



Working to Perfect the Flow of Energy

PJM Manual 01
**Control Center
Requirements**

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Prepared by
System Operations Division

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PJM Manual 01

Control Center Requirements

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Dispatch Department

Revision History

Revision 09 (9/01/05)

Added Attachment C: PJM System Operator Training Requirements.

Added Nuclear Power Plant voltage notification.

Revision 08 (1/01/05)

Miscellaneous member comments and reflect the retirement of the Back Up Analog Control System.

Revision 07 (5/15/04)

Miscellaneous member comments, not incorporated in Revision 6

Updated PJM List of Manuals

Revision 06 (3/31/04)

Added descriptions of the Generation Management System (GMS), the Process Control Test (PCT) System, the Back-Up Control Center (BUCC) System, the PJM SCADA System, the OSI PI Data Historian System and clarified member obligations for ICCP communications including data integrity requirements and transmission monitoring requirements.

Revision 05 (12/31/03)

Added Attachment B: Nuclear Plant Communications Protocol, December 17, 2003

Revision 04 (05/01/03)

Revised Section 3: Communications & Data Exchange Requirements. Updated to include satellite phone requirements for generation operator control centers.

Revision 03 (04/04/03)

Complete revision of manual to reflect PJM Standards and Systems.



Revision 02 (12/31/00)

Removed Attachment A: Definitions and Abbreviations. Attachment A is being developed into a 'new' PJM Manual for [**Definitions and Abbreviations \(M-35\)**](#).

Revision 01 (04/01/98)

Attachment B: Information Access Matrix

Exhibit B.7: Grid Accounting Services revised to change "Market Clearing Price" to "Locational Marginal Price."

Revision 00 (07/30/97)

This revision is the preliminary draft of the PJM Manual for ***Control Center Requirements***.



Introduction

Welcome to the PJM Manual for **Control Center Requirements**. In this Introduction, you will find the following information:

- What you can expect from the PJM Manuals in general (see “About PJM Manuals”).
- What you can expect from this PJM Manual (see “About This Manual”).
- How to use this manual (see “Using This Manual”).

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by the PJM Interconnection, L.L.C. for the operation, planning, and accounting requirements of the PJM RTO and the PJM Energy Market.

Transmission	M01: Control Center Requirements	M02: Transmission Service Requests	M03: Transmission Operations
	M04: PJM OASIS Operation	M05: Power System Application Data	M06: Financial Transmission Rights
PJM Energy Market	M09: PJM eSchedules	M10: Pre-Scheduling Operations	M11: Scheduling Operations
	M12: Dispatching Operations	M13: Emergency Operations	M15: Cost Development Guidelines
	M36: System Restoration		
Generation and Transmission Interconnection	M14A: Generation and Transmission Interconnection Process Overview	M14B: Generation and Transmission Interconnection Planning	M14C: Generation and Transmission Interconnection Facility Construction
	M14D: Generator Operational Requirements	M14E: Merchant Transmission Specific Requirements	M16: eDART Operations
Reserve	M17: Capacity Obligations	M19: Load Data Systems	M20: PJM Reserve Requirements
	M21: Rules and Procedures for Determination of Generating Capability	M22: Generator Resource Performance Indices	M23: eGADS User Manual
	M24: PJM eCapacity	M25b: eFuel 2.0 – User Manual	
Accounting & Billing	M27: Open Access Transmission Tariff Accounting	M28: Operating Agreement Accounting	M29: Billing
PJM	M33: Administrative Services for PJM Interconnection Agreement	M35: Definitions and Acronyms	

Exhibit 1: List of PJM Manuals

About This Manual

The PJM Manual for **Control Center Requirements** is one of a series of manuals within the Transmission Owners manuals. This manual focuses on the requirements for control centers of signatories to the Operating Agreement of PJM Interconnection, L.L.C. The manual describes the telecommunication linkages to the PJM Interconnection, L.L.C. and the recommended characteristics of these control center computer systems and the buildings housing these systems. It also summarizes the computer services and systems at the PJM Interconnection, the standards for billing quality MWh meters, and meter accuracy standards.

The PJM Manual for **Control Center Requirements** consists of five sections. The sections are as follows:

- Section 1: PJM Systems
- Section 2: Control Center Requirements
- Section 3: Communications & Data Exchange Requirements
- Section 4: Billing Metering Standards
- Section 5: Meter Accuracy Standards

Intended Audience

The intended audiences for the PJM Manual for **Control Center Requirements** are:

- Applicants to the Operating Agreement of PJM Interconnection, L.L.C.
- PJM Members
- PJM staff

References

There are some other reference documents that provide both background and detail. The PJM Manual for **Control Center Requirements** does not replace any of the information in these reference documents. These documents are the primary source for specific requirements and implementation details. The references for the PJM Manual for **Control Center Requirements** are:

- PJM Manual for Transmission Service Request (M-02)
- PJM Manual for Transmission Operations (M-03)
- PJM Manual for PJM OASIS Operation (M-04)
- PJM Manual for Financial Transmission Rights (M-06)
- PJM Manual for Pre-scheduling Operations (M-10)
- PJM Manual for Scheduling Operations (M-11)



- PJM Manual for Dispatching Operations (M-12)
- PJM Manual for Load Data Systems (M-19)
- PJM Manual for PJM Reserve Requirements (M-20)
- PJM Manual for Open Access Transmission Tariff Accounting (M-27)
- PJM Manual for Operating Agreement Accounting (M-28)
- PJM Manual for Billing (M-29)
- PJM Manual for Administrative Services for PJM Interconnection Agreement (M-33)
- PJM Manual for Definitions and Acronyms (M-35)

Using This Manual

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

What You Will Find In This Manual

- A table of contents
- An approval page that lists the required approvals and the revision history
- This introduction
- Sections containing the specific guidelines, requirements, or procedures including PJM actions and Market Participant actions
- Attachments that include additional supporting documents, forms, or tables in this PJM Manual



Section 1: PJM Systems

Welcome to the *PJM Systems* section of the PJM Manual for **Control Center Requirements**. In this section you will find the following information:

- Descriptions of the PJM control center systems (see “*PJM Systems*”).

PJM Systems

PJM operates several functional systems that directly interface with PJM Members. Systems that are wholly internal to PJM and have no direct PJM Member interface are not listed.

The following systems are used to operate the PJM RTO and support the Energy Market:

- Energy Management System (EMS)
- Generation Management System (GMS)
- PJM SCADA System
- OSI PI Data Historian System
- Enhanced Energy Scheduler (EES)
- Two Settlement System (eMKT)
- Dispatch Management Tool (DMT)
- Unit Dispatch System (UDS)
- Regulation Market
- Spinning Reserve Market
- Operations Planning Tools
- Available Transfer Capability (ATC) Program
- Open Access Same-Time Information System (OASIS)
- Dispatcher Analysis and Reporting Tool (eDART)
- Other eSuite Tools (eMTR, eSchedules, eFTR)
- PJM Voice Communications

The following systems are used for planning purposes:

- Generator Availability Data System (eGADS)
- Capacity Reporting Program (eCapacity)
- Generator Outage Rate Program (GORP)

- Generator Unavailable Subcommittee (GUS)
- Central Planning Database
- Transmission Planning Tools

Energy Management System (EMS)

The PJM EMS performs the real-time monitoring and security analysis functions for the entire PJM region. In addition, it issues generation control signals to units in the PJM Eastern Region. Generation control functions for the PJM Western Region are handled by the Generation Management System (GMS) described in the next section.

The EMS consists of seven major subsystems:

- *Real-Time EMS* — the Real-time EMS is responsible for monitoring, analysis, and real-time coordination of the PJM region. It includes a full complement of monitoring, generation control, state estimation and security analysis software. PJM Members supply telemetered data to the PJM real-time EMS and may receive data and control signals from the PJM real-time EMS.
- *HIS* — The Historical Information System (HIS) stores periodic and event-driven snapshots of telemetered and calculated EMS data. There is no direct interaction between PJM Members and the HIS system.
- *DTS* — The Dispatcher Training Simulator (DTS) system is used to train PJM dispatchers. There is no direct interaction between PJM Members and the DTS system.
- *Development System* — The Development System allows the PJM staff to develop software, database, and displays for the Real-Time EMS, HIS, BUCC, GMS and DTS systems, without interfering with the operation of those systems. There is no direct interaction between PJM Members and the Development System.
- *Test System* — The Test System provides an independent test environment to validate changes developed on the Development System, prior to installing them on the Real-Time EMS. PJM Members may exchange telemetry with the Test System to verify telemetered points, to test data communications, to test communications failover capabilities and to test application programs.
- *Process Control Test (PCT) System* — The PCT system is a parallel test system with access to live data used to test and verify software and database changes prior to promoting those changes to the on-line production EMS. There is no direct interaction between PJM Members and the PCT system.
- *Back-Up Control Center (BUCC) EMS* -- The BUCC system provides an off-site back-up EMS capability which is completely separate from the

redundantly configured production EMS. In the event that the PJM main control room or computer facility is unavailable, the BUCC system can assume all EMS on-line functions. PJM Members may exchange telemetry with the BUCC system when it is activated in place of the real-time production EMS.

Generation Management System (GMS)

The GMS is a fully redundant generation control system located at the PJM Western Region office. It provides generation control functions for the PJM Western Region. PJM Members in the Western Region supply telemetered data to the GMS and may receive data and control signals from the GMS. Western Region Members shall also supply transmission system data to the PJM EMS in the Eastern Region office to support the state estimator and security analysis functions.

SCADA-Supervisory Control and Data Acquisition

The PJM SCADA system allows PJM to communicate directly with individual generators or smaller Control Centers. The system uses computer, database and digital communications technology to implement the use of common standards in an open environment, independent of any particular vendor or proprietary protocols system.

The PJM SCADA system is designed to allow transfer of both generation and revenue data via one system. A data concentrator (e.g. Remote Terminal Unit, Generator Control System, etc.) is located at the Member's site, and, after collecting data from the industrial metering equipment, communicates with PJM's SCADA system using either DNP 3.0, Level 2 (Distributed Network Protocol) or ICCP (Inter-Control Center Protocol).

The system allows real-time bi-directional transfer of analog and digital data into the system database for storage and real-time transfer to the EMS system.

Information can also be sent from the EMS system through the SCADA system via ICCP and/or DNP 3.0 to the customer, allowing for Automatic Generation Control (AGC), analog set point, device control, and other functions.

NOTE: Although DNP 3.0, Level 2 is a minimum functional requirement, the additional installation of object 23.5 is strongly recommended for all users. Without this object installed, collection of revenue data becomes difficult.

OSI PI Data Historian System

The OSI PI Data Historian System serves as a data archive for operational data in near-real-time. It provides visualization tools for presenting data to operators and provides a permanent archive of data for post-event study and analysis.



Telemetered data is archived from EMS and other operational data is imported from other sources, including Market Systems

Enhanced Energy Scheduler (EES)

The Enhanced Energy Scheduler (EES) records customer requests for interchange transactions, the bulk power scheduled between PJM and neighboring regions. PJM personnel use EES to process and schedule these transactions. The EES validates PJM ramp, use of transmission reservation rights, and other PJM scheduling business rules as described in the PJM Manual for Scheduling Operations.

Two Settlement System (eMKT)

The Two-Settlement system consists of two markets, a day-ahead market and a real-time balancing market. The Day-ahead Market is a forward market in which hourly clearing prices are calculated for each hour of the next operating day based on generation offers, demand bids Increment offers, Decrement bids and bilateral transaction schedules submitted into the Day-ahead Market. The balancing market is the real-time energy market in which the clearing prices are calculated every five minutes based on the actual system operations security-constrained economic dispatch. Separate accounting settlements are performed for each market, the day-ahead market settlement is based on scheduled hourly quantities and on day-ahead hourly prices, the balancing settlement is based on actual hourly (integrated) quantity deviations from day-ahead scheduled quantities and on real-time prices integrated over the hour. The day-ahead price calculations and the balancing (real-time) price calculations are based on the concept of Locational Marginal Pricing.

The Day-ahead Market enables participants to purchase and sell energy at binding day-ahead prices. It also allows transmission customers to schedule bilateral transactions at binding day-ahead congestion charges based on the differences in LMPs between the transaction source and sink. Load Serving Entities (LSEs) may submit hourly demand schedules, including any price sensitive demand, for the amount of demand that they wish to lock-in at day-ahead prices. Any generator that is a PJM designated capacity resource must submit a bid schedule into the day-ahead market even if it is self-scheduled or unavailable due to outage. Other generators have the option to bid into the day-ahead market. Transmission customers may submit fixed, dispatchable or 'up to' congestion bid bilateral transaction schedules into the day-ahead market and may specify whether they are willing to pay congestion charges or wish to be curtailed if congestion occurs in the Real-time Market. All spot purchases and sales in the day-ahead market are settled at the day-ahead prices. After the daily quote period closes, PJM will calculate the day-ahead schedule based on the bids, offers and schedules submitted, using the scheduling programs described in section 2 of this manual, based on least-cost, security constrained unit commitment and dispatch for each hour of the next operating day. The day-ahead scheduling process will incorporate PJM reliability

requirements and reserve obligations into the analysis. The resulting Day-ahead hourly schedules and Day-ahead LMPs represent binding financial commitments to the Market Participants. Financial Transmission Rights (FTRs) are accounted for at the Day-ahead LMP values (see the PJM Manual for [Financial Transmission Rights \(M-06\)](#)).

The Real-time Energy Market is based on actual real-time operations. Generators that are designated PJM capacity resources that are available but not selected in the day-ahead scheduling may alter their bids for use in the Real-time Energy Market during the Generation Rebidding Period from 4:00 PM to 6:00 PM (otherwise the original bids remain in effect for the balancing market). Real-time LMPs are calculated based on actual system operating conditions as described by the PJM state estimator. LSEs will pay Real-time LMPs for any demand that exceeds their day-ahead scheduled quantities (and will receive revenue for demand deviations below their scheduled quantities). Generators are paid Real-time LMPs for any generation that exceeds their day-ahead scheduled quantities (and will pay for generation deviations below their scheduled quantities). Transmission customers pay congestion charges based on Real-time LMPs for bilateral transaction quantity deviations from day-ahead schedules. All spot purchases and sales in the balancing market are settled at the Real-time LMPs.

Dispatch Management Tool (DMT)

The Dispatch Management Tool (DMT) is a software tool that is designed to enable the PJM dispatchers to manage generating unit and transmission constraint information and administer the Real-Time Regulation Market. Since many of the current dispatcher logging activities are position independent, the DMT allows each dispatcher position to view the same generation and transmission constraint information simultaneously. This real-time sharing of logging information provides the PJM dispatchers with an efficient communication vehicle to help them perform their job functions more effectively.

The DMT is used by the PJM dispatchers to:

- View and record real-time unit generation information
- View and record unit generation scheduling information
- Review the chronological log of generation events
- Analyze system resources
- Record and calculate regulation assignment information
- Record and calculate spinning reserve assignment information
- View and record real-time transmission constraint information



Open Access Same-time Information System (OASIS)

The PJM OASIS system maintains transmission and ancillary services information for PJM Members. OASIS operates on a collection of PJM and PJM Member computers linked by private and public networks. For additional information, see the PJM Manual for ***PJM OASIS Operation (M-04)***.

Other eSuite Tools (eMTR, eSchedules, eFTR)

The other eSuite tools are all Web-based tools that PJM members use to facilitate the exchange of information with PJM and support various PJM market activities

Planning Systems

PJM operates several planning systems which are used to run studies for reliability and capacity planning and for transmission planning. Reliability and capacity planning includes the Generating Availability Data System (GADS) database and the Generation Outage Rate Program (GORP) which are used by the Generator Unavailable Subcommittee (GUS). eGADS and eCapacity are computer programs and databases used for entering, storing, and reporting generating unit data concerning outages, unit performance, and fuel performance. In addition, PJM Members provide information to the PJM Central Planning Database, a database containing planning information relating to generation production costs, load flow analyses, short circuit and system dynamics studies, and LSE load data. Additional details about these planning functions may be found in the PJM Manual for [**Load Data Systems \(M-19\)**](#), and the PJM Manual for [**PJM Reserve Requirements \(M-20\)**](#).

PJM also performs transmission planning studies. For example, PJM Members staffs provide transmission planning capacity and load data to the PJM Transmission Planning Tool which generates performance adequacy and reliability assessments (see the PJM Manual for [**Transmission Service Request \(M-02\)**](#)).



Section 2: Control Center Requirements

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

- A description of the different categories of control centers (see “*PJM Control Center Categories*”).
- An overview of PJM Member responsibilities (see “*PJM Member Data Exchange*”).
- Computer system requirements for Control Centers (see “*Computer System Requirements*”).
- Communications requirements (see “*Communications Requirements*”).
- Requirements for control center physical facilities (see “*Facilities Requirements*”).
- Control center staffing recommendations (see “*Control Center Staffing*”).

PJM Control Center Categories

PJM Members may be involved with transmission operations, generation operations, load service operations, and/or PJM Energy Market participation. Depending upon the functions they perform and the services they require from PJM, the control center for each PJM Member will fall into one or more of the designations defined below. The specific functions, systems, and communications capabilities of that control center depend upon the responsibilities of the PJM Member:

- *Local Control Center* — An entity that participates in the Operating Agreement of PJM Interconnection, L.L.C. (Agreement) and operates and controls Designated Transmission Facilities establishes a Local Control Center (LCC) to facilitate its responsibilities regarding the security of the PJM RTO.
- *Market Operations Center* — An entity that participates in the Agreement and operates and controls generation within the PJM RTO establishes a Market Operations Center (MOC) to facilitate its responsibilities regarding the security of the PJM RTO.
- *Load Service Center* — any entity that participates in the Agreement and operates and controls load (but without generation or Designated Transmission Facilities) establishes a Load Service Center (LSC) to facilitate its responsibilities for its load in the PJM RTO. Entities responsible for load that also operate transmission and/or generation may not need an LSC, as they can discharge these responsibilities from an LCC or MOC.



- *Marketing Center* — a participant in the Agreement as a Power Marketer, Wholesale System User, Other Supplier, or Transmission Customer establishes a Marketing Center to facilitate communications with PJM concerning its participation in the PJM Energy Market.

Many PJM Members are involved in more than one of the four areas of responsibility discussed above. Each member is obligated to be in compliance with the Code of Conduct requirements established in FERC Order 2004. Entities participating in the PJM Energy Market may establish a separate MOC. All of these four categories of control centers are referred to collectively in this manual as “control centers”.

PJM Member Data Exchange

PJM Members support a variety of PJM functions appropriate to their business requirements and level of participation requirement in PJM. For each of the PJM services described in this section, data is exchanged between PJM and one or more of the categories of PJM Member control centers. The following PJM services are further defined in Attachment A, Information Services Matrix. In this attachment, the references to “Member Type” translate to control center category as follows:

1. Regional Transmission Owner — Local Control Center (LCC)
 2. Generating Entity — Market Operations Center (MOC)
 3. Load Serving Entity — Load Service Center (LSC)
 4. Marketer — Marketing Center
- *Generation Scheduling Services* — MOCs input generation, pre-scheduling, scheduling, spinning reserve bids, and regulation bids, and outage data to PJM, and PJM output hourly and daily generation scheduling information to LCCs, MOCs, and LSCs (see the PJM Manual for [Pre-Scheduling Operations \(M-10\)](#) and the PJM Manual for [Scheduling Operations \(M-11\)](#)).
 - *EMS Services* — LCCs, MOCs and LSCs input real-time transmission and generation information plus generator regulation and availability data and PJM outputs real-time transmission status, generation status, generation dispatch and regulation signals, and operations & emergency information (see the PJM Manual for [Dispatching Operations \(M-12\)](#)).
 - *Transmission Maintenance Planning Services* — LCCs input transmission maintenance schedules which are confirmed by PJM to all PJM Members (see the PJM Manual for [Transmission Operations \(M-03\)](#)).
 - *Transmission Services* — OASIS is used at LSCs and Marketing Centers to input transmission reservations and by PJM to output Available Transmission Capacity, energy transactions, transmission congestion information, approved transmission reservation requests, and other market information to



all categories of control centers (see the PJM Manual for [Transmission Service Request \(M-02\)](#) and the PJM Manual for [PJM OASIS Operation \(M-04\)](#)).

