



Metering Task Force Conclusions and Manual 01 Revision

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August 25, 2016

Background:

- Meter data accuracy, reliability, and availability are foundational to almost all electric utility operations – dispatch, protection, markets... .
- Manual 01, Section 5, is the main body of PJM metering requirements.
- In 2015, PJM proposed a Manual 01 revision; however additional discussion and study was needed between PJM and member companies and the revision was withdrawn for further analysis.
- MTF started in November of 2015, follow PJM CBIR process to provide organization and structure to gather and assess information, and make consensus-based data-driven decisions.

Task Force:

- 12 topics of analysis & education to ensure that all participants' concerns and issues were considered and addressed.
- Two surveys conducted in the TF to collect information regarding members' current metering infrastructure and common practice.
- In June the group reached consensus with a Tier-1 solution which consists 11 design components.
- 54 responses, all in support of the package were received.

MTF Deliverables, Manual 01, Control Center and Data Exchange Requirements, Section 5: Metering System Requirements is significantly updated and restructured.

- New areas of guidance:
 - Accuracy definition and determination
 - What components are included in the “metering system”
 - Precision, scan rates, and latency
- Metering system requirements are comprehensive
 - New category, General Telemetry, with unique requirements

- Tie Lines
 - Defined in specific categories/subcategories beyond “external/internal”, each with a specific accuracy, scan rate, and telemetry source requirement.
 - Definitions
 - External
 - Dynamic Transfers (Pseudo-Tie, Dynamic Schedule)
 - Internal (Control Zone, Transmission Zone, EDC, East EHV)
 - Special Cases (Transformer Ties)
 - New OA & OATT Tie Line definitions coordinated with M01 changes for better alignment between PJM governing documents and Manuals (refers to Appendix for details)

- Metering maintenance, accuracy verification, and investigation
 - General requirements for metering/telemetry accuracy monitoring and verification. Follow-up process for metering/telemetry investigations when operational issues occur.
- Applicability by date
 - Requirements that can be reasonably interpreted as new are applicable from publish date of R33
- Other M01 R33 changes:
 - References to NERC BAL-005 updated
 - Updated restricted times for planned system changes/outages
 - Minor updates to Section 4, Interpersonal Communication Capability

Manual 01 R33:

1st read in OC – August 9, 2016

1st read in MRC – August 25, 2016

2nd read in OC – September 13, 2016

2nd read in MRC – September 29, 2016

1st & 2nd read in MC - September 29, 2016

OA/OATT:

FERC filing in October, 2016

* Final report and all supporting documents are posted on : [PJM Metering Task Force Website](#)

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Appendix

Metering Task Force (MTF) Update

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Operating Committee

August 9, 2016

- Meter data accuracy, reliability, and availability are foundational to almost all electric utility operations – dispatch, protection, markets... .
- Manual 01, Section 5, is the main body of PJM metering requirements.
- In 2015, PJM SMEs tried to address questions, concerns and comments with a Manual revision; however significant issues remained and the revision was withdrawal.
- MTF started in November of 2015, follow PJM CBIR process to provide organization and structure to gather and assess information, and make consensus-based data-driven decisions.

- 12 topics of cooperated investigation & education were to ensure that all participants' concerns and issues were considered and addressed;
- Two surveys were conducted in the TF to collect information regarding members' current metering infrastructure and common practice;
- In June, the group reached consensus with a Tier-1 solution;
- 54 responses, all in support of the package were received.

- The recommended package consisted of eleven components:
 1. Metering boundary: from first measurement to first digitization of the measurement;
 2. Accuracy definition: Within +/- x% of true value;
 3. Accuracy Calculation: system accuracy may be decided by one of three methodologies: calculate using nameplate accuracy, as-build calculation, or testing;
 4. Measurement Category:
 - Billing Meters (Accumulator data)
 - System Control and Monitoring (Instantaneous data): Tie-lines, area regulation, generation dispatch, generation reserve, system restoration, and general telemetry.

5. Measurement Accuracy: the meter accuracy and periodicity of data transmission is specified for each class: 2% or 5%;

6. Tie-Line definitions: Circuit connecting two balancing authority areas, control areas, or fully metered electric system regions.

