations Outage Coordination Document R9 for more details on this topic).

MP2 (and lower) Facilities

Facilities categorized as MP2 (or lower) are not eligible for LMP Market Relief Actions, however, at the request of the Transmission Owner, PJM will redispatch generation to reduce loading on these facilities when absolutely necessary, assuming they are modeled and monitored in the PJM EMS. Redispatch costs will be solely allocated to the Transmission Owner requesting the redispatch. From an AEP standpoint, this is generally not a preferable solution since redispatch costs can easily exceed hundreds of thousands of dollars but AEP operators should not hesitate to utilize this option to relieve an emergency condition to maintain system reliability.

For additional information please refer to the AEP East Congestion Management Guidelines rev 2 document on the TOPS Sharepoint at Engineering>Operating Guidelines>AEP EAST>General

AEP Confidential Special Handling-CEII

SPP Congestion Management

In AEP West five methods of controlling thermal overloads on the AEP West transmission system:

1. CME
2. TLR
3. Market based congestion management
4. OOME – Manual Dispatch
5. Re-configuration or load shed

Congestion management is a process the Reliability Coordinator uses to manage operating constraints in the market. It may work in conjunction with the TLR process which manages non-market flow. SPP Constraint Status tool is used to control Market flow affecting operating limit violations.

Constraint actions:

- To Activate a Constraint means to have the solutions in the RTBM (Real-Time Balancing Market) honor or enforce a constraint limit.

- Bind a Constraint means to have the RTBM limit the flow across a constraint with re-dispatch that is out of economic order.

- Violate a Constraint means an Activated Constraint limit is exceeded.

When a constraint is observed in real-time, a SPP Congestion Management Event (CME) may be initiated and the constraint may be activated in RTBM. The CME can be initiated through declaration of a TLR and/or through an activation of a constraint in RTBM if an overload situation has been identified internal to the SPP Balancing Authority Area that does not require a TLR. SPP will declare a TLR if curtailable schedules exist in the NERC IDC above the curtailment threshold. The CME will cause RTBM to produce a Security Constrained Economic Dispatch using all available dispatchable Resources to provide appropriate reduction in flows to relieve the constraint. SPP will use RTBM to reliably manage and economically maximize the flow of power on flowgates to within the applicable operating limits as prescribed by NERC for CME events initiated either by IDC via a TLR or initiated through constraint activation for internal SPP constraints not requiring a TLR.

In the Market Flow Congestion Management Process (CMP) in Attachment 1 of the SPP-MISO Joint Operating Agreement), SPP determined and submits to the IDC its Market Flows on all SPP Coordinated Flowgates (CFs) and Reciprocal Coordinated Flowgates (RCFs). SPP's CFs are flowgates identified as being impacted by activities within SPP.

SPP may issue reliability directives via a Manual Dispatch Instruction to any on-line Resource to resolve a reliability issue the market system cannot resolve (referred to in the system as OOME, or out-of-merit energy)

AEP Confidential Special Handling-CEII

or to resolve an Emergency Condition. In addition, a local transmission operator may request SPP to issue OOME dispatch directives to applicable on-line Resources to resolve a reliability issue or may issue OOME dispatch directives directly to resolve a Local Emergency Condition. Time permitting, OOME dispatch directives will be issued by SPP.

For additional information please refer to the AEP West Congestion Management Guidelines rev 1 document on the TOPS Sharepoint at Engineering>Operating Guidelines>AEP West>General

AEP has reconfiguration / load shed guides to help control flows on facilities that would be coordinated with the SPP RC for a congestion event. The PCAP procedures are stored at the http://topsweb URL under the Dispatch tab.

AEP Confidential Special Handling-CEII

NERC Transmission Loading Relief (TLR) Procedure

The NERC Transmission Loading Relief (TLR) Procedure is an Eastern Interconnection-wide procedure to allow the Reliability Coordinator to:

- Respect Transmission Service reservation priorities, and
- Mitigate potential or actual limit violations.

TLR Level	Reliability Coordinator Action	Comments
1	**Notify** Reliability Coordinators of potential System Operating Limit (SOL) or Interconnection Reliability Limit (IROL)violations.	
2	**Hold** Transfers at present level to prevent SOL or IROL violations.	Of those transactions at or above the Curtailment Threshold, only those under existing Transmission Service reservations will be allowed to continue, and only to the level existing at the time of the hold. Transactions using Firm Point-to-Point Transmission Service are not held.
3a	**Reallocation** of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service.	Curtailment follows Transmission Service priorities. Higher priority transactions are enabled to start by the Reallocation process. See Attachment 1 to IRO-006, Section 2.3 and Section 6.0.
3b	**Curtail** Interchange Transactions using Non-firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation.	Curtailment follows Transmission Service priorities. There are special considerations for handling Transactions using Firm Point-to-Point Transmission Service. See Attachment 1 to IRO-006, Section 2.4 and Section 7.0.
4	**Reconfigure** transmission system to allow Transactions using Firm Point-to-Point Transmission Service to continue.	There may or may not be an SOL or IROL violation. There are special considerations for handling Interchange Transactions using Firm Point-to-Point Transmission Service. See Attachment 1 to IRO-006, Section 2.5.
5a	**Reallocation** of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point.	Attempts to accommodate all Transactions using Firm Point-to-Point Transmission Service, though at a reduced ("pro rata") level. Pro forma tariff also requires curtailment/REALLOCATION on pro rata basis with Network Integration Transmission Service and Native Load. See Attachment 1 to IRO-006, Section 2.6 and Section 6.0.
5b	**Curtail** Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL Violation	Pro forma tariff requires curtailment on pro rata basis with Network Integration Transmission Service and Native Load. See Attachment 1 to IRO-006, Section 2.7.
6	**Emergency Procedures**	Could include demand-side management, re-dispatch, voltage reductions, interruptible and firm load shedding. See Attachment 1 to IRO-006, Section 2.8.
0	**TLR Concluded**	**Restore** transactions.

Figure VI-2 Transmission Loading Relief (TLR) Procedures

Unless explained otherwise, "curtailment" refers to those INTERCHANGE TRANSACTIONS with a 5% or greater DISTRIBUTION FACTOR on the CONSTRAINED FACILITY.

Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to the Open Access Transmission Tariff (OATT).

Priority Table

Priority 0	Non-Firm Next Hour Market Service - NX
Priority 1	Non-Firm Service over secondary receipt and delivery points – NS
Priority 2	Non-Firm Hourly Service – NH
Priority 3	Non-Firm Daily Service – ND
Priority 4	Non-Firm Weekly Service – NW
Priority 5	Non-Firm Monthly Service – NM
Priority 6	Non-firm imports for native load and network customers from sources not designated as network resources – NN
Priority 7	Firm Point to Point Service – F and Network Integration Transmission Service from Designated Resources FN

AEP Confidential Special Handling-CEII

NERC "Implementation Guideline for Reliability Coordinators: Eastern Interconnection TLR Levels" document list examples of possible system conditions for each TLR level.

TLR-1	• At least one Transmission Facility is expected to approach or exceed its SOL or IROL within 8 hours.
TLR-2	• At least one Transmission Facility is approaching or is at its SOL or IROL. Analysis shows that holding new and increasing non-firm Interchange Transactions and energy flows for the next hour can prevent exceeding this SOL or IROL.
TLR-3a	• At least one Transmission Facility is expected to exceed its SOL or IROL within the next hour. Analysis shows that full or partial curtailment or reallocation[1] of non-firm Interchange Transactions and energy flows can prevent exceeding this SOL and IROL.
TLR-3b	• At least one Transmission Facility is exceeding its SOL or IROL, or • At least one Transmission Facility is expected to exceed its SOL or IROL within the current hour Analysis shows that full or partial curtailment or reallocation[2] of non-firm Interchange Transactions and energy flows can prevent exceeding this SOL or IROLs.
TLR-4	• At least one Transmission Facility is expected to exceed its SOL or IROL. Analysis shows that full curtailment of non-firm Interchange Transactions and energy flows, or reconfiguration of the transmission system can prevent exceeding this SOL or IROL.
TLR-5a	• At least one Transmission Facility is expected to exceed its SOL or IROL within the next hour. Analysis shows that the following actions can prevent exceeding the SOL or IROL: • Full curtailment non-firm Interchange Transactions and energy flows, and • Reconfiguration of the transmission system, if possible, and • Full or partial curtailment or reallocation[3] of firm Interchange Transactions and energy flows.
TLR-5b	• At least one Transmission Facility is exceeding its SOL or IROL, or • At least one Transmission Facility is expected to exceed its SOL or IROL within the current hour. Analysis shows that the following actions can prevent exceeding the SOL or IROL: ▪ Full curtailment of non-firm Interchange Transactions and energy flows, and ▪ Reconfiguration of the transmission system, if possible, and ▪ Full or partial curtailment or reallocation[4] of firm Interchange Transactions and energy flows.
TLR-6	• At least one Transmission Facility is exceeding its SOL or IROL, or • At least one Transmission Facility is expected to exceed its SOL or IROL upon the removal from service of a generating unit or another transmission facility.
TLR-0	• No transmission facilities are expected to approach or exceed their SOL or IROL within 8 hours, and the ICM procedure may be terminated

Additional PJM Emergency Procedures

PJM – Thermal Operating Guides

(Excerpts from PJM Transmission Operations M03 and Emergency Manual M13) Additional details may be found in specific operating memos outlined above.

Thermal Limit Exceeded	Corrective Actions	Time to Correct with Load Shed (Note 1)
Normal Rating (Acutal flow greater than Normal Rating but less than Emergency Rating)	Non-cost actions, off-cost actions, emergency procedures except load shed.	Correct in 15 minutes, load shed is not used
Emergency Rating (Actual flow greater than Emergency Rating but less than load Dump Rating)	All of the above plus shed load to control violation below Emergency Rating.	Within 15 minutes of violation (Note #2)
Load Dump Rating (Actual flow greater than Load Dump Rating)	All of the above plus shed load to control violation below Emergency Rating.	Within 5 minutes of violation

Figure VI-3 Actual Overload Thermal Operating Guides

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.

Note 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 (PJM m03) for the facility, if other corrective actions were not successful.

AEP Confidential Special Handling-CEII

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 dump.**	**30 minutes**
Load Dump	**All of the above however, shed load only if necessary to avoid post-contingency cascading.**	**30 minutes**

Figure VI-4 Post Contingency Simulated Thermal Operating Guide

Legend
Non-Cost
Off-Cost
Load Shedding

Note: System readjustment should take place within 30 minutes. PCLLRW should be implemented as post-contingency violations approach 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.

Transmission Planning determines AEP's facility normal , emergency, and short time ratings. The Short Time Equipment Limit Methodology is utilized for determining PJM Load Dump Limits as required by PJM. At present, short time equipment limits are not required for AEP facilities in the SPP or ERCOT footprints in addition to the already established equipment normal and emergency ratings.

For additional details refer to the AEP Short Time Equipment Limit Methodology document located on the TOPS Sharepoint at Engineering>Business Practices

AEP Confidential Special Handling-CEII

Voltage Limit Violations

Voltage Limit Exceeded	If Actual voltage limits are violated	Time to correct
High Voltage	Use all effective non-cost and off-cost actions.	Immediate
Normal Low	Use all effective non-cost actions, off-cost actions, and emergency procedures except load dump.	15 minutes
Emergency Low	All of the above plus, shed load if voltages are decaying.	5 minutes
Load Dump Low	All of the above plus, shed load if analysis indicates the potential for a voltage collapse.	Immediate
Transfer Limit Warning Point (95%)	Use all effective non-cost actions. Prepare for off-cost actions. Prepare for emergency procedures except load dump.	Not Applicable
Transfer Limit	All of the above, plus shed load if analysis indicates the potential for a voltage collapse	15 minutes or less depending on severity.

Figure VI-5 Actual Voltage Limit Violations

Voltage Limit Exceeded	If post contingency simulated voltage limits are violated.	Time to correct
High Voltage	Use all effective non-cost actions.	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 dump.	15 minutes
Load Dump Low	All of the above plus, shed load if analysis indicates the potential for a voltage collapse.	5 minutes
Voltage Drop Warning	Use all effective non-cost actions.	Not Applicable
Voltage Drop Violation	All effective non-cost actions, off-cost actions plus, shed load if analysis indicates the potential for a voltage collapse	15 minutes

Figure VI-6 Post Contingency Simulate Voltage Limit Exceeded

Transmission Planning determines AEP's Voltage Limits.

AEP Confidential Special Handling-CEII

Heavy Load, Low Voltage Conditions (PJM Manual 13 - Section 5)

The following may be used to supplement other existing procedures when system loads are heavy and bulk power voltage levels are, on an anticipated or actual basis, at or approaching undesirable low levels. These procedures consist of the following:

- Low Voltage Alert
- Heavy Load Voltage Schedule Warning
- Heavy Load Voltage Schedule Action

Low Voltage Alert

The purpose of the Low Voltage Alert is to heighten awareness, increase planning, analysis, and preparation efforts when heavy loads and low voltages are anticipated in upcoming operating periods. PJM will issue this alert to members (Generation and Transmission) when projections show these conditions are expected. This Alert can be issued for the entire PJM RTO, specific Control Zone(s) or a subset of Control Zone(s).

- PJM will conduct power flow analysis of the impact of future load and transfer increases upon the PJM system. Using this forward analysis, evaluation and planning will take place; including ensuring any reasonable necessary off-cost generation is ready to respond to anticipated transfer constraints. In this evaluation, consideration will also be given to changing the Reactive Transfer back-off limit from its normal value of 50 MW to 300 MW (interface dependent). If the decision is made to implement this measure, PJM will continually reassess the impact of this change on operations. .
- PJM will review generation and transmission outages (internal and external) and their impact on projected voltage problems.
- PJM will assess the impact of transfers and be prepared to rapidly identify any curtailable transactions that are adversely impacting reactive transfer limits.
- Using the NERC Interchange Distribution Calculator (IDC), PJM will assess the impact of parallel flows on its own facilities and transfer limits. If these flows are seen to be significant, PJM will be prepared, prior to dumping load, to invoke the NERC Transmission Loading Relief (TLR) process to provide relief from these parallel flows. .
- PJM will enhance reactive reporting from members by requesting a Reactive Reserve Check (RRC). (Also see PJM Manual M14D: Generator Operational Requirements, Attachment D: PJM Generating Unit Reactive Capability Curve Specification and Reporting Procedures.)
- PJM will enhance communications among SOS Transmission members via conference calls to discuss the status of critical equipment, voltage trends, and possible corrective actions.
- PJM dispatcher cancels the alert, when appropriate.
- SCC/MO notify their management and advise all stations and key personnel.
    - Transmission / Generation dispatchers ensure that all deferrable maintenance or testing affecting capacity or critical transmission is halted. Any monitoring or control maintenance work that may impact operation of the system is halted.
- SCC/MO to respond to PJM Reactive SSR by checking status and availability of all critical reactive resources. This includes polling generating stations of their reactive capabilities and the status of automatic voltage regulators. Any deviations or deficiencies of any equipment's reactive capabilities from what is modeled in the PJM EMS must be reported to PJM Power Dispatch.

AEP Confidential Special Handling-CEII

<u>Heavy Load Voltage Schedule Warning</u>

A Heavy Load Voltage Schedule Warning is issued to members via the ALL-CALL system (Generation and Transmission) to request members to prepare for maximum support of voltages on the bulk power system. This Warning can be issued for entire PJM RTO, specific Control Zone(s) or a subset of Control Zone(s).

- Four hours prior to requesting the actual implementation of the Heavy Load Voltage Schedule, PJM may give advance notice to members of the upcoming need for this schedule. At that time, members will be requested to verify that all actions have been taken on the distribution and sub-transmission systems to support the voltage at the EHV level.
- PJM dispatcher cancels the Heavy Load Voltage Schedule Warning, when appropriate.
- SCC while observing established limits should ensure that where possible, all underlying reactors are out of service, all capacitors on the underlying system are in service, and transformer taps are adjusted to ensure distribution capacitors are in-service.
- SCC should contact MO and verify that all unit voltage regulators are in service.

<u>Heavy Load Voltage Schedule</u>

A Heavy Load Voltage Schedule is issued to members (Generation and Transmission) at peak load periods via the ALL-CALL system to request maximum support of voltages on the bulk power system and increase reactive reserves at the EHV level. This Action can be issued for entire PJM RTO, specific Control Zone(s) or a subset of Control Zone(s).

- PJM at peak load period, request all companies implement the Heavy Load Voltage Schedule via the ALL-CALL system.
- PJM dispatcher cancels the Heavy Load Voltage Schedule, when appropriate.
- SCC while observing established limits should ensure that where possible, all reactors are out of service, all capacitors on the underlying system are in service, capacitors at the EHV level with PLC's are in service where required.
- SCC should verify that all unit voltage regulators are in service.
- SCC should ensure all units on the EHV are at there normal schedule
- SCC should ensure all units on the 230 kV system and below should increase MVAR output as necessary to maintain designated bus voltage schedules.
    - o Attempt to have units run at the high end of their voltage schedule; i.e. if the voltage schedule is 1.009, and the top band is 1.014, have units operate at this level.
    - o If higher than scheduled voltages are required, increase voltage schedules in 1 volt increments until voltage conditions improve, or a Max. Mvar limit is reached.
- Generating units should notify the TDC when they are approaching any reactive limits
- TDC should notify SCC of any units approaching reactive limits
- SCC should keep the PJM Power Dispatcher informed of any units approaching maximum MVAR output, any abnormal unit MVAR restrictions, and any voltage regulators that are out of service.

AEP Confidential Special Handling-CEII

Post Contingency Local Load Relief Warning (PJM Manual 13 - Section 5.4)

The purpose of the Post Contingency Local Load Relief Warning is to provide advance notice to a transmission owner(s) of the potential for load shed in their area(s). It is issued after all other means of transmission constraint control have been exhausted or until sufficient generation is on-line to control the constraint within designated limits and timelines as identified in PJM Manual 3 Transmission Operations, Section 2 –Thermal Operating Guidelines. A Post Contingency Local Load Relief Warning is to be communicated to the applicable TO(s) and posted via the Emergency Procedures Posting Application and is not communicated via the "PJM All-Call"). The PCLLRW is not considered a standing Directive to the TO for load shed. If the contingency for which the PCLLRW was issued occurs, PJM will evaluate the system conditions and then, if needed, issue a Load Shed Directive. The Load Shed Directive will be posted via the Emergency Procedures Posting Application. This procedure is distinct and separate from the MANUAL LOAD DUMP WARNING (Use "ALL CALL"). Refer to Manual Load Dump Warning procedure for Capacity Shortages, Interface Reactive Constraint Management or Multi Area Transmission Constraint Management.

> **Note 1**: Except for the single area "Post Contingency Local Load Relief Warning", the Manual Load Dump Warning is unchanged. This change should preserve the sense of urgency appropriate for both.
>
> **Note 2**: Post-Contingency Local Load Relief Warnings are intended to relieve localized constraints, generally 230kV and below. A Manual Load Dump Warning should still be used for Capacity Shortage conditions which result in Interface Reactive Constraint or Multi Area Transmission Constraint Management.

PJM Actions

- PJM and transmission owner dispatcher review contingency flows / limits and discuss off-cost operations/switching solutions prior to implementation of a Post- Contingency Local Load Relief Warning, system conditions and time permitting.
- PJM and transmission owner dispatcher(s) review and implement acceptable pre-contingency switching options in lieu of issuing a Post-Contingency Local Load Relief Warning. Post-contingency switching options documented in the PJM Transmission Operations Manual (M03), Attachment D: Post Contingency Congestion Management Program may alleviate the need to issue a Post-Contingency Local Load Relief Warning.
  - **NOTE**: If post contingency flows exceed the Load Dump rating, PJM will direct the Transmission Owner to implement any available switching solutions, provided they do not create any additional actual overloads in exceedance of their normal rating or post-contingency overloads.
- PJM dispatcher commits/de-commits effective generation consistent with Manual 12 – Dispatch Operations, Attachment B – Transmission Constraint Control Guidelines, including adjusting hydro/pumping schedules, curtailing interchange transactions, and/or committing quick-start generation to control flows within acceptable limits, as appropriate. The market to market redispatch must be implemented where applicable.