- *Energy Transaction Services* — bilateral energy transactions are input from all categories of control centers and are confirmed by PJM (see the PJM Manual for [Scheduling Operations \(M-11\)](#) and the PJM Manual for [Dispatching Operations \(M-12\)](#)).
- *Long-term Planning Services* — LCCs, MOCs, and LSCs input capacity, load, system characteristics information, generator events, production costs, outage reports and long-term planning information and PJM outputs the results of studies and assessments to all categories of control centers (see the PJM Manual for [Load Data Systems \(M-19\)](#)).
- *PJM Administration Services* — PJM outputs general administrative information and FERC filings to all PJM Members via the PJM Web site.

Computer System Requirements

Each PJM Member's control center serves as the primary operating link to the PJM control center and includes computer system hardware and software that supports their responsibilities under the Agreement.

Transmission Monitoring Capability

Transmission Owners shall provide transmission monitoring at their Local Control Centers including monitoring of circuit loading, voltages, limit violations and contingency analysis. Basic software should include State Estimation and Security Analysis functions to monitor actual and contingency conditions.

In the event that PJM's monitoring systems are unavailable, PJM may request Transmission Owners to monitor their portions of the bulk power transmission systems, as a substitute for the unavailable PJM systems, in order to preserve system reliability. In that scenario, PJM will communicate the need via the All-Call and PJM is expecting that the Transmission Owner(s) will use their monitoring systems to (1) assess the reliability of their portions of the bulk power transmission system via contingency analysis and SCADA; (2) communicate any contingency or limit violations on any bulk power facility to PJM as soon as possible. If the Transmission Owner determines that corrective actions are necessary to preserve system reliability, then PJM shall approve the corrective action, unless immediate action is necessary. If immediate action is necessary, the TO shall implement the action and report to PJM any actions taken.

The continuous calculation and monitoring of post-contingency voltages for nuclear power plants (for the loss of the nuclear unit) is an important requirement to ensure that adequate voltage is always available for the operation of the nuclear safety



systems. Given this requirement, the nuclear power plant(s) shall be notified in cases where the transmission monitoring capability (at PJM and the Transmission Owner) becomes unavailable and the ability to calculate the post-contingency voltages is lost. [There may be situations where the calculations are only being performed at PJM. In this case, loss of the PJM capability shall trigger the notification to the nuclear power plant(s).] The notification will go via the All-Call from PJM to the Transmission Owner(s) who will then communicate with the applicable nuclear power plant(s). **System Availability**

The computer hardware and software at each control center shall achieve a long-term 99.95% availability level for those critical functions directly affecting the successful operation of PJM. Any application that supplies operational data to PJM, accepts generation control signals from PJM, or otherwise links to the real-time operational aspects of the PJM control system is considered critical. Other applications may be considered to be critical to a PJM Member's operations and therefore, shall also achieve a 99.95% availability. Redundant hardware configurations with either automatic or rapid manual failover schemes are generally necessary to achieve 99.95% availability.

Data Backup & Archiving

All PJM Members shall prepare and implement a backup and archiving plan which minimizes the loss of critical data upon the occurrence of any hardware failure or a catastrophic system loss.

Computer System Security

Control centers with electronic data links to the PJM computer systems require rigorous computer system security provisions to prevent unauthorized access and unintentional operation. Due to the sensitive nature of both operational and financial data, control center computer systems shall include various techniques such as password log-on for internal users, hardware and software security controls for external users, and on-line virus detection capabilities. Telecommunication circuits connected to any control center computer system shall utilize firewall technology to prevent unauthorized access from external sources.

System Maintenance

Due to the critical operational requirements and economic benefits of a PJM Member's control center computer system, a computer system (hardware, software, and network) maintenance service arrangement with 24-hour, 7 day/week call-out provisions or on-site staff, is required to ensure appropriate levels of system availability to implement database changes, and to modify user interface displays.



Expansion Capability

PJM Member computer system hardware, software, and network shall be expandable to accommodate growth in their system and operations and to accommodate future changes to the organization and responsibilities of the PJM RTO and the PJM Energy Market. PJM services and marketing activities are all expected to increase and the control center computer systems shall be expandable to accommodate this expected growth. System design shall provide for orderly addition of computer hardware, software, and network through adherence to accepted system standards and Good Utility Practice.

Data Integrity

PJM maps quality codes sent by member companies into to four quality codes:

1. Good (valid data);
2. Manually Substituted by company;
3. Telemetry Failure; and
4. Suspect (usually indicating value is bad).

Details on quality code translations are given in the following documents:

- ☞ PJM ICCP Network Interface Control Document, Version 1.1, March 27, 2000.
- ☞ PJM ICCP Communications Workbook, Version 1.1, March 27, 2000.
- ☞ Running list of updates to the PJM ICCP NICD and Workbook, Version 1.1 January 30, 2001.

Member companies should only send valid quality codes. In particular, companies with front-end data servers should insure that the front-end server does not initiate data transfers with PJM until the front-end server has begun receiving valid and current data from the company EMS or other data source. Sending even a single scan with zero values or other bad data for analog or switch statuses can cause massive alarm generation and improper operation of State Estimator and other critical functions.

PJM provides new members and existing members the testing requirements for system commissioning and on-going support. When commissioning a new system, members should request the latest copy of the *PJM ICCP Testing Requirements* document from PJM. The required tests include:

For new members:

1. Server to server communication verification over PJMNET
2. Exchange of NERC ICCP Association Information Exchange Form



3. Exchange of client and server data points needed before ICCP Association testing
4. Ability to initiate an ICCP Association with PJM
5. Ability to support an ICCP Dual direction Client-Server Association
6. Ability to provide real-time SCADA data during testing along with the ability to change values and quality codes
7. Ability to participate in testing with the designated PJM TEST system
8. Participation in Failover testing to verify required network, server, and communication redundancy

For existing members:

1. All of the above (1. to 8.) New members testing requirements
 2. The ability to test with the designated PJM TEST system while supporting the real time PJM EMS system
 3. The ability to test changes with the PJM designated TEST system before putting the changes in production with the real time PJM EMS system
 4. The ability to support Failover testing to verify required network, server, and communications redundancy for existing member changes while still supporting the real time PJM EMS system
- PJM Member companies are required to successfully complete the PJMNET ICCP Communications Failover Test before going into production with the PJM real time EMS system. The purpose of this test is to verify redundancy from company ICCP servers to PJM ICCP servers. In the process of doing this ICCP server to server Failover testing all network hardware components such as: routers, firewalls, and PJMNET communication lines will have their redundancy validated.
 - In order to accomplish site to site failover between PJM EMS and the PJM BUCC or PJM GMS and PJM EMS (depending on member company situation), member company ICCP systems must be able to support up to four IP addresses in their ICCP association start up sequential server hunt list.

Communications Requirements

Telecommunications (voice and data) circuits, which must be reliable and secure, shall be tested regularly and/or monitored on-line, with special attention given to emergency channels.

Facilities Requirements

This section discusses the control center facility considerations for a PJM Member, including the physical space housing operations staff and, if appropriate, a computer room, communications room, and power supply area. While these considerations apply to all PJM Member categories, the specific implementation of control center facilities considerations shall be appropriate for the nature of the computer systems and communications equipment installed.

Environmental Characteristics

In order to ensure the PJM Member's computer system availability and data reliability discussed in the previous section, its control center facilities shall provide an environment that is suitable for its equipment and personnel during the hottest and coldest outdoor temperatures that can be anticipated.

- The range of control center temperature and humidity shall be controlled appropriately for the installed computer systems and communications equipment. The most restrictive temperature and humidity characteristics of any item of equipment in each room of the control center, the total heat load of that equipment, and the projected growth shall establish the design criteria for the heating, ventilating, and air conditioning systems provided.
- Control room operators, technical staff, and maintenance personnel should be able to function comfortably.
- Where feasible, heating, and air conditioning equipment shall be backed up with redundant or auxiliary systems to allow operations to continue indefinitely following the failure of any single temperature controlling device or motor control center.
- If the control center is located in the proximity of a polluting atmosphere such as a coal-fired power plant, a positive pressure shall be maintained in the computer room using filtered air to minimize the accumulation of airborne contaminants on the computer system circuit boards and components.

Power Supply & Conditioning

Because of the importance of non-stop operation of the PJM RTO and the sensitivity of computer equipment to minor power disturbances, a stable and secure supply of AC power for the equipment in the control room, computer room, and communications room shall be provided and installed in compliance with current National Electric Code provisions.

- An uninterruptible power supply (UPS) (i.e., battery charger, battery, and inverter) and a backup generator is necessary to supply power to operator display equipment, computer systems and communications equipment. A completely redundant power supply with dual UPS may also be utilized.



- K-rated transformers and oversized neutral conductors shall be employed as necessary to mitigate the effects of harmonic distortion created by non-linear loads.
- The UPS battery shall have sufficient capacity to operate the computer system, and communications equipment until stable emergency generation can be achieved. Periodic maintenance and testing of the battery cells and inter-cell connections shall be performed.
- The backup generator shall be tested periodically under load to ensure its availability under loss of power conditions. Fuel supply for the backup generator should be sufficient for a five-day period. If applicable, redundant backup generators should be considered.
- An emergency lighting system should be provided with adequate battery capacity for several hours.
- The heating, cooling, and ventilation equipment shall also be powered by the backup generator (but not by the UPS).
- A high quality, common earth ground shall be provided, in accordance with IEEE standards, for the computer system and communications equipment to provide a low impedance path for rapid clearing of electrical faults and to reduce electromagnetic interference.
- If UPS power is not provided, TVSS protection for power and communications circuits shall be provided to mitigate the effects of lightning strikes and AC power excursions.
- Where warranted, external power to the control center shall be supplied from two sources, such as two distribution feeders that follow diverse routing from separate electric substations.

Area Access Security

Access to PJM Member control rooms should be restricted. For example, access could be controlled by means of a single entry point monitored by office personnel during business hours and, at other times, either by control room personnel via closed-circuit TV monitors and remotely controlled locks or by a cipher/key/badge-reader lock. Emergency exits/entrances should be sealed and alarmed in conformance with local fire regulations.

Information Flow to Control Room Personnel

A protocol shall be established concerning information transfer from PJM Member staff to the critical staff members and their supervisor responsible for coordinating and directing work in the PJM Member's control center. Topics covered shall include the following:



- Inquiries to the shift team and their on-shift supervision.
- Access control to the control room.
- Approvals for Computer outages.
- The PJM shift supervisor and Support Center shall be notified of any computer system outages.
- In case of implementation of PJM Emergency Procedures, all non-essential personnel shall leave the control center and non-essential computer system hardware and software maintenance should be terminated.

Smoke & Fire Protection

Smoke and fire detection equipment shall be installed to detect smoke and fire, warn personnel to hand-extinguish the fire or evacuate the facility, and, where warranted, automatically extinguish the fire. Smoke and fire protection equipment shall conform to the current version of NEC, local, state, and national codes.

Backup Recovery Procedures

PJM Members shall comply with PJM backup procedures. For PJM Members that interface with the PJM EMS, all the necessary backup voice and data circuits must be provided between the Local Control Center and PJM. Generation owners should design their generation control systems with the capability to accept alternate control inputs from back-up PJM systems including manual operation as directed by PJM operations personnel.

PJM Members shall provide PJM backup operations training for its operators and participate in the training exercises conducted by PJM. PJM Members shall review the design of their backup support plans with the PJM Customer Relations Department to ensure compliance with this requirement.

All PJM Members shall develop a backup recovery plan to cover various contingencies, including maintaining an off-site storage location for updated copies of all software and data files necessary to restore critical functions. The backup recovery plan is subject to review by PJM.

Control Center Staffing

PJM Member control centers should be staffed with competent personnel trained for all normal and emergency situations that might be anticipated. Training courses for operations, technical staff and maintenance personnel should be conducted. The PJM Customer Relations and Training Department can provide assistance, as required, for training related to PJM operations.



Training

Training of system operators and other operating personnel is essential to promoting reliable operation of the system. Formal PJM sponsored training programs for system operators and others are available on a regularly scheduled basis. Standard PJM system operator training courses include: Initial Training Program (ITP - basic concepts and PJM operating procedures, 4 weeks), Generation MOC Orientation (MOC – generation dispatch procedures, 5 days), and the annual PJM System Operator Seminar (Seminar – updates and refreshers on PJM procedures, 4 days, done 6 time or more yearly)

Key topics in PJM System Operator Training include: normal and emergency operating procedures, data reporting requirements, and other specific procedures for generation and transmission system operators. Other PJM courses for operating personnel are delivered on an “as needed” basis. All PJM training courses are posted on the PJM website and available to all PJM members.

Minimum training requirements have been established for Local Control Center (LCC) operators, Market Operations Center (MOC) operators, and PJM system operators, effective January 1, 2006. The requirements address initial training, as well as on-going training, and are detailed in Attachment C: PJM System Operator Training Requirements.

PJM System Operator Certification

PJM has instituted a System Operator Certification Program to promote the reliability of the PJM systems. The Certification Program went into effect as of March 1, 2003.

Who and When

The PJM certification program is required of all generation and transmission system operators who operate on the PJM systems, are in direct communication with PJM system operators located at any PJM Control Center, and perform daily operations-related functions at the direction of PJM system operators during normal, emergency and/or system restoration states. PJM system operators must also be PJM certified.

System Operators who were operating on the PJM systems on March 1, 2003 have until February 28, 2005 to become PJM Certified. System Operators who begin operating on the PJM systems after March 1, 2003 are allowed two years to become PJM Certified.

Certification Examinations

There are two PJM Certification Exams: one for Generation System Operators and the other for Transmission System Operators. Details are as follows:

- System Operators who participate in the real time operations of the PJM system by dispatching generation resources and performing other generation-related real time duties of a Market Operation Center (MOC),



PJM or PJM West system operator are required to complete and pass the PJM Generation Examination.

- System Operators who participate in the real time operations of the PJM transmission systems and perform other transmission-related real time duties of a Local Control Center (LCC), PJM or PJM West system operator are required to complete and pass the PJM Transmission Examination.

For further information go to: http://www.pjm.com/training/sys_ops/index.html

Control room operator staffing levels should be prudently determined based upon the criticality level of the PJM Member's operations. Possibilities for control room staffing include combinations of the following:

- one or more operators in the control room 24 hours a day, 7 days a week
- one or more operators in the control room during business hours or hours of operation
- responsible personnel not in the control room but able to be contacted by the PJM dispatcher within one minute

While staffing guidelines cannot cover all situations, the following general guidelines may be useful:

- Transmission Owners, Generation Owners, and other Load Serving Entities that participate in the operation and security of the PJM RTO and/or that must respond to generation adjustment or load shedding during normal or emergency conditions must staff their control center 24 hours a day, 7 days a week, with 99.9% availability of staff.
- Owners of generation which operates infrequently may require continuous control center staffing only during the hours of their units' operation. They must be able to answer telephone questions and directions within one minute of a call initiation by PJM.
- Market Participants must be able to respond to telephone questions about their scheduled transactions within one minute of a call initiation by PJM.

Staffing Upon Loss of an EMS or a 765 kV, 500 kV, or 345 kV RTU

If a PJM Member's EMS becomes unavailable, some PJM Members move their dispatchers to a backup control center while others send staff to man their critical facilities. PJM Members should continue to stay in contact with and provide as much information as possible to PJM. If an EHV substation RTU becomes unavailable, the respective Transmission Owner may be required to send staff to that substation to telephone information to the LCC and to PJM.



Section 3: Communications & Data Exchange Requirements

Welcome to the *Communications & Data Exchange Requirements* section of the PJM Manual for **Control Center Requirements**. In this section you will find the following information:

- Data exchanges with new PJM Members (see “*Introduction*”).
- Data exchanged between PJM and PJM Member’s EMS systems (see “*Energy Management System (EMS) Data Exchange*”).
- Information available to Market Participants (see “*OASIS Information Exchange*”).
- Data exchanged over telephone and facsimile machines (see “*Dispatch Voice and Facsimile Communications*”).
- Usage of backup communications systems (see “*Alternative Voice Communications*”).
- Requirement to support the PJM emergency backup dispatch center (see “*EMS Backup Communications*”).

Introduction

Communications between PJM Members and PJM depend upon a combination of electronic data, dispatch and business voice links, facsimile, Internet communications (e.g., to OASIS), and floppy disk and paper reports sent by courier or US mail.

- PJM Members (and PJM) may require additional time after signing the Operating Agreement to establish electronic data links.
- PJM Members with real-time data to be exchanged with PJM and with a significant participation in the supply of information to the PJM RTO require electronic communications via the EMS and eSuite data exchanges.
- New PJM Members with a small amount of data to be exchanged and that do not require real-time links to PJM should use facsimile and voice communications for their PJM communications.
- New PJM Members already communicating with PJM through another PJM Member’s electronic communications systems should arrange to continue using those communications systems where this is feasible; separate electronic communications links can be planned and installed subsequently if necessary.



Energy Management System (EMS) Data Exchange

Energy Management System (EMS) information is exchanged between PJM EMS computers and the EMS systems of PJM Members primarily to support real-time functions such as PJM RTO network monitoring, generation control, and security analysis as well as non-real time functions, such as generation scheduling, accounting information, messages, and reports. The information exchange occurs periodically, by exception, and upon demand.

EMS Communications System

PJM and PJM Members exchange EMS information between their respective EMS computer systems via PJMnet, which is a dual redundant frame relay network using the Inter-control Center Communications Protocol (ICCP).

PJM EMS Communication Protocols

The EMS utilizes a communication protocol based on the Inter-control Center Communications Protocol (ICCP) standard. PJM supports block 1 (scanned data), block 2 (exception data) and block 4 (messages) of this protocol. PJM requires that members support blocks 1 and 2.

ICCP is a comprehensive, international standard for real-time data exchange within the electric power utility industry. It is intended to support inter-utility real-time data exchange which is critical to the operation of interconnected systems.

A detailed description of the format and content of the ICCP Conformance Blocks as adopted to PJM needs may be found in the following documents:

- PJM ICCP Network Interface Control Document (NICD) Version 1.1, dated March 27, 2000.
- PJM ICCP Communications Workbook Version 1.1, dated March 27, 2000.
- Running list of updates to the PJM ICCP NICD and Workbook, Version 1.1, January 30, 2001.

The appropriate documents will be supplied to applicant PJM Members to describe data types and message structures and to supply detailed information on network protocol and line discipline.

EMS Data Exchange

EMS data is exchanged between each PJM Member's EMS and the PJM EMS computer system periodically on one of several fixed cycles, as well as on demand, by exception, and interactively.