- External Tie Lines
- Dynamic Transfers
- Internal Tie Lines: Control Zone Tie Lines; Transmission Zone Tie Lines; Fully Metered EDC Tie Lines; and East EHV Tie Lines.
- Special Cases and transformer Ties

7. Tie-Line telemetry/measurement requirements: For each class of Tie-line data, the meter accuracy, redundancy and periodicity of data transmission are specified.

8. ANSI/IEEE reference: Broad References to specific standards;

9. Maintenance/ Calibration intervals:

- Billing Meters: Status Quo - 2 years maintenance/ calibration cycle
- System Control and Monitoring Metering:
 - Equipment owners shall develop, maintain and execute their own testing, calibration and maintenance policies and procedures; a periodic test plan or exception-based maintenance plan.
 - PJM can request an investigation at specific locations based on actual or projected market and system conditions into the existing overall or component accuracy (and telemetry periodicity)

10. Grandfather Clause: the installation date of the equipment

- a. Earlier than 1997 or the company integration date to PJM - exempted;
- b. Between a and the publication of the new revision of M01, meet all the requirements except few categories: general telemetry (section 5.2.6), kV requirements (not including external Tie line); control zone tie scan rate for any tie lines less than 100kV;
- c. All new equipment installed after publication shall be fully compliant with these metering standard;
- d. Replacing, upgrading or modifying existing grandfathered equipment may cause the equipment installation date to be reset and the equipment no longer grandfathered.

11. PJM historical database:

- Billing Meter :documenting errors of greater than 1% for auditing purposes.
- System Control and Monitoring Metering: document the conclusions of significant investigations for history and future guidance

- Task Force deliverables;
 - Manual 1 (Control Center and Data Exchange Requirements) Section 5: Complete rewrite
 - OA & OATT: adding in Tie-line definition
 - OA:
 1. Definition S-T
Tie Line: "Tie Line" shall have the same meaning provided in the Open Access Transmission Tariff.
 2. Capitalized "T" & "L" for tie-in in section 2.6A (a), 3.2.1 (d), 3.6.3, 3.6.4, 5.1.3 (e), 5.4.3 (e)
 - OATT:
 1. Definitions – T – U – V
Tie Line:
"Tie Line" shall mean a circuit connecting two balancing authority areas, Control Areas or fully metered electric system regions. Tie Lines may be classified as external or internal as set forth in the PJM Manuals.
 2. Capitalized "T" & "L" for tie-in in section 2.6A (a), 3.2.1 (d), 3.6.3, 3.6.4, 5.1.3 (e), 5.4.3 (e)

New revision will provide clear standard, requirement, and practice related to metering

- Reduce the risk of non-compliance
- Provide clear guidance for the new equipment specification and design
- Improve EMS State Estimation solution
- Ensure operation reliability and market fairness

1st read in OC – August 9, 2016

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Manual 01, Revision 33

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Section 2.5.6. Reference to NERC BAL-005-0 (out of date) changed to BAL-005.

Section 3.7. Two bullets regarding Tie Lines edited to address concerns with BAL-005 and align with Section 5 edit.

Section 3.8. Additional time restrictions on outages including PJM model build days, holidays and other major critical events.

Section 4.1. Communications expanded to specifically include external entities and non-member internal entities in addition to PJM Members. Delete of text box describing language and communications (redundant with Section 4.5).

Section 4.3.3. Removed. Section 4.5 replaces the content.

Section 4.5.5, 4.5.6. Now refer to 4.5.2 for operators required to complete training.

Section 4.5.2, 4.5.6. Applicable persons expanded to include member company dispatchers (was only operators before).

Section 5. Metering Requirements update and restructuring. Clearer breakdown by types of meters. Better separation between operations and billing meters. Clarifications on topics such as accuracy, maintenance, and applicability. Added official detailed definition of Tie Line subtypes. Revised "grandfather clause" for rewritten requirements that can be reasonably construed as new.

