Operating Procedures

ISO New England Operating Procedure No. 18

Metering and Telemetering Criteria

Effective Date: June 1, 2010
Revision No. 10

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REFERENCES:

ISO New England Market Rules and Procedures
ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Resources and Asset Related Demands (OP-14)
ISO New England Operating Procedure No. 17 - Load Power Factor Correction (OP-17)

LOCAL CONTROL CENTER INSTRUCTIONS:

CONVEX:	**None**
MAINE:	**None**
NEW HAMPSHIRE:	**None**
NSTAR	**None**
REMVEC:	**None**
VELCO:	**None**

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I. PURPOSE

These criteria establish standards for metering (measurement) and telemetering (data transmission) for the purposes of ISO New England (ISO) dispatching, Market Settlement, Market Participant (MP) peak load determination, factors that impact voting shares and load power factor (lpf) measurement. The power system parameters which the MPs are to meter and/or telemeter are identified. Standards are established to ensure that the equipment which MPs install will provide an appropriate level of accuracy and/or appropriate recordings for audit purposes. Maintenance procedures and schedules to be followed by the MPs are prescribed so that the level of accuracy which is attainable will be realized.

II. IMPLEMENTATION

MPs shall have in-service or be progressing towards having in-service all the metering, recording or telemetering equipment necessary to meet the requirements of ISO New England Operating Procedure No. 18 – Metering and Telemetering Criteria (OP-18) or for future use in this document, this OP. The equipment standards for new and replacement installations, and the testing, calibration, and maintenance standards, contained in this OP, are applicable upon adoption of this OP and all revisions.

III. METERING, RECORDING AND TELEMETERING ON INTERCONNECTIONS WITH SYSTEMS OUTSIDE NEW ENGLAND

A. OVERALL REQUIREMENTS

1. The metering, recording and telemetering requirements for each transmission line interconnecting Pool Transmission Facilities (PTF) to systems outside of New England are:
   - Metering and Telemetering of instantaneous megawatts (MW) from all terminals of the line
   - Metering and Telemetering of instantaneous megavars (MVAR) from all terminals of the line (except for direct current (dc) interconnections)
   - Metering, Recording and Telemetering of Megawatt hours (MWh) per hour (i.e. energy per hour)

2. Instantaneous megawatts (MW) and megawatt hours (MWh) per hour metering shall be at the same terminal of each interconnection.

3. The location of the metering terminal shall be agreed upon by the MP and non-MP who own the line.

4. Wherever feasible, both technically and economically, data transmission in the New England Control Area/Balancing Authority Area (CA/BAA) should be via the New England dispatch communications network.

B. INSTANTANEOUS MEGAWATTS AND MEGAVARS

1. This data must be telemetered to both ISO and the control center of the interconnected system.

2. This data may also be required by other dispatch centers within either system and by systems beyond the interconnecting systems.

3. For new interconnections, and any upgrades of existing equipment, state-of-the-art telemetering equipment shall be used and quantities shall be transmitted to each receiver location directly without retransmission (i.e. without an intermediate receiver and transmitter).

C. MEGAWATT-HOURS PER HOUR

1. There shall be a device at each interconnection facility to record the hourly billing watt-hours on site. In all new and upgraded installations, solid-state data recorders shall be installed.

2. The Megawatt-hour data shall be telemetered hourly to either ISO or the control center of the interconnected system. If it is telemetered to ISO, it shall be telemetered via the MP's Local Control Center (LCC), which has responsibility for the particular interconnection line.

3. The watt-hour data shall be compensated for line losses to the New England CA/BAA boundary.

4. Megawatt-hours may be recorded and telemetered as a net or as two quantities, MWh IN and MWh OUT.

IV. METERING AND RECORDING FOR SETTLEMENTS

A. OVERALL REQUIREMENTS

1. Megawatt-hour (MWh) per hour (i.e. energy per hour) data is required for each Generator Asset, Tie-Line Asset and Load Asset as these assets are defined in ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Resources and Asset Related Demands (OP 14) and ISO New England Manual for Definitions and Abbreviations Manual M-35.