1. The EMS data sent cyclically from PJM Members to PJM includes the following types of information sent with associated data quality codes:
 - ☞ data needed for the PJM control programs
 - ☞ data needed for monitoring generation
 - ☞ data needed for monitoring transmission
 - ☞ data needed for monitoring interchange
2. The EMS data sent cyclically from the existing PJM EMS to each PJM Member's EMS includes the following types of information:
 - ☞ system control data
 - ☞ generation and transmission information required for monitoring and security analysis programs
 - ☞ Area Regulation data
3. Cyclic data exchanged at the fast scan rate (i.e., two seconds) is used to develop the PJM Area Control Error (ACE) and associated individual PJM Member Area Regulation megawatt values. Cyclic data exchanged at a slower scan rate (i.e., every ten seconds) is used to develop dispatch control values, security monitoring, and data tracking.
4. Cyclic data may also be sent hourly from PJM Members which define the accumulated energy values.
5. PJM Members are responsible for the accuracy of the data they send to PJM. A maximum of 2% overall inaccuracy in the repeatability of data from transducers or potential transformers/current transformers (PTs/CTs) is allowed for instantaneous monitored values (see Section 5, Meter Accuracy Standards). Hourly MWh readings data must be provided to PJM daily to ensure accurate billing. Regular calibration of PJM Member metering is necessary to keep the data as accurate as possible (see Section 4, Billing Metering Standards).
6. Data exchanged either by exception, on demand or interactively between PJM Member's and the PJM EMS systems include the following:
 - ☞ breaker, disconnect, and line status changes, with associated data quality code information (integrity scans for exception data shall be at 30 minute intervals)
 - ☞ emergency messages in text format



Each PJM Member is responsible for determining data quality indicators for all data transmitted to PJM. Both failed individual values and any value calculated using a failed point must be flagged. At times, state estimated values may suffice for an interim period. However, when a point fails for an extended period, a manual update of the point’s value is necessary to keep the data as accurate as possible.

PJMnet Communications System

PJMnet is a dual-redundant frame relay network that PJM utilizes as the primary wide-area network for communicating Control Center data to and from PJM. PJMnet will support:

- Inter-Control Center Communications Protocol (ICCP) data links to Control Centers.
- SCADA links to plants via remote terminal units (RTUs) using Distributed Network Protocol (DNP).

PJMnet connects member Local Control Centers (LCCs), Market Operations Centers (MOCs) and generating plants to PJM's primary and emergency backup Control Centers in the Eastern Region as well as to the PJM Control Center in the Western Region. Private voice and data permanent virtual circuits (PVCs) are provided to link to PJM's primary and emergency backup Control Centers. The number of physical interfaces and their capacity will be determined by the impact of your facilities on overall PJM Operations. LCCs, MOCs and generating plants are expected to install metering and use their own EMS/GMS/SCADA or equivalent system to collect data. PJM will provide redundant ICCP network connections and dual routers at the member company location.

The table below shows the types of equipment necessary for exchanging generation data with PJM. This was taken from Exhibit 4.4 in the Generation Requirements Manual M-14-D.

Situation	Real Time & Billing Metering	Operational Changes Sent via	Generator Bidding
<10 MW injection to grid or unit runs infrequently.	RTU at plant, single DNP network connection, single router may be required based upon Metering Plan requirements. Refer to Manual 14-D, Section 4.	Internet, through eMKT	Internet, through eMKT
>10 MW and <50MW injection to grid; unit runs continuously.	RTU at plant, single DNP network connection, single router	Internet, through eMKT	Internet, through eMKT
>50 MW and <500MW injection to grid; unit runs continuously.	RTU at plant, redundant network connection, single router.	Internet, through eMKT	Internet, through eMKT
>500 MW injection to grid; unit runs continuously	RTU at plant or ICCP via SCADA system, redundant ICCP or DNP	Internet, through eMKT	Internet, through eMKT



Situation	Real Time & Billing Metering	Operational Changes Sent via	Generator Bidding
	network connection, dual routers.		
Control Center for Multiple Units	Install metering and use SCADA System; redundant ICCP network connection to PJM, dual routers.	Internet, through eMKT	Internet, through eMKT and PJMnet

Exhibit 2: Equipment Types for Generation Data Exchange with PJM

PJM will supply a PJMnet connection to LCCs and generation sites per customer eligibility as indicated in Exhibit 2 above. This will include installation of the frame relay connections (local loop, PVC’s, etc.) and routers as well as ongoing Network Operations Support and maintenance of the PJMnet components. If dual circuits are provided, PJM will route them as diverse from each other as practicable within the existing infrastructure. Installation will be completed within 90 calendar days of the completion of the site survey contingent upon timely completion of the member supplied items. The member company will be responsible for the following:

- AC power within five (5) feed of equipment site.
- Power outlet(s) will be quad box outlet on a separate breaker for each router.
- Adequate cooling.
- Mounting location for PJMnet router and modem equipment.
- An environment clean and free from excessive dust or debris, dry (5 to 95% humidity, non-condensing), of moderate temperature (32 to 104 degrees F), well-ventilated and well-illuminated.
- Adequate station ground.
- Dial up modem lines for out of band router access by NOC.
- Return of the “Welcome Letter” either agreeing to PJM assigned IP address scheme or providing specific member requirements in this area.

OASIS Information Exchange

PJM is responsible for providing the Open Access Same-time Information System (OASIS) for PJM RTO Transmission Providers and Customers (see the PJM Manual for [PJM OASIS Operation \(M-04\)](#)). The information on the OASIS network includes Available Transfer Capability and other important transmission and ancillary services data. Market Participants are responsible for establishing Market Operations Centers which implement the necessary communications with OASIS.

Transmission Customer Communications

Transmission Customers use the public Internet to access PJM OASIS via World Wide Web browsers, such as Netscape Version 3.0. OASIS Customers must



register with PJM before they access the PJM OASIS system and login each time a connection is established. The primary interface to request transmission or ancillary service and to provide information to PJM OASIS is on-line data entry forms available on the OASIS display pages. These forms are used to request the purchase of services and to offer products for sale, as well as to post other transmission-related information. Instructions on how to interface with OASIS are available on the OASIS display pages or from the PJM OASIS Account Administrator. If a Transmission Customer enhanced OASIS connections, a direct connection is available, at additional cost.

Transmission Provider Communications

Transmission Providers are directly connected to the PJM OASIS system via PJMNET and it is possible for them to use SQL*NET protocol and ORACLE Forms user interface software to display and post information to the OASIS. ORACLE Forms are used to post and modify data, approve purchase requests, offer products for sale, and post "Want" ads. PJM is responsible for administering and posting information associated with the provision of transmission service as required by FERC.

Dispatch Voice & Facsimile Communications

The dispatch voice system provides high-priority voice communications between PJM and various PJM Members, as described below. The dispatch voice system hardware consists of the All Call system, Ring Down circuits, and manual dial circuits. Equipment at PJM includes an IPC Tradenet digital switch and a Nortel Meridian PBX. Access and interfacing to the communications service providers is configured so that either switch can operate in stand-alone mode, but economy and performance are optimized when they are operating together.

Communications via facsimile machines is another redundant means of exchanging information between PJM operations, accounting, and planning personnel and all categories of PJM Members.

All Call System

The All Call system is used by PJM operators to contact Local Control Centers (LCCs), Market Operations Centers (MOCs), and Load Serving Centers (LSCs), either individually or simultaneously for information exchange under both normal and emergency situations. The All Call is based on the Dialogic Communications Corp. Communicator, an emergency notification system that provides PJM system operators the ability to broadcast voice, text or fax messages. The All Call operates over PSTN (Public Switched Telephone Network). The system is capable of sending messages to 72 numbers simultaneously. If the more than 72 locations must be contacted the system will dial the additional numbers as lines become available. Continuous retry logic ensures 100% of the facilities are contacted by



cycling through primary, secondary, and tertiary numbers until positive confirmation of message receipt. Both real-time displays and reports of response status are available to PJM System Operators.

Each control facility is required to have a dedicated PSTN line for the primary All Call number. Secondary and tertiary do not have to be dedicated to the All Call System; they may be PBX or cellular, not pager. Acknowledgement of message receipt by each participant is required. Logs of responses and response times are provided to PJM's Performance Compliance department for analysis.

Ring Down Circuits

Private Lines with automatic ringing (PLAR) or dual central office (DCO) lines are used to provide Ring Down or simulated Ring Down capability to LCCs, Market Operations Centers (MOCs), and Load Service Centers (LSCs). These circuits provide virtually instantaneous point to point access between PJM and PJM Members.

Manual Dial

In addition to private line capability, the PJM Tradenet switch also interfaces with both the PJM Meridian PBX and Central Office (CO) Lines to provide manual dial capability to all categories of PJM Members via the Public Switch Telephone Network (PSTN). Manual dial serves as backup to the Ring Down system in case that system fails.

Facsimile Communications

Facsimile communications is widely used in the PJM Control Center to communicate with all PJM Members. Facsimile machines support energy marketing, energy scheduling, unit scheduling, accounting, dispatch operations, and system restoration. These facsimile machines are connected to either the PJM Nortel Meridian PBX or CO Lines.

Alternative Voice Communications

The dispatch voice system (All Call, Ring Down, and manual dial PBX) is designed to provide voice communications during normal circumstances. Should the PJM primary All Call System, Ring Down, Manual Dial, and Facsimile Communication fail, the following systems provide alternative communication capabilities in the event the normal system is not effective for some reason:

Business Voice System

Each dispatch position is provided with a standalone phone set, configured with speed dial using CO Lines, which serve as a backup for the PJM Tradenet switch to



provide communication between the PJM control center and all PJM Members in the event of Tradenet switch failure.

Cellular Telephones

Cellular telephones are used by PJM dispatchers as an alternate method of voice communication. Cellular phones can be used to coordinate activities while physically moving personnel to the PJM emergency dispatch center.

Satellite Telephones

Satellite telephones are used by PJM dispatchers as an alternate method of voice communication. These telephones are used to protect against loss of common carrier services. Member companies desiring to avail themselves of satellite point to point capability must apply via PJM Customer Relations (610-666-8980).

PJM expects all Transmission Owners to have two phone capabilities at both their primary and back-up facilities. Satellite phones are required for all Generation Operator (GO) control centers which control one or more units totaling 500 MW or greater.

Functional Requirements for Satellite Phones:

- Compatible with PJM satellite network
- Ability to receive dedicated all-call
- Ability to bypass the ground phone (PSTN) network

Additional Notes:

- If the emergency plan for a generator control center is to co-locate with a transmission control center which has a satellite phone, this will meet the requirement, however, companies need to examine the availability of these systems for both transmission and generator communications during an emergency.
- Companies need to also provide similar (radio, satellite, etc.) redundant communications from their control centers to their plants.
- PJM may also require specific critical generation units to maintain a satellite phone.



EMS Backup Communications

To implement backup communications, multi-point voice grade telephone circuits transmit key EMS telemetry information from the LCCs' electric systems to PJM. These circuits are bridged and extended to the PJM Emergency Dispatch Center. In addition, the PJM EMS control information is sent to the Western Region Generation Management System (GMS) so that the GMS can back up the PJM EMS for AGC purposes if there is a PJM EMS outage. Generation owning members need to be prepared to accept AGC signals from the back up sources to ensure control continuity in the event of an AGC outage on either EMS or GMS.

Section 4: Billing Metering Standards

Welcome to the *Billing Metering Standards* section of the PJM Manual for **Control Center Requirements**. In this section you will find the following information:

- A general description of the purpose of having billing metering standards (see “*Purpose & Criteria*”).
- The overall requirements for the billing metering (see “*General Guidelines*”).
- The basic metering requirements in terms of accuracy, backup, location, alternative installation methodology, tie circuits, non-contiguous load, and maintenance (see “*Primary Metering Requirements*”).

Purpose & Criteria

All electricity recording metering equipment is operated and maintained to assure, to the maximum extent possible, that the equipment provides an accurate record of the quantities supplied to and received by all parties. Each PJM Member is responsible for properly maintaining its metering and telemetering equipment in accordance with applicable ANSI standards.

This section provides the minimum standard requirements for the billing metering for new meter installations to be used in transactions with PJM. The standards apply to new meter installations, replacement meter installations, or upgrades to existing installations.

The standards in this section are a minimum requirement and do not supersede more restrictive agreements. In cases in which standards differ, the most restrictive criteria takes precedence. More specific standards may be required by local, state, or federal regulations, host utilities, service providers, or as are mutually agreed upon.

General Guidelines

All PJM Members involved with any interface with PJM abide by the following general guidelines for Billing Meter Standards:

- Reliable and compliant operational metering equipment is in place for any metered service that is billed.
- Meter information is automatically electronically communicated to PJM by either the producer, host utility, or transmitter in order to ensure timely accounting and billing. This enables PJM to identify and resolve erroneous information and to account and bill for services. Communication between PJM Members other than PJM may utilize any method, such as voice notification or paper document that is mutually agreeable.

- Billing metering systems are capable of collecting and storing bi-directional information for intervals as determined by the parties involved. The expense and practicality of reporting information for small data intervals may not be cost effective or prudent. The average of instantaneous values can be used, providing a mutually agreed upon accuracy is obtained and applicable standards are achieved. Meter intervals can be of lesser duration for some services, but common intervals are fifteen minutes, thirty minutes, and sixty minutes. Collected meter information may be transmitted to the appropriate parties with a different frequency than it is collected, as communications systems permit.
- The megawatt-hour (MWh) is the standard unit of service measurement. Service may be measured in kilowatt-hours (kWh) if required by specific services, local or state regulations, host utilities, service providers, or as are mutually agreed upon by the parties involved. kWh information may be used by the parties involved but must be converted to MWh information before transmission to PJM.
- All metered generator data values are to be supplied to the required parties in “net” form. “Net” shall be defined as “gross” output minus unit station light and power components. When metering limitations require “gross” values to be used, the “gross” to “net” calculation method must be approved by the PJM Operating Committee for use by PJM Members in the calculation of “net” data values.
- All meter records and associated documentation are retained for a period of seven years for independent auditing purposes.
- Any dispute involving any aspect of the billing metering standards or their application are resolved as described in the PJM Manual for [Administrative Services for the PJM Interconnection Agreement \(M-33\)](#).

Primary Metering Requirements

The primary metering requirements are:

- For billing purpose, watt-hour meters are recognized as the official source of meter information.
- Metering devices must be capable of collecting and storing information for intervals required by the service provided, and as mutually agreed upon by the parties involved.
- Any generation unit participating in the PJM Energy Market is required to have independent metering devices that are capable of recording generation net MWh output. When metering limitations require variance from this standard, the metering system must be mutually agreed upon by the parties involved.

- All manual or additional meter reading or comparisons required to ensure consistent valid meter information (“true-up”), are performed prior to the billing cycle, as mutually agreed by the parties involved. Current billing cycles are monthly.

Each meter must follow the specific metering requirements associated with:

- Accuracy
- Backup Metering Requirements
- Location of Meter Points
- Alternative Approach
- PJM Member-to-PJM Member Tie Circuits
- Geographically Non-Contiguous Load
- Pool-to-Pool Tie Circuits
- Maintenance

Accuracy

The minimum metering accuracy for each measuring device is defined by prevailing ANSI standards. The standards in this attachment are a minimum requirement, and do not supersede more restrictive agreements. In cases in which standards differ, the most restrictive criteria takes precedence.

The manufactured accuracy class of all energy interchange billing devices should be accurate within $\pm 0.3\%$ of full scale.

An individual metering system at a metering point location includes all components from the meter location through to the system operator destination. The accuracy of the total energy interchange billing metering system, at each generator or transformer location, is to be within 1.0%. More restrictive standards may be required by local or state regulations, host utilities, service providers, or as are mutually agreed upon by the parties involved.

Each individual metering system at each metering point location used for billing is tested by the owner of the equipment at intervals of two years and its accuracy of registration maintained in accordance with good practice. At the request of any party, an individual meter system will be tested, but, if an error of less than 1.0% is observed, the requesting party will pay for the test. PJM is to be notified of the error for auditing purposes.

Backup Metering Requirements

The backup metering system is of sufficient accuracy to serve as a replacement for the primary metering system. The average of instantaneous values may be used as

a backup source, provided mutually agreed upon accuracy is obtained and applicable standards are achieved.

The backup metering system is capable of collecting interchange data and logically comparing data with the primary meter system so that material differences may be detected in a reasonable time.

If any test of an individual metering system discloses an error of greater than 1.0%, the accounts of the parties shall be adjusted for no more than two months for which the inaccuracy is estimated to have occurred. Longer correction periods, if confirmed by recorded information or defined as a result of the dispute resolution process, may be mutually agreed upon by the parties involved. All errors of the above magnitude shall be reported to PJM and documented for auditing purposes.

Location of Meter Points

Interchange billing metering is provided on the system as follows:

- *Transformers: Through-Transmission* — EHV interchange metering points are provided from the secondary side of all through-transmission transformers connected to the 500 kV EHV system. For example, interchange metering is provided on the 230 kV side of a 500/230 kV through-transmission transformer.
- *Generators and Transformers Radially Tapped* — Generators and transformers that are not through transmission (including unit station service transformers) and that are tapped directly on the 500 kV EHV system are provided with interchange metering on the primary side (500 kV) of the step-up, station service or radial transformer. For instance, a generator connected to the EHV system has an interchange metering point on the 500 kV side of the unit step-up transformer. All other generators and transformers not connected to the 500 kV system provide information as received from the high side of the unit transformer.

Alternative Approach

In lieu of providing interchange billing metering, a PJM Member may elect to install a watt-hour metering system on the opposite side of the transformer than directed above (the 500 kV side of the through-transmission transformer or the 230 kV side of the radial transformers) provided that a compensation system is included to capture and adequately adjust interchange values to account for transformer losses. Any design for alternative metering approaches shall be documented and made known to PJM and all parties involved. Any alternative approach must be approved by PJM.

For through-transmission transformers, interchange values may be determined from the 500 kV side if compensation is installed which subtracts transformer losses when power is imported to the PJM Member or adds transformer losses for exported power.



PJM Member-to-PJM Member Tie Circuits

PJM Member-to-PJM Member tie circuits not associated with the EHV system and under the direction of PJM have interchange metering provided at one terminal end with or without the agreed upon compensation circuitry per agreement between the two PJM Members. This terminal is regarded as the official source for interchange values.

Geographically Non-Contiguous Load

Any PJM Member serving a load which is geographically non-contiguous to its defined service area documents and makes known to PJM, and all other parties involved, any metering and system conventions implemented in order to meter the load. Metering devices may be met by contractual arrangement with any party involved. Any alternative approach must be approved by PJM prior to implementation. This enables PJM to monitor and control the transmission system, to identify and resolve erroneous information, to account and bill for services, and to take appropriate action for reliability concerns.

Control Area-to-Control Area Tie Circuits

The requirements for documentation for any Control Area-to-Control Area tie circuit interchange delivery and metering point is set forth in the agreements between PJM and applicable parties. The requirements for the metering of these points conforms to the standards contained in this document, except in the case of existing equipment. If existing equipment is used in metering of these points, and the equipment does not comply with these standards, both parties then mutually agree to accept the metering. For billing purposes, watt-hour meters are recognized as the official source of meter information.

Maintenance

The accuracy of all recording meters, as required to transact energy services, is verified by tests conducted by the equipment owner once every two years. If such test identifies, or other indications show, a recording meter is out of service or inaccurate, the owner must take action to restore the meter to correct operation within a reasonable time. In the interim, backup metering may be used as mutually agreed by the parties involved. All equipment must be restored to correct operation within the period of 30 days from the date of discovery, or a date mutually agreed upon by all parties. If equipment installation or replacement is required to resolve the inaccuracy, all equipment must be correctly operating at a date mutually agreed upon by all parties. PJM is notified of the inaccuracy, interim procedures, and resolution for auditing purposes.

Periodic accuracy compliance testing may be requested by PJM Member agreement groups, as required. Authentication of current meter testing and validation of newly installed or repaired meter systems may also be required.



The results of all accuracy testing are reported to PJM. As a minimum, PJM maintains a metering database documenting the test results for all PJM Member metering tests that show errors of greater than 1% for auditing purposes.