AEP Confidential Special Handling-CEII

- PJM dispatch implements 100% Synchronized Reserves and/or declares a Local Maximum Emergency Generation Event, as appropriate.
- PJM dispatcher issues the Post-Contingency Local Load Relief Warning to the transmission owner dispatcher(s) stating the estimated amount of relief that is required on the monitored facility to return flows below the Emergency Rating or an agreed upon level. . If the TO does not have sufficient load to shed or sufficient time to shed the load to comply, the TO will inform PJM. PJM will then review the PCLLRW to include neighboring TO loads if applicable or develop an alternative plan to control.
- PJM dispatcher provides the load distribution factor report to the impacted transmission owner dispatcher(s) via e-mail. Load Distribution Factor reports should be redistributed as changes to system reconfiguration warrant.
- PJM Dispatcher issues a Post-Contingency Local Load Relief Warning via Emergency Procedure Posting Application to PJM web-site, detailing any post-contingency switching, generation reduction, procedure or load-transfer solution, providing additional information regarding the firmness of anticipated post-contingency load dump.
- PJM and transmission owner dispatcher (s) periodically review and monitor approved post-contingency switching options.
- PJM dispatcher reviews acceptable post-contingency switching options. Post-contingency switching, generator reduction, or load transfer options should be implemented prior to implementing a Load Shed Directive.
- PJM and Transmission Owner Dispatcher(s) should review potential post-contingency manual generation trip schemes. Manual generation trip schemes should be identified and agreed to in advance.
- PJM and transmission owner dispatcher (s) should agree upon post-contingency load transfer options. Transmission owner dispatch(s) would need to periodically re-evaluate the load transfer solution.
- PJM dispatch establishes a mutual awareness with the appropriate transmission owner dispatcher(s) of the need to address the occurrence of a serious contingency with minimum delay.
- PJM dispatch examines area bulk power bus voltages and alerts the appropriate transmission owner dispatcher(s) of the situation.
- PJM dispatch shall be prepared to implement a Load Shed Directive if post-contingency switching, generator reduction, or load transfer options fail and the contingency occurs. The Load Shed Directive will be posted via the Emergency Procedures Posting Application.
- PJM dispatcher cancels the warning, when appropriate.

SCC Actions:

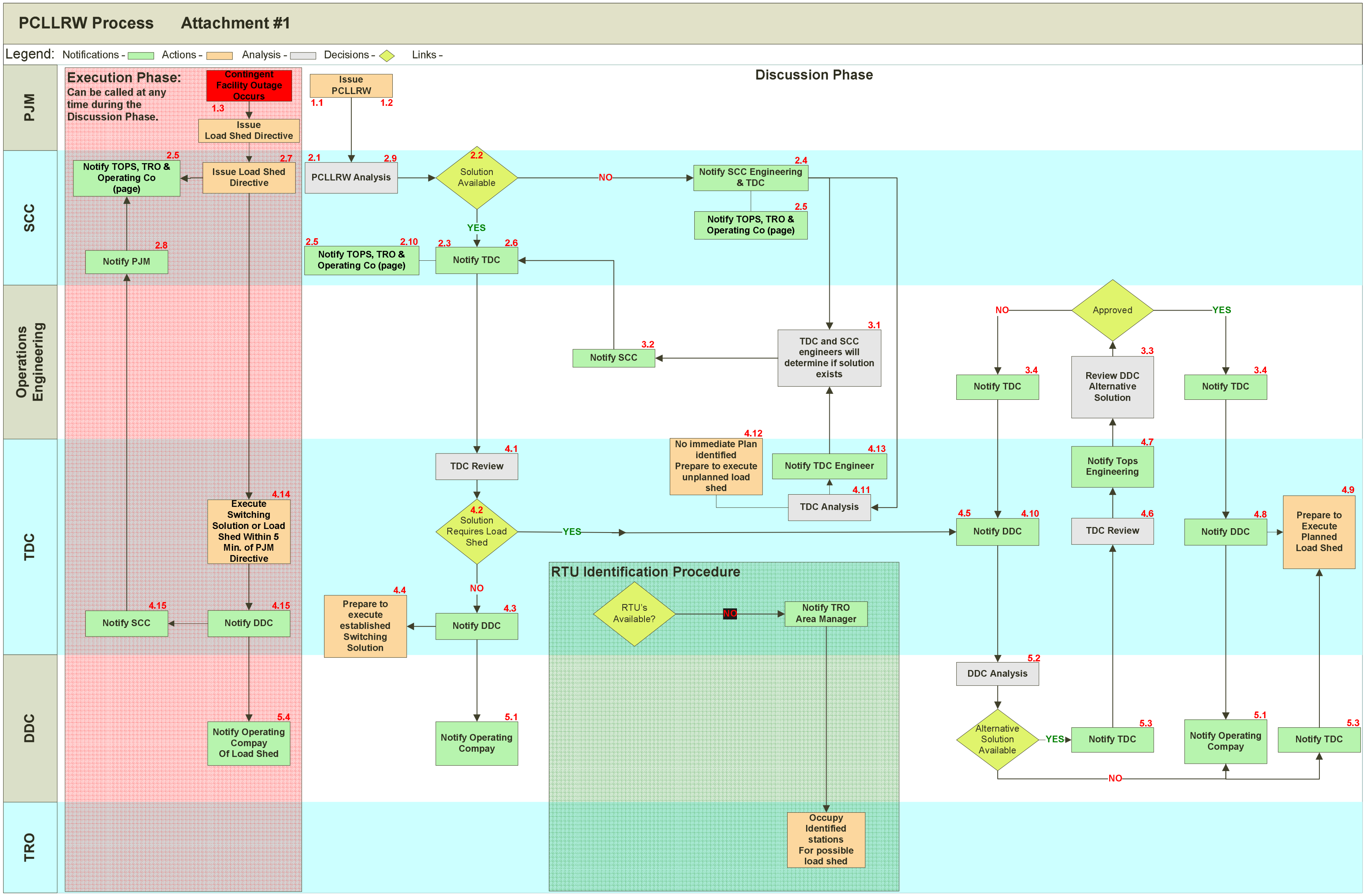
- PJM and the SCC discuss the amount of load to be curtailed to return flows below emergency ratings and the effective location(s). The SCC shall utilize the PCLLRW eTool application to notify PJM when the load to shed has been identified. The SCC will also notify PJM if there is not sufficient load to shed, or sufficient time to implement the load shed, to reduce the post contingency flows below the emergency rating.
- PJM allows post-contingency switching for Market Priority One (MP1) facilities to control a projected overload (or, an actual overload post-contingency), provided it is studied in advance and documented in M-03, "Post Contingency Congestion Management Program." They will concurrently issue a Post-Contingency Local Load Relief Warning (PCLLRW) for a load shed amount to alleviate the same constraint that will reduce flow on the overloaded facility to below

100% of the current, temperature-adjusted emergency rating. In essence, this is a backup solution in case the studied switching solution is either ineffective or becomes unavailable. PJM will issue a DFAX report with the PCLLRW detailing potential load shed relief locations and amounts calculated by their EMS.

  - Please refer to PJM website to view the list of switching solutions PJM has previously identified.(http://www.pjm.com/markets-and-operations/etools/oasis/system-information/switching-solutions.aspx)

- For Market Priority Two (MP2) facilities, the switching solution does not have to be documented formally in M-03. The PCLLRW issued will also be considered "Non-market."
  - In consultation with the PJM RC, AEP has reconfiguration / load shed guides to help control flows on facilities. The PCLLRW procedures are stored at the http://topsweb URL under the Dispatch tab

The AEP PCLLRW Procedure Document has specific procedures to determine the course of action to mitigate the overloads/undervoltage if the identified outage was to occur for a PCLLRW. The AEP procedures follow the PJM Member Actions in Section 5.4 of M-13. Please refer to PCCLLRW Process Document located on the TOPS Sharepoint at **>SCC>SCCO East** for additional information. A flowchart for the PCLLRW Process appears in Attachment 1 below.



AEP Confidential Special Handling-CEII

Post-Contingency Load Dump Limit Exceedance Analysis (PJM Manual 13 Section 5.4.1)

Once all available switching or off-cost has been exhausted to control a constraint with an issued PCLLRW, if the expected post-contingency loading exceeds 115% of the applicable load dump limit, PJM will initiate additional analysis to determine if unplanned tripping of the facility could lead to a potential cascading scenario. If no additional overloads above 115% of applicable load dump limits or voltage deviations result from the study, the scenario is expected to be a local problem and not subject to cascading failure. If, however, additional overloads beyond 115% of load dump are encountered, the study is performed sequentially for up to five total facilities. If at any point solution non-convergence occurs or additional overloads exist at the conclusion of the study, pre-contingency load shedding will be required to alleviate the potential cascade. More details are located in PJM Manual-13: Emergency Operations

Complete details of the switching solution process are available in PJM Manual-03: Transmission Operations.

For AEP Transmission Operations' specific response to PCLLRWs issued by PJM, please see the PCLLRW Process Document noted previously.

PJM Reactive Reserve Check (RRC) (PJM Manual 14D Attachment D)

Upon the request of PJM, The System Control Centers (SCC) will provide a "Reactive Reserve Check" report to PJM. This report filled out in the eDart RRC form will include the following information within the Transmission Owners zone: Refer to our MVARS display on the ADXfg - SCC machine for the desired values.

This report will include the following information within the Transmission Owner's zone:

- Unit MVAR Reserve (The sum of the differences between the present operating points, leading or lagging, and the lagging MVAR capability of all synchronized units.)
- Lagging MVAR Reserve (The sum of the lagging MVAR capability of all on-line condensers and Static Var Compensators.)
- Transmission Capacitor/Reactor MVAR Reserve (The sum of the nameplate MVAR values of capacitors that are capable of being energized or reactors that can be removed from service.)
  Note: The first two items require open dialogue between the Transmission Owner and the Generation Owners within the Transmission Owner's footprint.
- PJM will make the report available to Local Control Centers.

PJM Reactive Reserve Check (RRC)			
Transmission Owner	Unit MVAR Reserve	Lagging MVAR Reserve	Transmission Capacitor/ Reactor Reserve
PJM TOTAL			

Units equipped with [redacted]

Plant Name (Station Name)	Unit No.	Summer Net Real Power Capability	PSS/E Bus Name	PSS/E Unit ID	Status
AEP-RFC[1]					
Anderson CT	3	75	05ANDCT	3	
Ceredo (Twelve Pole Creek)	1	80	05TWELVE	1	
Ceredo (Twelve Pole Creek)	2	80	05TWELVE	2	
Ceredo (Twelve Pole Creek)	3	80	05TWELVE	3	
Ceredo (Twelve Pole Creek)	4	80	05TWELVE	4	
Ceredo (Twelve Pole Creek)	5	80	05TWELVE	5	
Ceredo (Twelve Pole Creek)	6	80	05TWELVE	6	
Conesville	4	775	05CVG4	4	Not Activated
Conesville	5	400	05CVG5	5	
Conesville	6	400	05CVG6	6	
Foothills (Baker)	1	167	20FOOTHL	1	
Foothills (Baker)	2	167	20FOOTHL	2	
Hanging Rock (Cornu)	1A	175	05CORNU	1A	
Hanging Rock (Cornu)	1B	175	05CORNU	1B	
Hanging Rock (Cornu)	1S	250	05CORNU	1S	
Hanging Rock (Cornu)	2A	175	05CORNU	2A	
Hanging Rock (Cornu)	2B	175	05CORNU	2B	
Hanging Rock (Cornu)	2S	250	05CORNU	2S	
Lawrenceburg	G1	560 total	05LAWBG1	1A	
Lawrenceburg	G2		05LAWBG1	1B	
Lawrenceburg	S1		05LAWBG1	1S	
Lawrenceburg	G3	560 total	05LAWBG2	2A	
Lawrenceburg	G4		05LAWBG2	2B	
Lawrenceburg	S2		05LAWBG2	2S	
R.P. Mone	1	170	05CONVOY	1	
R.P. Mone	2	170	05CONVOY	2	
R.P. Mone	3	170	05CONVOY	3	
Riverside (Zelda)	1	167	20ZELDA	1	
Riverside (Zelda)	2	167	20ZELDA	2	
Riverside (Zelda)	3	167	20ZELDA	3	
Rockport	1HP	666	05RKG1	1H	
Rockport	1RH	654	05RKG1	1R	
Rockport	2HP	656	05RKG2	2H	
Rockport	2RH	644	05RKG2	2R	
Rolling Hills (Flatlick)	1	170	05FLTLCK	1	
Rolling Hills (Flatlick)	2	170	05FLTLCK	2	
Rolling Hills (Flatlick)	3	170	05FLTLCK	3	
Rolling Hills (Flatlick)	4	170	05FLTLCK	4	
Rolling Hills (Flatlick)	5	170	05FLTLCK	5	
Sugar Creek (Darwin)	1A	167	05DARWIN	1A	
Sugar Creek (Darwin)	1B	167	05DARWIN	1B	
Sugar Creek (Darwin)	1S	243	05DARWIN	1S	
Washington (Beverly)	1A	175	05BEVERL	1A	
Washington (Beverly)	1B	175	05BEVERL	1B	

AEP Confidential Special Handling-CEII

Plant Name (Station Name)	Unit No.	Summer Net Real Power Capability	PSS/E Bus Name	PSS/E Unit ID	Status
Washington (Beverly)	1S	250	05BEVERL	1S	
Waterford	GT1	810 total	05WATERF	1A	
Waterford	GT2		05WATERF	1B	
Waterford	GT3		05WATERF	1C	
Waterford	ST1		05WATERF	1S	
AEP-SPP					
East Texas Co-gen (Eastex Switching via North Texas Eastman)	G1	178.5	ESTGAS1	1	
East Texas Co-gen (Eastex Switching via North Texas Eastman)	G2	178.5	ESTGAS2	1	
East Texas Co-gen (Eastex Switching via North Texas Eastman)	S1	128	ESTSTM1	1	
Gateway (Tenaska Switch)	G1	179	TENGAS	1	
Gateway (Tenaska Switch)	G2	179	TENGAS	1	
Gateway (Tenaska Switch)	G3	179	TENGAS	1	
Gateway (Tenaska Switch)	S1	400	TENSTM	1	
Green Country (Riverside)	G1	183	COGEN G1	G	
Green Country (Riverside)	S1	115	COGEN S1	S	
Green Country (Riverside)	G2	183	COGEN G2	G	
Green Country (Riverside)	S2	115	COGEN S2	S	
Green Country (Riverside)	G3	183	COGEN G3	G	
Green Country (Riverside)	S3	115	COGEN S3	S	
Harrison County (Lebrock)	G1	211	LEBROCG1	1	
Harrison County (Lebrock)	G2	211	LEBROCG2	1	
Harrison County (Lebrock)	S1	275	LEBROCS1	1	
J.L. Stall	6A	153	ARSHILL2	G1	
J.L. Stall	6B	153	ARSHILL3	G2	
J.L. Stall	6S	187	ARSHILL4	S1	
Mattison	1	75	MATISN-1	1	
Mattison	2	75	MATISN-2	1	
Mattison	3	75	MATISN-3	1	
Mattison	4	75	MATISN-4	1	
Northeastern (Northeast Gas)	1A	150	NES1-1A	1	
Northeastern (Northeast Gas)	1B	150	NES1-1B	1	
Oneta	S1	255	OECSTM1	1	
Oneta	G1-1	175	OECGT1-1	1	
Oneta	G1-2	175	OECGT1-2	1	
Oneta	S2	255	OECSTM2	1	
Oneta	G2-1	175	OECGT2-1	1	
Oneta	G2-2	175	OECGT2-2	1	
Riverside	3	73	RSS NG3	1	
Riverside	4	73	RSS NG4	1	
Southwest	4	71	SWS NG4	1	
Southwest	5	71	SWS NG5	1	
Turk	1	600	TURKCOAL	1	

AEP Confidential Special Handling-CEII

(1) While the [redacted] units are physically capable of connecting to the AEP system, they are owned by NIPSCO and currently operate connected to the Duke Energy Midwest system (MISO footprint). Per the interconnection agreement, these units cannot operate concurrently on the AEP system and the Duke Energy Midwest system.

The Voltage_and_Reactive_Guide_AEPE_AEPW-SPP contains the latest list of [redacted] which resides on the AEP TOPS Sharepoint at **Engineering>Operating Guidelines>AEP System Wide Guides and Information.**

AEP Confidential Special Handling-CEII

Conservative Operation

The need to operate the SPP/PJM RTO, the AEP West Control Area, and the AEP East Control Zone more conservatively can be triggered by any number of weather, environmental, terrorist, or computer events, including:

- forest fires/brush fires that threaten major transmission circuits
- weather-related events, such as ice/snow/wind storms,serverly cold / hot weather, hurricanes, tornadoes, severe thunderstorms, and floods
- environmental alerts
- terrorist alerts
- solar magnetic disturbance events
- widespread fuel related emergencies
- failure of Energy Management System (EMS)/Control Area CAMS computers.

During conservative operations, SPP/PJM Reliability Coordinator may reflect conservative transfer limit values, select double-contingencies for review, and/or evaluate maximum credible disturbances.

- SPP/PJM Reliability Coordinator has the authority to reduce transfers into, across, or through the SPP/PJM RTO or take other actions, such as cost assignments to increase reserves and reduce power flows on selected facilities.
- It is SPP/PJM Reliability Coordinator's responsibility to analyze the reliability of the SPP/PJM RTO and determine if it is in jeopardy. If required, operations planning branch staff are called upon to develop revised limitation curves.
- SCC transmission dispatchers, MO generation dispatchers and MO/PJM marketers respond, as required, to specific requests and directives of the SPP/PJM Reliability Coordinator subject to the constraints noted in the Operator Responsibility and Authority to Act document in Appendix VI.
- SCC engineering personnel to provide support to transmission dispatchers.

A. If the State Estimator Real Time Network (RTNET) or Real Time Contingency Analysis (RTCA) solutions are invalid (after 3 solution attempts) or the Control Area CAMS computers fail, take the following actions:

1. SCC Operator to notify SPP/PJM Reliability Coordinator (RC) within **15 minutes** of State Estimator RTNET or RTCA invalid solution or CAMS computer failures as appropriate for the AEP East/West desks.
2. SPP/PJM to assist in monitoring system and advise the SCC Operator of any abnormal conditions or contingency loading concerns.
3. SCC Operator to notify TDC's to monitor SCADA/CAMS systems and advise the SCC of any transmission or unit CB operations, line overloads or abnormal voltages.
4. SCC Operator to notify STE Support 24x7 of RTNET or RTCA invalid solution /CAMS computer failures; STE Support to resolve issue as soon as possible.

AEP Confidential Special Handling-CEII

Note: A**n unknown operating state is declared** if the SPP/PJM RC EMS analysis tools are also invalid or unavailable concurrently with the AEP analysis tools. Notify Operations Engineering 24x7, in addition to STE Support if this condition exists.

B. If the RTCA routine fails to solve for a particular contingency (after 3 solution attempts), the SCC Operator should take the following actions as outlined:

1. SCC Operator to notify SPP/PJM RC of unsolved contingency & validate RC contingency solution.
2. Perform State Estimator STNET/STCA study to determine solution for unsolved contingency. If the case solves, screen for thermal and voltage violations and rerun the analysis every 30 minutes until the RTCA successfully solves the contingency. Notify Operations Engineering on-call 24x7 if STNET solution does not solve or causes thermal/voltage violations. Notify STE Support if SCC Operator is unable to perform periodic studies every 30 min until unsolved contingency issue is resolved
3. If the case does not solve, the SCC Operator is to notify the SPP/PJM Reliability Coordinator (RC) and ask the RC to assist in monitoring the contingency conditions.
4. Notify the STE Support on-call personnel to review the solution problem.

Note: If the State Estimator Real Time Network (RTNET) or Real Time Contingency Analysis (RTCA) solutions are invalid (after 3 solution attempts) or the Control Area CAMS computers fail, **an unknown operating state is declared** if the SPP/PJM Reliability Coordinator EMS analysis tools are also invalid or unavailable concurrently with the AEP analysis tools.

Refer to the “Operating in an Unknown State” procedure located on the TOPS Sharepoint >Engineering>Operating Guidelines> AEP System Wide Guidelines and Information area for more detailed information.

Emergency Messages

Samples of messages to be broadcast in affected areas and procedures for communicating transmission emergencies are included in Figures VI-7 through VI-10. Messages will be modified as necessary to convey the nature of the problem and the extent of the area affected.

This is an Emergency Message from American Electric Power Company

<u>*Location, Date*</u> –A serious electric transmission constraint is anticipated <u>*today/tomorrow*</u>, <u>*Day, Date*</u> as a result of the extremely <u>*hot*</u> weather.