2. In order for an asset to be eligible to participate in one or more of the markets the asset must have watt-hour (Wh) metering as defined in this OP. The exception to this is in the case of intra-MP Tie Line Assets as defined in section IV.D.3 of this OP.

3. For Real-Time Demand Response Resource Assets and Real-Time Emergency Generation Assets, megawatt-hour (MWh) per 5 minute interval data is required for each asset. The 5 minute data reported is calculated by measuring the consumption or generation in the 5 minute interval and multiplying that value by 12 (resulting in an effective hourly consumption or generation). In order for an asset to be eligible to participate in one or more of the markets the asset must have watt-hour (Wh) metering or recording device as defined in this OP. Where statistical sampling is used, the data submitted will be in the same format, but shall be developed in accordance with an ISO approved Measurement and Verification plan.

B. WATT-HOUR (Wh) METERING AND MEGAWATT-HOUR (MWh) PER HOUR DATA

1. New and upgraded Wh metering installations shall conform to the requirements in Section VII. of this OP.

2. The hourly MWh per hour data shall be submitted to ISO in accordance with ISO New England Manual for Market Rule 1 Accounting Manual M-28.

3. The hourly MWh per hour data may be recorded for a given asset as two quantities, MWh IN and MWh OUT, but must be submitted to ISO as a net quantity.

4. The MWh per hour data quantities must be automatically recorded at no greater than hourly interval in accordance with Section VII.B.5 of this OP.

5. Wh meters shall be equipped with kilowatt-hour (kWh) or MWh registers which shall be read a minimum of once a month. The purpose of this register read is to validate hourly data and allow for an adjustment, which corrects the sum of the hourly readings submitted to ISO during the month to the total energy actually metered.

6. The location of applicable Wh metering shall comply with this OP and be reported to ISO by the responsible MP.

7. The hourly MWh per hour data shall be reported to ISO to reflect the asset at the Interconnection Point. The Interconnection Point is hereafter defined as: i.) the PTF boundary, ii.) the agreed upon point of interconnection between two MPs or, iii.) the agreed upon Interconnection Point between a MP and a non-Participant. Wh meters not located at the Interconnection Point shall be compensated for losses to the Interconnection Point as follows:

   a) Level I Accuracy

      Wh metering which is:

      - Physically located at the Interconnection Point, or
      - Not physically located at the Interconnection Point but continuously compensated within the Wh meter or Wh metering circuit for excitation and load losses to the Interconnection Point.

   b) Level II Accuracy

      Wh metering that complies with this OP, except that it's not physically located at the Interconnection Point, but the recorded meter data is compensated through external calculations for excitation and load losses to the Interconnection Point. The integration interval for the loss compensation calculations shall not exceed a one-hour period Compensation calculations shall be based on both real power (kW) and reactive power (kVar or kQ) measurements. Voltage may be either measured or assumed constant.

   c) Level III Accuracy

      Existing Wh metering without reactive recording capability that complies with this OP, and is not physically located at the Interconnection Point, may have its' MWh recorded meter data compensated through external calculations for excitation and load losses to the Interconnection Point. In such cases, the compensation calculations will be based on real power (kW) measurements, a fixed 95% power factor, and voltage may be either measured or assumed constant. The integration interval for the loss compensation calculations shall not exceed a one-hour period.

8. For Real-Time Demand Response Resource assets and Real-Time Emergency Generation assets, the 5 minute (MWh) data submitted to the ISO in accordance with ISO New England Manual for Market Rule 1 Accounting Manual M-28 shall be either Energy Billing quality as defined in Appendix C or in the case where metering is installed specifically for the Demand Response Resource asset (and will not be used for utility billing purposes), a metering system with an overall accuracy as defined in Appendix C may be used. Metering used for utility billing purposes is also known as Revenue quality metering.

C. GENERATOR ASSETS

1. Generators directly connected to the 345 kV PTF system shall be metered at the PTF boundary or compensated to the PTF boundary in accordance with Section IV.B of this OP.

2. Generators directly connected to the PTF system at 230 kV or below where PTF boundary metering is utilized (Section IV.E.1) shall be metered at the PTF boundary or compensated to the PTF boundary in accordance with Section IV.B of this OP.