Section 5: Meter Accuracy Standards

Welcome to the *Meter Accuracy Standards* section of the PJM Manual for **Control Center Requirements**. In this section you will find the following information:

- A general description of the purpose and applicability of metering standards (see “*Purpose*”).
- The overall requirements for telecommunications metering (see “*General Guidelines*”).
- The overall requirements for metering accuracy (see “*Primary Metering Accuracy*”).
- Requirements for data needed for system control data (see “*System Control Monitoring Requirements*”).
- Requirements for data used in system security monitoring (see “*Real-Time Analysis Monitoring Requirements for System Security*”).
- A description of the requirements intended to assure reliable dispatch (see “*Dispatching Requirements*”).

Purpose

This section provides the minimum standard requirements for telecommunications metering, such as MW, MVAR, and kW values, to be used when communicating information to PJM. The standards apply to new meter installations, replacement meter installations, or upgrades to existing installations. The requirements for billing meters are covered in Section 4.

These standards are a minimum requirement and do not supersede more restrictive agreements. In cases in which standards differ, the most restrictive criteria takes precedence. More specific standards may be required by local, state, or federal regulations, host utilities, service providers, or as are mutually agreed upon.

General Guidelines

All PJM Members involved with any interface with PJM abide by the following general guidelines for telecommunications metering:

- All electric measurement equipment is operated and maintained so as to assure, to the maximum extent possible, that it provides an accurate record of the quantities supplied to and received by all parties.
- Each PJM Member is responsible for properly maintaining its metering and telemetering equipment in accordance with applicable ANSI standards.

- Metered information is automatically electronically communicated to PJM by the producer, host utility, or transmitter in order to ensure system security and reliability.
- It is important to recognize the importance of accurate data as well as the need to meet deadlines associated with updating this data, since the failure to provide accurate and timely data affects reliable system operations.

Primary Metering Accuracy

For all new metering installations, the following primary transducer accuracy guidelines are followed:

Primary Transducer	Accuracy Guideline
Frequency Transducers	0.001 Hz
Potential Transformers	0.30%
Current Transformers	0.30%
MW/MVAR/Voltage Transducers	0.25%
Remote Terminal Units (A/D)	0.25%

Exhibit 3: Primary Transducer Accuracy Guideline

These accuracy guidelines result in an overall metering accuracy better than 2%. Billing accurate telemetered data values should be supplied whenever possible.

System Control Monitoring Requirements

Data required for system control monitoring provides PJM dispatcher with the necessary information to meet the continuous requirement of matching the generation with the load demand and to assure that system security is maintained. There are four classes of system control data:

- system control data
- area regulation data
- dispatch data
- reserve data

The frequency and accuracy of data transmission, unless otherwise noted, applies to the primary source of telemetered data, the backup source when the primary is unavailable, and analog backup source for tie line and frequency data.

System Control Data

System control data is required to match the load demand with the available generation. This is accomplished by measuring the actual tie-flow values and the actual frequency and using them in a calculation with the scheduled total tie-line

value and the scheduled frequency. PJM Members that control generation participate in time error control by raising or lowering frequency schedules by 0.02 Hz at the direction of PJM (see the PJM Manual for [Dispatching Operations](#) (M-12)).

- Frequency of Acquisition — ≤ 4 seconds
- Metering Accuracy — 2%

Area Regulation

Area regulation data is required to ensure that the instantaneous mismatches of load and generation are corrected by sending a generation control signal to those plants/stations/PJM Members scheduled to provide this ancillary service. PJM calculates the desired area regulation signal and the signal is transmitted to the designated provider of this service.

- Frequency of Acquisition — ≤ 4 seconds
- Metering Accuracy — 2%

PJM Members must have the ability to receive a regulation signal and must have the ability to adjust generation manually to maintain scheduled interchange if automatic generation control becomes inoperative.

Dispatch Data

The plant/station/PJM Member provides to PJM the individual generation availability by providing the necessary information to dispatch the generation. For PJM dispatchable generation, the appropriate operating data points are provided to PJM either through an EMS data link or through the eMarket interface whenever the data changes. For self-scheduled generation, the self-scheduled value is transmitted twenty minutes prior to any changes. PJM uses its Unit Dispatch System (UDS) to determine the appropriate generation output which is then sent to each plant/station/PJM Member in the form of an individual unit MW basepoint, to be used as the dispatch signal, and an individual unit dispatch lambda, used for informational purposes only. PJM Members with generation notify PJM of any actual or potential changes in unit status or capacity.

- Frequency of Acquisition — ≤ 10 seconds
- Metering Accuracy — 2%

Reserve Data

The availability of generation reserve is transmitted to PJM from the individual plant/station/PJM Member. This data is used to determine the reliability of the PJM RTO.

- Frequency of Acquisition — ≤ 10 seconds

- Metering Accuracy — 2%

Real-Time Analysis Monitoring Requirements for System Security

PJM analyzes the system security of the PJM system using information telemetered from PJM Members. Phase and line-end location of metering is as mutually agreed between the two connected systems, must be consistent with established system metering, and must be coordinated with PJM. The following analog and status information is required for this analysis:

- Required Analog Data:
 1. voltages for buses at 34 kV and above (or 69 kV and above, if lower voltage equipment is not monitored), MW and MVAR values for generating units greater than 1 MW including steam, nuclear, hydro and combustion turbine units and non-utility generator units (usually individual unit generation but total station generation may be telemetered in special circumstances) if connected directly to the transmission system.
 2. MW and MVAR values (both ends) for designated transmission lines at 69 kV and above (if single-phase metering is employed, the B-phase is preferred)
 3. transformer phase angle regulator (PAR) tap positions for modeled and controlled transformers (high side metering or low side with a loss calculation)
 - ☞ MVAR values for synchronous condensers
 - ☞ MVAR injection on 34 kV buses (or 69 kV if lower voltage equipment is not monitored)
 - ☞ Selected station frequencies
- Frequency of Acquisition — ≤ 10 seconds
- Required Status Data:
 - ☞ Circuit breaker status for each modeled facility at 69 kV and above
 - ☞ breaker and disconnect statuses as modeled
 - ☞ transformer fixed tap settings (change in no-load tap setting)
- *Frequency of Acquisition* — Upon change of status.

PJM Members have the capability to validate data and send accurate manually adjusted data until inaccurate metering is corrected if state estimated data will not suffice. In case of a computer failure or outage, all data should be sent once the computer reinitializes. See the PJM Manual for [Transmission Operations \(M-03\)](#) for more information.



Dispatching Requirements

The following requirements are intended to assure reliable dispatch and operation of the PJM system:

- All tie line MW and MWH data are telemetered to PJM and the neighboring Control Area and emanate from a common agreed upon terminal using common primary metering equipment. Daily billing MWH data can be submitted via eMTR.
- Combustion turbines supply accurate real-time status information and report failure-to-start situations.
- 500 kV and strategic 345 and 230 kV locations require disturbance recording equipment for post-disturbance analysis. These devices should have the capability to retain historical data for future analysis.
- PJM Members participate in the payback of the accumulation of inadvertent interchange as directed by PJM.
- The amount of generator regulating capacity reported to PJM is accurate and committed to the system.
- The amount of generator reserve capacity reported to PJM is accurate and committed to the system.

PJM Members, generating stations, and fault recorders are time synchronized to assure accurate recording times for system events.



Attachment A: Information Access Matrix

The following Information Access Matrix lists each of the major PJM services that affect PJM Members. It differentiates these services by PJM member type and by information access method. This Information Access Matrix should be considered as a rough approximation only. The PJM Customer Relations and Training Department is available to provide more specific information concerning PJM services and access methods.

A: Generation Scheduling Services						
	Information Services	PJM Member Regional Transmission Owner	PJM Member Generating Entity	PJM Member Load Serving Entity	PJM Member Marketer	Neighboring Control Areas
	Inputs to PJM					
A.1	Hydro Constraint Information (pool scheduled resources) [submitted daily by hydro plants]		2			
A.2	Generator Outage Information [submitted daily]		1			4
A.3	Daily Generator Bids (cost, availability, etc.) [submitted by noon for next day]		3			
	Outputs from PJM					
A.4	Daily Hydro Schedules (hourly generation and capacity) [read only]		2			
A.5	Daily Hydro Schedule Updates		2			
A.6	Daily Managers Report on Joint Owned Units [reported to joint plant owners]		5			
A.7	Daily Load Forecasts (peak loads, congestion)	X		O	O	O
A.8	Reliability Information (Forecasted Load, Minimum Generation Problems, Outages, Available Capacity)	X				X
A.9	Daily Generator Bid Confirmations (cost, availability, etc.)		2			
A.10	Selected Generators (next day schedule)[distributed to selected generator owners]		2			
Key: X - Required Service O - Optional Service 1 - Mandatory For All Generation Within the PJM RTO 2 - Mandatory For Unit Specific Generation Bidding 3 - Mandatory For All Capacity Resources 4 - System Reliability Information Only 5 - Mandatory For Joint-Owned Unit Owners 6 - Mandatory If Not Attainable From Existing Telemetry 7 - Mandatory For Generators Offering Regulation						

Exhibit 4: Generation Scheduling Services



B: EMS Services						
	Information Services	PJM Member Regional Transmission Owner	PJM Member Generating Entity	PJM Member Load Serving Entity	PJM Member Marketer	Neighboring Control Areas
	Inputs to PJM					
B.1	CT Generator Availability Updates		1			
B.2	Confirmed Regulation MWs		7			
B.3	Telemetry Status & Analog Values [real-time]	X	X	6		4
	Outputs from PJM					
B.4	CT On/Off Times for PJM Units Only		1			
B.5	Requests for Regulation MWs		7			
B.6	Real-time Transmission Status (Line Outages, etc.) [PJM dispatcher communication to other CCs]	X				4
B.7	Real-time Generation Status (Generation Inquiries, etc.) [PJM dispatcher communication to other CCs]		X			4
B.8	Real-time Informational, Operational, and Emergency Messages [broadcast to all LCCs]	X				
B.9	Generation Dispatch [relayed every 5s, or manually]		X			
B.10	Generation Regulation Control [relayed every 5s]		7			
B.11	Real-time Telemetry (status & analog values) [relayed to other CCs]	X	X	6		4
Key: X - Required Service O - Optional Service 1 - Mandatory For All Generation Within the PJM RTO 2 - Mandatory For Unit Specific Generation Bidding 3 - Mandatory For All Capacity Resources 4 - System Reliability Information Only 5 - Mandatory For Joint-Owned Unit Owners 6 - Mandatory If Not Attainable From Existing Telemetry 7 - Mandatory For Generators Offering Regulation						

Exhibit 5: EMS Services



	Information Services	PJM Member Regional Transmission Owner	PJM Member Generating Entity	PJM Member Load Serving Entity	PJM Member Marketer	Neighboring Control Areas
	Inputs to PJM					
C.1	Historical EMS Information Requests [submitted periodically to PJM for processing]	X				4
	Outputs from PJM					
C.2	Historical EMS Information [distributed to requesting parties]	X				4
Key: X - Required Service O - Optional Service 1 - Mandatory For All Generation Within the PJM RTO 2 - Mandatory For Unit Specific Generation Bidding 3 - Mandatory For All Capacity Resources 4 - System Reliability Information Only 5 - Mandatory For Joint-Owned Unit Owners 6 - Mandatory If Not Attainable From Existing Telemetry 7 - Mandatory For Generators Offering Regulation						

Exhibit 6: Historical EMS Data Services



D: Transmission Maintenance Planning Services						
	Information Services	PJM Member Regional Transmission Owner	PJM Member Generating Entity	PJM Member Load Serving Entity	PJM Member Marketer	Neighboring Control Areas
Inputs to PJM						
D.1	3-4 Day Ahead Transmission Maintenance Schedules [planned outages, submitted by transmission providers]	X				
D.2	3-4 Day Ahead Neighboring Control Area Transmission Maintenance Schedules (planned outages) [submitted by neighboring control areas]					X
Outputs from PJM						
D.3	3-4 Day Ahead Transmission Maintenance Schedules (planned outages) [confirmation of D.1]	X				X
D.4	3-4 Day Ahead Neighboring Control Area Transmission Maintenance Schedules (planned outages) [confirmation of D.2]					X
D.5	Transmission Maintenance Schedule (planned outages) [monthly report sent to all transmission providers]	X				X
Key: X - Required Service O - Optional Service 1 - Mandatory For All Generation Within the PJM RTO 2 - Mandatory For Unit Specific Generation Bidding 3 - Mandatory For All Capacity Resources 4 - System Reliability Information Only 5 - Mandatory For Joint-Owned Unit Owners 6 - Mandatory If Not Attainable From Existing Telemetry 7 - Mandatory For Generators Offering Regulation						

Exhibit 7: Transmission Maintenance Planning Services



E: Transmission Services						
	Information Services	PJM Member Regional Transmission Owner	PJM Member Generating Entity	PJM Member Load Serving Entity	PJM Member Marketer	Neighboring Control Areas
Inputs to PJM						
E.1	Transmission Reservations [reserved through OASIS]		O	X	X	
E.2	Network Transmission Services			X		
Outputs from PJM						
E.3	Available Transmission Capacity [posted on OASIS]			X	X	
E.4	Actual Energy Transactions [posted on OASIS 7 days later]	X	X	X	X	
E.5	Informational Messages [posted on OASIS]	X	X	X	X	
E.6	Ancillary Services [posted on OASIS]	X	X	X	X	
E.7	Approved Transmission Reservation Requests			X	X	
E.8	Summary of Month End Transactions	X				
Key: X - Required Service O - Optional Service 1 - Mandatory For All Generation Within the PJM RTO 2 - Mandatory For Unit Specific Generation Bidding 3 - Mandatory For All Capacity Resources 4 - System Reliability Information Only 5 - Mandatory For Joint-Owned Unit Owners 6 - Mandatory If Not Attainable From Existing Telemetry 7 - Mandatory For Generators Offering Regulation						

Exhibit 8: Transmission Services



F: Energy Transaction Services						
	Information Services	PJM Member Regional Transmission Owner	PJM Member Generating Entity	PJM Member Load Serving Entity	PJM Member Marketer	Neighboring Control Areas
Inputs to PJM						
F.1	External Energy Transactions			X	X	
F.2	Non-PJM Energy Transactions (Wheels, etc.) [submitted by neighboring control areas]					X
F.3	Updates / Additions to Energy Transaction Schedule			X	X	X
F.4	Internal Energy Transactions			X		
Outputs from PJM						
F.5	External Energy Transactions [collectively confirmed by PJM & communicated to neighboring control areas]			X	X	X
Key: X - Required Service O - Optional Service 1 - Mandatory For All Generation Within the PJM RTO 2 - Mandatory For Unit Specific Generation Bidding 3 - Mandatory For All Capacity Resources 4 - System Reliability Information Only 5 - Mandatory For Joint-Owned Unit Owners 6 - Mandatory If Not Attainable From Existing Telemetry 7 - Mandatory For Generators Offering Regulation						

Exhibit 9: Energy Transaction Services



G: Long-term Planning Services						
	Information Services	PJM Member Regional Transmission Owner	PJM Member Generating Entity	PJM Member Load Serving Entity	PJM Member Marketer	Neighboring Control Areas
	Inputs to PJM					
G.1	Capacity Information (spreadsheets)	X				
G.2	Load Information (spreadsheets)	X				
G.3	Load Flow Information	X				
G.4	Short Circuit Information	X				
G.5	Dynamics Information	X	1			
G.6	LAS Load Information	X	1			
G.7	Generator Events Information (GADS dataset) [submitted by plant operations]	X	1			
G.8	PROMOD information File (Generation Production Cost Information) [submitted by generation planning into central planning database]	X	1			
G.9	Generation Planning Maintenance Outage Reports [compiled from transmission planning tools]	X	1			
G.10	Long-term Capacity Planning Information [submitted by transmission planning]	X				
G.11	Performance Adequacy Assessments (financial Studies)	X	X	X	X	
G.12	Generator Planning Study [distributed to GUS committee members]	X	O	O	O	
G.13	Supplemental Agreement (Forecast Obligation) [distributed to GUS committee members]	X	O	O	O	
G.14	LAS Report [submitted to Reliability Committee]	X	O			
G.15	GORP Reports [distributed to generation planning]	X	O			
Key: X - Required Service O - Optional Service 1 - Mandatory For All Generation Within the PJM RTO 2 - Mandatory For Unit Specific Generation Bidding 3 - Mandatory For All Capacity Resources 4 - System Reliability Information Only 5 - Mandatory For Joint-Owned Unit Owners 6 - Mandatory If Not Attainable From Existing Telemetry 7 - Mandatory For Generators Offering Regulation						

Exhibit 10: Long-term Planning Services



H: PJM Administration Services						
	Information Services	PJM Member Regional Transmission Owner	PJM Member Generating Entity	PJM Member Load Serving Entity	PJM Member-Marketer	Neighboring Control Areas
	Outputs from PJM					
H.1	PJM Information [on PJM Web site]	X	X	X	X	X
H.2	MAAC Information [on PJM Web site]	X	X	X	X	X
H.3	FERC Filings [on PJM Web site]	X	X	X	X	X
H.4	Training Information [on PJM Web site]	X	X	X	X	X
H.5	Emergency Information [on PJM Web site]	X	X	X	X	X
H.6	General Administration Information [distributed via fax to all participants]	X	X	X	X	X
H.7	Regulatory Reporting (FERC 714, 715; EIA 411)	X	X	X	X	
<p>Key: X - Required Service O - Optional Service 1 - Mandatory For All Generation Within the PJM RTO 2 - Mandatory For Unit Specific Generation Bidding 3 - Mandatory For All Capacity Resources 4 - System Reliability Information Only 5 - Mandatory For Joint-Owned Unit Owners 6 - Mandatory If Not Attainable From Existing Telemetry 7 - Mandatory For Generators Offering Regulation</p>						

Exhibit 11: PJM Administration Services



Attachment B: Nuclear Plant Communications Protocol

Purpose

PJM and its member companies have a responsibility to ensure the safe, reliable operation of the bulk power transmission system while facilitating a fair and open energy market. The nuclear plant owners and operators have the responsibility to safely operate their facilities in compliance with all of the rules and requirements in order to protect the safety of the public. The proper execution of these responsibilities by the respective set of parties can have very significant impact on the others. The collective requirements are not mutually exclusive, but support the business needs of nuclear and transmission as they both strive to maintain operational excellence.

It is imperative that the nuclear plant owners and operators, the transmission owning members of PJM, and PJM work seamlessly together to carry out these significant responsibilities. A key aspect of that mutual effort to achieve operational excellence is to provide accurate and timely communications among the parties so that all operations are conducted safely and reliably.

Given that the respective regulatory obligations and lexicons are different, the purpose of this document is to provide explanatory information for both the nuclear and transmission businesses to enable the seamless cooperation and communication that we all seek. Also, each business needs to understand the key phrases and terms that each other use to signify critical events that require open and immediate response from the other. Understanding and properly using the key phrases will ensure that each business supports the other in the proper execution of their respective responsibilities and obligations.

This document provides examples of significant events that require implementation of this protocol document in order to ensure safe and reliable operation of both the transmission system and nuclear generation facilities.