5.1 Purpose & Criteria

The purpose of these PJM metering requirements is to ensure all electricity metering systems are installed, operated and maintained to provide PJM with system control and monitoring data and an accurate record of the energy quantities supplied to and received by all market parties. Each PJM Member is responsible for properly maintaining its metering systems. **This section provides the minimum requirements for metering data - such as, MW, MVAR, kV, AMP, HZ, and MWH values - when communicating information to PJM.**

5.1 Purpose & Criteria

...

This section is not comprehensive in regards to where metering and telemetry is required. Some subsections, such as 5.2.1.1 External Tie Lines, does dictate minimum required metering placement and location. However other governing documents – for example Interconnection Agreements, standards, or other PJM Manuals - may also require metering at specific locations or for specific criteria. In those cases the metering system performance requirements are still here in Manual 01, Section 5.

...

5.1.1 Applicability by Date

The grandfather clause has been revised. We'll come back to this on a later slide.

5.1.2 Applicability by Equipment

In Section 5: Metering Requirements the word “metering” means any system of components that measures something relevant to electric power – MW, MVAR, kV, Amps, MWHR, HZ – and is the source of that measurement for PJM. This may include devices that are technically considered an actual electrical meter, which satisfy ANSI standards for meters, or furthermore a revenue grade meter which tend to meet the highest accuracy thresholds.

5.1.2 Applicability by Equipment

...

This may also include devices that are not typically considered an electrical meter, such as protective relays or transducers, which by design and function will often have lower accuracy than an actual meter; this is sometimes referred to as “operational metering”. The requirements described in Section 5 either apply or do not apply to any given system of devices or components based on the provided criteria and definitions of the data the device or system provides, regardless of what the actual devices or components are.

5.1.2 Applicability by Equipment

...

It is intended that all measurements being provided to PJM fall into at least one category in Section 5 for clear and explicit requirements. In the case a metering system falls into more than one category, the more restrictive requirements apply. If a measurement provided to PJM does not clearly fall into any category, the equipment owner should contact PJM for clarification.

5.1.2 Applicability by Equipment

...

In general these Section 5 requirements applies to generation and transmission, not distribution. However voltage level is not a full proof indicator of applicability for transmission and distribution owners. All equipment at a Designated Facility or PJM OAT Tariff Facility or a facility otherwise participating in any PJM market (ex. generation facility in capacity market) must comply with these requirements. A list of transmission facilities, including a flag for PJM OAT Tariff Facility status, is available at...

5.1.3 Accuracy Determination

...

Metering system performance is a complex metric with many factors, making consistent calculation and determination difficult across all systems. For this reason **the accuracy requirement applicable to a metering system may be met by satisfying at least one of any three methodologies:**

1. Calculate Using Nameplate Accuracy...
2. Calculate Using Designed and As-built Loads...
3. Test...

5.1.4 Preference for Best Available Accuracy

The efficiency, reliability and fairness of PJM operations and markets for all members and customers are impacted by the accuracy of the metering covered in Section 5. Wherever possible, **the most accurate metering available should be telemetered to PJM**. This is especially true for Tie Lines or other points of large energy transaction, where the real-time telemetry data is often used to verify revenue grade billing data.

5.1.5 Metering and Telemetry ...

The scan frequency requirements presented here are to ensure the rate at which PJM can poll the serving entity for the data. However, if the upstream system has any link scans at a slower rate than the final PJM polling rate, then there is no benefit of PJM scanning at a faster rate. For example if a meter only measures a real time value at once every 10 seconds, there is no benefit for PJM to scan that value at once every 4 seconds. Therefore **it is preferred that the telemetry system between the meter and PJM not present any measurement or scan rate limitations that would reduce the actual rate of update to PJM.**

5.1.5 Metering and Telemetry

...

The telemetry system between the metering system and PJM should not at any point reduce data precision to a degree that would effectively reduce the accuracy of the telemetered values received by PJM.

...

[I]t is preferred and beneficial that data latency, the time between measurement and PJM receipt of data, be kept as low as reasonably possible.

...