3. Generators directly connected to the PTF system at 230 kV or below where PTF boundary metering is not utilized (Section IV.E.3) shall be metered at either the generator terminals in accordance with the terms of the Interconnection Agreement of the parties involved, or as moreover recommended at the PTF boundary or compensated to the PTF boundary in accordance with Section IV.B of this OP.

4. Generators not connected to the PTF system shall be metered at the Interconnection Point or compensated to the Interconnection Point in accordance with Section IV.B of this OP. The Interconnection Point is determined in accordance with the terms of the Interconnection Agreement of the parties.

D. TIE-LINE ASSETS

1. Tie-Lines connect a MP to another MP, a non-Participant or the PTF system. Tie-Lines are also used to connect different sections of a MP's system that is divided by a Load Zone boundary.

2. Tie-Lines shall have a Wh or in the case of intra-MP tie-lines an instantaneous watt meter to calculate Wh at the Interconnection Point or compensated to the Interconnection Point with the other MP or non-Participant unless otherwise agreed by the parties involved or the PTF boundary as appropriate and in accordance with Section IV.B of this OP.

3. Intra-MP tie-lines are Tie-lines used to connect different sections of a MP's system that is divided by a Load Zone boundary. For these Tie Line Assets, Megawatt-hour per hour data derived from integrating instantaneous megawatt data used for Dispatch purposes (Section V.) is acceptable provided the metering equipment meets the minimum accuracy standards defined in Appendix C.

E. LOAD ASSETS

1. Every Load Asset except Real-Time Demand Response Resource Assets and Real-Time Emergency Generation Assets shall have a Wh meter or be determined on an hourly basis as an allocation of Wh meters. Wh meter must be located either at the Interconnection Point or compensated to the Interconnection Point in accordance with Section IV.B of this OP.

2. The load that is measured by a MP's Load Asset metering system may include PTF losses. If the Load Asset metering system includes such PTF losses, these losses (as determined by the ISO's state estimator in accordance with the procedures embodied in ISO New England Manual for Market Rule 1 Accounting Manual M-28 will be supplied to the MP by ISO, and will be subtracted from the total load as metered, to determine a MP's non-PTF Demand.

V. INTERNAL NEW ENGLAND METERING AND TELEMETERING FOR DISPATCH, MARKET, AND RELIABILITY PURPOSES

A. GENERATOR AND LOAD TELEMETERING CRITERIA

Instantaneous metering is required for all Generators and Loads (excluding Real-Time Demand Response Resources and Real-Time Emergency Generation Resources) which are modeled and defined in the ISO Energy Management System (EMS) and are eligible to participate in the hourly markets. The instantaneous metering must meter a Generator or Load Asset as it is bid in the Market in accordance with OP 14. Any major change to modify an existing facility shall conform to the procedures set forth below. In this context, an existing facility is one that was commercial prior to January 1, 2001.

The following quantities are to be telemetered from the Remote Terminal Unit (RTU) and made available to the New England dispatch communications network:

1. Market Requirements:

   a) Generator net (Net_1) MW, net (Net_1) MVAR and breaker status must be telemetered. Refer to Appendix D "OP18 Metering and Telemetering Diagram" for definition of Net_1. In a combined cycle configuration modeled as a single asset in the Markets, the total net output (Net_2) is required. MPs may request exception to the MVAR and breaker status telemetering requirement on a case-by-case basis depending on the physical location of a generator and its connection to the power system. Such requests will be addressed by ISO, the LCC and the MP.

   b) Dispatchable Asset Related Demands (DARDs) MW must be telemetered.

   c) Generator net (Net_3) MW and (Net_3) MVAR status must be telemetered for Pseudo Combined Cycle Generators. Refer to Appendix E "OP18 Metering and Telemetering Diagram" for definition of Net_3.

   d) No telemetering is required for Generators receiving "Settlement Only" treatment and Generators being treated as load reducers in accordance with ISO New England Operating Procedure No. 14, Technical Requirements for Generators, Demand Resources and Asset Related Demands**.**

e) For Real-Time Demand Response Resource Assets and Real-Time Emergency Generation Assets, MWh per 5 minute interval must be telemetered and meet the requirements specified in Appendix G of this document. The 5 minute data reported is calculated by measuring the consumption or generation in the 5 minute interval and multiplying that value by 12 (resulting in an effective hourly consumption or generation). For settlement purposes, revised MWh per 5 minute interval is submitted through the appropriate MUI (Market User Interface) as defined in ISO New England Manuals.