Nuclear Safety

The Atomic Energy Act of 1954, as revised [e.g., Sections 3(c) and (e)], and the Energy Reorganization Act of 1974 [Section 204(b)(1)], give NRC the responsibility for ensuring that the peaceful uses of nuclear energy "make the maximum contribution to the common defense and security and the national welfare, and..."¹

The nuclear industry is strictly regulated because of the potential hazards involved in using radioactive materials. These radioactive materials give off radiation, which can be hazardous to people if they are exposed to it in significant amounts. The extent of the risk depends on the type and amount of radiation emitted by the radioactive

¹ NRC Website

material, the distance between the source of the radiation and a person, and the length of time a person is exposed to the radiation. If radioactive materials are properly handled and regulated, they do not pose a significant risk to the public or to workers.²

Grid Reliability

Bulk-power systems are fundamentally different from other large infrastructure systems, such as air-traffic control centers, natural-gas pipelines, and long-distance telephone networks. Electric systems have two unique characteristics:

- The need for continuous and near instantaneous balancing of generation and load, consistent with transmission-network constraints. This requires metering, computing, telecommunications, and control equipment to monitor loads, generation, and the voltages and flows throughout the transmission system, and to adjust generation output to match load. Generation must follow load in near real time because it is difficult and expensive to store electricity.
- The transmission network is primarily passive. Unlike natural gas pipelines, transmission grids have few “control valves” or “booster pumps” to regulate electrical flows; control actions are limited primarily to adjusting generation output and to opening and closing switches to add or remove transmission lines from service.

These two unique characteristics lead to four reliability consequences with practical implications that dominate power system design and operations. The consequences are:

- Every action can affect all other activities on the grid. Specifically, changes in the locations and amounts of power generated and consumed, and in the configuration of the transmission grid can affect flows throughout the system.

Therefore, the operations of all bulk-power participants must be coordinated.

- Cascading problems that increase in severity are a real problem. Failure of a single element can, if not managed properly, cause the subsequent rapid failure of many additional elements, disrupting the entire transmission system.
- The need to be ready for the next contingency, more than current conditions, dominates the design and operation of bulk-power systems. It is usually not the present flow through a line or transformer that limits allowable power transfers, but rather the flow that would occur if another element fails.
- * Because electricity flows at nearly the speed of light, maintaining reliability often requires that actions be taken instantaneously (within fractions of a

² Ditto



second), which requires computing, communication, and control actions that are automatic.³

Operating Philosophy

Nuclear Safety

Nuclear Risk Management

Nuclear power plants assess risk based on a plant risk model, usually a computer model, at various plant operating conditions. The objective of risk management is to control risk increases from maintenance activities on maintenance rule⁴ (10CFR50.65) structure systems and components (SSC's). While the plant may experience an increase in instantaneous risk during scheduled activities, the overall plant risk will decrease as a result of the activities. Preventative and corrective maintenance and modifications control the aging process, renew equipment and correct deficiencies in the equipment. The equipment reliability is improved as a result of the activities.

The risk program will protect systems and equipment vital to the safe shutdown of the nuclear units. Performing work on maintenance rule equipment for any reason - corrective or preventative maintenance, surveillance testing, etc. - removes the equipment from its normal alignment. The additional risk involved with these evolutions must be assessed. The results of the assessment must then be used to manage the risk based on the magnitude and duration of the risk impact, the nature of the activity and other factors.

Nuclear Safety Significant

A condition or potential condition which can lead to operation in a degraded mode, with regard to safety systems, which may exceed the Limiting Conditions for Operation (LCO) as defined by the plants Technical Specifications. Events declared as "Nuclear Safety Significant" by the nuclear plant operators are with the intent to minimize the consequences of undue risk to the public health and safety.

In these scenarios, requests for information that may ordinarily be understood as market sensitive due to Code of Conduct concerns should be granted as the nuclear safety concerns are paramount.

Transmission

The bulk transmission system is planned, maintained and operated such that it can withstand the loss or outage of any single element, such as a transmission line, a

³ Hirst, Eric. Electric Reliability—Potential Problems and Possible Solutions. May 2000 (EEI Website), page 4
⁴ Maintenance rule equipment generally includes any equipment that could cause a plant trip and may include switchyard equipment and other non-safety related equipment. The purpose of the maintenance rule is to monitor and analyze important plant equipment to ensure that the overall maintenance program related to this equipment is effective.

transformer, a generation plant without causing the remaining elements of the system to become overloaded or to cause cascading outages.

The philosophy is contained in this excerpt from NERC Policy 2, Transmission:

1. Basic reliability requirement regarding single contingencies. All CONTROL AREAS shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.
 - (a.) Multiple outages. Multiple outages of a credible nature, as specified by Regional policy, shall also be examined and, when practical, the CONTROL AREAS shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from these multiple outages.
 - (b.) OPERATING SECURITY LIMITS. OPERATING SECURITY LIMITS define the acceptable operating boundaries.
2. Return from OPERATING SECURITY LIMIT Violation. Following a contingency or other event that results in an OPERATING SECURITY LIMIT violation, the CONTROL AREA shall return its transmission system to within OPERATING SECURITY LIMITS soon as possible, but no longer than 30 minutes. [PJM's internal objective is that such violations shall be corrected within 15 minutes in 80% of the cases.]
 - (a.) Reporting Non-compliance. Each violation of this Standard shall be reported to the Regional Council and NERC Compliance Subcommittee within 72 hours.
 - (b.) Reporting format. The report will be submitted on the NERC Preliminary Disturbance Report Form as found in Appendix 5F, "Reporting Requirements for Major Electric System Emergencies."⁵

To ensure that the N-1 operating philosophy is not violated, PJM and the other control area operators of North America use analytical tools which simulate the loss of each element (a contingency) and calculate that the remaining system will be secure from the thermal (conductor or equipment heating), voltage (magnitude and stability) and stability (transient and dynamic) perspectives. (In PJM's case, the analysis is on-line, running approximately every minute.) If the security analysis program identifies a contingency or actual violation, PJM's operators will initiate any number of actions, including redispatch of generation, reconfiguring the transmission system (e.g. opening lines, removing equipment from service, etc.), invoking

⁵ NERC Policy 2, Transmission



emergency procedures, or interrupting load or combinations of the above. Normally, the consequences of not responding correctly or timely enough is to cause protective devices on the equipment to operate taking the equipment out of service. However, such events can also lead to catastrophic equipment failure from overheating, or induce a cascading outage which can interrupt large numbers of customers, etc.

Roles and Responsibilities

Nuclear Plant Operations

Operate in compliance with the license

The nuclear plant must operate in accordance with the provisions of its license. It is accountable to the NRC and personnel face criminal penalties for violations of the requirements of the license and the associated documents, including the technical specifications.

Any request for a nuclear plant to deviate from any regulatory requirement must allow time for the plant owner, the transmission owner, and PJM to approach the NRC with the appropriate analysis to justify the request. It is simply not possible for the nuclear plant to honor such requests in real time. Also, such a request will only be considered when the electrical system emergency is such that there is significant risk of widespread outages impacting large numbers of consumers. Therefore, it is imperative that PJM, through the transmission owner and the applicable market operations center, fully inform the nuclear plant of any impending system problems or emergencies that could require unusual operations by the nuclear plant.

Inform Market Operations Center (MOC) and/or Local Control Center (LCC) of impending plant status changes or regulatory circumstances that could impact power production

Nuclear plant generation is a very significant portion of the PJM generating assets. As such, any changes to the ability of the nuclear plants to provide energy will likely have significant impacts to PJM's generation schedule and will be difficult to replace in a short period of time. Therefore, it is very important that any condition of the nuclear plant's operational capability be communicated to the MOC, the associated LCC, and to PJM so that analysis can be conducted to assess any system impacts and to develop contingency plans.

Coordinate maintenance outages with MOC and/or LCC

Normally, the nuclear plant outages are planned far in advance. However, there can be situations where transmission work needs to be done in the window of the nuclear plant outage. Such coordination is important to ensuring that the minimum amount of outage time is needed to accomplish the necessary maintenance for the nuclear plants and the transmission facilities.



Respond to transmission system operator requests

Requests from the transmission system operators will come into the nuclear plant from the MOC or the LCC. In some circumstances, the various parties may be convened by PJM on a conference call. All requests need to be complied with on a timely basis after consideration of consequences to nuclear safety, personnel safety, and equipment protection. If there are questions or doubts in the nuclear plant operators' minds, the request should be questioned with the requestor and elevated as necessary to assure that there is understanding of the situation and the request.

Affiliated Power Marketer Operations Center (MOC)

Inform PJM of nuclear plant conditions that could impact the continued power production of the nuclear plant.

If there are conditions that have the potential to result in the nuclear plant having to reduce generation or go off line, the LCC and PJM need to know as soon as possible. If the situation is regulatory-related, that is important information that needs to be conveyed.

Submit bidding information for applicable nuclear plants

The MOC needs to understand the business implications of any nuclear and transmission system situation that could impact the nuclear plant operations so that it can accurately reflect the impact into the market.

Interface with PJM regarding maintenance outage requests and other potential reliability issues

If the situation will require the nuclear plant to be out of service, the MOC will need to process the appropriate outage request for approval by PJM.

Transmission Owner Local Control Center (LCC)

Inform the MOC and the nuclear plant operations staff of system events or conditions that could impact the continued safe operation of the nuclear plant.

The LCC is a critical link in the communications chain from PJM to the nuclear plant and back. The LCC also has the clearest picture of the local situation in the vicinity of the nuclear plant. It can be an important facilitator in the discussions between PJM, the MOC, and the nuclear plants.

PJM Control Center

Operate the transmission system in accordance with NERC policies, regional reliability council requirements, PJM agreements, and PJM manuals

PJM is responsible for the safe and reliable operation of the transmission facilities on behalf of the PJM transmission owners. PJM is accountable to NERC, the regional



councils, the PJM members, and the various state regulatory bodies who have oversight responsibility for PJM's activities.

In an emergency situation, PJM has the authority to direct any necessary action to be taken to preserve the reliability of the system. Normally, PJM will work directly with the LCCs to accomplish these actions, but there may be situations where PJM will need to gather the nuclear plant operators, LCCs, MOCs together to explain a request for coordinated action by all parties.

Inform the LCC and MOC of system conditions and events that need to be communicated to nuclear plant operations.

Timely information is the key for permitting the proper response to any operating situation. Regarding the nuclear plants, it is important to convey the details behind the event, so that the need for understanding that is ingrained in the nuclear business can be satisfied.

It is incumbent upon PJM to keep timely and accurate information flowing to all of the operating entities during the course of transmission system events. Effective concerted action can only be accomplished when the all of the operating entities completely understand the situation and their role in implementing the solution. In order to facilitate rapid communications to the nuclear plant, the Code of Conduct should be bypassed when conditions are such that the nuclear plant needs to have immediate information on the transmission system.

Facilitate communications among nuclear plant operations, MOC, and LLC as necessary to ensure that nuclear plant and transmission system event information is transferred and understood by the respective operational entities.

Ensuring that all entities understand the situation and are clear in their role in the response is the key to successfully mitigating any negative impacts. Since the level of understanding of the transmission system may be an issue, PJM must strive to get the right parties together and take the time to explain what is happening and what response PJM seeks.

Implementation of the Protocol

Event Initiation and Identification

Normal Communications

Communications between and among the nuclear plants, MOCs, LCCs, and PJM should be in accordance with accepted professional practices. There is a need to be able to clearly direct and communicate instructions in a timely manner to ensure safe and reliable operations. Nothing in this protocol supercedes the need for professional behavior by all of the parties.

Special Situations

There will be special situations where the need to communicate rapidly and clearly will be heightened. The need for clear, accurate communications will be even more important due to the impact either to nuclear safety or transmission system reliability or both. All parties need to be prepared to understand the language used and the implications associated with the situation. Listed below are the special terms to which all parties need to be especially attentive. (The following is not intended to be an all-inclusive list, but is meant to identify many of the situations that operators can be expected to face.)

KEY NUCLEAR TERMS

Limiting condition for operation (LCO)

The section of Technical Specifications that identifies the lowest functional capability or performance level of equipment required for safe operation of the facility. Failure to resolve the LCO within the established timeframe will result in a controlled shutdown of the plant. Nuclear Power Plants are required to follow the actions of the LCO unless prior NRC approval is obtained.

Implication: If the LCO time period ends without satisfactory resolution of the problem, the nuclear plant is required to immediately implement a safe shutdown of the plant. Immediate replacement of the energy of the plant will be necessary. During the course of any LCO event, the transmission system operators should be planning for the potential loss of that plant's energy at the end of the LCO time limit. [Bear in mind that multiple unit sites can have differing requirements and an LCO may apply to one or all units at the site.]

Safety limit

A restriction or range placed upon important process variables that are necessary to reasonably protect the integrity of the physical barriers that guard against the uncontrolled release of radioactivity. The nuclear plant cannot violate these limits under any circumstances.

Implication: When the nuclear plant communicates that it is up against a safety limit that is the end of any discussion about providing any additional output (MW or MVar).

Safety related

The managerial controls, administrative documents, operating procedures, systems, structures, and components that have been designed to mitigate the consequences of postulated accidents that could cause undue risk to public health and safety.

Implication: When the nuclear plant reports degradation of safety related equipment (nuclear safety system unavailability, diesel generator unavailability, off site power loss, etc.), a serious situation exists which the nuclear plant is required to immediately resolve or face near-term shutdown. Any assistance that can be immediately rendered should be dispatched. Plans should be developed to replace the plant's energy.

Scram

The sudden shutting down of a nuclear reactor, usually by rapid insertion of control rods, either automatically or manually by the reactor operator. (May also be called a reactor trip)

Implication: A SCRAM is an unplanned manual or automatic trip of a Nuclear Plant. In many cases the initiating event of a SCRAM may not be known. In these situations the Transmission system operators should be supportive to the nuclear plant information request, as the nuclear plant operators may need expeditious answers to questions from regulator or plant oversight safety review committees.

Reactor Shutdown

A decrease in the rate of fission (and heat production) in a reactor.

Implication: A nuclear plant is never completely out of service, unless it is decommissioned. A nuclear plant in shutdown mode still is required to have its safety systems and off site power sources in service and maintain them in service throughout any outage.

Technical Specifications

Part of an NRC license authorizing the operation of a nuclear production or utilization facility. A Technical Specification establishes requirements for items such as safety limits, limiting safety system settings, limiting control settings, limiting conditions for operation, surveillance requirements, design features, and administrative controls.

Implication: Technical specifications are non-negotiable, mandatory requirements that the nuclear plant must comply with as part of its license to operate. Requesting that the nuclear plant provide a variance to a technical specification is simply not an option.

Notice of Enforcement Discretion (NO ED)

Term used when the nuclear facility goes to the NRC to request an extension of an LCO (see 5.2.2.1 above) to prevent plant shutdown when the LCO limit is reached. NRC can grant extension of LCO time if the nuclear facility can demonstrate that they know precisely the problem (i.e. they are not troubleshooting) and a clear time estimate to fix the problem is available.

Implication: In order to provide this discretion to the nuclear plant, the NRC may require detailed information from the transmission operators that would provide the justification for granting this discretion. These requests should be immediately elevated to management for a response.

KEY TRANSMISSION TERMS

First Contingency Violation

The transmission system is operated so that the single loss of any facility (line, generator, etc.) will not result in violation of any operating limit. The single loss is called the first contingency. The transmission operators have software that simulates the first contingency individually for a number of facilities on the system.

Implication: The operators are required to correct any first contingency violation that will violate the emergency ratings on any facility within a period of time (normally within 30 minutes). If the operators ask the nuclear plant to take action as the result of the first contingency violation, the action should be implemented unless the action will jeopardize nuclear safety, personnel safety, or equipment protection.

Actual Overload/Voltage Violation

The transmission operators receive telemetered data from a large number of facilities and are monitoring actual thermal overloads (excessive flow) and actual voltages. Violations are alarmed and require immediate action from the operators to prevent equipment damage.

Implication: Actual overloads need to be mitigated quickly (minutes). Requests to the nuclear plant should be accommodated unless nuclear safety, personnel safety, or equipment protection would be jeopardized. Such requests may include changing voltage regulator modes to either increase or decrease VAR output.

Voltage Stability/Collapse

Stability or collapse conditions are serious situations for the transmission system because they can result in significant loss of load in an instant. Stability problems occur in two scenarios: Transient instability—Instability caused by a sudden outage of equipment. Normally, these situations are analyzed ahead of time but may arise when equipment*** is removed from service for maintenance in certain combinations or patterns. Dynamic instability—***Instability caused by the interaction of various system elements, characterized by oscillating flows or voltages.******

Voltage collapse can occur when there are insufficient reactive resources (capacitors, generator VARs, etc.) in an area leading to local blackout or a



cascading outage, which is an outage that spreads to large areas of the system (e.g. the Northeast Blackout of August 14, 2003).

Implication: All of these situations are serious situations that require quick action by the transmission operators. Transmission operators will attempt to mitigate these conditions as quickly as possible. The transmission operators may ask for additional VAR output from the nuclear plant in these scenarios.

These requests need to be implemented immediately to avoid system collapse and blackout.

Emergency Procedures

Emergency procedures are a set of steps that are implemented by transmission system operators to avoid loss of load associated with a lack of capacity (capacity emergency). The procedures are a sequence of escalating measures, generally starting with alerts and warnings, progressing to voluntary curtailments, voltage reductions, and ultimately load shedding. Issuance of NERC EEAs (Energy Emergency Alerts) can also be a part of emergency procedures, indicating an impending capacity emergency.

Another type of emergency procedure is a Minimum Generation Emergency. In this scenario, demand is forecast to be lower than the level of economically dispatchable generation. Demand and generation must match in real time, so PJM will issue a Minimum Generation event, and call for reducible generation to reduce output. There may be times when the call for reducible generation will fall upon the nuclear plants.

Emergency procedures can also be implemented for other situations. Responses to security threats, solar magnetic disturbances (SMDs), or local reliability issues are examples of other problems that can cause PJM to invoke emergency procedures. PJM Manual M-13, Emergency Procedures should be consulted for complete descriptions of emergency procedure scenarios and guidance as to the associated PJM response.

Implication: Invoking emergency procedures means that a capacity emergency or other reliability problem is anticipated or imminent. The last stages of the emergency procedures can result in load shedding. These situations are very serious situations and **require the full support of all of the parties.**

Communication of the Event

Dissemination

The receiver of the initial message concerning a special situation needs to quickly disseminate the message among their shift team, particularly to the shift supervision.



3-part communication is necessary to verify that the received message is correct and any requested action is accurately heard and recorded. Any questions regarding the message or requested action should be immediately raised with the requester. Reference to this protocol may be necessary. Accurate logging is important to assure that actions that were requested for later investigation. (Inevitably, these special situations are of such a magnitude that post-event investigations are the norm in both the nuclear and transmission businesses.)

PJM operators may be required to report some of these events to the Department of Energy, NERC, or other entities. Similarly, nuclear plant operators may be required to report to the NRC or other regulatory bodies. All organizations should be mindful of these reporting responsibilities and be supportive to ensure that all reporting obligations are carried out within the mandated times.

Transmission operators, including PJM and the PJM transmission owners are required to abide by a Code of Conduct as required by FERC Order 889. Normally, the Code of Conduct prohibits the disclosure of transmission information by PJM or the LCCs to market entities outside of the OASIS system.

There will be situations where the Code of Conduct should be bypassed, because the potential nuclear safety implications take precedence. Examples of applicable situations are: (1) actual or imminent transmission system degradation or failure that could impact the nuclear plant and its off-site power sources; (2) ongoing or forecasted system conditions that may **result in emergency procedures, outages, or blackout; (3) transmission stability issues that could impact the nuclear plant and its off-site power sources. If PJM or the LCCs choose to disclose this information to the market entities**, PJM will be required to follow-up that information with a posting on the PJM OASIS.

Elevation

Shift personnel should not carry the full burden of managing these events. It is important to elevate the event to management. Management may decide to further communicate the event within the respective organization.

PJM will normally implement conference calls with the System Operators Subcommittee to coordinate information and response to special situations. PJM may also implement additional communications with neighboring systems as necessary to assure coordinated action.