To help ease this problem AEP urges all its customers in homes, factories, stores and everywhere in <u>*Districts Affected,*</u> to reduce their usage of electric power in every possible way, during the hours of 7AM through 9PM on <u>*Day, Date*</u>. Please avoid using such appliances as clothes washers, dishwashers, clothes dryers and ranges; turn off unnecessary lighting; and turn up the thermostat for air conditioning or turn off the air conditioning. Cooperation in reducing the demand for electricity during daylight hours all day will help prevent interruption of electric service.

AEP will keep customers informed with public announcements until this transmission constraint eases.

Energy Conservation Tips:

- Set the thermostat between 78 and 80 degrees and operate ceiling fans for additional comfort with raised temperatures.
- Draw drapes and close blinds to help cool the home.
- Turn off unnecessary lights.
- Turn off all non-essential equipment and appliances.
- Reduce hot water consumption
- Limit opening refrigerators and freezers.
- Limit water consumption if you are on well water.
- Limit use of kitchen appliances, dishwashers, ranges, etc.
- Avoid using washers and dryers

AEP appreciates the patience and cooperation of our customers during this extreme heat wave. Please cooperate now by reducing your use of electricity. By doing this, you can help prevent possible interruptions in your electric service. AEP will continue to keep you informed with public announcements until this problem eases and we thank you for your cooperation.

Figure VI-7
Voluntary Load Curtailment Initiation Announcement to the Public

This is an Emergency Message from American Electric Power Company.

A serious electric transmission constraint has developed as a result of (*unprecedented cold weather, unprecedented hot weather*).

To avoid uncontrolled blackouts it has become necessary to interrupt electric service to customers for periods ranging from ten minutes to two hours. To minimize inconvenience, the interruptions will take place on a rotating basis; while some areas will be off, others will be on. Later, the areas of outages will be reversed, so that no group of customers will have to bear all of the inconvenience.

When service is restored in your house, you can help AEP hasten the job by turning off all appliances, lights, radios, stereos, and television sets that were in use at the time the electricity went off. We recommend that you leave one low-watt electric light in the "on" position so that you'll know when the power has been restored.

AEP thanks you for your cooperation in helping us to get through this critical time.

Figure VI-8
Mandatory Load Curtailment Initiation Announcement to the Public

AEP Confidential Special Handling-CEII

This is an Emergency Message from American Electric Power Company.

The power curtailment to AEP's customers is continuing. In an effort to make this situation as easy as possible for all customers, the company is alternating the power cut-off among groups of customers for periods ranging from ten minutes to two hours. Make sure that all appliances are turned off so that, when the power is restored, it will not cause an overload and create further problems. If you are receiving power, please keep your usage to a bare minimum. With everyone cooperating, the company hopes to be able to restore full service as soon as conditions permit.

AEP regrets that the critical problem it now faces has made these drastic steps necessary, and thanks all of its customers for their cooperation and understanding.

Further announcements will follow as the situation continues to develop.

Figure VI-9
Mandatory Load Curtailment Information Statement to the Public

AEP Confidential Special Handling-CEII

This is a Message from American Electric Power Company.

AEP reports that the serious electric transmission constraint has now eased, and full-time electric service to its customers is being restored as quickly as possible.

While the power situation has improved enough to permit us to restore service, we ask you to continue to be careful in your power use. With your cooperation, we have come through this emergency in good shape, and we are grateful.

AEP thanks you.

Figure VI-10
Transmission Emergency Termination Statement to the Public

AEP Confidential Special Handling-CEII

Section VII
Major Storm Restoration

No aspect of operations is more important than the health and safety of people. Our customers' needs are met in harmony with environmental protection.

Introduction:

Super Storm Sandy, the June 2012 Derecho, the 2008 Hurricane Ike, and other big storms have brought a critical eye on the way utilities respond to large storms and other emergencies. Hurricane Ike is unique in that it impacted both the AEP West and AEP East areas. Initially the storm involved the AEP West SWEPCO area. The remnants of the storm then produced significant wind damage across the AEP East Ohio area.

As a result of the frequent large storm events, AEP developed the Emergency Response Plan to improve emergency response efforts. In addition, Transmission Operations has further developed several tools and process documents, such as the Outage Tracking System (OTS), the New Albany Transmission Operations Center Major Event Coordination document, and the TDC Storm Manual Tulsa Region, which align with the AEP Emergency Response Plan.

AEP Emergency Response Plan - Overview:

The AEP Emergency Response Plan (ERP - http://erp/) is a multi-year project to improve emergency response efforts within AEP and between Regulatory agencies and customers. The ERP project focuses on three key areas to improve AEP's emergency response:

1. Incident Command System (ICS) – ICS is a comprehensive approach to incident management. The management tool responds to both small and large emergencies.
2. Technology Deployment
   a. Outage Management System (OMS – http://OMS/)
   b. Enhanced Estimated Time of Restoration (ETR)
   c. Assessment and restoration processes.
3. Process Improvement – Improve the storm management structure and focus on assessment and restoration processes

ERP currently has 32 processes within the AEP ICS system. Each process is described in detail at the http://erp/ web page under the forms, checklist, procedures, and training materials area. A number of these processes are transmission specific and are listed below. Transmission Field Services (TFS) is the owner for the following transmission processes:

- ICS_Event_Level_Determination_-_Transmission_Process
- Transmission_Assessment_Process
- Transmission_Priority_Process

AEP ERP - Declaration of Transmission Emergency

One of the most important steps in the ERP is assessing the impact of the event and determining the severity of the event. For transmission related events, Transmission Field Services (TFS) and Transmission Operations (TOPS) play a key role in the initial event assessment. The ICS Event Level Determination – Transmission Process document contains a process flow chart to identify the event level to activate the appropriate transmission response. The response levels vary from I to V with I being the most severe.

A declaration of a Transmission Emergency will be determined by the TFS Managing Director and the TOPS Managing Director or their designees. Upon the declaration, the Directors will notify the VP's of AEP Transmission, as well as, the State Presidents of the emergency. The System Control Center Operator's will notify the Managing Directors of AEP Transmission, Corporate Communications, Network Command Center, Customer Services and the TDC's. The TDC's will notify Region Managers and the DDC's.

AEP ERP - Transmission Operations Overview:

Upon declaration of a Transmission Emergency, TOPS will utilize processes outlined in the Storm Restoration Plan below and as shown in the New Albany Transmission Operations Center Major Event Coordination document (located on TOPS Sharepoint>Emergency Plans>NATOC Major Event Coordination) and the TDC Storm Manual Tulsa Region (located on the TOPS Sharepoint at TDC>Tulsa>Emergency Plans>). These plans establish roles and responsibilities, and notification requirements during a major transmission event. Objectives include assessing the event, stabilizing the grid, restoring customers in a safe, efficient manner, and restoration of the grid to its original configuration. The TDC Unit Leader is part of the ICS structure and will be the liaison to ICS. The TDC Unit Leader must meet the training requirements defined by ICS.

TOPs will utilize the Outage Tracking System (OTS – http://ots/), which enhances communication between Transmission Dispatch, Distribution Dispatch, Transmission Field Services, and AEP management during major system events by providing a shared communication tool for the exchange of transmission outage information. OTS will be the catalyst for setting restoration priorities. The OTS program supports ICS during system events by allowing all approved AEP employees access to transmission and sub-transmission outage data via the OTS web page.

AEP ERP - Training Personnel

TOPS dispatch personnel, as well as applicable personnel throughout Transmission, have been trained in the ICS process. Additional ICS training manuals and links to the online training in KEY are listed on the http://erp/ web site under the References book icon and are available as needed. In addition, TOPS and Transmission Field Services Management are responsible for scheduling and training personnel on a regular basis so that the appropriate personnel are prepared to utilize the ICS structure and implement the Storm Restoration Plan when a major event occurs.

Storm Restoration Plan

THE KEY TO A SUCCESSFUL RESTORATION EFFORT IS IN THE EARLY ASSESSMENT OF THE EXTENT OF THE DAMAGES!

It is important to initiate the Storm Restoration Plan as soon as possible to ensure early assessment. The earlier the need for additional resources is identified, the sooner those resources can be mobilized and utilized in the restoration effort. However, as the outage situation worsens and the outage footprint expands, additional resources must be called upon to be involved in the restoration efforts. Communications with the various Coordination Centers will be facilitated by the use of Conference Bridges. As noted in the NATOC Major Event Coordination document, the Conference Bridge number(s) will be disseminated to all parties via text or email.

A. Restoration Priority

When a major outage emergency occurs, there is usually damage to the Company facilities at a number of locations. The removal of hazardous conditions has the highest priority. Maximum effort will then be placed in stabilizing the transmission grid to prevent the spread of outages to other areas not directly impacted by the storm. Once the transmission grid is stabilized, service to stations and customers will proceed as quickly and safely as possible with the primary effort being placed where the largest number of customers will be impacted.

Communicating accurate information in a timely manner during a major event is a critical component in the expedient restoration of the transmission system. The Outage Tracking System (OTS) will provide the communication interface between Transmission Dispatch, Distribution Dispatch and Transmission Field Services by providing multiple designated users the ability to input "real-time" data into a shared Web application. The shared Web application "**Data Entry Interface**" can be accessed by typing *http://otsnew* into the address bar of an internet access page.

The OTS program supports the ICS structure during system events by allowing all **approved** AEP employees access to transmission and sub-transmission outage data via the OTS web page. The web page gives users the ability to sort and research data. Data will include; Transmission outages, Distribution network circuit outages, affected stations, estimated assessment times (EAT), estimated field repair time (EFRT), estimated restoration times (ERT), trouble information, priority status (Station and Circuit/Equipment) and restoration rank. Please refer to the Outage Tracking System Guide -2015 users guide for additional information on the accessing the OTS system.

B. **Staffing**

The TDC Unit Leader and the SCC Lead Operator are responsible for allocating appropriate staff to manage the event. Additional staffing information is included in the NATOC Major Event Coordination document which also includes staffing responsibilities for Transmission Operations Engineering and State Estimator Support personnel. Transmission Operations management will also continually evaluate the staffing needs as the event progresses.

AEP Confidential Special Handling

C. Communications

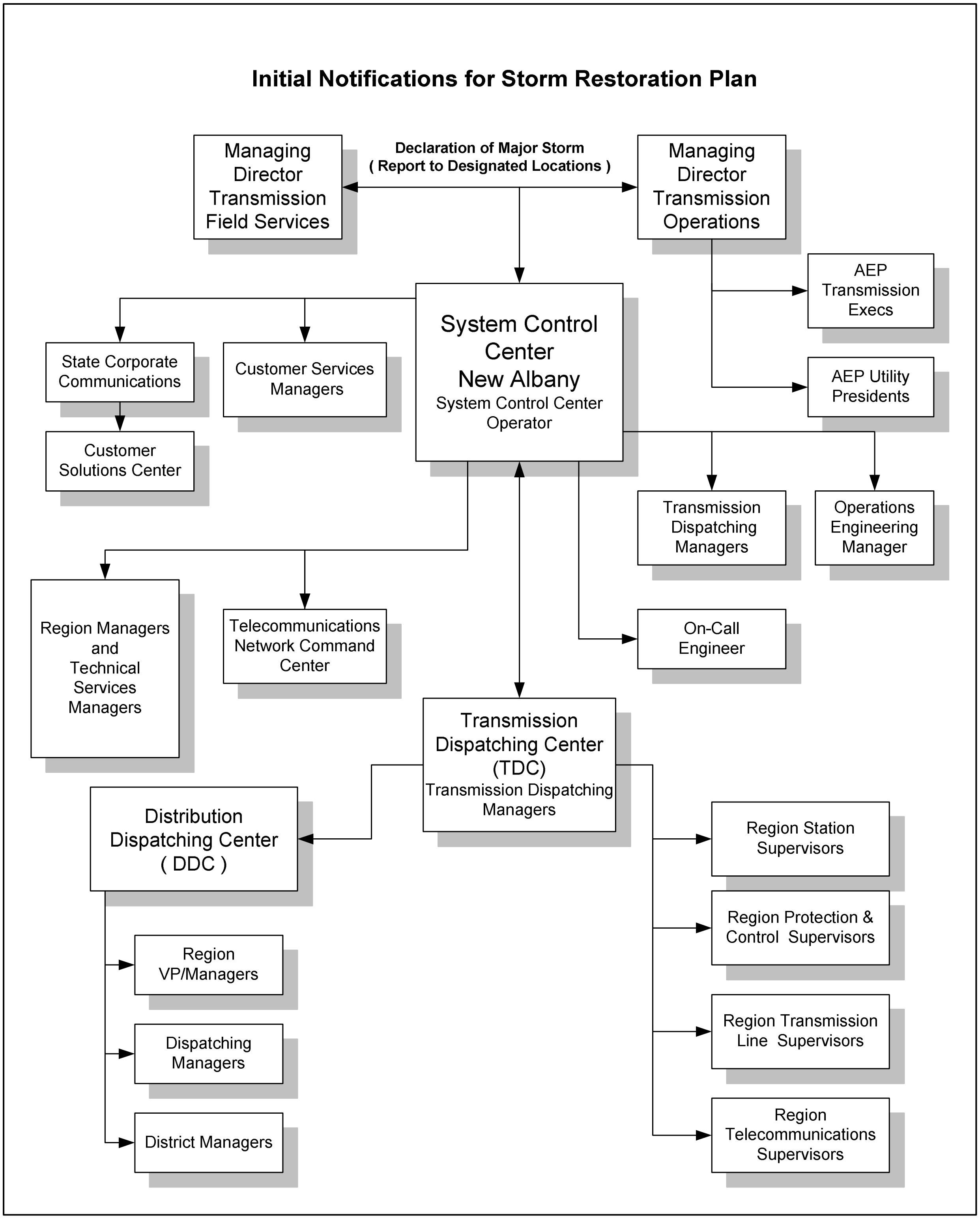


Figure VII-1

D. **Storm Organization Responsibilities**

Transmission Svcs. VP, Transmission Operations VP, Transmission Svcs.Region Directors, Transmission Operations Managers and personnel, T-Line supervision and engineers, Station Managers and engineers, P&C supervision, clerks and Distribution Operations.

Storm Titles	Description of Responsibilities	Likely Sources
Transmission Field Services (TFS)	1. Determine work priorities and convey them to the SCC. 2. Interface with state commissions via Regulatory Services, Corporate Communications, State Emergency Services, and all other outside entities. 3. Interface with Distribution Region management. 4. Receive damage assessments from the TFOps and the SCC. 5. Receive from the TFOps the manpower needs and equipment needs. 6. Obtain additional manpower and equipment to meet the needs of the TFOps. 7. Assign foreign crews to TFOps. 8. Set storm administrative policies. 9. Request Telecom. to call out personnel to reprogram radios. 10. Determine location for reprogramming 800 Mhz radios. 11. Determine the additional communication equip. required and request Telecom. to acquire. 12. Provide the TFOps with general data on incoming crews. 13. Arrange for line fault locating equipment. 14. Determine equipment that foreign crews should bring	Transmission Region Director and designees, Transmission Operations Managers and their designees, Distribution Operations representative

	with them. 15. Keep management informed and provide reports as required.	
Storm Titles	**Description of Responsibilities**	**Likely Sources**
System Control Center (SCC)	1. Inform the TFS of the status of facilities. 2. Assist the TFS in making work priorities. 3. Interface with Customer Services with regards to customer inquiries and obtain related info. from the TDCs. 4. Obtain info. from the TDCs on the status of company facilities. 5. Assist in informing Company Management. 6. Call in Operations Engineering	Transmission Operations Managers System Control Center Operators Engineering Support
Transmission Dispatch Center (TDC)	1. Dispatch crews. 2. Direct necessary switching. 3. Convey area and D-Region work priorities to SCC. 4. Receive damage assessment from crews. 5. Assign personnel to stations as needed. 6. Monitor location of crews. 7. Coordinate priorities with the DDCs and pass regional work priorities to the DDCs. 8. Convey equipment status to the DDCs and SCC. 9. Provide outage/restoration info. To the SCC at regular intervals. 10. Assign 800 Mhz radio storm emergency channels for Transmission work crews.	Dispatching Supervisors Dispatching Coordinators Transmission Dispatchers

Storm Titles	**Description of Responsibilities**	**Likely Sources**
Transmission Field Ops (TFOps)	1. Supply damage assessment and routine reports to TDCs and TFS. 2. Administer the administrative directives of the TFS. 3. Monitor crew progress and locations. 4. Receive damage assessments from crews. 5. Determine materials, equipment and manpower needs. 6. Provide food and lodging services. 7. Provide crew guides/scouts as needed. 8. Provide TDCs with detailed information about incoming crews. 9. Provide time keeping. 10. Establish work orders, answer phones, administer charge cards, supply employee handbooks.	T-Line Area supervision Station Area Managers P&C Area Supervision Clerks Material coordinators
Distribution Dispatching Center (DDC)	1. Direct switching on the distribution system from the feeder breakers out. 2. Coordinate work priorities with the TDCs. 3. Dispatch personnel in response to distribution alarms. 4. Provide reports on total customers outaged at regular time intervals. 5. Provide distribution equipment status to TDCs. 6. Work directly with the Customer Solutions Center to respond to customer outages. 7. Interface with critical customers such as those on life support systems.	Dispatching Managers Dispatching Supervisors Distribution Dispatchers

Storm Titles	Description of Responsibilities	Likely Sources
Field Crews	1. Provide damage assessments to TDCs and TFOps. 2. Determine equipment, materials and manpower needs and provide this information to TFOps and others as assigned. 3. Administer the administrative directives of the TFS. 4. Restore service to facilities as directed by the TDC. 5. Provide property owner damage assessments to TFOps. 6. Respond to property owner's damage. 7. Receive and conduct switching orders from the TDC. 8. Clear roads into stations. 9. Operate line fault locating equipment. 10. Maintain station batteries. 11. Assist Telecommunication to reach MW sites as requested. 12. Have all accident investigation forms	T-Line personnel P&C personnel Station personnel
Telecommunications	1. Lease cell phones. 2. Provide temporary communications equipment. 3. Provide communications equipment maintenance to include microwave sites. 4. Program 800 MHz radios for incoming crews at the designated location. 5. Provide hand held 800 MHz radios to field personnel as requested. 6. Provide outside maintenance services as required.	Telecommunication technicians

Storm Titles	Description of Responsibilities	Likely Sources
Customer Services	1. Respond to inquiries from customers. 2. Interface with the SCC\TDC with regard to restoration status. 3. Inform customers of estimated restoration times.	A person from Customer Services will be assigned to interface with their Field Engineers.
Shared Services	1. Provide 24 hours per day vehicle and stores services. Provide specialty permits for incoming crews.	Stores attendants Garage attendants
Corporate Communications	1. Act as the liaison between the TFS Directors, the outside media, and Government Organizations.	Corporate Communications
Customer Solutions Center	1. Respond to customer inquiries 2. Generate trouble tickets 3. Inform customers of estimated restoration times	Customer Solutions Center

These activities support the AEP Emergency Response Plan. The ICS structure is still being implemented in the APCO area.

E. **Storm Emergency Communications**

Sixteen storm channels have been created on the 800 MHz radio system for use by AEP East Transmission Operations during major storms. Emergency channels have been designated for each of the 5 dispatching areas (corresponds to dispatching desks) on the AEP East System as follows:

Dispatching Area		Storm Channels
Columbus West TDC	-	[redacted]
Columbus Central TDC	-	
Columbus East TDC	-	
Roanoke North TDC	-	
Roanoke South TDC	-	

The TDC Storm Manual Tulsa Region indicates the Transmission Dispatcher in the Tulsa TDC and Shreveport TDC in the AEP West region will determine when the storm channels will be used during a transmission emergency.

The Transmission Dispatcher will determine when their assigned storm channel(s) will be used during transmission emergencies to increase communications within their dispatching area. It will be the responsibility of the Transmission Dispatcher to inform both the transmission crew supervisors working in his area, and the TFOps, when storm channels are to be used.

Each AEP East transmission vehicle with an 800 MHz radio will have 12 storm channels programmed on their radio and will be able to communicate via the radio sites in the normal area of use, plus as many radio sites as possible in the adjacent area(s). For example, vehicles in the Columbus Central and possibly Columbus West dispatching areas will likely be able to assist during emergencies in the Columbus Transmission Region on transmission storm channel [redacted] without reprogramming. This will permit vehicles maximum flexibility to assist in adjacent dispatching areas generally with no reprogramming required. However, when vehicles are transported beyond the adjacent dispatching area (and out of range of approximately 8 storm channels), the radios must be re-programmed by telecommunications personnel at the receiving location.