2. Transmission Reliability Requirements:

a) Generator net (Net) MW, MVAR as measured at the low side of the generator step-up transformer (GSU). Refer to Appendix D "OP18 Metering Diagram" for definition of Net. Combined cycle plants are required to supply measurements for each unit.

b) Automatic voltage regulation indicator, which indicates whether the unit is in automatic voltage regulating mode and regulating voltage. Combined cycle plants will provide this indication for each unit at the plant. (Note: power factor regulation is not performed within the New England CA/BAA).

c) By exception, the local SCADA, LCC or ISO may request MW and MVAR station service load values.

d) By exception, the local SCADA site, LCC or ISO may request generator terminal voltage measurements.

B. TRANSMISSION SYSTEM TELEMETERING CRITERIA

The following quantities are to be telemetered from the RTU and made available to the New England dispatch communications network by MPs. Any major change to modify an existing facility shall conform to the procedures set forth below. In this context, an existing facility is one that was commercial prior to January 1, 2001.

1. Transmission substation voltage from the following:

a) All generating stations 50 MW or larger that connect to the 69 kV and above transmission system.

b) All 345 kV, 230 kV and 115 kV substations where two (2) or more line sections terminate with protective circuit interruption capability, such as a circuit breaker.

c) Other transmission busses which, for reliable transmission operations, require regulation, control or are otherwise needed to ensure satisfactory results of the ISO/LCC state estimators. The determination of the other transmission bus voltages which must be telemetered will be made jointly by ISO, the LCC and the MP.

NOTE: The preferred metering of bus voltage is phase-phase metering. In the event that phase-phase metering is not selected, compensated phase-ground metering will be acceptable.

2. MW and MVAR from each terminal of all non-radial inter-LCC lines.

3. MW and MVAR from every terminal of all 345 kV and 230 kV lines and at least one end of each non-radial 115 kV line.

4. MW and MVAR from all transformers connected to 115 kV and above.

5. MW and MVAR from 115 kV transformers installed prior to January 1, 2001 that are required to ensure satisfactory results of the ISO/LCC state estimators. The determination of which 115 kV transformers must be telemetered will be made jointly by ISO, the LCC and the MP.

6. MW and MVAR from one end of each intra-LCC lines which are necessary for reliable transmission operations, to support bulk power transfers, or are otherwise needed for satisfactory results of the ISO/LCC state estimators. The determination of which intra-LCC lines must be telemetered will be made jointly by ISO, the LCC and the MP.

7. The status of all 345 kV, 230 kV and 115 kV breakers.

8. The status of 69 kV switching devices which affect the transfer capability of or within the bulk power network. The determination of which switching devices must be telemetered will be made jointly by ISO, the LCC and the MP.

9. The tap positions of all 345 kV and 230 kV autotransformers and all phase-shifting transformers which are equipped and operated for tap changing under load.

10. Other telemetered data to be determined on a case-by-case basis which are required for bulk power system operation (i.e. High Voltage Direct Current (HVDC) terminals, Static VAR Compensator (SVC), capacitor/reactor status, frequency,Flexible Alternating Current Transmission System (FACTS) devices, Northeast Power Coordinating Council Inc. [NPCC] Type I Bulk Power Special Protection Systems [SPS]). The determination of the data that must be telemetered will be made jointly by ISO, the LCC and the MP.

C. TELEMETERED DATA SCAN RATES

The following minimum standards are established for the frequency at which telemetered quantities are to be scanned and made available to the local Inter-Control Center Communication Protocol (ICCP) Communication Network Processor (CNP) or ISO Communications Front End (CFE).

Frequency of Scanning (Seconds)

1. The data required for Automatic Generation Control (AGC) operation, which includes unit MW for AGC generators, will be made available to the local ICCP CNP or ISO CFE within four (4) seconds. This four (4) second time interval is measured as the time the data is scanned at the remote terminal unit (RTU) until the time the data is received at the local ICCP CNP or the backup dispatch site.