5.1.5 Metering and Telemetry ...

The scan frequency requirements presented here are to ensure the rate at which PJM can poll the serving entity for the data. However, if the upstream system has any link scans at a slower rate than the final PJM polling rate, then there is no benefit of PJM scanning at a faster rate. For example if a meter only measures a real time value at once every 10 seconds, there is no benefit for PJM to scan that value at once every 4 seconds. Therefore **it is preferred that the telemetry system between the meter and PJM not present any measurement or scan rate limitations that would reduce the actual rate of update to PJM.**

5.1.6 Types of Metering Systems

There are two major types of metering systems defined in this Section, characterized by use and data type.

1. System Control and Monitoring (Instantaneous data)...

Requirements for System Control and Monitoring are specified in Section 5.2.

2. Billing (Accumulator data)...

Requirements for Billing Metering and meter data are specified in Section 5.3.

5.2 System Control and Monitoring (Instantaneous data)

5.2.1 Tie Lines

5.2.1.1 External Tie Lines

5.2.1.2 Dynamic Transfers

Pseudo-Ties and Dynamic Schedules

5.2.1.3 Internal Tie Lines

Control Zone Tie Lines

Transmission Zone Tie Lines

Fully Metered EDC Tie Lines

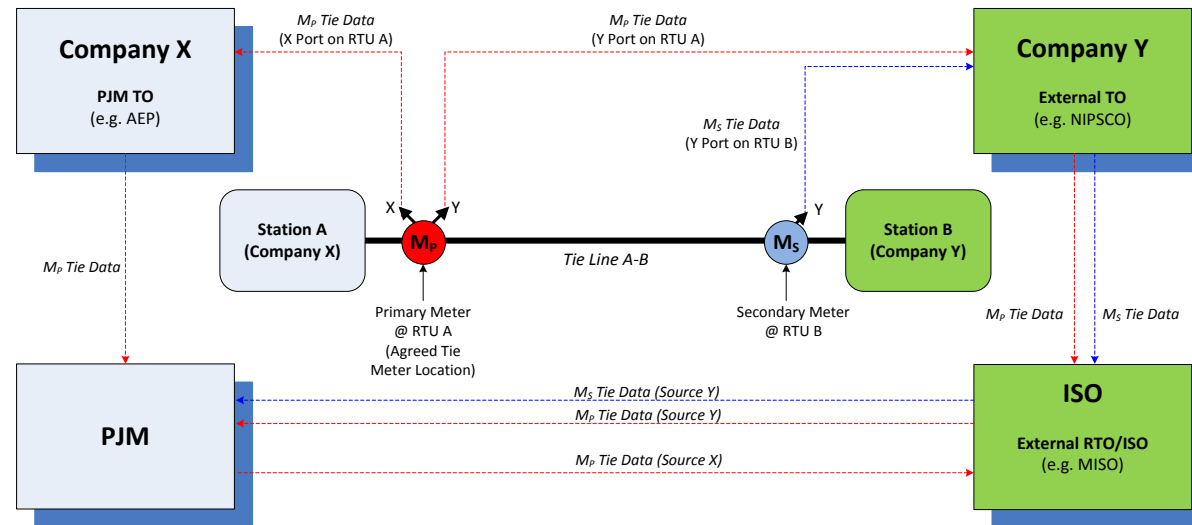
East EHV Tie Lines

5.2.1.1 External Tie Lines

<i>Meter</i>	<i>Accuracy</i>	<i>Scan Freq.</i>	<i>Telemetry</i>
Primary	+/- 2%	4 sec. or less between scans	Primary meter telemeters to both TOs at each end of the line. Both TOs telemeter to their respective BA. BAs telemeter to each other.
Backup /Secondary	+/- 5%	4 sec. or less between scans	Secondary meter telemeters to the secondary end TO. TO telemeters to the secondary end BA. The BA telemeters to the primary end BA.

5.2.1.1 External Tie Lines

External Tie Line Metering Primary Metering at PJM End of Tie Line



5.2.1.1 External Tie Lines

External Tie Lines have additional NERC BAL requirements. The NERC accuracy guideline results in an overall metering accuracy better than 2% and satisfies the NERC BAL standard.