The TFS is responsible for requesting Telecommunications to reprogram vehicles that will be traveling beyond their 800 MHz range. The TFOps is responsible to have the incoming vehicles go to a staging location where Telecommunications personnel will provide the required reprogramming.

AEP Confidential Special Handling

Section VIII
System Restoration

Black Start

Introduction:

The NERC EOP 005-2 and EOP 006-2 standards requires the AEP East and AEP West restoration plans to be approved by the respective PJM/SPP Reliability Coordinators. Copies of the Reliability Coordinator approved plans are stored on AEP TOps Sharepoint server for the AEP East and AEP West areas. Since there is an approved plan for each area, we need to refer to approved plan for additional information.

External entities previously identified have received a copy of the approved plan(s).

AEP Confidential Special Handling-CEII

Section IX

Introduction DOE and NERC Event Reporting requirements

This section relates to the NERC reporting requirements under NERC standard EOP-004-2. AEP applicable NERC entities include Transmission Operators and Generator Operators registrations. In addition, the Department of Energy (DOE) requires OE-417 form, "Electronic Incident and Disturbance Report" be completed and filed for incidents listed in "Schedule 1" of form OE-417 and in the instructions for form OE-417.

Process:

Recognition:

It is critical that AEP employees focus on reporting all types of events and activities, suspicious or otherwise that could jeopardize the reliability of the Bulk Electric System. For example, what appears as vandalism in a substation yard or control house may be exactly what it seems, or it might be part of a larger act. See Attachment 1 for a list of all events that need to be reported. It is important to note the reporting time requirements range from 1,6, or 24 (72 hours Final DOE report) for various events in Attachment 1.

ReportingResponsibilities:

Security Services

- AEP employees should focus on reporting all types of suspicious activity to Security Services
  - 1-866-747-5845 or audient 8-200-1337.
  - Security Services will ask if the incident has been reported to local law enforcement. If not, Security Services will request the caller to contact and report to local law enforcement if applicable.
- When AEP employees report information concerning suspicious activities, the IT Security Team will evaluate cyber security incidents in accordance with NERC CIP ‐ 008 Incident Response document and the Security Services Team will evaluate physical security incidents in accordance with the Security Services Investigation and Reporting Policies and Procedures.
- Security Services and/or IT Security will work with the appropriate business unit(s) and with law enforcement or investigative authorities to investigate the incident and report the findings of that investigation to the appropriate company and regulatory agency authorities.
- If applicable, Security Services will submit the CIPIS report to the NERC ESISAC. AEP participates with the NERC Electricity Sector Information Sharing and Analysis Center (ESISAC)and reports and receives alerts pertaining to incidents of a physical or electronic (cyber) nature.

Transmission Operations

The Transmission **System Control Center Operator** or **Corpus Christi TDC Dispatcher** are responsible for completing and filing all reports within applicable time requirements (AEP owned or Operated generation, as well as transmission events) with NERC and other entities documented in this memo (see below) with a copy being sent to TOPS management. The On-Call Engineer, System Control Center (SCC) or Corpus Christi TDC management can be consulted for assistance in completing the report.

If the event is applicable to both EOP-004-2 and DOE OE-417, AEP will file a **DOE OE-417 Report** on the incident since the DOE reporting time requirement is shorter than the **NERC EOP-004 Attachment 2** requirement. In this instance, the DOE Form OE-417 can be submitted to NERC in place of the NERC EOP-004-2 Attachment 2 form so there is no need to file both reports. Once an event has been recognized to meet the threshold, the form must be submitted within the applicable time frame as shown in Attachment 1.

Generally copper theft incidents will not be reported under this policy. However, copper theft incidents that result in customer outages or include control house breaches or other unusual circumstances will be reviewed by Transmission and Security personnel to determine if reporting is appropriate.

Attachment 1

Incident	Threshold	EOP-004 Attach 2 and/or OE-417 Reportable	File Report within:	Who Files Report for AEP Texas?	Who Files Report for AEP West?	Who Files Report for AEP East?	File Report With
Physical Attack[1]	Causes major Interruptions or impact to critical infrastructure facilities or to operations	**OE-417**	1 Hr	Corpus Christi TDC	SCCO West	SCCO East	NERC, RC, RE, DOE
BES Emergency requiring public appeal for load reduction	Public appeal for load reduction event.	**EOP-004 Attach 2 or OE-417**	**1 Hr**	**ERCOT or CC TDC***	**SPP or SCCO West***	**PJM or SCCO East***	**NERC, RC, RE, DOE**
BES Emergency requiring system-wide voltage reduction	System wide voltage reduction of 3% or more.	**EOP-004 Attach 2 or OE-417**	1 Hr	ERCOT	SPP or SCCO West*	PJM or SCCO East*	NERC, RC, RE, DOE
BES Emergency requiring manual firm load shedding	Manual firm load shedding ≥ 100 MW	**EOP-004 Attach 2 or OE-417**	1 Hr	Corpus Christi TDC	SCCO West	SCCO East & PJM	NERC, RC, RE, DOE
Complete operational failure or shut down of the transmission and/or distribution electrical system		**OE-417**	1 Hr	Corpus Christi TDC	SCCO West	SCCO East	NERC, RC, RE, DOE
Cyber Event[1]	Causes interruptions of electrical system operations	**OE-417**	1 Hr	AEP IT Security	AEP IT Security	AEP IT Security	NERC, RC, RE, DOE

Incident	Threshold	EOP-004 Attach 2 and/or OE-417 Reportable	File Report within:	Who Files Report for AEP Texas?	Who Files Report for AEP West?	Who Files Report for AEP East?	File Report With
Loss of firm load	Loss of firm load for ≥ 15 Minutes: ≥ 300 MW for entities with previous year's demand ≥ 3,000 OR ≥ 200 MW for all other entities	**EOP-004 Attach 2 or OE-417**	1 Hr	Corpus Christi TDC	SCCO West	SCCO East	NERC, RC, RE, DOE
System separation (islanding)	Each separation resulting in an island ≥ 100 MW	**EOP-004 Attach 2 or OE-417**	1 Hr	Corpus Christi TDC	SCCO West	SCCO East & PJM	NERC, RC, RE, DOE
Cyber Event[1]	Could potentially Impact electric powersystem adequacy or vulnerability	**OE-417**	6 Hrs	AEP IT Security	AEP IT Security	AEP IT Security	NERC, RC, RE, DOE
Fuel supply emergencies	Could impact electric power system	**OE-417**	6 Hrs	Corpus Christi TDC	SCCO West	SCCO East & PJM	NERC, RC, RE, DOE
Loss of electric Service	≥50,000 customers ≥1 hour	**OE-417**	6 Hrs	Corpus Christi TDC	SCCO West	SCCO East	NERC, RC, RE, DOE
Physical attack[1]	Could potentially impact electric power system adequacy or reliability; or vandalism which targets components of any security systems	**OE-417**	6 Hrs	Corpus Christi TDC	SCCO West	SCCO East	NERC, RC, RE, DOE
Damage or destruction of a facility	Damage or destruction of its Facility that results from actual or suspected intentional human action.	**EOP-004 Attach 2**	24Hrs	Corpus Christi TDC	SCCO West	SCCO East	**NERC, RC, RE**

Incident	Threshold	EOP-004 Attach 2 and/or OE-417 Reportable	File Report within:	Who Files Report for AEP Texas?	Who Files Report for AEP West?	Who Files Report for AEP East?	File Report With
BES Emergency resulting in automatic firm load shedding	Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or SPS/RAS).	**EOP-004 Attach 2**	24Hrs	**Corpus Christi TDC**	SCCO West	**SCCO East**	**NERC, RC, RE**
Complete loss of monitoring capability	Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.	**EOP-004 Attach 2**	24Hrs	Corpus Christi TDC	SCCO West	SCCO East	NERC, RC, RE
Complete loss of off-site power to a nuclear generating plant (grid supply)	Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement	**EOP-004 Attach 2**	24Hrs	Corpus Christi TDC	N/A	SCCO East	NERC, RC, RE
Complete loss of voice communication capability	Complete loss of voice communication capability affecting a BES control center for 30 continuous minutes or more.	**EOP-004 Attach 2**	24Hrs	Corpus Christi TDC	SCCO West	SCCO East	NERC, RC, RE
Damage or destruction of a facility	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in actions to avoid a BES Emergency	EOP-004 Attach 2	24Hrs	Corpus Christi TDC	SCCO West & SPP	SCCO East & PJM	NERC, RC, RE

Incident	Threshold	EOP-004 Attach 2 and/or OE-417 Reportable	File Report within:	Who Files Report for AEP Texas?	Who Files Report for AEP West?	Who Files Report for AEP East?	File Report With
Generation loss	Total generation loss, within one minute, of : ≥ 2,000 MW for entities in the Eastern or Western Interconnection OR ≥ 1,000 MW for entities in the ERCOT or Quebec Interconnection	**EOP-004 Attach 2**	24Hrs	ERCOT	SCCO West & SPP	SCCO East & PJM	NERC, RC, RE
IROL Violation (all Interconnections)	Operate outside the IROL for time greater than IROL Tv (all Interconnections)	**EOP-004 Attach 2**	24Hrs	**ERCOT**	**SPP**	PJM	NERC, RC, RE
Physical threats to a Facility	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at a Facility. Do not report theft unless it degrades normal operation of a Facility.	**EOP-004 Attach 2**	24Hrs	**Corpus Christi TDC**	SCCO West	SCCO East	NERC, RC, RE

Incident	Threshold	EOP-004 Attach 2 and/or OE-417 Reportable	File Report within:	Who Files Report for AEP Texas?	Who Files Report for AEP West?	Who Files Report for AEP East?	File Report With
Physical threats to a BES control center	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at a BES control center.	**EOP-004 Attach 2**	24Hrs	Corpus Christi TDC	SCCO West	SCCO East	NERC, RC, RE
Transmission loss	Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).	**EOP-004 Attach 2**	24Hrs	Corpus Christi TDC	SCCO West	SCCO East	NERC, RC, RE
Unplanned BES control center evacuation	Unplanned evacuation from BES control center facility for 30 continuous minutes or more.	**EOP-004 Attach 2**	24Hrs	Corpus Christi TDC	SCCO West	SCCO East	NERC, RC, RE
Voltage deviation on a Facility	Observed within its area a voltage deviation of ± 10% of nominal voltage sustained for ≥ 15 continuous minutes.	**EOP-004 Attach 2**	24hrs	Corpus Christi TDC	SCCO West	SCCO East & PJM	NERC, RC, RE

Notes:
*-Initiating Entity is responsible for reporting
1- There are two Physical Attack and Cyber Event Incident listings with distinct reporting time requirements.
This table has been sorted by the “File Report within” time column

For additional information, refer to the current version of the AEP Event Reporting Operating Plan located on the TOps Sharepoint at SCC>Reporting Requirements & Notification>NERC Event Reporting EOP_004_2. The AEP plan contains detailed information on the completion of the reporting forms; and, contains flow charts on the reporting process. This area also contains the NERC EOP-004-2 Attachment 2 reporting form. The DOE Report Form OE-417 is also available on the TOps Sharepoint or on line at http://www.oe.netl.doe.gov/oe417.aspx.

Section X

Emergency Communications

The following items from PJM, SPP, and NERC Standard COM-002 define the conditions when emergency communications should take place between Reliability Coordinators, System Control Center Operators or Operating Authorities, and Transmission Dispatchers.

PJM Manual 01 rev 30 Section 2.6.1 and Attachment C addresses emergency EMS outages. Section 3.2.3 addresses data exchange during a loss of EMS data.

SPP Criteria 10 addresses emergency communications in the SPP area. Appendix B of the SPP BA Emergency Operating Plan indicates AEP West SCC can provide information to the SPP Reliability Coordinator and the RC will forward to appropriate SPP desk.

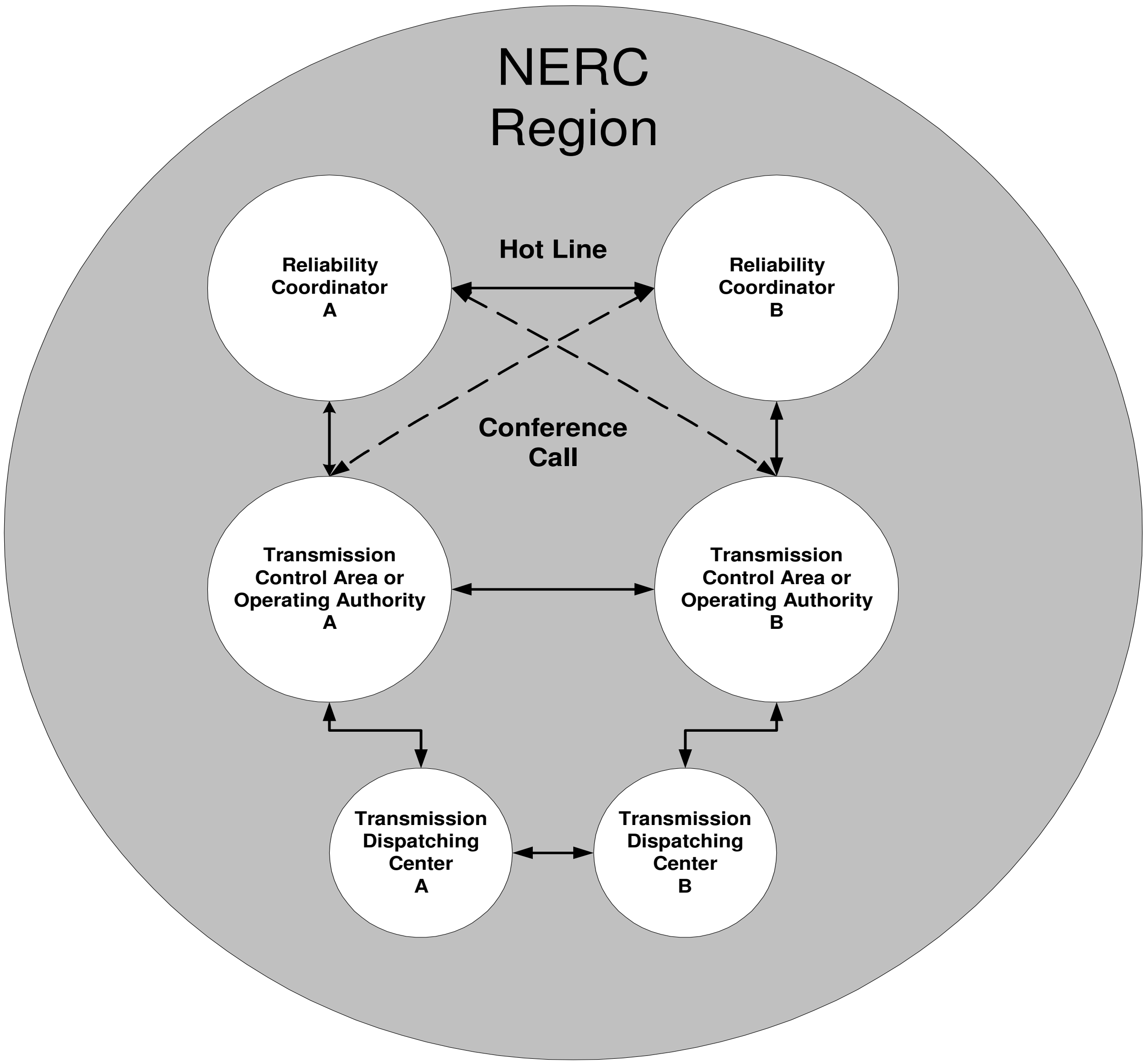
NERC Standard COM-002-02
<u>Requirements</u>

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall have communications (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators. Such communications shall be staffed and available for addressing a real-time emergency condition.

> **R1.1.** Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators through predetermined communication paths of any condition that could threaten the reliability of its area or when firm load shedding is anticipated.

R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall ensure the recipient of the directive repeats the information back correctly; and shall acknowledge the response as correct or repeat the original statement to resolve any misunderstandings.

The following communications diagram depicts the various paths of the required communication:



The Hot Line is typically between Reliability Coordinator and Reliability Coordinator. The Conference Call is usually requested by a Reliability Coordinator or Transmission Control Area or Operating Authority, and will involve several Reliability Coordinators, Transmission Control Area's and Operating Authorities.

The AEP communication system has been designed to allow control and operation of the geographically dispersed stations and plants from the System Control Center (SCC), and 4 Transmission Dispatch Centers (TDC). This system has been designed to maintain reliable communication paths for the exclusive use of the SCC, TDC's and station personnel during emergencies. AEP East and AEP West utilize public switched communication networks for external communications. Internal communications is via company owned or leased facilities including microwave and fiber optic media.

Types of Communication Systems

800 Mhz Radio and Fiber Optics System

The backbone of the communication system is the AEP 800 Mhz radio and fiber optics system, its equipment and path switching techniques.

The availability of 800 Mhz and fiber optics facilities during emergency situations is ensured by each microwave terminal and repeater station having an emergency power supply using a propane-powered automatic generator with sufficient fuel for three to fourteen days (typically 7 days), or 24-hour emergency batteries.

Audinet System

The AEP Audinet system permits override on any congested tie-line group, disconnecting lower priority users. To minimize the possibility of overheating temperature-sensitive switches, air conditioning for the communication equipment rooms is supplied from the emergency generators during a power outage.

TDC to Plant Communication

Plant control rooms have a telephone console with a button dedicated to the Transmission Dispatching Centers (TDC) communication. At the TDC’s and System Control Center, each of the telephone consoles has a button dedicated to each plant. All of the above equipment is battery-powered and will continue to function if plant power is lost.

Satellite Communications

Satellite communication systems are also available in case of a loss of both the dedicated and the public telephone systems. Satellite Communications are the preferred backup systems for PJM, ERCOT, and the SPP Reliability Coordinators, as well as, Market Operations.

Scada Communications – AEP East/PJM

The Eastern AEP SCADA host computers communicate with the substation RTUs via a communication front-end called the Station Data Gateway (SDG). The SDG can be located either local to the SCADA host or remote. There are currently more SDGs than SCADA hosts to provide for sufficient diversity in case of the loss of a SDG.

The SDGs communicate with the SCADA host via the internal Transmission SCADA Network (TSN) via TCP/IP. The TSN provides redundant paths to each SDG to provide for a single contingency communications path loss. Between the redundant communication paths and diverse SDG locations, AEP has constructed an extremely robust network for RTU communications.

Scada Communications – AEP West/SPP

The Western AEP SCADA host computers communicate with the substation RTUs via a communication front-end called the Station Management Platform (SMP) computers. The SMPs can be located either local to the SCADA host or remote. They are currently co-located with the SCADA hosts, but there is a project underway to expand the number of SMPs to provide for sufficient diversity in case of the loss of the single SMP that currently communicates with all RTUs for the Operating Company.

The SMPs communicate with the SCADA host via the internal Transmission SCADA Network (TSN) via TCP/IP. The TSN provides redundant paths to each site to provide for a single contingency communications path loss. Between the redundant communication paths and diverse SMP locations, AEP has constructed an extremely robust network for RTU communications.

AEP Confidential Special Handling

AEP Satellite Telephones

[redacted]

<u>800 Mhz Talk Groups</u>

AEP/PJM		
***NO CONDUIT RULE APPLIES!!		
Plant	**Unit**	**Talk Group**
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]	[redacted]		[redacted]
[redacted]			
[redacted]	[redacted]		[redacted]
[redacted]	[redacted]		[redacted]
[redacted]	[redacted]		[redacted]
[redacted]	[redacted]		[redacted]
[redacted]	[redacted]		[redacted]
[redacted]	[redacted]		[redacted]
[redacted]			
[redacted]	[redacted]		[redacted]
[redacted]	[redacted]		[redacted]
[redacted]	[redacted]		[redacted]
[redacted]	[redacted]		[redacted]
[redacted]	[redacted]		[redacted]
[redacted]	[redacted]		[redacted]
[redacted]	[redacted]		[redacted]
[redacted]			[redacted]
[redacted]	[redacted]		[redacted]
[redacted]	[redacted]		[redacted]
[redacted]			[redacted]
[redacted]	[redacted]		[redacted]
[redacted]	[redacted]		[redacted]

[redacted]	[redacted]		[redacted]
			[redacted]

[redacted]	[redacted]		[redacted]
			[redacted]

[redacted]	[redacted]		[redacted]
			[redacted]

Decision Making/Collaboration

AEP SCC, TDC, PO shall use English language for all communications internally. The SCC shall use English language for all communications externally with the NERC Reliability Coordinator, Transmission Operator, and Balancing Authority.