Monitoring

Vigilance is necessary to ensure that any continuing surveillance or action is being properly implemented. Periodic reviews of the situation are required, both within the shift personnel and management. Shift turnovers are particularly important as a means to make sure that accurate information is both available and being acted upon in these events.

Close Out

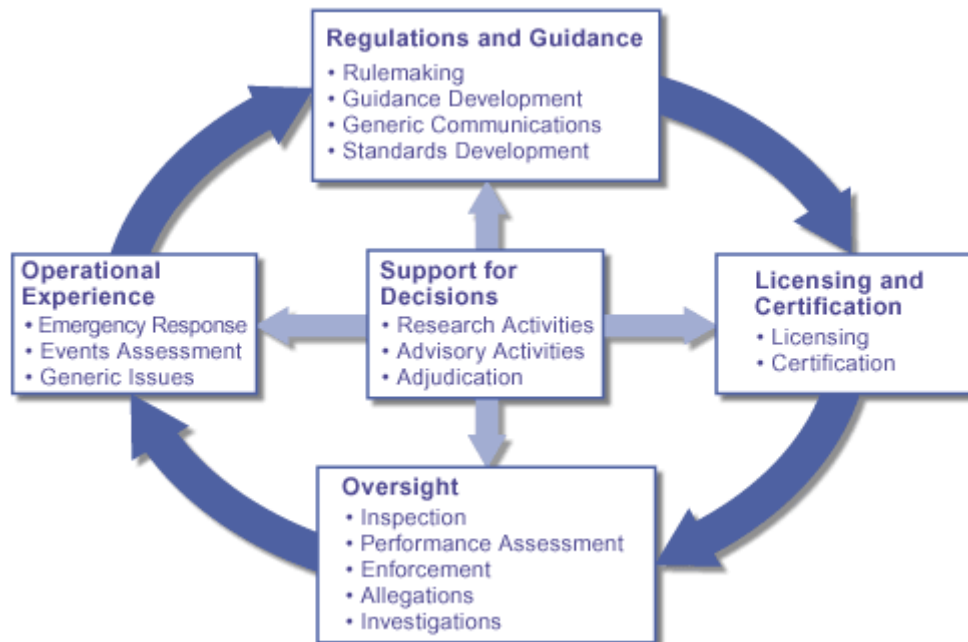
Once the situation has been resolved, communications need to go to close out the event and to clearly indicate to the operating entities to resume normal operations.

Appendix 1 – Regulatory Background

US Nuclear Regulatory Commission (NRC)

The U.S. Nuclear Regulatory Commission (NRC) was formed in 1975 to regulate the various commercial and institutional uses of nuclear energy, including nuclear power plants. The agency succeeded the Atomic Energy Commission, which previously had responsibility for both developing and regulating nuclear activities.

Under its responsibility to protect public health and safety, the NRC has three principal regulatory functions: (1) establish standards and regulations; (2) issue licenses for nuclear facilities and users of nuclear materials; and (3) inspect facilities and users of nuclear materials to ensure compliance with the requirements. These regulatory functions relate to both nuclear power plants and to other uses of nuclear materials -- like nuclear medicine programs at hospitals, academic activities at educational institutions, research work, and such industrial applications as gauges and testing equipment.



This diagram gives an overview of NRC's regulatory process which has five main components (1) developing regulations and guidance for our applicants and licensees, (2) licensing or certifying applicants to use nuclear materials or operate



nuclear facilities, (3) overseeing licensee operations and facilities to ensure that licensees comply with safety requirements, (4) evaluating operational experience at licensed facilities or involving licensed activities, and (5) conducting research, holding hearings to address the concerns of parties affected by agency decisions, and obtaining independent reviews to support our regulatory decisions.⁶

Nuclear Plant Licensing Summary

The licenses for nuclear power plants are issued for a 40-year period. Licenses for nuclear power plants can be amended and updated as the result of operating experiences at that plant or at other plants. When necessary, the NRC can impose new regulations or require changes in operating procedures or equipment to improve the safety of nuclear power plant operations.

In addition to licensing the facility, the NRC also licenses the individuals who operate the controls of the reactor. Licenses fall into two categories -- reactor operator and senior reactor operator. The second category is necessary for supervisory positions. Before operator licenses are issued, individuals must complete an extensive training program conducted by the utility and pass license examinations administered by NRC examiners. Once licensed, the operators continue to receive training and are periodically tested to show they remain qualified to operate the plant.

Key Licensing Documents

The application for a nuclear plant license contains many parts which form the basis for the enforcement program that follows once the application is approved and the plant goes into service. Key documents include:

Updated Final safety analysis report (UFSAR).

Each application for a license to operate a facility shall include a final safety analysis report. The final safety analysis report shall include information that describes the facility, presents the design bases and the limits on its operation, and presents a safety analysis of the structures, systems, and components and of the facility as a whole.⁷

The Final Safety Analysis report contains information on the plants Transient Stability Studies that are required to show, for transmission configurations with various bus and line faults, the system remains stable and satisfactory recovery voltages are maintained, resulting in uninterrupted supply to the offsite power system. The acceptance criteria are based on the reliability requirements of the applicable NERC regional reliability council along with any plant specific stability requirements listed in their FSAR or design basis documents.

⁶ NRC Website

⁷ 10CFR 50.34



In order for the nuclear power plants to be able to support their design basis, the transmission system minimum allowable voltages have been determined and provided to PJM. PJM uses these plant specific voltage requirements to ensure under all contingency cases and as part of the PJM planning process, these voltage limits are not violated. The plant specific voltage requirements are usually contained in design basis calculations or plant Technical Specifications. The FSAR provides the design basis criteria in which the plant voltage limits need to support.

Technical Specifications

Each license authorizing operation of a production or utilization facility of a type described in §50.21 or §50.22 will include technical specifications. The technical specifications will be derived from the analyses and evaluation included in the safety analysis report, and amendments thereto, submitted pursuant to §50.34. The Commission may include such additional technical specifications as the Commission finds appropriate. Technical specifications will include items in the following categories:

- *Safety limits, limiting safety system settings, and limiting control settings.*
- Limiting conditions for operation (LCO) (i) Limiting conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specifications until the condition can be met.
- Surveillance requirements Surveillance requirements are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met.
- Design features
- Administrative controls
- Decommissioning
- Initial notification
- (8) Written Reports⁸

Enforcement

Violations are identified through inspections and investigations. All violations are subject to civil enforcement action and may also be subject to criminal prosecution. Unlike the burden of proof standard for criminal actions (beyond a reasonable

⁸ 10CFR 50.36 (33 FR 18612, Dec. 17, 1968, as amended at 48 FR 33860, July 26, 1983; 51 FR 40308, Nov. 6, 1986; 53 FR 19249, May 27, 1988; 60 FR 36959, July 19, 1995; 61 FR 39299, July 29, 1996)

doubt), the NRC uses the Administrative Procedures Act standard in enforcement proceedings (preponderance of evidence, i.e., information that is of greater weight or credibility or is more likely correct than not). After an apparent violation is identified, it is assessed in accordance with the Commission's Enforcement Policy.⁹

1. The Commission may obtain an injunction or other court order to prevent a violation of the provisions of -- (1) The Atomic Energy Act of 1954, as amended; (2) Title II of the Energy Reorganization Act of 1974, as amended; or (3) A regulation or order issued pursuant to those Acts.
2. The Commission may obtain a court order for the payment of a civil penalty imposed under Section 234 of the Atomic Energy Act: (1) For violations of -- (i) Sections 53, 57, 62, 63, 81, 82, 101, 103, 104, 107, or 109 of the Atomic Energy Act of 1954, as amended; (ii) Section 206 of the Energy Reorganization Act; (iii) Any rule, regulation, or order issued pursuant to the sections specified in paragraph (b)(1)(i) of this section; (iv) Any term, condition, or limitation of any license issued under the sections specified in paragraph (b)(1)(i) of this section. (2) For any violation for which a license may be revoked under section 186 of the Atomic Energy Act of 1954, as amended.¹⁰

Federal Energy Regulatory Commission (FERC)

The Commission is a five-member independent regulatory agency, which succeeded to the regulatory responsibilities of the Federal Power Commission in 1977. The Commission's responsibilities include the licensing of non-federal hydroelectric facilities, the certification of natural gas pipelines, regulating the rates of natural gas pipelines and pipelines transporting crude oil and oil products, and regulating the rates and other aspects of electric utility activities.

Since 1935, the Commission has regulated certain electric utility activities under the Federal Power Act (FPA). Under FPA Sections 205 and 206, the Commission oversees the rates, terms and conditions of sales for resale of electric energy and transmission service in interstate commerce by public utilities. The Commission must ensure that those rates, terms and conditions are just and reasonable, and not unduly discriminatory or preferential. Under FPA Section 203, the Commission reviews mergers and other asset transfers involving public utilities. The utilities regulated under FPA sections 203, 205 and 206 are primarily investor-owned utilities; government-owned utilities (such as the Tennessee Valley Authority [TVA], the federal power marketing agencies, and municipal utilities) and most cooperatively-owned utilities are not subject to the Commission's regulation, with certain exceptions.¹¹

⁹ NRC Website, Enforcement Program Overview

¹⁰ 10CFR50.110 Violations (57 FR 55075, Nov. 24, 1992)

¹¹ FERC Website



Open Access Order (Order No. 888)

FERC issued Order 888 in April 1996, requiring investor-owned utilities to file tariffs for open-access transmission. The Order also encouraged utilities to form and join independent system operators (ISOs) to operate transmission grids and be independent of all commercial interests.

Today, these systems are used to transport power over longer distances, often across several utility systems. Both the number and complexity of these wholesale power transactions have grown dramatically in recent years, stimulated by the creation of more than 700 FERC-approved power marketers.¹²

Code of Conduct and OASIS (Order No. 889)

FERC issued Order 889 in April 1996, requiring each transmission service provider to provide an Open Access Same-time Information System (OASIS), where transmission customers could view availability and product information to enable them to make informed purchase decisions. In addition, the Order required transmission service providers and others who possess transmission information to establish a Code of Conduct which would ensure that transmission information was not made available to affiliated marketing organizations of vertically integrated utilities and other power marketers in a preferential manner. Such information was only to be made available via OASIS or other suitable electronic means.

RTO Order (Order No. 2000)

FERC issued Order 2000 in December 1999, setting forth requirements for the formation of Regional Transmission Organizations (RTO) which FERC indicated were the key to advancing competitive wholesale markets and eliminating anti-competitive behaviors by vertically integrated utilities. The RTO characteristics and functions are as follows:

Minimum Characteristics:

1. Independence
2. Scope and Regional Configuration
3. Operational Authority
4. Short-term Reliability
5. Minimum Functions:
6. Tariff Administration and Design
7. Congestion Management
8. Parallel Path Flow

¹² Hirst, Eric. Electric Reliability—Potential Problems and Possible Solutions. May 2000 (EEI Website), page 6



9. Ancillary Services
10. OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC)
11. Market Monitoring
12. Planning and Expansion
13. Interregional Coordination

PJM was granted RTO status by FERC in July 2001.

North American Electric Reliability Council (NERC)

NERC's mission is to ensure that the bulk electric system in North America is reliable, adequate and secure. Since its formation in 1968, NERC has operated successfully as a voluntary organization, relying on reciprocity, peer pressure and the mutual self-interest of all those involved. Through this voluntary approach, NERC has helped to make the North American bulk electric system the most reliable system in the world.

To fulfill its mission, NERC:

- Sets standards for the reliable operation and planning of the bulk electric system.
- Monitors, assesses and enforces compliance with standards for bulk electric system reliability.
- Provides education and training resources to promote bulk electric system reliability.
- Assesses, analyzes and reports on bulk electric system adequacy and performance.
- Coordinates with Regional Reliability Councils and other organizations.
- Coordinates the provision of applications (tools), data and services necessary to support the reliable operation and planning of the bulk electric system.
- Certifies reliability service organizations and personnel.
- Coordinates critical infrastructure protection of the bulk electric system.
- Enables the reliable operation of the interconnected bulk electric system by facilitating information exchange and coordination among reliability service organizations.
- Administers procedures for appeals and conflict resolution for reliability standards development, certification, compliance and other matters related to bulk electric system reliability.



Operating Policies

NERC reliability standards define the reliability requirements for planning and operating the North American bulk electric system. NERC's ANSI-accredited standards development process is defined in the Reliability Standards Process Manual and is guided by reliability and market interface principles. The Reliability Functional Model defines the functions that need to be performed to ensure the bulk electric system operates reliably, and is the foundation upon which the reliability standards are based.

Compliance Philosophy

Compliance with NERC's standards has typically been achieved through the voluntary actions of individual market participants. However, the continued growth of competition and the structural changes taking place in the electric industry have made it necessary for NERC to transform its voluntary system of reliability management to one that is mandatory. To achieve this, NERC has established a compliance enforcement program to monitor and enforce compliance with select operating policies and planning standards.

Regional Reliability Councils

Regional Reliability Councils (RRCs) are the organizations that implement and enforce NERC policy in the various regions of the North American system. In addition, the RRCs can issue regional guidance and requirements to support reliability in their regions. The PJM members are contained within two RRCs: Mid-Atlantic Area Council (MAAC) and ECAR (East Central Area Reliability council).

The RRCs have a compliance organization to conduct audits and assess penalties if necessary and permitted. All PJM members must be a member of one of the RRCs and hence subject to the compliance protocols of the respective RRC.

State Regulatory Commissions

State regulatory commissions exert broad powers over jurisdictional utilities and are involved with most activities of utilities as it relates to providing reliable and cost effective service to distribution customers. Transmission is not normally state jurisdictional; it is regulated by FERC. Similarly, nuclear power generation is not normally state jurisdictional; it is regulated by the NRC. However, to varying degrees, PJM members are vertically integrated and hence, subject to state regulatory oversight in many areas, including transmission and nuclear power generation.

The following is an explanation of the Pennsylvania state regulatory process, which is typical of state regulatory regimes:



Regulation

In order to provide the most economical, efficient and practical service to a community, the state grants a utility the sole right to provide its service within a specified geographical area. Experience and past history have determined that the construction of facilities by more than one utility company in the same location would be extremely costly and disruptive to community life and property. In exchange for the geographic monopoly, the utility accepts regulation by state government to assure that rates are fair and service safe and adequate for customers who cannot choose a different company.

Commission Role

The PUC is responsible for ensuring safe, adequate service for consumers at fair and reasonable rates. The Commission is required to make decisions that allow utilities to meet all prudent expenses including the cost of borrowing money for expansion to provide service. The PUC does not exist solely for the benefit of any one group, but must balance the concerns of all the parties. The Office of Trial Staff, which has experts in economics, engineering, law and financial accounting, represents the public at large by reviewing the company records and rate requests and presenting its view on what is in the public interest.

Utility Role

Regulated utilities must meet all reasonable requests for service by customers within their designated territories. To provide adequate service, it is recognized that the company must obtain a return on its investment sufficient to attract investors. If a company must expand its capacity to provide increased or improve service, it must borrow money, persuade investors to make money available, or seek a rate increase from the PUC.

Ratepayer Role

Ratepayers must pay for the service they use, which includes a share of the cost of utility company expenses, such as salaries, equipment, maintenance and taxes. While the ratemaking process is complex, consumers have the right to be informed about the process; to receive an explanation of their utility bills; to have their complaints resolved in a prompt and fair manner; and to receive continuous utility service if payment responsibilities are met.¹³

¹³ "An Overview of the Ratemaking Process", PA PUC Annual Report, 2001-2002, Page 6.



PJM Agreements

PJM and member roles and responsibilities are defined in the main agreements that PJM members must execute as a condition of membership—Operating Agreement, Transmission Owners Agreement, and the Transmission Tariff. Following are excerpts from the agreements which outline major roles for each party:

Operating Agreement

PJM Roles and Responsibilities

The Office of the Interconnection, under the direction of the President as supervised and overseen by the PJM Board, shall carry out the following duties and responsibilities, in accordance with the provisions of this Agreement (list shortened to include only applicable operations duties):

- a. Prepare, maintain, update and disseminate the PJM Manuals;
- b. Comply with NERC, and Applicable Regional Reliability Council operation and planning standards, principles and guidelines;
- c. Maintain an appropriately trained workforce, and such equipment and facilities, including computer hardware and software and backup power supplies, as necessary or appropriate to implement or administer this Agreement;
- d. Direct the operation and coordinate the maintenance of the facilities of the PJM RTO and PJM West Region used for both load and reactive supply, so as to maintain reliability of service and obtain the benefits of pooling and interchange consistent with this Agreement, the Reliability Assurance Agreement, and the Reliability Assurance Agreement-West;
- e. Direct the operation and coordinate the maintenance of the bulk power supply facilities of the PJM RTO and PJM West Region with such facilities and systems of others not party to this Agreement in accordance with agreements between the LLC and such other systems to secure reliability and continuity of service and other advantages of pooling on a regional basis;
- f. Perform operating studies of the bulk power supply facilities of the PJM RTO and PJM West Region and make such recommendations and initiate such actions as may be necessary to maintain reliable operation of the PJM RTO and PJM West Region;
- g. Perform those functions and undertake those responsibilities transferred to it under the East Transmission Owners Agreement and West Transmission Owners Agreement, including (A) direct the operation of the transmission facilities of the parties to the East



Transmission Owners Agreement (B) direct the operation of the transmission facilities of the Parties to the West Transmission Owners Agreement, (C) administer the PJM Tariff, and (D) administer the Regional Transmission Expansion Planning Protocol set forth as Schedule 6 to this Agreement;

- h. Perform those functions and undertake those responsibilities transferred to it under the Reliability Assurance Agreement, as specified in Schedule 8 of this Agreement, and those functions and responsibilities transferred to it under the Reliability Assurance Agreement-West, as specified in Schedule 8A of this Agreement;
- i. Monitor the operation of the PJM RTO and PJM West Region, ensure that appropriate Emergency plans are in place and appropriate Emergency drills are conducted, declare the existence of an Emergency, and direct the operations of the Members as necessary to manage, alleviate or end an Emergency;
- j. Incorporate the grid reliability requirements applicable to nuclear generating units in the PJM RTO and PJM West Region planning and operating principles and practices.¹⁴

Member Roles and Responsibilities

Each Member shall, to the extent applicable;

- a. Maintain adequate records and, subject to the provisions of this Agreement for the protection of the confidentiality of proprietary or commercially sensitive information, provide data required for (i) coordination of operations, (ii) accounting for all interchange transactions, (iii) preparation of required reports, (iv) coordination of planning, including those data required for capacity accounting under the Reliability Assurance Agreement and Reliability Assurance Agreement-West; (v) preparation of maintenance schedules, (vi) analysis of system disturbances, and (vii) such other purposes, including those set forth in Schedule 2, as will contribute to the reliable and economic operation of the PJM RTO and PJM West Region;
- b. Provide such recording, telemetering, communication and control facilities as are required for the coordination of its operations with the Office of the Interconnection and those of the other Members and to enable the Office of the Interconnection to operate the PJM RTO and PJM West Region and otherwise implement and administer this Agreement, including equipment required in normal and Emergency operations and for the recording and analysis of system disturbances;

¹⁴ PJM Operating Agreement, Sheet 42



- c. Provide adequate and properly trained personnel to (i) permit participation in the coordinated operation of the PJM RTO and PJM West Region, (ii) meet its obligation on a timely basis for supply of records and data, (iii) serve on committees and participate in their investigations, and (iv) share in the representation of the Interconnection in inter-regional and national reliability activities;
- d. Comply with the requirements of the PJM Manuals and all directives of the Office of the Interconnection to take any action for the purpose of managing, alleviating or ending an Emergency, and authorize the Office of the Interconnection to direct the transfer or interruption of the delivery of energy on their behalf to meet an Emergency and to implement agreements with other Control Areas interconnected with the PJM RTO or PJM West Region for the mutual provision of service to meet an Emergency, and be subject to the emergency procedure charges specified in Schedule 9 of this Agreement for any failure to follow the Emergency instructions of the Office of the Interconnection.