<i>Primary Transducer</i>	<i>Accuracy Guideline</i>
Frequency Transducers	0.001 Hz
Potential Transformers	0.30% of Full Scale
Current Transformers	0.50% of Full Scale
MW/MVAR/Voltage Transducers	0.25% of Full Scale
Remote Terminal Units (A/D)	0.25% of Full Scale

5.2.1.1 External Tie Lines

...

Note: **NERC Frequency Transducer requirements apply only to the PJM Time Error devices in the PJM Control Center.** The requirements do not apply to telemetered frequency measurements provided to PJM. However, PJM still receives and references frequency telemetry from members. The highest accuracy frequency available is requested.

5.2.1.2 Dynamic Transfers

A primary meter is required.

<i>Meter</i>	<i>Accuracy</i>	<i>Scan Freq.</i>	<i>Telemetry</i>
Primary	+/- 2%	4 sec. or less between scans (2 sec. preferred)	One primary meter is at each Point of Interconnection. Each primary meter telemeters to the owning MOC/TO. The MOC/TO telemeters to PJM and the native BA.

5.2.1.3 Internal Tie Lines Control Zone Tie Line Requirement

A primary meter and backup or secondary meter is required.

<i>Meter</i>	<i>Accuracy</i>	<i>Scan Freq.</i>	<i>Telemetry</i>
Primary	+/- 2%	4 sec. or less between scans (2 sec. preferred)	A meter at each side of the line. One of the meters is primary. The primary meter telemeters to the primary end TO. Primary end TO telemeters to PJM.
Backup /Secondary	+/- 5%	4 sec. or less between scans (2 sec. preferred)	A meter at each side of the line. One of the meters is backup. The backup meter telemeters to the secondary end TO. Secondary end TO telemeters to PJM.

5.2.1.3 Internal Tie Lines

Transmission Zone, Fully Metered EDC, East EHV Tie Line Requirements

A primary meter is required.

<i>Meter</i>	<i>Accuracy</i>	<i>Scan Freq.</i>	<i>Telemetry</i>
Primary	+/- 2%	10 sec. or less between scans	The primary meter telemeters to the owning TO and other end TO. Both TOs telemeter to PJM.

5.2.2 Area Regulation: $\pm 2\%$, 4 second

5.2.3 Generation Dispatch Data: $\pm 2\%$, 10 second

5.2.4 Generation Reserve: $\pm 2\%$, 10 second

5.2.5 System Restoration: $\pm 2\%$, 4 second

5.2.6 General Telemetry

PJM receives real-time telemetry for many measurements that do not fall into any of the preceding categories in Section 5.2. These measurements may be related to transmission facility telemetry requirements for observability in PJM Manual 03 and 03A, or related to the Interconnection Agreement for a particular facility, or any other operation or market reason to telemeter data to PJM.

The requirements for General Telemetry metering systems are:

- Metering Accuracy: **Within $\pm 5\%$ of true value.**
- Scan Frequency: 10 sec. or less between scans

5.2.7 System Control and Monitoring Metering Maintenance

Equipment owners shall develop, maintain and execute their own testing, calibration and maintenance policies and procedures for all metering systems, including systems with devices other than actual meters that provide PJM with system control and monitoring real-time data. All metering systems that provide PJM with system control and monitoring real-time data should be covered by either a periodic test plan, where all equipment is tested at some set time interval, or exception-based maintenance, where equipment testing is triggered based on some continuous or periodic method to identify probable out of spec performance.

...

5.2.8 Accuracy Investigations

PJM can request an investigation at specific locations based on actual or projected market and system conditions into the existing overall or component accuracy (and telemetry periodicity) at the identified sites.

...

5.2.8 Accuracy Investigations

PJM and the equipment owner will produce a mitigation plan that considers the specific situation, local topology, and costs to equipment owner. ...

PJM investigation requests will be based on and justified on demonstrable conditions such as: ...