It is important to be aware and to determine when the transmission system is in a stressed or abnormal state. Reliability Coordinators, System Control Center Operators and Transmission Dispatchers have the authority to implement emergency procedures to remedy emergency or abnormal conditions. In this regard, emergency and/or abnormal conditions should be reported, and discussed with the System Control Center Operators, Reliability Coordinators, and local Engineering support staff as necessary, to help determine the nature and severity of the emergency or abnormal system and to further determine and agree on actions to be taken. Urgency of a situation must be clearly communicated to assure timely decisions on actions to relieve the emergency or abnormal condition and to return the system to a normal or secure state. If it is determined that an emergency state, or near emergency state exists; then the necessary emergency communication contacts should be made by the system experiencing the abnormal conditions. The notifications should be made to those systems most affected by the abnormal conditions (see communications diagram), and the Reliability Coordinator can make use of the Reliability Coordinator Information System (RCIS), and NERC Hot Line, to inform other Reliability Coordinators of the situation.

In some instances a Hot Line may be set up between Reliability Coordinators, or a Conference Call may be initiated between the Reliability Coordinators and Transmission Control Area's or Operating Authorities affected by the abnormal system to discuss the nature of the emergency, what corrective actions are being taken to return the system to a normal state, and how long the system will be in the abnormal state.

Communication Failures

When problems are encountered with either the IT systems or Telecom infrastructure, the System Control Center Operators /Dispatchers are trained to contact the on-call support personnel, and/or the Network Command Center (NCC) and/or the SCC IT support group. Once that call is made, the NCC and SCC IT support group are charged with troubleshooting the issue, making appropriate support call-outs as required if they are not able to correct the problem, and with keeping all concerned parties apprised of the conditions as appropriate. The NCC monitors AEP's internal communications system functions 24/7 and advises the SCC and TDC's of any planned or emergency outages that could affect our telecommunications or SCADA facilities via e-mail.

In the case of the loss of a critical Transmission RTU, the Transmission Dispatcher may request that field personnel physically man the station. The decision to man the station needs to be coordinated with the SCC. The SCC will notify the Reliability Coordinator (PJM or SPP) of the loss. The SCC, the Oncall Engineer and the Reliability Coordinator will evaluate the impact of the RTU loss to their respective EMS systems. Factors to consider in the evaluation include:

- Estimated length of the outage
- Pre-existing conditions such as an open ring bus or pre-existing alarms
- System loading levels
- Weather
- Visibility from neighboring stations via the EMS
    - The Reliability Coordinator need for frequent manual data updates if visibility is missing.
- Is RTU part of an IROL facility

The field personnel will periodically report any abnormal conditions or questionable measurements to the dispatcher. The SCC will notify the Reliability Coordinator when the RTU is normal.

Testing

- Satellite communications are routinely tested with SPP, PJM, Market Operations, PSO and SWEPCO.
- Emergency telephone communications contact numbers with interconnected utilities listed in Appendix VII are updated as part of the EOP .
- 800 Mhz communications will be tested though normal usage or by a designated test.

Refer to the most recent copy of the following Operating Memo on the SCC – All Inclusive>Communications>Satellite Phones>TOPS Sharepoint folder(s) for more details:

- TRTO Satellite Phone Testing

AEP Confidential Special Handling

Section XI

The NERC Standards EOP-005 and PER-005 describe general training requirements for this plan. It is the responsibility of the various AEP Training departments to develop and maintain an emergency operating training program for each area of responsibility.

System Operator Training

Purpose – Implement System Operator training to ensure plans, procedures, and resources are practiced/simulated to restore the electric system to a normal condition in the event of a partial or total shut down of the system.

Objectives – Learning objectives shall be based on this Emergency Operating Plan as well as company-specific reliability-related tasks performed by System Operators.

Requirements

- System Operators shall receive emergency operations training applicable to its organization that reflects emergency operations topics, which includes system restoration using drills, exercises or other training required to maintain qualified personnel..
- System Operators shall be trained in the implementation of the AEP System restoration plan. Such training shall include simulated exercises, if practicable.
- Emergency Operations drills or simulations will be conducted each year to evaluate the effectiveness of the plan, and to evaluate the knowledge and competency of the SCC System Operators and Transmission Dispatchers.
- Documentation must be retained in the personnel training records that operating personnel have been trained annually in the implementation of the plan and have participated in restoration exercises.

AEP Confidential Special Handling

Appendix I

Station Equipment Problems Resulting from Loss of AC

Station Batteries

Station batteries may have only six (6) hours of useful life in very cold weather. MOAB's should be operated manually (provided the line is de-energized) to conserve battery life.

Portable Generators

The Transmission Regions have portable generators capable of providing emergency power to battery chargers at blacked-out stations.

Operation of Transmission Breakers During a Loss of Auxiliary Power

All transmission circuit breakers on the AEP system use a form of stored energy to operate the breaker mechanism. This stored energy is in the form of compressed air or gas, compressed springs, or station batteries. Unless this stored energy has been lost due to leakage or discharge, each breaker should be capable of a minimum of one open-close-open sequence of operations without the need for AC auxiliary power.

Closed oil circuit breakers are always capable of being tripped. The energy used to close the breaker also charges the tripping springs. The BBC/ITE type GA-145, GA-362 and Westinghouse type SF-362 and SFA-800 breakers also use spring energy to trip and can always trip when closed; however, proper interruption depends upon having the proper SF6 gas pressures. All other transmission breakers rely on compressed air or gas to provide the energy to trip the breaker. Those with hydraulic mechanisms use oil or SF6 gas for current interruption and have hydraulic systems small enough to be charged by a manual operator on the pump. Pneumatically operated breakers, which use oil or SF6 gas for current interruption, use compressed air at pressures and volumes that can be supplied from a cylinder of compressed dry air or nitrogen.

Air blast breakers use compressed air to operate the breaker and for current interruption. The amount of air required per operation would make supplying the air from gas cylinders impractical, but not impossible. Mechanisms using spring closing can perform only one closing operation without recharging. All other types of mechanisms can provide between four and eleven stored operations, depending upon the type of breaker. With normal leakage most breakers will be capable of close-open operation for several days after the loss of auxiliary power. However, the loss of heaters in cold weather may cause difficulties in the operation of some breakers. This is especially true for two-pressure SF6 breakers in which the high pressure gas must be kept above 52 degrees Fahrenheit to keep the pressure above the MTP point. The following information may be used to determine the capabilities for operation of the various types of circuit breakers following a loss of AC power.

Breaker Details

Oil Circuit Breakers - All Types

Tripping
All can be tripped from the closed position.

Closing

Pneumatic mechanisms	A cylinder of dry air or nitrogen can be used to raise the mechanism storage tank pressure to the operating range.
Hydraulic mechanisms	A hand operator on the pump can be used to raise the pressure to the operating range.
Spring mechanism	A ratchet handle and socket can be used to charge the closing springs.
Motor or solenoid mechanism	A station battery or substitute DC power supply is required.

Air Blast Breakers - General Electric Type ATB, Delle Type PK and Brown Boveri Type DLF

Operating air is supplied from a high pressure reservoir that is filled by an electrically driven air compressor.

Tripping and Closing
Proper air pressure in the low pressure system is required for any operation. The high pressure system can be connected to the high pressure supply of another breaker, or cylinders of dry air or nitrogen may be used to raise the low pressure system pressure. One cylinder would supply approximately one close-open operation of a 138-kV breaker.

Two-Pressure SF6 Breakers - BBC/ITE Type GA, Westinghouse Types SF, SFA, and SFV

Compressors and heaters are required to maintain the high pressure gas temperature above 52 degrees Fahrenheit and the pressure above 230 psi. Consequently, at ambient temperatures below 52 degrees Fahrenheit these breakers will become inoperable within hours of a loss of AC power and will remain so until the restoration of AC power. If the circuit breaker has proper SF6 gas pressures, operation will depend upon the mechanism.

Tripping

- Westinghouse type SF and SFA, and ITE/Brown Boveri type GA circuit breakers can be tripped from the closed position. The tripping springs are charged when the breaker is closed.
- The Westinghouse type SFV uses high pressure SF6 gas to operate the mechanism and move the contacts and can be operated if the SF6 gas pressure is above the MTP point.

Closing

- The SF, SFA and GA breakers have pneumatic closing mechanisms. A cylinder of dry air or nitrogen can be used to raise the mechanism storage tank pressure to the operating range.
- The SFV uses the high pressure SF6 gas to operate the mechanism and close the contacts. It can be closed if the SF6 gas pressure is above the low pressure cut-off point.

Single Pressure SF6 Breakers -
BBC Types PA, ELF and ELK, Delle Types FR and FX, Siemens Type 3AT5 and Hitachi

These breakers use SF6 gas and 86 psig and do not require either gas compressors or heaters. If the SF6 pressure is above the cut-off point, operation will depend upon the mechanism.

Tripping

- Delle type FR, FX; BBC type PA, ELK; and Siemens type 3AT5 use hydraulic mechanisms. A hand operator on the pump can be used to raise the pressure to the operating range.
- Brown Boveri type ELF, the Hitachi type OFPTB, and the Westinghouse type SP use pneumatic mechanisms. A cylinder of dry air or nitrogen can be used to raise the mechanism storage tank pressure to the operating range.

Closing

- The FR, FX, ELK and 3AT5 use hydraulic mechanisms and can be pumped up with a hand operator.
- The Westinghouse SP and Hitachi OFPTB close from springs charged by the tripping operation.
- The ELF uses a pneumatic mechanism to close the breaker. A cylinder of dry air or nitrogen can be used to raise the mechanism storage tank pressure.

Many types of breakers can be operated manually, but the breaker must be de-energized with disconnects open before this is done. Local Station Department breaker personnel or breaker specialists should be contacted to supervise manual operation.

The approximate AC power requirements for compressors and heaters for transmission breakers are listed below.

Oil Circuit Breakers		
345-kV	10 kW	
138-kV	<5 kW	
Air Blast Breakers - All 240 Volt 3-Phase		
765-kV	Delle type PK BBC DLFK Definite Purpose Breaker	20 kW 20 kW 20 kW
345-kV	GE Type ATB Delle type PK BBC type DLFK	20 kW 15 kW 15 kW
138-kV	GE type ATB Delle type PK	15 kW 15 kW
Two Pressure SF6 Breakers - All 240 Volt 3-Phase		
765-kV	Westinghouse SFA	25 kW
345-kV	ITE/BBC GA	15 kW
138-kV	Westinghouse type SFV ITE/BBC type GA	25 kW 10 kW
Single Pressure SF6 Breakers - All 240 Volt 3-Phase		
765-kV	BBC type ELF Siemens 3AT5 Delle FR	7.5 kW 5 kW 30 kW
All Other Single Pressure SF6 Breakers < 5 kW		

Table AII-1
AC Power Requirements for Compressors and Heaters for Transmission Breakers

Restoration of AC Power to Air Blast and SF6

Breakers Following an Interruption in Cold Weather

The proper operation of all of the 765-kV breakers on the AEP system, as well as many of the other system breakers, depends to a great extent on the maintenance of proper temperatures and pressures in the breaker. This in turn depends on the station service power to operate the heater and compressor motors. Failure to maintain these pressures and/or temperatures may result in damage to breaker components, mis-operation, or failure to operate. The following information is intended to provide guidelines to the system operators for situations where station service power has been lost during cold weather.

The Delle Type PK, Brown Boveri Type DLFK and General Electric Type ATB breakers use compressed air at 360-510 psi to operate the contacts and interrupt fault current. This operating air is supplied by 3600 psi storage air, which is replenished by compressors. Heaters in the compressor, relay and control cabinets provide heat to prevent condensation of moisture in the breaker cabinets and the breaker air systems. Condensation on the relays, controls or panel surfaces can result in corrosion, tracking and component failure. Condensation and freezing inside the air system can result in air leaks, blockages in air passages or jammed components, resulting in a loss of air or a failure to operate. Loss of heat in the compressor cabinet will allow the compressor oil to thicken, increasing the starting torque required of the motor.

It is very important that all the heaters and thermostats in these breakers be operating correctly. Should a breaker have experienced a loss of AC power to the heaters for more than 30 minutes in sub-freezing weather, it will be necessary to restore power to the heaters before closing the breaker or operating the compressor. To prevent the compressor from starting when power is restored, the 2-pole AC control power switch in the compressor control cabinet should be opened. The closing of an open air blast breaker should be delayed until the cabinet heaters have warmed up the valves. It is recommended that a minimum time of 30 minutes at 32 degrees Fahrenheit, increasing to 1 hour at 0 degrees Fahrenheit, be observed before operating the compressor or closing the breaker.

Two pressure SF6 breakers depend on heaters to prevent liquefaction of the high pressure (250 psi) SF6 gas at temperatures below 60 degrees Fahrenheit. Following the loss of power to the heaters, the SF6 gas in the high pressure system will begin to liquefy as its temperature drops until the saturation point is reached; at 0 degrees Fahrenheit it would be 100 psi.

On the ITE-Brown Boveri Type GA and Westinghouse Type SFA breakers, the compressor governor switch monitors the high pressure system and, if the pressure drops enough, will close to start the compressor when power is restored. The Westinghouse Type SFV breaker controls the compressor with a pressure switch on the low pressure system that will not respond to a pressure drop in the high pressure system unless the pressure in the low pressure system is raised by operations or gas leaks.

Immediate starting of a compressor under these conditions should be avoided for two reasons. First, the oil in the compressor may be cold, causing lubrication or starting problems that could damage the compressor or motor. Second, in the Type GA and SFA breakers, there will probably be sufficient SF6 in the high pressure system to achieve normal pressure once the normal temperature is reached.

Operating the gas compressor before all the liquid SF6 is evaporated will add additional SF6 to the high pressure system, possibly lowering the low pressure system to the alarm or compressor lockout point and causing excessive pressure on the high pressure system when normal operating temperature is reached. Since the SF6 heaters are primarily intended only to maintain a satisfactory temperature, they may require hours to regain this temperature if the outage was long or the ambient temperature very low. Until enough liquid SF6 evaporates to bring the gas pressure above the MTP point, the breaker will be in a breaker failure mode. This time can be shortened by selective valve operation and compressor operation; however, this should only be done by a breaker specialist familiar with this type of breaker.

All system breakers are interlocked to prevent operation if the air or gas pressure is too low to successfully operate the breaker. In an urgent system operating condition, these procedures (which are recommended to reduce the possibility of compressor system damage or breaker mis-operation) may be disregarded in the interest of restoring or maintaining service.

Section II C-11 Loss of Station Auxiliary Power of the AEP EHV System Operating Guidelines manual contains additional information on the operation of circuit breakers during an outage. A copy of the manual is kept on the TOPS Sharepoint site at >Engineering >AEP EHV System Operation Guide > EHV OPERATING GUIDELINE

Appendix II

<u>High Voltage Limits on Equipment – AEP East/PJM System</u>

1. High Voltage Limits at Transmission Stations – Anticipating Light Transformer Loadings

   See ***Table AII-1: High Voltage Limits During Off Peak Load Periods***

2. High Voltage Limits at Transmission Stations – Anticipating Heavy Transformer Loadings

   See ***Table AII-2 High Voltage Limits During Peak Load Periods***

3. Location and time delay setting of overvoltage relays (trip at 811-kV, 1.061 p.u.)

   See ***Table AII-3 Location and Time Delay Setting of Overvoltage Relays***

4. High Voltage Limits for Circuit Breakers

   See ***Table AII-4 High Voltage Limits for Circuit breakers***

Note: Data in tables taken from section V-C Station Voltage Limits of the AEP EHV Operating Guidelines.

Station		**High Voltage Limit**	**Liability**
Amos	765-kV	103.3%	T3 @ 108.75% of tap setting
Axton	765-kV	105.0%	Shunt reactors
Baker	765-kV	104.6%	765-kV breakers
Belmont	765-kV	104.6%	T-5 current transformer
Broadford	765-kV	104.6%	765-kV breakers
Cloverdale	765-kV	104.6%	765-kV breakers
Cook	765-kV	102.6%	T-2 @ 108% of tap setting
Culloden	765-kV	104.6%	765-kV breakers
Dumont	765-kV	104.6%	765-kV breakers
FlatLick	765-kV	104.6%	765-kV breakers
Gavin	765-kV	103.3%	T-1 & T2 @ 108.75% of tap setting
Greentown	765-kV	104.5%	T-1 and T-2 @ 110% of tap setting
Hanging Rock	765-kV	104.6%	765-kV breakers
Jacksons Ferry	765-kV	104.6%	765-kV breakers
Jefferson	765-kV	104.6%	765-kV breakers
Joshua Falls	765-kV	104.6%	765-kV breakers
Kammer	765-kV	102.2%	Mitchell T-1 @ 107.5% of tap setting
Marquis	765-kV	102.2%	T-1 and T-2 @ 107.5% of tap setting
Marysville	765-kV	104.6%	765-kV breakers
Mountaineer	765-kV	103.3%	T-1 @ 108.75% of tap setting
North Proctorville	765-kV	104.5%	T-1 @ 110% of tap setting
Maliszewski	765-kV	104.6%	765 kV breakers
Rockport	765-kV	104.6%	765-kV breakers
South Canton	765-kV	104.5%	T-3 @ 110% of tap setting
Sullivan	765-kV	102.5%	T-1 and T-2 @ 110% of tap setting
Wyoming	765-kV	104.6%	T-1 and T-2 current transformers
Belmont	500-kV	113.5%	T-5 @ 107.5% of tap setting
Broadford	500-kV	113.5%	T-4 @ 107.5% of tap setting
Cloverdale	500-kV	109.7%	T-6A and T-6B @ 107.5% of tap setting
Jacksons Ferry	500-kV	110.5%	T-1 @ 107.5% of tap setting
Kammer	500-kV	116.5%	T-200 @ 107.5% of tap setting
Nagel	500-kV	110.0%	500-kV breakers

Table AII-1
High Voltage Limits During Off-Peak Load Periods

Station		**High Voltage Limit**	**Liability**
Allen	345-kV	104.9%	345-kV breakers
Amos	345-kV	104.9%	345-kV breakers
Baker	345-kV	104.8%	Big Sandy T-2 @ 107.5% of tap setting
Beatty	345-kV	104.9%	345-kV breakers
Benton Harbor	345-kV	111.0%	T-A and T-B @ 110% of tap setting
Beverly	345-kV	104.9%	345 kV breakers
Bixby	345-kV	104.9%	345-kV breakers
Breed	345-kV	106.8%	345-kV breakers
Canton Central	345-kV	104.9%	345-kV breakers
Clifty Creek	345-kV	103.5%	T-1 through T-6 @ 105.3% of tap setting
Cloverdale	345-kV	104.9%	T-10 @ 107.5% of tap setting
Conesville	345-kV	104.9%	T-4, T-5 and T-6 @ 107.5% of tap setting
Convoy (RP -Mone)	345	104.9%	345-kV breakers
Cook	345-kV	104.9%	345-kV breakers
Corridor	345-kV	104.9%	345-kV breakers
Darwin	345-kV	104.9%	345-kV breakers
Dequine	345-kV	104.9%	345-kV breakers
DeSoto	345-kV	104.9%	345-kV breakers
Dumont	345-kV	104.9%	345-kV breakers
East Elkhart	345-kV	111.0%	T-2 @ 110% of tap setting
East Lima	345-kV	104.9%	345-kV breakers
Eugene	345-kV	104.9%	345-kV breakers
Fall Creek	345-kV	104.9%	345-kV breakers
Foothills	345-kV	104.9%	345-kV breakers
Fostoria Central	345-kV	104.9%	345-kV breakers
Galion	345-kV	104.9%	345-kV breakers
Hayden	345-kV	104.9%	345-kV breakers
Hyatt	345-kV	104.9%	345-kV breakers
Jackson Road	345-kV	111.0%	T-3 @ 110% of tap setting
Kammer	345-kV	104.9%	345-kV breakers
Kanawha	345-kV	104.9%	345-kV breakers
Kenzie Creek	345-kV	111.0%	T-1 @ 110% of tap setting
Keystone	345-kV	104.9%	345-kV breakers
Kirk	345-kV	104.9%	345-kV breakers
Kyger Creek	345-kV	104.2%	T-1 through T-5 @ 106% of tap setting
Marquis	345-kV	104.9%	345-kV breakers
Marysville	345-kV	104.9%	345-kV breakers
Matt Funk	345-kV	104.9%	345-kV breakers