Facilities Planning and Operation

Consistent with and subject to the requirements of this Agreement, the PJM Tariff, the governing agreements of the Applicable Regional Reliability Councils, the Reliability Assurance Agreement, the Reliability Assurance Agreement-West, the West Transmission Owners Agreement, the East Transmission Owners Agreement, and the PJM Manuals, each Member shall cooperate with the other Members in the coordinated planning and operation of the facilities of its

System within the PJM RTO or PJM West Region so as to obtain the greatest practicable cooperate with the other Members in the coordinated planning and operation of the facilities of its System within the PJM RTO or PJM West Region so as to obtain the greatest practicable degree of reliability, compatible economy and other advantages from such coordinated planning and operation.

In furtherance of such cooperation each Member shall, as applicable:

- a. Consult with the other Members and the Office of the Interconnection;
- b. coordinate the installation of its electric generation and Transmission Facilities with those of such other Members so as to maintain reliable service in the PJM RTO and PJM West Region;
- c. Coordinate with the other Members, the Office of the Interconnection and with others in the planning and operation of the regional facilities to secure a high level of reliability and continuity of service and other advantages;
- d. Cooperate with the other Members and the Office of the Interconnection in the implementation of all policies and procedures



established pursuant to this Agreement for dealing with Emergencies, including but not limited to policies and procedures for maintaining or arranging for a portion of a Member's Capacity Resources, at least equal to the applicable levels established from time to time by the Office of the Interconnection, to have the ability to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system;

- e. Cooperate with the members of Applicable Regional Reliability Councils to augment the reliability of the bulk power supply facilities of the region and comply with Applicable Regional Reliability Councils and NERC operating and planning standards, principles and guidelines and the PJM Manuals;
- f. Cooperate with the Office of the Interconnection's coordination of the operating and maintenance schedules of the Member's generating and Transmission Facilities with the facilities of other Members to maintain reliable service to its own customers and those of the other Members and to obtain economic efficiencies consistent therewith;
- g. Cooperate with the other Members and the Office of the Interconnection in the analysis, formulation and implementation of plans to prevent or eliminate conditions that impair the reliability of the PJM RTO and PJM West Region; and
- h. Adopt and apply standards adopted pursuant to this Agreement and conforming to NERC, and Applicable Regional Reliability Council standards, principles and guidelines and the PJM Manuals, for system design, equipment ratings, operating practices and maintenance practices.¹⁵

Transmission Owners Agreement

The Transmission Owners Agreement (TOA) defines the relationship between and among PJM and the transmission owning members of PJM. The TOA binds the transmission owners to operating their facilities in accordance with applicable rules and policies and at the direction of PJM. The following is an excerpt from the TOA, regarding operations:

Operation of Transmission Facilities

Each Party shall operate its Transmission Facilities in accordance with (i) the terms of this Agreement, (ii) applicable NERC and MAAC reliability principles, guidelines, and standards, (iii) the PJM Manuals, and (iv) the direction of the Office of the Interconnection. Consistent with the provisions of this Section 4.4, the Parties shall conform to the Office of the Interconnection's operating instructions as they apply to

¹⁵ Ditto, Sheet 43



such Party's Transmission Facilities. Nothing in this Agreement shall be construed to require a change in the physical control of any Transmission Facilities using a Party's existing facilities and equipment.¹⁶

¹⁶ PJM Transmission Owners Agreement, Page 9.



Attachment C: PJM System Operator Training Requirements

Overview

In order to promote the reliability of the PJM system, system operators participating in real time operations on the PJM system at the direction of the PJM System Operator must know and understand their assigned roles and responsibilities in the operation of the PJM system and be able to perform their assigned duties using the PJM eTools according to PJM procedures as detailed in the PJM Manuals.

PJM sponsors a variety of training courses for system operators to ensure all system operators have the opportunity to learn the principles and specifics required to operate on the PJM system. In addition, PJM offers an annual continuing education program known as the PJM System Operator Seminar which serves as the forum to keep all system operators up to date on new and revised operating procedures and tools, refreshers on critical topics including emergency and system restoration procedures, awareness of relevant operating events and industry events and trends.

All system operators participating in real time operations on the PJM system must also complete Emergency Preparedness training activities including drills, table-top exercises, simulations, and instruction on identified training topics referenced in Appendix 1. On a rotating basis all system operators should participate in PJM Emergency Procedures and System Restoration Drills which are conducted twice yearly.

Training Requirements for MOC Generation System Operators

Initial PJM MOC System Operator Training

Minimum required:

1. Effective January 1, 2006, new MOC and PJM system operators must successfully complete within one year PJM sponsored training which includes the subjects and times per subject as detailed below. The one year is referenced to the date on which the operator takes shift as an MOC or PJM system operator. This requirement can be met by successful completion of the Generation MOC course, or the Generation 101, 201, 301 and Operations 101 course series, or the Generation track of the PJM Initial Training Program (ITP).
2. Effective January 1, 2006, all new MOC and PJM system operators must successfully complete the Generation track of the ITP or equivalent within two years of participating in real time PJM operations. See Appendix 2. Note: Experienced MOC system operators employed by companies integrating into PJM only need to complete the MOC course, or the Generation 101, 201, 301, and Operations 101 courses series. An experienced MOC system operator is defined as an individual who has two or more years of experience



participating in real time operations at the time of the company's integration into PJM.

Strongly recommended is successful completion of the ITP Standard or Generation Track within the first year of participating in PJM system operations, see Appendix 2. Also Recommended is completion of the System Dynamics Extended Training Class following completion of the ITP, see Appendix 3.

Company Sponsored Initial Training

The attached Check List for New System Operators at LCCs and MOCs is intended to serve as a help reference to draw from for their initial in-house training of new system operators before they take shift. See Appendix 4.

PJM Initial Training Subjects and Times for MOC System Operators:

The following subjects represent the minimum PJM sponsored training which an MOC system operator and PJM system operators must complete within one year of participating in real time operations on the PJM system. Generation topics require at least 30.75 hours (4 days) to complete presentations and course related activities including a course overview, quizzes and evaluation of training.

Orient to PJM Organization, Markets, and Services (0.5 hours)

- Orient to PJM organization and governance
- Orient to Markets and services

How PJM Operates and Dispatches (2.25 hours)

- Describe the role of PJM in generation/load control
- Describe using incremental cost in gen dispatch, and operating factors
- Describe Unit Dispatch Program functions and use
- Describe the dispatch process during load pick-up

LMP Overview (2.0 hours)

- Describe how Locational Marginal Price (LMP) is determined
- Describe the relationship of Dispatch Rate to LMP
- Use Power world simulations to illustrate LMP in unconstrained and constrained operations

Two-Settlement (2.0 hours)

- Discuss the purpose and features of the Two-Settlement Process
- Discuss Two-Settlement Business Rules and Examples
- Walk-thru data illustrating the Day-Ahead and Real-Time LMPs, Generation, Load and Congestion

Generation Outages and eDART (3.25 hours)

- Orient to key concepts of the PJM Outage Reporting
- Orient to the types of PJM defined outages
- Discuss Outage Examples
- Discuss and demonstrate Outage Reporting Using eDART
- Orient to the Reactive Outage Ticket Business Rules

PJM Day Ahead Scheduling Process (3.5 hours)

- Orient to PJM Operating Reserves
- Discuss Production Cost
- Describe the Two-Settlement Process



Discuss and demonstrate eMKT Two-Settlement User Interface

Ancillary Services (4.5 hours)

Orient to Market Based Regulation
Describe the Spinning Reserve Market
Discuss Black Start Service
Discuss Reactive Services

Overview of Market Settlements (2.0 hours)

Review Terminology
Discuss Line Items of PJM Invoice
Discuss Ancillary Services items
Discuss Operating Reserves items

Overview of Market Monitoring (1.0 hours)

Explain the need for Market Monitoring and Plan
Walk-thru examples of Market Mitigation Measures
Identify corrective actions Market Monitoring may use

Orient to PJM System Operator Certification Program (0.5 hour)

Orient and explain the program, purpose, and who must conform.
Discuss exam preparation and application process

PJM Emergency Procedures (4.25 hours)

Discuss the need for emergency procedures
Orient to the triggers and actions performed for the following conditions:
- Capacity Shortages
- Light Load Operations
- Transmission and Voltage Emergencies
- Conservative Operations

PJM Communications Protocols and All Call (1.25 hours)

Review principles of effective communications
Review guidelines for two-way and one-way communications
List All Call protocols and categories of messages
Review required protocols for operator logging
Review the role of SCADA and the operator's role in monitoring and responding to inaccuracies

System Restoration (1.75 hours)

History of Blackouts
Types and causes of Blackouts
Initial Assessment / System Status activities
System Restoration Process: Bottom up, Top down and Combined
System Restoration for PJM Mid-Atlantic region
System Restoration for the PJM West region
Orient to PJM Emergency Procedures and Restoration Drills

Orient to PJM Website, eSuite and eDATA (1.0 hour)

Orient to the PJM website
Orient to the eSuite and purpose of the eTools
Illustrate how to use and customize e-Data



MOC System Operator Continuing Training

Effective January 1, 2006:

Beginning the first full calendar year after assuming shift responsibilities in real time PJM operations, all MOC system operators shall complete at least fifty four hours (~ 18/year) per rolling three year calendar period of Refresher, Operations and Markets Updates and Emergency Preparedness training by the following or its equivalent:

1. Attendance and successful completion of relevant activities of the annual PJM System Operator Seminar (or equivalent).
2. Completion of company and PJM sponsored Emergency Preparedness activities including drills, table-top exercises, simulations, and instruction on identified training topics referenced in Appendix 1. On a rotating basis, all system operators should participate in PJM Emergency Procedures and System Restoration Drills as practical.

Completion of required elements of PJM Initial Training will count toward satisfying the PJM MOC Continuing Training Requirement during the first two years of participating in real time PJM system operations. As part of the continuing training on Refresher, Updates and Emergency Preparedness training, the following training topics are mandatory and must be completed by all MOC system operators:

1. PJM System Operator Communications Protocols and Crew Resource Management
2. PJM Markets and Ancillary Services
3. PJM Emergency Procedures
4. PJM System Restoration

Determination of Equivalent Training

PJM recognizes that member companies have rigorous training programs that provide similar training identified in the PJM sponsored training courses. These member company training courses will be considered for equivalency if they are organized, documented, and meet the criteria of the NERC Continuing Education Program (CEP). Member company courses submitted as equivalency to meet PJM training requirements will be handled as follows:

- (a.) PJM Training will accept company training courses as equivalent if they are approved for NERC Continuing Education Hours (CEH) and identified as acceptable Emergency Preparedness activities.
- (b.) Company courses which are not approved for NERC CEH will be evaluated on a course by course basis. To be considered a course must have the following components:
 - learning objectives



- training plan
- training content
- training activity method
- training delivery team
- methods of evaluation both for participant's learning and the program
- methods for verification and documentation of participant training completed

PJM System Operator Seminar

The PJM System Operator Seminar is an annual continuing education program which is developed with input from the SOS, DTF, PJM operations and markets groups, and system operators.

The schedule for each year's Seminar program includes a set of standard reliability and markets topics, presentations on topics such as PJM and NERC system operator certification, and projections for future PJM market integration. The time devoted to a particular standard Seminar topic will vary according to the identified priorities of a particular year. Standard Seminar activities that come under Emergency Preparedness Training includes: at least eighteen hours on the following subjects: State of PJM and Updates on Markets, Updates on PJM Operating Procedures and Tools, Refresh and exercises on PJM Emergency and System Restoration Procedures, "Lessons Learned" from Operating Events, Communications and Crew Resource Management, and Refreshers on Technical Topics.

Emergency Preparedness Drill and Exercises

The goal of Emergency Preparedness drills and exercises is to reinforce the knowledge and skills of system operators and their proficiency to detect and effectively respond to emergency conditions and events and maintain or restore the electric power system to steady state reliability.

To be effective, drills must be organized and documented. The following are the required elements of an emergency preparedness drill or exercise upon which a PJM template and process will be developed:

- Purpose and objectives to be achieved are stated
- Plan of action or a scenario which includes stated triggers to initiate and terminate the drill or activity.
- Measures of required performance are identified
- A description of how the progress of the drill will be monitored
- A description of the evaluation process that will be used to assess the achievement of drill objectives, identify problems, and develop corrective actions.



- Assignment of specific roles, and objectives to be achieved by the system operators participating in an emergency preparedness drill or exercises including their role in the evaluation process
- Recording and documenting emergency preparedness activities and operator participation in each such activity and reporting same to PJM

PJM System Operator Certification

System operators must be PJM certified, if they (1) operate on the PJM RTO systems, (2) communicate directly with PJM, and (3) perform daily operations-related functions at the direction of the PJM System Operators during normal, emergency and/or system restoration states. PJM system operators must also be PJM certified.

Incumbent System Operators: System operators who currently operate on the PJM RTO systems will be allowed twenty four months to become PJM certified. The deadline for system operators who were operating on the PJM RTO systems on March 1, 2003 to become PJM certified is February 28, 2005.

New System Operators: New system operators and system operators with companies integrating into PJM will have a maximum of twenty four months to become PJM certified after they begin operating on the PJM RTO systems.

Certification Examinations

There are two PJM Certification Exams: one for Generation System Operators and the other for Transmission System Operators. Details are as follows:

System Operators who participate in the real time operations of the PJM system by dispatching generation resources and performing other generation-related real time duties of a Market Operation Center (MOC) or a PJM system operator are required to complete and pass the PJM Generation Examination. System Operators who participate in the real time operations of the PJM transmission systems and perform other transmission-related real time duties of a Local Control Center (LCC) or PJM system operator are required to complete and pass the PJM Transmission Examination.

Dual Certification

System operators operating on the PJM system who perform both generation and transmission tasks must be PJM certified in both generation and transmission. Since there is no overlap of the Content Outlines, a combination examination is not available. Any individual may apply for, pay the appropriate fees and complete both the PJM Generation and the Transmission Examinations.

Term of Certification

A PJM System Operator certificate is valid for five years. Recertification requires taking and passing the PJM certification examination.



Prerequisites

There are no training or work experience requirements that candidates must satisfy before they can apply to sit for a PJM certification exam.

Further Information on PJM System Operator Certification

For further information on PJM System Operator Certification go to:

<http://www.pjm.com/services/training/train-sys-op.html>

Training Requirements for LCC System Operators

Initial LCC System Operator Training

Minimum required:

1. Effective January 1, 2006, new LCC and PJM system operators must successfully complete PJM sponsored training within one year which includes the subjects and times per subject as detailed below. The one year is referenced to the date on which the operator takes shift as a LCC system operator. This requirement can be met by successful completion of the Transmission LCC course, or the Transmission 101 and Operations 101 course series, or the Standard track of the PJM Initial Training Program (ITP).
2. Effective January 1, 2006, all new LCC and PJM system operators must successfully complete the Standard track of the ITP or equivalent within two years of participating in real time PJM operations. See Appendix 2 for ITP subjects. Note: Experienced LCC system operators employed by companies integrating into PJM only need to complete the LCC course or the Transmission 101 and Operations 101 courses series. An experienced LCC system operator is defined as an individual who has two or more years of experience participating in real time operations at the time of the company's integration into PJM.

Strongly recommended is successful completion of the ITP Standard Track (all modules) within the first year of participating in PJM system operations, see Attachment 2. Also Strongly Recommended is completion of the System Dynamics Extended Training Class following completion of the ITP, see Appendix 3.

Company Sponsored Initial Training

The attached Check List for New System Operators at LCCs and MOCs is intended to serve as a help reference to draw from for their initial in-house training of new system operators before they take shift. See Appendix 4.

Control Room Visits: Strongly recommended is within the first year LCC operators should visit the PJM control room, and PJM system operators should visit one or more LCC control rooms.



PJM Initial Training Subjects and Times for Transmission System Operators

The following subjects represent the minimum PJM sponsored training which an LCC system operator and a PJM system operator must complete within one year of participating in real time operations on the PJM system. Transmission topics require at least 24.5 hours (3 days) to complete presentations including a one hour for course intro, quizzes and evaluation of training.

Introduction to the PJM Organization, Operations, Systems, (2.0 hours)

- Orient to PJM organization and governance
- Orient to the Markets and services
- Orient to PJM and LCC operator duties
- Review the physical features of the PJM system, operating characteristics, operating ratings and limits

Orient PJM Website, eSuite, and eDATA, (1.0 hour)

How PJM Operates and Dispatches, (2.0 hours)

- Describe the role of PJM in generation/load control
- Describe using incremental cost in gen dispatch, and operating factors
- Describe the Unit Dispatch Program functions and use in dispatch
- Describe the dispatch process during load pick-up for a typical day

Overview of Markets, (3.0 hours)

- Describe Location Marginal Price (LMP)
- Illustrate LMP by way of Power World simulation
- Describe the relationship of Dispatch Rate to LMP
- Discuss the purpose and business rules of the Two-Settlement Process
- Walk-thru data illustrating the Day-Ahead and Real-Time LMPs, Generation, Load and Congestion.

PJM Communications Protocols and All Call (1.25 hours)

- Review the principles of effective communications
- Review guidelines for two-way and one-way communications
- List the PJM All Call protocols, and categories of PJM All Call messages.
- Review required protocols for operator logging
- Review the purpose of SCADA and the operator's role in monitoring and responding to inaccuracies

Orient to PJM Operator Certification (0.5 hour)

- Orient to Program, purpose, scope and who must be certified
- Identify key document to review to prepare for an exam
- Orient to exam application process.

Transmission Operations Criteria (4.0 hours)

- PJM Physical System
- Operating Definitions
- "Basics" of Transmission System Operation
- Thermal Operating Criteria
- Voltage Operating Criteria
- Reactive Transfer Limits
- Real Time Constraint Identification

Transmission Outages and e-DART (3.5 hours)

- Planning for Scheduled Outages
- PJM Scheduling Procedure



- Scheduling Overview
- eDART and Transmission Outages
- Additional eDART Functionality for Transmission Owners
- eDART Training TERM

PJM Emergency Procedures (4.5 hours)

- Basics
- Capacity Shortages
- Light Load Operations
- Transmission and Voltage Emergencies
- Conservative Operations

System Restoration (1.75 hours)

- History and Effects of Blackouts
- Types and Causes of Blackouts
- Initial Assessment / System Status
- System Restoration Process: Bottom up, Top down and Combined
- System Restoration from PJM Mid-Atlantic Control Center, and from PJM West Control Center
- Orient to PJM Emergency Procedures and Restoration Drills

Annual LCC System Operator Continuing Training

Effective January 1, 2006

Beginning the first full calendar year after assuming shift responsibilities in real time PJM operations, all LCC and PJM system operators shall complete at least thirty two hours per year of Emergency Preparedness training by the following or its equivalent:

1. Attendance at the annual PJM System Operator Seminar (or equivalent) and successful completion of eighteen hours of Seminar activities related to the NERC Emergency Preparedness Training requirement.
2. Complete yearly at least fourteen hours of company and PJM sponsored Emergency Preparedness activities including drills, table-top exercises, simulations, and instruction on identified training topics referenced in Attachment 1. On a rotating basis, all system operators should participate in PJM Emergency Procedures and System Restoration Drills. During the first two years of participating in real time PJM system operations, completion of required elements of PJM Initial Training will count toward satisfying the PJM 32 hour Emergency Preparedness training requirement.