Mitigation plans may include deliverables and actions such as: lowering the State Estimator weighting, checking modeling, bringing additional available telemetry in the area online to PJM, testing or calibrating existing equipment, or equipment upgrade/replacement. PJM will review the proposed mitigation plan to ensure it address all concerns, such as reliability, market efficiency and market fairness, in a reasonable time frame. A reasonable deadline for the execution of the plan shall be agreed upon by all impacted parties.

5.2.9 Special Considerations and Requirements for Voltage and Amps

The PJM EMS primarily makes use of MW, MVAR and Voltage, as the real time data consumed to allow critical applications to run successfully. The metering accuracy requirements in Section 5.2, as previously mentioned, includes the entire metering system from measurement to first digitization.

Voltage in particular is an important class of measurements to PJM operations. Because voltage is one component of determining MW and MVAR, and because overall system error cannot be better than the worst error of any individual component, voltage data should meet (or beat) the same minimum requirements of metering accuracy as dictated by the rest of Section 5.2. Note that External Tie Lines, as detailed in Section 5.2.1.1, have additional NERC BAL derived requirements that apply directly to Potential Transformers, Transducers or RTUs that may be part of that associated metering system.

5.3 Billing (Accumulator data)

5.3.1 Collection Intervals and Units

5.3.2 Primary Meter Accuracy

5.3.3 Backup Meter Requirements

5.3.4 Maintenance

5.3.5 Accuracy Checks and Retention

5.3.6 Location of PJM Mid-Atlantic 500 kV Meter Points

5.3.6.1 Measuring Point Compensation

5.3.7 Geographically Non-Contiguous Load

5.3.8 Generation Billing Metering

5.3.9 Small Energy Billing Metering

The applicability of Section 5 Metering Requirements depends on the installation date of the equipment in question and the start date of each requirement.

The effective date is December 1st, 1997, or alternately the date of integration into PJM for companies that integrated after December 1st 1997, for the following requirements:

[All requirements explicitly already in M01 (since 1997)]

The effective date is (pub. Date of M01 R33) for the following requirements:

- 5.2.6 General Telemetry, MW and MVAR req.
- Section 5, All kV requirements except for 5.2 External Tie Lines
- 5.2 System Control and Monitoring, Control Zone Ties, the Scan frequency requirement for any Tie Lines less than 100 kV



M01 R33 Section 3, Data Exchange Requirements

Questions?

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3.8 Planning, Coordination and Notification of System Changes and Events

...

Outages should not be planned for execution during specific resource critical times including PJM quarterly model build days, due to heightened operational and technical complexity and risk. The PJM Model Build Schedule is posted on the PJM DMS webpage: ...

PJM will make all efforts to announce and post any schedule changes at least one week in advance. In addition to model builds, other unique and infrequent major events for PJM, such as major EMS upgrades or major company integrations, are also not allowed for outages. Major PJM events will be specially communicated to all impacted members.

3.8 Planning, Coordination and Notification of System Changes and Events

...

PJM holidays are not preferred for outages, due to constrained resource availability. The PJM Business Holiday Calendar is posted on the Billing, Settlements & Credit webpage: ...

Exceptions may be requested through outages@pjm.com.



M01 R33 Section 3, Data Exchange Requirements

Questions?

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Section 4.1. Dispatch Voice & Facsimile Communications

The dispatch voice system provides high-priority Interpersonal Communication (voice communications) capability between PJM and other parties, **including PJM Members, other internal entities and external entities**, as described below. ...

Communications via facsimile machines is another redundant means of exchanging information between PJM operations, accounting, and **other parties, including PJM Members, other internal entities and external entities**, as described below.

4.3.3 Three Part Communications *[deleted]*

Three part communications now defined along with other communication requirements under –

4.5 PJM Communication Protocol

4.5 PJM Communication Protocol

...

4.5.2 Applicability

These protocols apply to all PJM operators and operators/**dispatchers** at member companies that issue and/or receive Operating Instructions.

...

4.5.6 Communication Protocol Assessment

Evaluate each of an entity's operators/**dispatchers** adherence to the Communication Protocols outlined in section 4.5.4 at least once every 12 months.



M01 R33 Section 3, Data Exchange Requirements

Questions?

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