Table AII-1 (continued)
High Voltage Limits During Off-Peak Load Periods

Station		High Voltage Limit	Liability
Muskingum	345-kV	104.9%	345-kV breakers
Ohio Central	345-kV	108.1%	T-1 @ 110% of tap setting
Olive	345-kV	104.9%	345-kV breakers
Reynolds	345-kV	109.0%	T-1 @ 110% of tap setting
Roberts	345-kV	111.0%	T-2 @ 110% of tap setting
Robison Park	345-kV	104.9%	345-kV breakers
Sorenson	345-kV	104.9%	345-kV breakers
South Canton	345-kV	104.9%	345-kV breakers
Southeast Canton	345-kV	108.1%	T-1 @ 110% of tap setting
Southwest Lima	345-kV	104.9%	345-kV breakers
Sporn	345-kV	104.9%	345-kV breakers
Tanners Creek	345-kV	104.9%	345-kV breakers
Tidd	345-kV	103.0%	CB fault duties
Tri State	345-kV	104.9%	345-kV breaker
Twin Branch	345-kV	104.9%	345-kV breaker
Waterford	345-kV	104.9%	345-kV breakers
West Bellaire	345-kV	108.1%	T-1 @ 110% of tap setting
West Millersport	345-kV	104.9%	345-kV breakers
Zelda	345-kV	104.9%	345-kV breakers
Greentown	230-kV	107.5%	T-2 @ 107.5% of tap setting
Nagel	230-kV	112.2%	T-5 @ 107.5% of tap setting
Allen	138-kV	105.1%	138-kV breakers
Amos	138-kV	105.1%	138-kV breakers
Axton	138-kV	105.1%	138-kV breakers
Beatty	138-kV	105.1%	138-kV breakers
Benton Harbor	138-kV	105.1%	138-kV breakers
Big Sandy	138-kV	105.1%	138-kV breakers
Bixby	138-kV	105.1%	138-kV breakers
Broadford	138-kV	105.1%	138-kV breakers
Canton Central	138-kV	105.1%	138-kV breakers
Claytor	138-kV	105.1%	138-kV breakers
Clinch River	138-kV	105.1%	138-kV breakers
Cloverdale	138-kV	105.1%	138-kV breakers
Conesville	138-kV	104.6%	T-2 and T-3 @ 107.5% of tap setting
Corridor	138-kV	105.1%	138-kV breakers
DeSoto	138-kV	105.1%	138-kV breakers
East Elkhart	138-kV	105.1%	138-kV breakers

Table AII-1 (continued)
High Voltage Limits During Off-Peak Load Periods

Station		**High Voltage Limit**	**Liability**
East Lima	138-kV	105.1%	138-kV breakers
Fall Creek	138-kV	105.1%	138-kV breakers
Fostoria Central	138-kV	105.1%	138-kV breakers
Galion	138-kV	105.1%	138-kV breakers
Glen Lyn	138-kV	105.1%	138-kV breakers
Grangston	138-kV	105.1%	138-kV breakers
Greentown	138-kV	105.1%	138-kV breakers
Hyatt	138-kV	105.1%	138-kV breakers
Jacksons Ferry	138-kV	105.1%	138-kV breakers
Jackson Road	138-kV	105.1%	138-kV breakers
Joshua Falls	138-kV	105.1%	138-kV breakers
Kammer	138-kV	105.1%	138-kV breakers
Kanawha	138-kV	105.1%	138-kV breakers
Kenzie Creek	138-kV	105.1%	138-kV breakers
Kirk	138-kV	105.1%	138-kV breakers
Leesville	138-kV	105.1%	138-kV breakers
Matt Funk	138-kV	105.1%	138-kV breakers
Muskingum	138-kV	105.1%	138-kV breakers
Nagel	138-kV	105.1%	138-kV breakers
North Proctorville	138-kV	105.1%	138-kV breakers
Ohio Central	138-kV	105.1%	138-kV breakers
Olive	138-kV	105.1%	138-kV breakers
Picway	138-kV	105.1%	138-kV breakers
Reynolds	138-kV	105.1%	138-kV breakers
Roberts	138-kV	105.1%	138-kV breakers
Robison Park	138-kV	105.1%	138-kV breakers
Smith Mountain	138-kV	105.1%	138-kV breakers
Sorenson	138-kV	105.1%	138-kV breakers
South Canton	138-kV	105.1%	138-kV breakers
Southeast Canton	138-kV	105.1%	138-kV breakers
Southwest Lima	138-kV	105.1%	138-kV breakers
Sporn	138-kV	105.1%	138-kV breakers
Tanners Creek	138-kV	105.1%	138-kV breakers
Tidd	138-kV	105.1%	138-kV breakers
Tri State	138-kV	105.1%	138-kV breakers
Twelve Pole	138-kV	105.1%	138-kV breakers
Twin Branch	138-kV	105.1%	138-kV breakers

Table AII-1 (continued)
High Voltage Limits During Off-Peak Load Periods

Station		**High Voltage Limit**	**Liability**
West Bellaire	138-kV	105.1%	138-kV breakers
West Millersport	138-kV	105.1%	138-kV breakers
Wolf Hills	138-kV	105.1%	138-kV breakers
Wyoming	138-kV	105.1%	138-kV breakers

Table AII-1 (continued)
High Voltage Limits During Off-Peak Load Periods

Station		High Voltage Limit	Liability
Amos	765-kV	100.7%	T3 @ 105.95% of tap setting
Axton	765-kV	105.0%	Shunt reactors
Baker	765-kV	102.4%	T-100 @ 105% of tap setting
Belmont	765-kV	104.6%	T-5 current transformers
Broadford	765-kV	104.6%	765-kV breakers
Cloverdale	765-kV	104.6%	765-kV breakers
Cook	765-kV	102.6%	T-2 @ 108% of tap setting and T-4 @ 105% of tap setting
Culloden	765-kV	104.6%	765-kV breakers
Dumont	765-kV	104.6%	765-kV breakers
Gavin	765-kV	100.7%	T-1 & T2 @ 105.95% of tap setting
Greentown	765-kV	104.5%	T-1 and T-2 110% of tap setting
Hanging Rock	765-kV	104.6%	765-kV breakers
Jacksons Ferry	765-kV	104.6%	765-kV breakers
Jefferson	765-kV	102.4%	T-1 @ 105% of tap setting
Joshua Falls	765-kV	104.6%	765-kV breakers
Kammer	765-kV	99.8%	Mitchell T-1 @ 105% of tap setting
Marquis	765-kV	104.5%	T-1 @ 110% of tap setting
Marysville	765-kV	104.6%	765-kV breakers
Mountaineer	765-kV	100.7%	T-1 @ 105.95% of tap setting
North Proctorville	765-kV	104.5%	T-1 @ 110% of tap setting
Maliszewski	765-kV	104.6%	765 kV breakers
Rockport	765-kV	104.6%	765-kV breakers
South Canton	765-kV	104.5%	T-3 @ 110% of tap setting
Sullivan	765-kV	104.5%	T-1 @ 110% of tap setting
Wyoming	765-kV	104.6%	T-1 and T-2 current transformers
Belmont	500-kV	110.9%	T-1 @ 105% of tap setting
Broadford	500-kV	110.9%	T-4 @ 105% of tap setting
Cloverdale	500-kV	107.1%	T-6A and T-6B @ 105% of tap setting
Jacksons Ferry	500-kV	107.9%	T-1 @ 105% of tap setting
Kammer	500-kV	113.8%	T-200 @ 105% of tap setting
Nagel	500-kV	110.0%	500-kV breakers

Table AII-2
High Voltage Limits During Peak Load Periods

Station		High Voltage Limit	Liability
Allen	345-kV	104.9%	345-kV breakers
Amos	345-kV	104.9%	345-kV breakers
Baker	345-kV	102.4%	Big Sandy T-2 @ 105% of tap setting
Beatty	345-kV	104.9%	345-kV breakers
Benton Harbor	345-kV	111.0%	T-A and T-B @ 110% of tap setting
Bixby	345-kV	104.9%	345-kV breakers
Breed	345-kV	104.9%	345-kV breakers
Canton Central	345-kV	104.9%	345-kV breakers
Clifty Creek	345-kV	103.5%	T-1 through T-6 @ 105.3% of tap settings
Cloverdale	345-kV	104.9%	345-kV breakers
Conesville	345-kV	104.9%	345-kV breakers
Cook	345-kV	104.4%	T-1 @ 105% of tap setting
Corridor	345-kV	104.9%	345-kV breakers
Dequine	345-kV	104.9%	345-kV breakers
DeSoto	345-kV	104.9%	345-kV breakers
Dumont	345-kV	104.9%	345-kV breakers
East Elkhart	345-kV	111.0%	T-2 @ 110% of tap setting
East Lima	345-kV	104.9%	345-kV breakers
Eugene	345-kV	104.9%	345-kV breakers
Fall Creek	345-kV	104.9%	345-kV breakers
Fostoria Central	345-kV	104.9%	345-kV breakers
Galion	345-kV	104.9%	345-kV breakers
Hayden	345-kV	104.9%	345-kV breakers
Hyatt	345-kV	104.9%	345-kV breakers
Jackson Road	345-kV	111.0%	T-3 @ 110% of tap setting
Kammer	345-kV	103.7%	Mitchell T-2 @ 106.4% of tap setting
Kanawha	345-kV	104.9%	345-kV breakers
Kenzie Creek	345-kV	111.0%	T-1 @ 110% of tap setting
Kirk	345-kV	104.9%	345-kV breakers
Kyger Creek	345-kV	104.2%	T-1 through T-5 @ 106% of tap settings
Marquis	345-kV	104.9%	345-kV breakers
Marysville	345-kV	104.9%	345-kV breakers
Matt Funk	345-kV	104.9%	345-kV breakers
Muskingum	345-kV	103.2%	T-2 and T-4 @ 105% of tap setting
Ohio Central	345-kV	108.1%	T-1 @ 110% of tap setting
Olive	345-kV	104.9%	345-kV breakers

Table AII-2 (continued)
High Voltage Limits During Peak Load Periods

Station		High Voltage Limit	Liability
Reynolds	345-kV	111.0%	T-1 @ 110% of tap setting
Roberts	345-kV	111.0%	T-2 @ 110% of tap setting
Robison Park	345-kV	104.9%	345-kV breakers
Sorenson	345-kV	104.9%	345-kV breakers
South Canton	345-kV	104.9%	345-kV breakers
Southeast Canton	345-kV	108.1%	T-1 @ 110% of tap setting
Southwest Lima	345-kV	104.9%	345-kV breakers
Sporn	345-kV	104.9%	345-kV breakers
Tanners Creek	345-kV	104.9%	345-kV breakers
Tidd	345-kV	102.3%	T-3 @ 105% of tap setting
Tri State	345-kV	104.9%	345-kV breakers
Twin Branch	345-kV	104.9%	345-kV breakers
West Bellaire	345-kV	108.1%	T-1 @ 110% of tap setting
West Millersport	345-kV	104.9%	345-kV breakers
Nagel	230-kV	109.6%	T-5 @ 105% of tap setting
Allen	138-kV	104.6%	T-1 @ 105% of tap setting
Amos	138-kV	104.6%	T-7, T-8 and T-9 @ 105% of tap settings
Axton	138-kV	105.1%	T-1 @ 105% of tap setting
Beatty	138-kV	104.6%	T-3 and T-4 @ 105% of tap setting
Benton Harbor	138-kV	104.6%	T-A and T-B @ 105% of tap setting
Big Sandy	138-kV	105.0%	T-1 @ 105% of tap setting
Bixby	138-kV	104.6%	T-1 @ 105% of tap setting
Broadford	138-kV	105.0%	T-1 @ 105% of tap setting
Canton Central	138-kV	104.6%	T-1 and T-2 @ 105% of tap setting
Claytor	138-kV	105.1%	138-kV breakers
Clinch River	138-kV	102.9%	T-1, T-2 and T-3 @ 105% of tap setting
Cloverdale	138-kV	104.6%	T-3B and T-11 @ 105% of tap setting
Conesville	138-kV	102.2%	T-1, T-2 and T-3 @ 105% of tap setting
Corridor	138-kV	104.6%	T-1 @ 105% of tap setting
DeSoto	138-kV	104.6%	T-1 @ 105% of tap setting
East Elkhart	138-kV	104.6%	T-2 @ 105% of tap setting
East Lima	138-kV	104.6%	T-1A, T-1B and T-2 @ 105% of tap setting
Fall Creek	138-kV	104.6%	T-1 @ 105% of tap setting
Fostoria Central	138-kV	104.6%	T-1 @ 105% of tap setting

Table AII-2 (continued)
High Voltage Limits During Peak Load Periods

Station		High Voltage Limit	Liability
Galion	138-kV	106.5%	T-3 and T-4 @ 105% of tap setting
Glen Lyn	138-kV	102.9%	T-6 @ 105% of tap setting
Greentown	138-kV	105.0%	T-1 and T-2 @ 105% of tap setting
Hyatt	138-kV	104.6%	T-1A and T-1B @ 105% of tap setting
Jacksons Ferry	138-kV	105.0%	T-2 @ 105% of tap setting
Jackson Road	138-kV	104.6%	T-3 @ 105% of tap setting
Joshua Falls	138-kV	105.0%	T-1 @ 105% of tap setting
Kammer	138-kV	104.6%	T-100A, T-100B and T-300 @ 105% of tap setting
Kanawha	138-kV	103.2%	T-1 and T-2 @ 105% of tap setting
Kenzie Creek	138-kV	104.6%	T-1 @ 105% of tap setting
Kirk	138-kV	104.6%	T-4 @ 105% of tap setting
Leesville	138-kV	103.2%	T-1 @ 105% of tap setting
Matt Funk	138-kV	104.6%	T-1 @ 105% of tap setting
Muskingum	138-kV	105.1%	138-kV breakers
Nagel	138-kV	105.0%	T-3 @ 105% of tap setting
North Proctorville	138-kV	105.0%	T-1 @ 105% of tap setting
Ohio Central	138-kV	104.6%	T-1 @ 105% of tap setting
Olive	138-kV	104.6%	T-1 and T-2 @ 105% of tap setting
Picway	138-kV	102.4%	T-5 @ 105% of tap setting
Reynolds	138-kV	105.0%	T-1 @ 105% of tap setting
Roberts	138-kV	104.6%	T-2 @ 105% of tap setting
Robison Park	138-kV	104.6%	T-5 @ 105% of tap setting
Smith Mountain	138-kV	103.2%	T-1 and T-5 @ 105% of tap setting
Sorenson	138-kV	104.6%	T-1A, T-1B and T-2 @ 105% of tap setting
South Canton	138-kV	104.6%	T-1 @ 105% of tap setting
Southeast Canton	138-kV	104.6%	T-1 @ 105% of tap setting
Southwest Lima	138-kV	104.6%	T-1 @ 105% of tap setting
Sporn	138-kV	104.6%	T-4 @ 105% of tap setting
Tanners Creek	138-kV	105.1%	138-kV breakers
Tidd	138-kV	102.9%	Cardinal T-1 @ 105% of tap setting
Tri State	138-kV	104.6%	T-1 and T-2 @ 105% of tap setting
Twin Branch	138-kV	104.6%	T-6 @ 105% of tap setting
West Bellaire	138-kV	104.6%	T-1 @ 105% of tap setting
West Millersport	138-kV	104.6%	T-1 @ 105% of tap setting
Wyoming	138-kV	105.0%	T-1 and T-2 @ 105% of tap setting

Table AII-2 (continued)
High Voltage Limits During Peak Load Periods

765 kV Over-voltage Relay Timer Settings

		OVERVOLTAGE TIMER
STATION	CIRCUIT	SETTING
		(MINUTES)
		@1.061p.u.
Amos	Culloden	5.50
	Mountaineer	4.00
	Hanging Rock	5.50
Axton	Jacksons Ferry	4.50
Baker	Broadford	5.00
	Culloden	5.50
	Hanging Rock	4.50
Broadford	Baker	5.00
	Jacksons Ferry	4.50
Cloverdale	Jacksons Ferry	4.50
	Joshua Falls	4.00
Cook	Dumont	4.00
Culloden	Amos	5.50
	Baker	5.50
	Gavin	4.50
	Wyoming	5.50
Dumont	Cook	4.00
	Greentown	5.00
	Marysville	4.50
	Wilton Center	5.50
Gavin	Culloden	4.50
	Marysville	6.00
	Mountaineer	5.50
Greentown	Dumont	5.00
	Jefferson	5.50
Hanging Rock	Amos	5.50
	Baker	4.50
	Jefferson	4.00
	Marquis	5.00
Jacksons Ferry	Axton	4.50
	Broadford	5.00
	Cloverdale	5.50

	Wyoming	4.00
Jefferson	Greentown	5.50
	Hanging Rock	4.00
	Rockport	6.00
Joshua Falls	Cloverdale	4.00
Kammer	Maliszewski	5.00
	Mountaineer	4.50
	South Canton	5.50
Marquis	Hanging Rock	5.00
Marysville	Dumont	4.50
	Gavin	6.00
	Maliszewski	5.00
Mountaineer	Amos	4.00
	Gavin	5.50
	Kammer	4.50
Maliszewski	Kammer	4.50
	Marysville	5.50
Rockport	Jefferson	6.00
	Sullivan	5.50
South Canton	Kammer	5.50
Sullivan	Rockport	5.50
Wyoming	Culloden	5.50
	Jacksons Ferry	4.00

Table AII-3
Location and Time Delay Setting of Overvoltage Relays

Circuit Breaker Type	kV	Continuous	30 Minute	2 Hour	24 Hour
All types	138	145 kV (1.051 pu)	146 kV (1.058 pu)	146 kV (1.058 pu)	146 kV (1.058 pu)
	345	362 kV (1.049 pu)	(see below)	(see below)	(see below)
	500	550 kV (1.10 pu)			
	765	800 kV (1.046 pu)	(see below)	(see below)	(see below)
765 kV CBs w/o free standing Oil filled CTs	765	800 kV (1.046 pu)	840 kV (1.098 pu)	840 kV (1.098 pu)	840 kV (1.098 pu)
765 kV CBs with free standing Oil filled CTs	765	800 kV (1.046 pu)	840 kV (1.098 pu)	840 kV (1.098 pu)	840 kV (1.098 pu)
345 kV SF6 puffer CBs w/o free standing Oil filled CTs	345	362 kV (1.049 pu)	396 kV (1.148 pu)	396 kV (1.148 pu)	396 kV (1.148 pu)
345 kV air blast CBs w/o free standing Oil filled CTs	345	362 kV (1.049 pu)	396 kV (1.148 pu)	396 kV (1.148 pu)	396 kV (1.148 pu)
345 kV CBs with free standing Oil filled CTs	345	362 kV (1.049 pu)	396 kV (1.148 pu)	373 kV (1.081 pu)	362 kV (1.049 pu)
345 kV Oil CBs	345	362 kV (1.049 pu)	372 kV (1.078 pu)	372 kV (1.078 pu)	372 kV (1.078 pu)

Table AII-4
High Voltage Limits for Circuit Breakers

Appendix III

Under Frequency Guidelines – AEP/PJM

1. At 59.75 Hz
   a. Suspend Automatic Generation Control (AGC)
   b. Notify Interruptible Customers to drop load
2. At 59.5 Hz automatically shed 5 % System internal load by relay action. (25 cycle, .42 sec. delay)
3. At 59.3 Hz automatically shed an additional 5 % of System internal load by relay action. (25 cycle, .42 sec. Delay)
4. At 59.1 Hz automatically shed an additional 5 % of System internal load by relay action. (25 cycle, .42 sec. delay)
5. At 58.9 Hz automatically shed an additional 5 % of System internal load by relay action. (25 cycle, .42 sec. delay)
6. At 58.7 Hz automatically shed an additional 5 % of System internal load by relay action. (25 cycle, .42 sec. delay)
7. At 58.2 Hz automatically trip the D.C. Cook Nuclear Units 1 and 2.
8. At 58.0 Hz or at generator minimum turbine off-frequency value, isolate generating unit without time delay.

Criteria

1. Total load to be controlled by load shedding relays should equal a minimum of 25 % of System Internal Load.
2. The Trip Time Delay should be 25 cycles (.42 seconds)
3. The Restoration Frequency should be:
   a. 59.95 Hz — For non-supervisory controlled stations and remote/rural area feeders.
   b. Disabled — For supervisory controlled stations and feeders, or stations and feeders located in a metropolitan area with a 15 minute or less response time
4. The Block Voltage should be set at 75%; which is 90 volts on a 120 volt base.