As part of the thirty two hours on Emergency Preparedness training, the following training topics are mandatory and must be completed by all LCC and PJM system operators:

1. PJM System Operator Communications Protocols



2. Crew Resource Management Concepts
3. PJM Transmission Operations Criteria
4. PJM Emergency Procedures
5. PJM System Restoration

Determination of Equivalent Training

PJM recognizes that member companies have rigorous training programs that provide similar training identified in the PJM sponsored training courses. These member company training courses will be considered for equivalency if they are organized, documented, and meet the criteria of the NERC Continuing Education Program (CEP). Member company courses submitted as equivalency to meet PJM training requirements will be handled as follows:

- (a.) PJM Training will accept company training courses as equivalent if they are approved
- (b.) for NERC Continuing Education Hours (CEH) and identified as acceptable Emergency
- (c.) Preparedness activities.
- (d.) b. Company courses which are not approved for NERC CEH will be evaluated on a course
- (e.) by course basis. To be considered a course must have the following components:
 - learning objectives
 - training plan
 - training content
 - training activity method
 - training delivery team
 - methods of evaluation both for participant's learning and the program
 - methods for verification and documentation of participant training completed

PJM training personnel will advise the respective member company and the PJM Interregional Coordination and Compliance Department of company courses that are acceptable for meeting PJM training requirements.

PJM System Operator Seminar

The PJM System Operator Seminar is an annual continuing education program which is developed with input from the SOS, DTTF, PJM operations and markets groups and system operators. The schedule for each year's Seminar program includes a set of standard reliability and markets topics, and presentations on topics such as PJM and NERC system operator certification, and projections for future PJM



market integration. The time devoted to a particular standard Seminar topic will vary according to the identified priorities of a particular year. Standard Seminar activities that come under Emergency Preparedness Training includes: at least eighteen hours on the following subjects: State of PJM and Updates on Markets, Updates on PJM Operating Procedures and Tools, Refresh and exercises on PJM Emergency and System Restoration Procedures, "Lessons Learned" from Operating Events, Communications and Crew Resource Management, and Refreshers on Technical Topics.

Emergency Preparedness Drill and Exercises

The goal of Emergency Preparedness drills and exercises is to reinforce the knowledge and skills of system operators and their proficiency to detect and effectively respond to emergency conditions and events and maintain or restore the electric power system to steady state reliability.

To be effective drills must be organized and documented. The following are the required elements of an emergency preparedness drill or exercise upon which a PJM template and process will be developed:

- Purpose and objectives to be achieved are stated
- Plan of action or a scenario to include triggers to initiate and terminate the drill or activity are stated.
- Measures of required performance are identified
- A description of how the progress of the drill will be monitored
- A description of the evaluation process that will be used to determine how well the drill objectives were achieved, and problems identified and corrected
- Assignment of specific roles, and objectives to be achieved by the system operators participating in an emergency preparedness drill or exercises including their role in the evaluation process
- Recording and documenting emergency preparedness activities and operator participation in each such activity and reporting same to PJM

PJM System Operator Certification

System operators who operate on the PJM RTO systems, are in direct communication with the PJM and perform daily operations-related functions at the direction of the PJM System Operator during normal, emergency and/or system restoration states must be PJM certified. PJM system operators must also be PJM certified.

Incumbent System Operators: System operators who currently operate on the PJM RTO systems will be allowed twenty four months to become PJM certified. The deadline for system operators who were operating on the PJM RTO systems on March 1, 2003 to become PJM certified is February 28, 2005.



New System Operators: New system operators and system operators with companies integrating into PJM will have a maximum of twenty four months to become PJM certified after they begin operating on the PJM RTO systems.

Certification Examinations

There are two PJM Certification Exams: one for Generation System Operators and the other for Transmission System Operators. Details are as follows:

System Operators who participate in the real time operations of the PJM system by dispatching generation resources and performing other generation-related real time duties of a Market Operation Center (MOC) or a PJM system operator are required to complete and pass the PJM Generation Examination. System Operators who participate in the real time operations of the PJM transmission systems and perform other transmission-related real time duties of a Local Control Center (LCC) or PJM system operator are required to complete and pass the PJM Transmission Examination.

Dual Certification

System operators operating on the PJM system who perform both generation and transmission tasks must be PJM certified in both generation and transmission. Since there is no overlap of the Content Outlines, a combination examination is not available. Any individual may apply for, pay the appropriate fees and complete both the PJM Generation and the Transmission Examinations.

Term of Certification

A PJM System Operator certificate is valid for five years. Recertification requires taking and passing the PJM certification examination.

Prerequisites

There are no training or work experience requirements that candidates must satisfy before they can apply to sit for a PJM certification exam.

Further Information on PJM System Operator Certification

For further information on PJM System Operator Certification go to:

<http://www.pjm.com/services/training/train-sys-op.html>

Appendix 1

Letter from Mark Fidrych, Chairman, NERC Operating Committee, March 2, 2004

Recommended Operator Training topics

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731
March 2, 2004



TO: OPERATING COMMITTEE

Recommended Operator Training Topics

The Operating Committee's Personnel Subcommittee has developed a list of training topics that address the requirements of Recommendation #6 in "Recommendation 6: All reliability coordinators, control areas, and transmission operators shall provide at least five days per year of training and drills in system emergencies, using realistic simulations⁵, for each staff person with responsibility for the real-time operation or reliability monitoring of the bulk electric system. This system emergency training is in addition to other training requirements. Five days of system emergency training and drills are to be completed prior to June 30, 2004, with credit given for documented training already completed since July 1, 2003. Training documents, including curriculum, training methods, and individual training records, are to be available for verification during reliability readiness audits."

I have had a number of queries asking what kinds of training would fulfill this objective. In general, the recommendation requires five days of training to prepare operators for credible emergencies, for example, multiple contingencies, control center failure, voltage collapse, etc. The five days should include realistic simulations and drills, but could also include training in the principles and procedures needed for effectively recognizing and responding to emergencies. The bottom line is we need operators who are prepared to recognize and respond to emergencies. To achieve this goal, we must provide our system operators with hands-on training that is effectively provided by system simulations and drills, along with general study of the principles of interconnected systems operations that relate to recognizing and responding to system emergencies. The Personnel Subcommittee has developed a list of topics (See **Attachment**) that we believe fits Requirement 6. The subcommittee originally developed this list as a guide of suggested training courses for potential Continuing Education Providers. Therefore, this list is not all-inclusive. You may easily develop a course that is not listed below but still meets the recommendation.

If you have additional questions as to what type of training would be appropriate to meet the requirements of this recommendation, please contact me at 970-461-7240, or NERC's Training Manager John Theotonio at 609-452-8060.

Sincerely, Mark Fidrych
Chairman, NERC Operating Committee
cc: Regional Managers
304600, 3/17/05 13

Attachment

Recommended Operating Training Topics

A. Recognition and Response to System Emergencies

1. Emergency drills and responses
2. Communication tools, protocols, coordination
3. Operating from backup control centers
4. System operations during unstudied situations
5. System Protection



6. Geomagnetic disturbances weather impacts on system operations
7. System Monitoring – voltage, equipment loading
8. Real-time contingency analysis
9. Offline system analysis tools
10. Monitoring backup plans
11. Sabotage, physical, and cyber threats and responses
- B. Operating Policies Related to Emergency Operations**
 1. NERC policies, appendices, standards that deal with emergency operations (e.g. Policy 5, “Emergency Operations”)
 2. Regional reliability operating policies
 3. Sub-regional policies and procedures
 4. ISO/RTO policies and procedures
- C. Power System Restoration Philosophy and Practices**
 1. Blackstart
 2. Interconnection of islands – building islands
 3. Load shedding – automatic (underfrequency and undervoltage) and manual
 4. Load restoration philosophies
- D. Interconnected Power System Operations**
 1. Operations coordination
 2. Special protections systems
 3. Special operating guides
 4. Voltage and reactive control, including responding to eminent voltage collapse
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 5. Understanding the concepts of Interconnection Reliability Operating Limits versus System Operating Limits
 6. DC tie operations and procedures during system emergencies
 7. Thermal and dynamic limits
 8. Unscheduled flow mitigation – congestion management
 9. Local and regional line loading procedures
 10. Radial load and generation operations and procedures
 11. Tie line operations
 12. E-tagging and Interchange Scheduling
 13. Generating unit operating characteristics and limits, especially regarding reactive capabilities and the relationship between real and reactive output
- E. Technologies and Tools**
 1. Forecasting tools
 2. Power system study tools
 3. IDC
- F. Market Operations as They Relate to Emergency Operations**
 1. Market rules
 2. LMP
 3. Transmission rights
 4. OASIS



- 5. Tariffs
- 6. Fuel management
- 7. Real-time, hour-ahead and day-ahead tools

Appendix 2

PJM Initial Training Program for System Operators (ITP)

A modular based training course comprised of an AC Theory self-study module followed by four weeks of classroom instruction. There are two tracks for the ITP, a Standard track which includes all modules, and a Generation track which is limited to the core topics needed by generation dispatchers.

G. T = Transmission and Interchange – Standard Track: 18 days of classroom instruction all modules

G = Generation Track: 11 days of classroom instruction, mods FS, FC, GU, GT, GC, EM, GTE, SR, OS

Module FS: Introduction to the PJM System 4 hours

Module FC: Fundamentals of Communications and Control Room Tools 4 hours

Module GU: Generating Units 12 hours

Module GC: Generation Control 8 hours

Module GT: Generation Dispatch Tools and Concepts 8 hours

Module EM PJM Markets and Services 16 hours

Module TSO: Transmission System Operation 32 hours

Module TF: Transmission Substation Facilities 12 hours

Module FR: Relay Applications 16 hours

Module GTE: Responding to Generation and Transmission Emergencies 8 hours

Module SR: System Restoration Primer 16 hours

Module OS: Operating the PJM System 4 hours

Program Evaluation 4 hours

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Appendix 3

POWER SYSTEM DYNAMICS

Extended Training Class

SYLLABUS

Orientation/Introduction

Lesson 1 Review of Power System Flows and Limits

Lesson 2 Overview of System Dynamics

Lesson 3 Frequency Problems & Control

Lesson 4 Effect of Power Plants

Lesson 5 Islanded System Operation

Lesson 6 Voltage Deviations: High Voltage

Lesson 7 Voltage Deviations: Low Voltage



Lesson 8 Voltage Collapse

Lesson 9 PJM Methodology for Controlling Voltage

Lesson 10 Power System Oscillations I: Characteristics of Oscillations

Lesson 11 Power System Oscillations II: Causes and Effects of Oscillations

Lesson 11 Case Studies

Lesson 12 PJM Stability Criteria

Lesson 13 Other Dynamic Phenomenon

Lesson 14 Global Examples and Case Histories

Conclusion, and Evaluation

Evaluation and Wrap-up

Time: Five full days

Appendix 4

Check List for New System Operators at LCCs and MOCs

The following is a generic checklist of system operator tasks that are performed by LCC and MOC system operators separately or jointly.

This checklist is a set of suggested competencies to guide the training of new generation and transmission system operators.

The checklist is meant to serve companies as a help reference to draw from for their initial inhouse training of new operators before they take shift.

ALARMING

- Monitor and Identify Alarms
- Analyze and Respond to Alarms Operation or Misoperation
- Communicate Operation of Alarms

COMMUNICATIONS

- Know Communications Protocols: One Way, Two Way, Three Way (send – repeat –acknowledge)
- Use Communications Tools - (Knowledge of Operation: Satellite phones, Radio, PJM All-Call, Ring Down)
- Effective Communications: how to give orders, communicate in emergency conditions, effective listening skills
- Dispute/disagreement resolution
- Reporting – see REPORTING



- At Shift Turnover Communicate “Must Items”

DOCUMENTATION

- Logging and report writing: how to write brief concise reports of a system event or action
- Computer Skills
- Permits and Blocking, Switching Orders
- Shift Turnover - see also Communications

ELECTRICAL THEORY AND PRINCIPLES

- DC and AC elements and circuits, impedance principles
- Power principles in AC systems
- AC real and reactive power flow on transmission systems
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EMERGENCY PROCEDURES

Know and Perform Assigned Tasks when Emergency Procedures are Implemented

Internal to PJM

- Load 100% Spinning
- Capacity Shortages
- Loading of Max Emergency Generation
- Implement a Voltage Reduction
- Implement a VCLC
- Implement a Manual Load Dump
- Notify Management of Emergency procedures
- Conservative Operations
- Severe Weather (Hot and Cold)
- Solar Magnetic Disturbances
- Crisis Response (Terrorism)
- Fuel Disruption
- Transmission Loading Relief (Thermal and Reactive)
- Light Load Periods
- Implement Low and High Voltage Procedures



External to PJM

- NERC Transmission Loading Relief (TLR)
- See Reporting Disturbances to NERC and U.S. Dept. of Energy

EMS and COMPUTER SKILLS

- PC Usage: User Skills to Operate Hardware and Applications
- EMS: Skills to Use Applications
- Utilize EMS to Monitor System
- Utilize EMS to Perform Studies
- Utilize EMS to Perform Desk Duties
- Monitor PJM Links and Initiate Repairs if Problems Arise
- Monitor Digital Telecommunications and Initiate Repairs if Problems Arise
- Monitor and Use SCADA and Initiate Repairs if Problems Arise
- Recognize Problems with Stale or Erroneous Data
- Report Problems to Initiate a Fix of Stale / Erroneous Data
- Manually Replace Bad Data and Notify PJM of Telefail
- Updating Dispatch Lambda
- NETWORK ANALYSIS AND ADVANCED APPLICATIONS
- EMS Applications: Analyze and Properly Respond to Results:
 - Transmission Security
 - Voltage Security
 - Generation Control Security
 - State Estimator
 - Limits: Voltage, Thermal, Reactive
 - Contingencies
 - Power Flow Studies
 - Ratings
 - Distribution Factors
 - Security Constrained Dispatch
 - Security Analysis



GENERATION

- Applicable Types of Units: Fossil Steam, CT, Combined Cycle, Hydro RR&PS, Nuclear, Other(Cogen, IPPs)
- Operating Characteristic of Unit, Rate of Response, Constraints
- Unit Parameters and Limits (MW, MVAR)
- Environmental Limits and Requirements
- Unit and Plant Protection
- Generator Characteristic Curve
- Automatic Voltage Regulator (AVR)
- Governor Control (purpose, droop setting and controls)
- Unit Modes of Control and Control Systems

GENERATION CONTROL

- Generation Implications on System Control and Role in Reliability
- ACE
- AR
- Testing Units for Regulation
- Hourly Interchange (See Transmission)
- Effects of Outages
- Monitoring
- Effects of Energy Market on System
- Dynamic Stability Curves (if applicable)

GENERATION ECONOMICS

- Understanding of
- Cost following
- Cost Dispatch versus Price Dispatch
- Out of Merit (Off Cost) Operations
- Unit Compensation
- Cost Capping
- Selection of Units for Constraint Control
- Aborted Starts and Accounting
- Ancillary Services Markets and Services



- Regulation Market
- Spinning Market
- Blackstart Services
- Market Data Base (see PJM eTools - eMKT)
- Data Entry
- Updating Unit Data Monitoring
- Categories of Generating Units
- Dispatchable by PJM, Self Scheduled, Available
- Minimum Run Time
- Minimum Down Time

LOAD FORECASTING

- Retrieve Weather Forecast
- Build Projected Load Curve for Current Day
- Update Curve as Period Approaches
- Reporting Load Forecast to PJM Scheduler

MARKETING and TRANSACTIONS

- Code of Conduct (888, 889), Market Sensitive Information
- Energy Market
- LMP
- Two Settlement
- OASIS (Tool)
- EES (external – if applicable)
- Rules

OUTAGE REPORTING – see REPORTING PJM AUTHORITY

- Responsibility of LCC and MOU System Operators to Respond to PJM Directives
- Acknowledge and LOG PJM Request
- Implement PJM Directives
- Getting Clarification of a PJM Directive



PJM SYSTEM OPERATOR CERTIFICATION

- Generation
- Transmission

PJM TOOLS

Perform Assigned Tasks Using the following Applications:

- E-Data
- eDART
- EES
- OASIS
- E-MKT
- eSchedules

REPORTING

As Needed Collect Data, Enter onto Form and Submit the Following:

- Instantaneous Reserve Checks (IRC)
- Supplementary Status Reports (SSR)
- Reactive Reserve Check (RRC)
- Reduced Unit Reactive Capability
- Capacitor Availability
- Generation Outage Tickets - eDART
- Transmission Outage Tickets - eDART
- Outages of Automatic Voltage Regulators – see also GENERATION
- Governor Outage Reporting – eDART – see also GENERATION
- Status Reports
- Restoration Forms
- Min Gen Reducibles Report
- Reporting Disturbances to NERC and U.S. Department of Energy

RESERVE REQUIREMENTS

- Know Reserve Requirements and Conditions to Satisfy Reserve Obligations
- Collect Data and Calculate Reserves
- Monitoring Reserves on Ongoing Basis



- Re-allocating Reserve Categories as Necessary
- Types of Reserve (Spinning, Quick Start, Secondary, Beyond 30 minutes)

SYSTEM RESTORATION

- Procedures and Concepts
- PJM System Restoration Process
- Ascertain System Status
- Determine Restoration Process
- Disseminate Information
- Implement Restoration Procedures
- Member Interconnection
- PJM Assumes Control
- Company Restoration Process
- Communications and Telecommunications
- Voice and Logging Protocols, Role of Communications Coordinators
- Tools: Telephone Systems, Satellite Phones, Radio, UPS and Battery Emergency Power Supplies
- SCADA and Local Metering, Alarms, and EMS Limitations
- Reports and Forms – see REPORTING
- Voltage Control
- Reactive Regulation
- Transmission
- Minimum Source Requirements
- EHV Energization Guidelines
- Emergency Procedures
- Load Pickup
- 5% Rule of Thumb for Load Pickup in Island
- Cold Load Pickup
- System Control
- Flat Frequency
- Flat Tie
- Tie Lines Bias



- Control of an Island
- Load / Generation Balance
- Calculating ACE for an Island
- Frequency Control
- Reserves
- Spinning
- Dynamic Reserve
- Governor Reserve – Load Pickup Factors
- Underfrequency Load Dump Relays (Steps and Locations)
- Load Pick-up, Cold Load Pick-up and Load Dump
- Generation Dispatch
- Generating Stations
- Stabilizing Units Surviving Event
- Plant Shutdown
- Plant Startup Requirements
- Cranking Power and Black Start
- Frequency Control
- Nuclear Plant Requirements
- Substations
- Station Light and Power: AC and DC
- Circuit Breakers
- SF₆ heaters, Air Compressors
- Transformers
- Relays
- Shunt Capacitor and Reactors
- Series Capacitors
- Static VAR Compensators (SVC) and FACTS
- Synchronization
- Principles and Procedures
- Pre-Tie Information Exchange and Adjustments



- Post-Tie Stabilization

TRANSMISSION

- Substation Facilities: (purpose, range of operation, alarms, what to do if device malfunctions)
- Switching & Blocking, and Permits: Principles and Procedures
- Reportable Lines and Facilities and Reporting Responsibilities to PJM
- Relay Protection
- Principles, and DC Power Requirements
- Substation Schemes
- Line Schemes
- Special Purpose Relay Schemes
- Policies and Guides for Operators

TRANSMISSION OPERATIONS

- Monitor Transmission Lines and Substations
- Implement Control Strategies To Maintain Facilities Within Ratings and Initiate Response to Problems
- Communicate Substation Facility Operations to PJM and Field Personnel
- Transmission Outages – see REPORTING
- Thermal Operating Criteria and Procedures
- Voltage Operating Criteria and Procedures
- Reactive Operating Criteria and Procedures
- Hourly Interchange
- Surge Impedance Loading