AEP Confidential Special Handling

The Integrated and Straight Timer settings are as follows:

Load Restored	Integrated Time at or above 59.95 Hz	Straight Time at 59.95 Hz
1st Block - 1%	4 minutes	1 seconds
2nd Block - 1%	4 minutes	2 seconds
3rd Block - 1%	4 minutes	3 seconds
4th Block - 1%	6 minutes	4 seconds
5th Block - 1%	6 minutes	5seconds
6th Block - 1%	6 minutes	6 seconds
7th Block - 1%	8 minutes	7 seconds
8th Block - 1%	8 minutes	8 seconds
9th Block - 1%	8 minutes	9 seconds
10th Block - 1%	8 minutes	10 seconds
11th Block - 1%	10 minutes	11 seconds
12th Block - 1%	10 minutes	12 seconds
13th Block - 1%	10 minutes	13 seconds
14th Block - 1%	10 minutes	14 seconds
15th Block - 1%	10 minutes	15 seconds
16th Block - 1%	12 minutes	16 seconds
17th Block - 1%	12 minutes	17 seconds
18th Block - 1%	12 minutes	18 seconds
19th Block - 1%	12 minutes	19 seconds
20th Block - 1%	12 minutes	20 seconds
21st Block - 1%	14 minutes	21 seconds
22nd Block - 1%	14 minutes	22 seconds
23rd Block - 1%	14 minutes	23 seconds
24th Block - 1%	14 minutes	24 seconds
25th Block - 1%	14 minutes	25 seconds

Note: An additional 30 second integrated timer setting is normally applied to the older style mechanical relays.

Estimated AEP/PJM Mw load shed in each step, based on summer 2014 data:

AEP East Summer Peak Load		**18229**	Mws	Summer 2014			
Company		**59.5**	**59.3**	**59.1**	**58.9**	**58.7**	TOTAL
	PJM REGION 2014 PEAK	5.00%	5.00%	5.00%	5.00%	5.00%	25.00%
Appalachian		226	302	314	281	353	1476
Columbus Southern Power		323	164	224	371	298	1380
Indiana Michigan		292	268	239	295	381	1475
Kentucky		66	79	109	78	107	439
Kingsport		33	32	19	11	15	110
Ohio Power		222	320	216	414	341	1513
Wheeling Power		0	0	35	2	1	38
	TOTAL	1162	1165	1156	1452	1496	
	PERCENT	**6.37%**	**6.39%**	**6.34%**	**7.97%**	**8.21%**	**35.28%**

A listing of Under-Frequency circuits is on file at the TDC's.

AEP Confidential Special Handling

Under Frequency Guidelines – AEP/SPP

1. At 59.75 Hz
    a. Suspend Automatic Generation Control (AGC)
    b. Notify Interruptible Customers to drop load
2. At 59.3 Hz automatically shed 10 % of System internal load by relay action. (15 cycle, .25 sec. delay)
3. At 59.0 Hz automatically shed 10 % of System internal load by relay action. (15 cycle, .25 sec. delay)
4. At 58.7 Hz automatically shed 10 % of System internal load by relay action. (15 cycle, .25 sec. delay)
5. At 58.5 Hz isolate into islands in both PSO and SWEPCO (15 cycle, .25 sec. delay)
    a. PSO - 3 Islands, Refer to PSO UF plan for island boundaries
    b. SWEPCO – 3 Islands, Refer to SWEPCO UF plan for island boundaries.
6. At 58.0 Hz or at generator minimum turbine off-frequency value, isolate generating unit without time delay.

Criteria

1. Total load to be controlled by load shedding relays should equal a minimum of 30 % of System Internal Load.
2. The intentional relay trip delay should be set at 15 cycles (0 .25 seconds)
3. The Under-voltage inhibit should be set at 80%; which is 96 volts on a 120 volt base.
4. Current supervision can be used in locations where sizable motor load could cause relay misoperations.
5. Automatic reclosing shall be disabled for loads that are tripped by under-frequency. Delayed automatic restoration of load may be allowed under certain conditions.

AEP Confidential Special Handling

Estimated AEP/SPP Mw load shed in each step, based on summer peak load data:

PSO Summer Peak Load	2014	**4029**	Mws		
Distribution Region		59.3	59	58.7	Total 3 Steps
		10.00%	10.00%	10.00%	30.00%
Eastern		58	72	36	166
Northern		51	51	40	143
Tulsa		199	245	358	802
Western		124	80	93	296
	TOTAL	432	448	527	
	PERCENT	**10.72%**	**11.12%**	**13.07%**	**34.91%**

SWEPCO Summer Peak Load	2014	**4214**	Mws			
Distribution Region		59.3	59	58.7	Total for Steps 1-2	Total 3 Steps
		10.00%	10.00%	10.00%	20-25%	30.00%
Central		113	64	88	177	265
Northern		61	69	79	130	209
Southern		140	151	131	291	422
Western		98	129	127	227	354
West LA		20	19	0	39	39
West TX		3	0	13	3	16
Municipal		0	0	0	0	0
	TOTAL	435	432	437	867	1303
	PERCENT	**10.3%**	**10.3%**	**10.4%**	**20.6%**	**30.9%**

A listing of Under-Frequency circuits is on file at the TDC's

Appendix IV

AEP East/PJM - Voltage Reduction Guidelines

We have matched our voltage reduction stations to our manual load shedding stations to minimize time and manpower requirements.

We have basically three types of voltage regulating equipment; LTCs, Bus regulators and Feeder regulators. Some of these have no voltage reduction control, some have variable voltage reduction control, some have microprocessor controls and others have a toggle switch to implement the voltage reduction.

The majority of our voltage controls are not equipped with a voltage reduction feature. We normally set the controls to hold 125 volts, + or - 1 volt. Our voltage reduction program recommends a 2.5 % voltage reduction or approximately 3 volts on a 120 volt base. This would mean we need to re-adjust the set point to 122 volts + or - 1 volt. Some of the PT ratios on the Columbus Southern system are different from the above; however, whatever the set point is, it should be reduced by 3 volts. For those devices equipped with a toggle switch, simply throw the toggle switch, which is set internally to either a 2.5 % or 5 % reduction. The devices equipped with variable voltage reduction control; typically + or - 10% or + or - 7.5%, should be set at a 2.5% voltage reduction. The microprocessor type controls require a password, and should be set at a 2.5% voltage reduction.

The total voltage reduction load relief for AEP\PJM will be approximately **61** MWs; based on a 2% load relief.

The following sequence shows the events that will take place:

Under the conditions where the SCC has determined that a <u>Voltage Reduction Alert</u> should be issued to the TDC’s and Corporate Communications, the notification should include an estimate of the starting time and the duration of the deficiency.

When the order is issued to <u>Prepare for Voltage Reduction</u>, each TDC will dispatch personnel to predetermined stations to stand by for Voltage Reduction.

When the order is issued to <u>Execute Voltage Reduction</u>, each TDC will advise personnel to initiate voltage reduction as indicated in their station listings.

The time sequence of this step is not very critical; consequently, a coordinated response by field personnel is not required.

A listing of Voltage Reduction stations is kept on file at the TDC’s.

AEP West/SPP - Voltage Reduction Guidelines

At the present time, a voltage reduction program for AEP/SPP does not exist. This is not a wide spread practice among Control Areas in the SPP region.

Appendix V

AEP East/PJM - Manual Load Shedding Guidelines

The Manual Load Shedding Program is part of our Emergency Operating Plan because we may have a need to shed load to preserve the integrity of our interconnected system. This plan is usually activated for a Capacity Deficiency or a Transmission Emergency. The AEP-Dominion Interface procedure also has load shedding as an option. Refer to the IROL Relief Procedures AEPE PJM pdf document located on the TOPS SharePoint site for additional details at Engineering>Operating Guidelines>AEP East>General.

The AEP Advanced Load Shedding (ALS) plan opens a set of breakers to achieve a desired load shed objective. Once the objective is achieved, the program cycles though the breaker list by closing of an open breaker followed by opening up another breaker. The program also attempts to keep on track with the load shed objective.

The Menu Advanced Load Shedding (MALS) displays on the COTDC and ROTDC ADX systems shows the MVA load shed available for each area. Note, the LOAD displayed reflects the current real time area load.

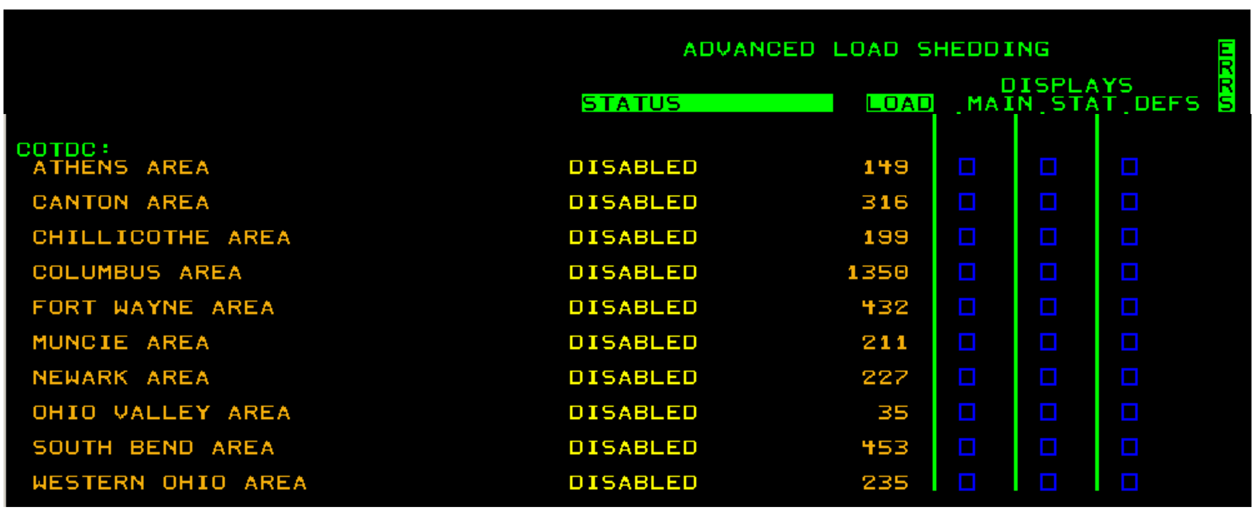


Figure AV-1 - MALS Display for COTDC System

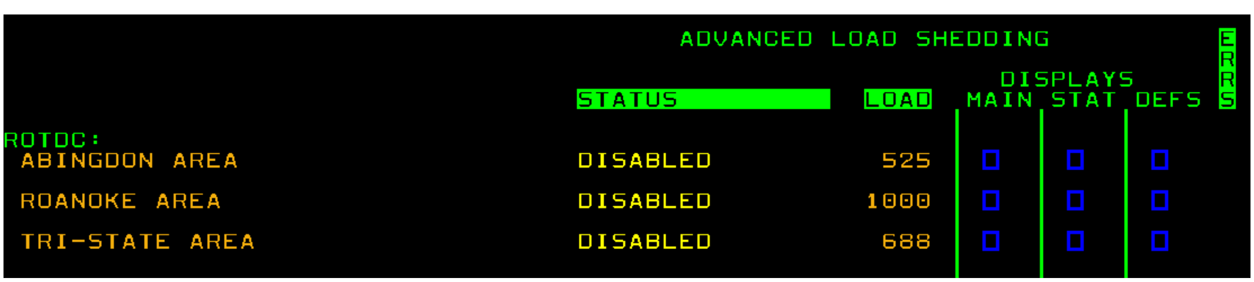


Figure AV-2 - MALS Display for ROTDC System

From the MALS display for the COTDC system, selecting Columbus Area we are directed to the Columbus Area Control screen.

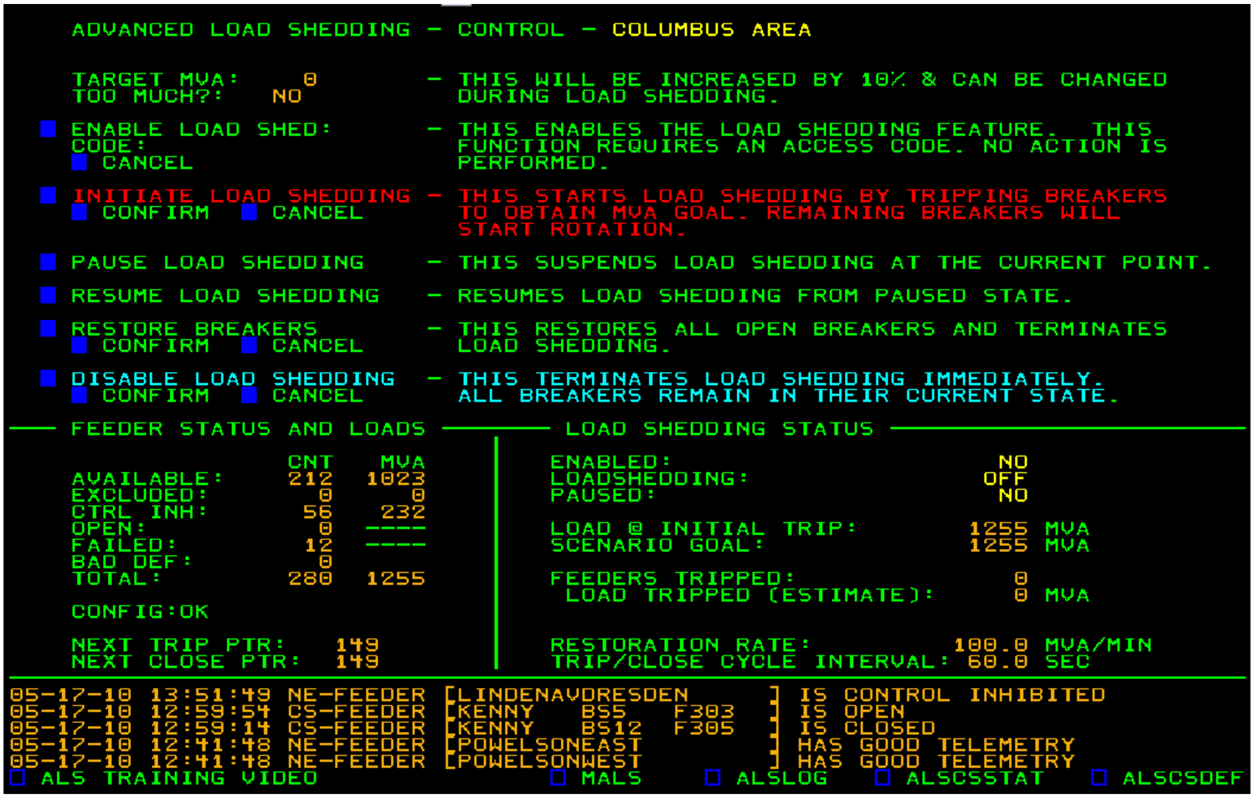


Figure AV-3 - ALSCS Display

From a high level perspective, to shed load the TDC

1. Enters the TARGET MVA load to shed
2. Selects Enable Load Shed poke point and enters the access code.
3. Selects Initiate Load Shedding followed by Confirm

The attached link to the ALS training video provides detailed step by step instructions on the program. http://topsweb/Videos/ALS/ALS%20for%20Dispatchers.html

Peak Non coincidental Mw Available on MALS for calendar year 2014						
ALS by TDC	**CCTDC**	**CETDC**	**CWTDC**	**RNTDC**	**RSTDC**	**Total**
MW's Available for ALS	3,393	879	1,883	2,230	1,320	9,705

Table AV-1

When the switch person receives the directive from the TDC to begin manual load shedding, they will immediately drop the Group within the present time slot and rotate the Groups on the hour, and half hour as indicated. When a Group of circuits is dropped; such as Group A, the Group B circuits must be opened first before restoring Group A. This assures that enough load remains off to avoid capacity problems.

AEP/PJM Group and Block Data - Summer Loads

	Group A (MWs)	Group B (MWs)
Supervisory Control	1,274	1,276
Block 1	174	168
Block 2	162	183
Block 3	160	177
Block 4	218	200
Total	1,988	2,004

Table AV-2

The following sequence shows the events that will take place:

The SCC will issue a Mandatory Load Curtailment Alert. Each TDC will identify predetermined stations to be utilized for manual load shedding

The SCC will issue a Mandatory Load Curtailment Warning. Each TDC will dispatch personnel to predetermined stations to stand by for Manual Load Curtailment, and\or prepare to shed load on the SVC controlled circuits via the SCADA systems. One person will be dispatched to handle only one station since this will minimize outages during the restoration procedure. In addition, each person assigned to a station must maintain communications with the TDC.

The final step is for the SCC to issue the order Execute Mandatory Load Curtailment. Each TDC will advise personnel to initiate Mandatory Load Curtailment as indicated in their station listings, and\or carryout the load shedding on the SVC controlled circuits via the SCADA systems.

A listing of Manual Load Shedding circuits is kept on file at the TDC's.

Load Shedding Criteria

The circuits should be prioritized by the following guidelines. These guidelines have been approved by Legal and meet the State requirements for the definition of "Priority Use". We will shed Priority 3 circuits first, then Priority 2, and if more load is needed, even Priority 1. We will need to select stations that have at least 2 feeders and each feeder should have at least 3,000 kW of load. Stations with supervisory control and meeting the above criteria should be selected since we can ultimately utilize them in a computer program. We need to shed at least 25 % of the Operating Company's peak summer/winter internal load. (12.5 % Group A, 12.5 % Group B)

Priority The feeders selected for use in controlled rotating blackouts are prioritized as follows:

Priority 1 - "Hospitals" which shall be limited to major institutions providing critical care to patients

Priority 2 - Police, fire, communication services, water and sewer services, government, transportation, emergency medical services, alternate energy and food services.

Priority 3 - All other customers

The following abbreviations can be used to describe the type of load on each circuit and in many cases the same circuit will have several priority users.

Abbreviation	***Definition***
HOSP	Hospitals
LS	Life support equipment
POL	Police stations and Government detention institutions
EMS	Emergency medical services
GOVT	Critical State and Federal government facilities
FIRE	Fire stations
COM	Communication services; i.e. telephone, radio, newspaper
WATER	Water and/or sewer services
TRAN	Transportation related services; i.e. transit systems, major airport terminals
ALT ENG	Alternate energy source services; i.e. IPP, Cogen
FOOD	Perishable food or medicine that represents substantially all of a customers load

Due to the vast number of distribution circuits with life support; if a circuit only has life support on it, it should be classified as a Priority 3. The life support equipment is required to have a backup power supply and will ride through any of the abnormal circuit outages we experience every day. That being the case, the planned rotation should not pose a problem.

The amount of load to be shed in each District should be in the same proportion as the District load is to the Operating Company's peak summer/winter internal load. That being the case, we need to make some estimate of what percentage the District load is to the Operating Company's peak summer/winter internal load. Keep in mind that we are to be nondiscriminatory in the load we shed.

Procedure:

1. Estimate % District load as a percentage of Operating Companies peak summer/winter internal load and calculate target load for summer and winter.
   (Target Load = % District Load x Operating Company peak load x 25 %)
2. Determine type of load on each Districts circuits and assign a Priority number.
3. Add the Priority 3 circuit loads and compare to target load for the District.
4. If Priority 3 circuits are not enough, select Priority 2 circuits and recalculate.
5. If Priority 2 circuits are not enough, select Priority 1 circuits and recalculate.

AEP West/SPP - Manual Load Shedding Guidelines

PSO Plan

Feeders are grouped in 8 Steps labeled "A" through "H". Each Step represents approximately 5% of the PSO summer peak load. The SCC will determine when it is necessary to put this plan into effect and will notify the Tulsa Transmission Dispatch Center (TDC). The Tulsa TDC would then coordinate with the Distribution Dispatch Center (DDC) who would implement load shedding. The feeders within each Step have supervisory control and can be operated individually from the DDC allowing load to be shed in increments up to the total load for the Step Each Step would take approximately 3-5 minutes to implement. The feeder rotation will be carried out in one-hour intervals. The objective of this plan is to have no circuits open more than two hours.

Division	Transmission Customers	Step A MW	Step B MW	Step C MW	Step D MW	Step E MW	Step F MW	Step G MW	Step H MW
Tulsa Urban (south)	134	75	80	68	80	64	70	71	75
Tulsa Rural (north)	27	12	14	11	12	6	8	6	5
McAlester	36	15	14	12	10	10	12	9	8
Lawton	48	20	27	20	20	19	21	13	13
Total	245	122	135	112	123	99	111	99	101

Notes:

- The PSO automatic load transfer in the Step is placed on manual during a manual load shed event which inhibits load transfer to the alternate source.
- A listing of Manual Load Shedding circuits is kept on file at the TDC's.

SWEPCo Plan

The SWEPCo plan has 6 Steps labeled A through F consisting of distribution feeders. Each distribution Step represents approximately 5 % of SWEPCo's peak internal load. Some of the Steps have supervisory control, and others will require manual load shedding by sending personnel to the station to rotate the feeders. Typically, Steps A, B & C are supervisory control from the DDC allowing load to be shed in increments up to the total load for the Step, and Steps D, E & F are a mixture. Each supervisory Step would take approximately 3-5 minutes to implement. The feeder rotation will be done similar to PSO on a one-hour interval. The objective of this plan is to have no circuits open more than two hours.

The summer peak Mw breakdown is as follows:

Division	Customers	Step A MW	Step B MW	Step C MW	Step D MW	Step E MW	Step F MW
Southern	74484	84.2	87.4	84.6	70.7	80.5	81.4
Western	35000	51.1	51.2	47.9	51.8	53	48.3
Central- TX	19206	23.4	22.4	27	26.2	34	24.7
Northern	29370	40.5	34.8	35.7	33.5	39	36.9
Central- AR	13457	12.3	16.1	13.2	17.4	10.5	15.2
TOTAL --	171517	211.6	211.9	208.3	199.6	216.9	206.4

A listing of Manual Load Shedding circuits is kept on file at the TDC's.

The following sequence shows the events that will take place:

The SCC will issue a Mandatory Load Curtailment Alert. Each TDC will identify predetermined stations to be utilized for manual load shedding

The SCC will issue a Mandatory Load Curtailment Warning. Each TDC will dispatch personnel to predetermined stations to stand by for Manual Load Curtailment, and\or prepare to shed load on the SVC controlled circuits via the SCADA systems. One person will be dispatched to handle only one station since this will minimize outages during the restoration procedure. In addition, each person assigned to a station must maintain communications with the TDC.

The final step is for the SCC to issue the order Execute Mandatory Load Curtailment. Each TDC will advise personnel to initiate Mandatory Load Curtailment as indicated in their station listings, and\or carryout the load shedding on the SVC controlled circuits via the SCADA systems.

Appendix VI

Purpose:

The Operator Authority to Act Policy document outlines the Responsibilities and Authorities of AEP Transmission System Control Center Operators and Transmission Dispatchers in performing various actions to alleviate operating emergencies and / or ensure stable and reliable operation of the AEP transmission system.

Revision 6 of the Operator Authority to Act Policy document follows:

TRANSMISSION OPERATIONS

Operator Authority to Act Policy

Revision 6

April 2, 2015

Table of Contents

Document Control 3
References 5
Purpose and Overview 5
Policy 6

Document Control

Preparation

ACTION	NAME(S)	TITLE
Prepared by:	Chris Shaffer	Planning and Engineering Supervisor
Reviewed by:	Tim Hostetler	Operations Engineering Manager
	Ed Schnell	Director, Transmission Dispatching
	Dennis Kunkel	Transmission Dispatching Manager
	Dennis Sauriol	Transmission Operations Reliability Manager

Approvals

NAME	TITLE	SIGNATURE / DATE
Paul Johnson	Managing Director, Transmission Operations	040215

Review Cycle

Quarterly	Semi-annual	Annual	Triennial X

Retention Period

Six months	One Year	Two Years	Three Years X

Release

VERSION	DATE	FILE NAME	CHANGE NOTICE
Revision 0.0	February 23, 2004	Operator Authority to Act Policy.pdf	Original statement granting authority, including load shedding as per CERC Operating Policy 8A
Revision 1.0	November 21, 2005	Operator Authority to Act Policy V1.pdf	Revised to reference NERC Standard PER-001-0
Revision 2.0	March 26, 2007	Operator Authority to Act Policy V2.pdf	Revised per Dec 2006 gap analysis, added reference to NERC Standard TOP-001-1 and added hierarchal operating authority and endorsements
Revision 3.0	January 27, 2009	Operator Authority to Act Policy V3.pdf	Added Paul Johnson as signee
Revision 4.0	April 25, 2011	Operator Authority to Act Policy V4.pdf	Minor NERC PER-001-0.1 update. Added approvals

Revision 5.0	October 17, 2012	Operator Authority to Act Policy V5.pdf	Reflecting NERC PER-001-0.2 and TOP-001-1a updates. Added PER-003-1 reference and clarified acknowledging of supplemental communications.
Revision 6.0	April 2, 2015	Operator Authority to Act Policy V6.pdf	Triennial Review. Updated NERC Standard references and NERC definitions included references to RC and TO/TOP authority documents in each region.

References

NERC Reliability Standards:

PER-001-0.2: Operating Personnel Responsibility and Authority
PER-003-1: Operating Personnel Credentials
TOP-001-1a: Reliability Responsibilities and Authorities
IRO-001-1.1 R8: Reliability Coordination – Responsibilities and Authorities
IRO-004-2 R1: Reliability Coordination – Operations Planning

PJM Manual 3: Transmission Operations, Section 1: Transmission Operations Requirements
PJM TO/TOP (Transmission Owner/Transmission Operator) Matrix
Southwest Power Pool Criteria & Appendices, Section 5.0 Reliability Coordination
ERCOT Coordinated Functional Registration Agreement and Matrix

Purpose and Overview

This policy outlines the Responsibilities and Authorities of AEP Transmission System Control Center Operators and Transmission Dispatchers in performing various actions to alleviate operating emergencies and / or ensure stable and reliable operation of the AEP transmission system,

The referenced NERC Reliability Standards and RTO manuals and matrices outline specific requirements pertaining to operating personnel responsibility and authority in taking actions to alleviate operating emergencies, as well as, complying with directives. The NERC Glossary of Terms defines a Reliability Directive as "a communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impact." An Emergency is defined in the NERC Glossary as "any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System". The NERC Glossary defines Adverse Reliability Impact as "the impact of an event that results in Bulk Electric System instability or Cascading.

This policy establishes operating responsibilities and authorities to maintain the safety and reliability of the AEP transmission system. Supplemental communications from engineering personnel, equipment specialists, field personnel, immediate supervision and management or any others may be acknowledged but shall not alter the Responsibility and Authority of Transmission System Control Center Operators and Transmission Dispatchers in performing actions required to maintain the safety and reliability of the AEP transmission system.

Policy

1. Transmission System Control Center Operators and Transmission Dispatchers hereby have the responsibility and authority to take or direct whatever actions are needed in real-time to maintain safety and reliability. These actions include, but are not limited to, re-dispatch generation, reconfigure transmission, reduce firm load, or curtailing transmission service to alleviate operating emergencies and/or to ensure the stable and reliable operation of the AEP transmission system. These actions do not require any prior approval from higher-level personnel within AEP.

2. The Transmission System Control System Operators are the highest real-time operating authority within AEP, except for the ERCOT Region, where the Transmission Dispatcher is the highest authority.

   For AEP within the PJM and SPP Regions:

   a. The Transmission System Control Center Operator shall comply with all reliability directives issued by the applicable NERC Reliability Coordinator (PJM for AEP facilities in the east or SPP for AEP facilities in the west external to ERCOT), unless such action(s) would violate safety, equipment, regulatory or statutory requirements. If such a directive cannot be complied with, the Transmission System Control Center Operator shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator can implement alternate remedial actions.

   b. All Generation Dispatchers and Transmission Dispatchers shall comply with all reliability directives issued by the Transmission System Control Center Operator, unless such action(s) would violate safety, equipment, regulatory or statutory requirements. If such a directive cannot be complied with, the Generation Dispatchers and/or Transmission Dispatchers shall immediately inform the Transmission System Control Center Operator of the inability to perform the directive so that the Transmission System Control Center Operator can implement alternate remedial actions.

   c. All Distribution Dispatchers shall comply with all Bulk Electric System reliability directives issued by the Transmission Dispatcher, unless such action(s) would violate safety, equipment, regulatory, or statutory requirements. If such a directive cannot be complied with, the Distribution Dispatchers shall immediately inform the Transmission Dispatcher of the inability to perform the directive so that the Transmission Dispatcher can implement alternate remedial actions.

For AEP with the ERCOT Region:

a. The Transmission Dispatcher within ERCOT shall comply with all reliability directives issued by the ERCOT Reliability Coordinator, unless such action(s) would violate safety, equipment, regulatory or statutory requirements. If such a directive cannot be complied with, the Transmission Dispatcher shall immediately inform the ERCOT Reliability Coordinator of the inability to perform the directive so that the ERCOT Reliability Coordinator can implement alternate remedial actions.

b. The Generation Dispatchers and Distribution Dispatchers shall comply with all Bulk Electric System reliability directives issued by the Transmission Dispatcher, unless such action(s) would violate safety, equipment, regulatory or statutory requirements. If such a directive cannot be complied with, the Generation Dispatchers and/or Distribution Dispatchers shall immediately inform the Transmission Dispatcher of the inability to perform the directive so that the Transmission Dispatcher can implement alternate remedial actions.

Appendix VII

Internal Contacts

Region	Name	JobTitle	Direct	Audinet	AEP Cell Phone
APCO/KGPCO (TN, VA, WVA)	Patton,Charles R	President & COO - Appalachian	[redacted]	[redacted]	[redacted]
APCO/KGPCO (TN, VA, WVA)	Wright P A (Philip)	VP Distribution Region Opers	[redacted]	[redacted]	[redacted]
APCO/KGPCO (TN, VA)	Dempsey M E (Mark)	VP External Affairs	[redacted]	[redacted]	[redacted]
APCO/KGPCO (TN, VA)	Bosta W A (Bill)	Dir Regulatory Svcs	[redacted]	[redacted]	[redacted]
APCO/KGPCO (TN, VA, WVA)	Matheney J H (Jeri)	Dir Communications	[redacted]	[redacted]	[redacted]
APCO (WVA)	Dempsey M E (Mark)	VP External Affairs	[redacted]	[redacted]	[redacted]
APCO (WVA)	Ferguson,Steven H	VP Regulatory & Finance	[redacted]	[redacted]	[redacted]
IN/MI	**Chodak III,Paul**	**President & COO - IN/MI**	[redacted]	[redacted]	[redacted]
IN/MI	Kratt, Thomas A	VP Distribution Region Opers	[redacted]	[redacted]	[redacted]
IN/MI	Lewis M E (Marc)	VP External Affairs	[redacted]	[redacted]	[redacted]
IN/MI	Williamson, Andrew J	Dir Regulatory Svcs	[redacted]	[redacted]	[redacted]
IN/MI	Bergsma, Brian	Director Communications & Govt Affairs	[redacted]	[redacted]	[redacted]
IN/MI	Wiard,Barry O	Dir Customer Svcs & Mktg	[redacted]	[redacted]	[redacted]
IN/MI	Williamson, Andrew J	Director Regulatory Svcs			
KY	**Pauley,Gregory G**	**President & COO - KY**	[redacted]	[redacted]	[redacted]
KY	Phillips E G (Everett)	Mng Dir Distr Region Opers	[redacted]	[redacted]	[redacted]
KY	Hall Brad N	Mgr External Affairs	[redacted]	[redacted]	[redacted]
KY	Wohnhas Ranie K	Mng Dir Regulatory& Finance	[redacted]	[redacted]	[redacted]
KY	Barker, Allison	Corporate Comms Mgr	[redacted]	[redacted]	[redacted]
OH	**Vegas Pablo A**	**President & COO – OH**	[redacted]	[redacted]	[redacted]
OH	Dias Selwyn J	VP Distribution Region Opers	[redacted]	[redacted]	[redacted]
OH	Froehle,Thomas L	VP External Affairs	[redacted]	[redacted]	[redacted]
OH	Spitznogle, Gary O	VP Regulatory & Finance	[redacted]	[redacted]	[redacted]
OH	Flora T M (Terri)	Director Communications	[redacted]	[redacted]	[redacted]
OH	Sloneker K L (Karen)	Dir Customer Svcs & Mktg	[redacted]	[redacted]	[redacted]
PSO	**Solomon J (J Stuart)**	**President & COO - PSO**	[redacted]	[redacted]	[redacted]
PSO	Baker,Steven F	VP Distribution Region Opers	[redacted]	[redacted]	[redacted]
PSO	Harper Jr.,John D	VP External Affairs	[redacted]	[redacted]	[redacted]
PSO	Shuart, Emily C	Dir Regulatory Svcs	[redacted]	[redacted]	[redacted]
PSO	Lyda, Tiffini S	Dir Communications	[redacted]	[redacted]	[redacted]
PSO	Mouser B M (Bobby)	Dir Customer Svcs & Mktg	[redacted]	[redacted]	[redacted]
SWEPCO	**McCellon-Allen,Venita**	**President & COO - SWEPCO**	[redacted]	[redacted]	[redacted]
SWEPCO	Smoak A M (Malcolm)	VP Distribution Region Opers	[redacted]	[redacted]	[redacted]
SWEPCO	Bond Terry Brian (Brian)	VP External Affairs	[redacted]	[redacted]	[redacted]
SWEPCO	Bennett Sandra S	VP Regulatory & Finance	[redacted]	[redacted]	[redacted]
SWEPCO	Brice Jr.,Thomas P	Dir Regulatory Svcs	[redacted]	[redacted]	[redacted]
SWEPCO	Sullivan, Carey	Director Communications	[redacted]	[redacted]	[redacted]
SWEPCO	Mattison B (Brett)	Dir Customer Svcs & Mktg	[redacted]	[redacted]	[redacted]
TX	**Evans Murray Bruce**	**President & COO - TX**	[redacted]	[redacted]	[redacted]
TX	Evans, Murry Bruce	VP Distribution Region Opers	[redacted]	[redacted]	[redacted]
TX	Reyes J C (Julio)	VP External Affairs	[redacted]	[redacted]	[redacted]

AEP Confidential Special Handling

TX	Ford R K (Ron)	VP Regulatory & Finance	[redacted]	[redacted]	[redacted]
TX	Larry Jones	Director Communications	[redacted]	[redacted]	[redacted]
TX	Murphy, J S (Joel)	Dir Customer Svcs & Mktg	[redacted]	[redacted]	[redacted]
TX	Talavera, J E (Judith)	Director Regulatory Svcs	[redacted]	[redacted]	[redacted]
Environment & Safety	**McManus,John M**	**VP - Environmental Services**	[redacted]	[redacted]	[redacted]
Environment & Safety	Hendricks,John C	Director-Air Quality	[redacted]	[redacted]	[redacted]
Environment & Safety	Wood,Alan R	Director-Water Quality	[redacted]	[redacted]	[redacted]
Commercial Operations	**Thompson, William R**	**Director Real Time Market**	[redacted]	[redacted]	[redacted]
Commercial Operations	Robert A Beller	Dir-Day Ahead RTO Ops	[redacted]	[redacted]	[redacted]

AEP East/PJM Region Neighboring System Contacts

Company	Real Time Desk #	Managers Name	Managers #	Manager Email	Group Email
AMRN	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Duke Carolina /Progress (CPL)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Duke East	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
EKPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
IPL	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LGEE (KU)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LGEE (LGE)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(MECS) ITC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NIPS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
OVEC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TVA Bal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TVA North Tans	[redacted]	[redacted]	[redacted]		
FE (South)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Buckeye Power	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	
ComEd	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DPL	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
DLCO	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Duke West (CIN)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
FE [West]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PJM Valley Forge	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]				

AEP Confidential Special Handling

Company	Real Time Desk #	Managers Name	Managers #	Manager Email	Group Email
	[redacted]				
PJM Milford	[redacted]				
VP/Dominion	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

AEP Confidential Special Handling

AEP East/PJM Region Generator Operators (IPP) Entity Contacts

Company	Real Time Desk #	Managers Name	Managers #	Email Address	Group Email
AMPO (Gorsuch)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
FE Buchanan	[redacted]	[redacted]	[redacted]	[redacted]	
ENEL North America Fries Hydro [12kv]	[redacted]	[redacted]	[redacted]	[redacted]	
DENA (Hanging Rock)	[redacted]	[redacted]	[redacted]	[redacted]	
DENA (Washington)	[redacted]	[redacted]	[redacted]	[redacted]	
DPLE (Keystone)	[redacted]	[redacted]	[redacted]	[redacted]	
			[redacted]		
Fowler Ridge	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
GRPP Summersville (Tower 117)	[redacted]	[redacted]	[redacted]	[redacted]	
Riverside/Foothills Operated by Twin Eagle Mgmt. LLC	[redacted]	[redacted]	[redacted]	[redacted]	
Mayflower	[redacted]	[redacted]	[redacted]	[redacted]	
Meadowlake	[redacted]	[redacted]	[redacted]	[redacted]	
MIRANT (Sugar Creek)	[redacted]	[redacted]	[redacted]	[redacted]	
RP Mone	[redacted]	[redacted]	[redacted]	[redacted]	
			[redacted]		
Sun Coke	[redacted]	[redacted]	[redacted]	[redacted]	

AEP Confidential Special Handling

Company	Real Time Desk #	Managers Name	Managers #	Email Address	Group Email
Teneaska Energy (Big Sandy Peaker)	[redacted]	[redacted]	[redacted]	[redacted]	
Tenaska Energy (Flatlick)	[redacted]	[redacted]	[redacted]	[redacted]	
Tenaska Energy (Wolf Hills)	[redacted]	[redacted]	[redacted]	[redacted]	
			[redacted]		
Blue Creek (Maddox Cr)	[redacted]	[redacted]	[redacted]	[redacted]	
Timber Sw. Wind Connect (Haviland)	[redacted]	[redacted]	[redacted]	[redacted]	
		[redacted]	[redacted]	[redacted]	
Wildcat EON (Strawton)	[redacted]	[redacted]	[redacted]	[redacted]	
		[redacted]	[redacted]	[redacted]	
IMPA (Anderson/Richmond)	[redacted]	[redacted]	[redacted]		
			[redacted]		
Keystone		[redacted]	[redacted]		
			[redacted]		
		[redacted]	[redacted]		
			[redacted]		
Dynegy (Beverly & Hanging Rock)	[redacted]	[redacted]			

AEP West/SPP Region Interconnection / External Entity Contact List

Company	Real Time Desk Number	Group Email Address
AECC - Fitzhugh	[redacted]	[redacted]
AECC (GOP)	[redacted]	[redacted]
AECC (TO plus the 17 CO-OP DP members)	[redacted]	[redacted]
AECI	[redacted]	[redacted]
Blue Canyon Windfarm (Psuedo Tie to WFEC)	[redacted]	[redacted]
CAJUN (LAGEN)	[redacted]	[redacted]
CLECO	[redacted]	[redacted]
Cogentrix IPP (aka Greencountry)	[redacted]	[redacted]
Dempsey Ridge Windfarm	[redacted]	[redacted]
EDE	[redacted]	[redacted]
Elk City Windfarms (Nextera)	[redacted]	[redacted]
ERCOT Transmission & Schedules	[redacted]	[redacted]
ESI	[redacted]	[redacted]
ETEX Cogeneration	[redacted]	[redacted]
Gateway IPP	[redacted]	[redacted]
GRDA	[redacted]	[redacted]
HCPP IPP	[redacted]	[redacted]
KGE-WR	[redacted]	[redacted]
Kiowa IPP	[redacted]	[redacted]
MISO South - Little Rock	[redacted]	[redacted]
Narrows Dam (Units 1, 2 and 3)	[redacted]	[redacted]
OGE	[redacted]	[redacted]
OMPA	[redacted]	[redacted]
ONETA IPP (Calpine)	[redacted]	[redacted]

Company	Real Time Desk Number	Group Email Address
Sleeping Bear Windfarm	[redacted]	[redacted]
Sheffield/AmerSteel	[redacted]	
SPA	[redacted]	[redacted]
SPS	[redacted]	[redacted]
SPP BA	[redacted]	[redacted]
SPP Engineer	[redacted]	[redacted]
SPPRC		[redacted]
US Steel (Lonestar Steel)	[redacted]	
Weatherford Wind - Florida (FPDC)	[redacted]	[redacted]

Company	Real Time Desk Number	Group Email Address
WFEC		[redacted]
	[redacted]	