2. The analog power system data, which includes all other analog data defined in Section V of this OP, shall be made available to the local CNP or ISO CFE within ten (10) seconds of a change in data at a RTU. For RTDR and RTEG shall be submitted in 5 minute interval. This data requirement recognizes the change detect logic employed by some RTU's in that the data is telemetered to the Supervisory Control And Data Acquisition (SCADA) system only after a change is detected by the RTU, and that the amount of change may be different for each point in an RTU.

3. Telemetered status data will be made available to the local CNP or ISO CFE within four (4) seconds of a change reported by an RTU.

D. NON-TELEMETERED DATA CRITERIA

Additional data has been defined as necessary for the overall operation of the ISO/LCC/MP dispatch computer systems. This data will originate from, and be the responsibility of, the dispatch center which has jurisdiction over the data. This data will be made available for transmission as required to the ISO/LCC/MP dispatch computer systems.

Examples of this type of data include, but are not limited to, the following:

1. Generator limits and unit control modes.

2. Text Messages.

3. Non-telemetered breaker and switching device status.

4. Calculated data including transfer limits and flows, interface limits and flows.

5. Economic dispatch basepoints/desired generations, and AGC setpoints.

E. TELEMETERED DATA IDENTIFICATION

ISO, the LCCs and the MPs shall uniquely and correctly identify the data being supplied to the network using the format described in Appendix A of this OP for CNP sourced data and Appendix F for ISO CFE data.

VI. METERING FOR POWER FACTOR MEASUREMENT PURPOSES

Each MP shall submit to ISO the quantities necessary to calculate MP load power factor as prescribed in OP 17, Load Power Factor Correction. While OP 17 allows for estimated quantities to be used in the calculation of load power factor, a sufficient number of the necessary quantities must be metered and recorded so that the resulting load power factor is a valid estimate.

VII. EQUIPMENT STANDARDS FOR NEW AND UPGRADED INSTALLATIONS

This section specifies standards for metering, recording and telemetering equipment that MPs install in all new and upgraded installations. MPs are not precluded from maintaining or repairing existing equipment with like or improved components, but MPs are required to choose equipment that meets all standards of this OP when they are replaced for purposes other than maintenance or repair (i.e. upgraded installations).

A. ANSI STANDARDS

All metering devices used shall conform to applicable American National Standard Institute (ANSI) C-12 standards as amended from time to time.

1. Metering of watt-hour, volt-hour, volt-ampere-hours, reactive volt-ampere-hour, Q-hours and the associated demand components should conform to ANSI standard C12.

2. Instruments or transducers for the analog or digital measurement of volt, volts-squared, amperes, amperes-squared, phase angle, volt-amperes, watts, and reactive volt-amperes should conform to ANSI standards C39.1, C39.5 and C37.90.

3. Instrument transformers should conform to ANSI standard C57.13.

B. SPECIFIC ISO NEW ENGLAND STANDARDS

All new and upgraded metering, recording and telemetering installations shall meet the following standards:

1. The design accuracy of individual components as well as overall systems shall conform to the standards contained in Appendix C.

2. Solid-state equipment (meters, recorders, transducers, etc.) shall be installed.

   MPs are advised that additional quantities, including delivered and received megavar-hours per hour (MVARh) in conjunction with megawatt-hours per hour (MWh), will likely require metering, recording and telemetering as a result of future revisions to this OP. MPs are encouraged to install meters and recorders that are capable of measuring and recording these quantities.

3. For all grounded wye system metering, three element meters and transducers shall be used. For all delta system (ungrounded) metering, two or three element meters and transducers may be used.

4. All bi-directional transducers shall have a milli-amp output into a load of no more than 10K ohm.

5. The requirement for data recorders shall be satisfied with the types of equipment listed below. The first type must be used on interconnections with systems outside ISO. Either type may be used internally.

   - A solid-state data recorder installed at the metering location. A MP may elect to use on-site plant computers as recorders when they are used to record accumulated pulses. Data shall be retrieved from recorders by on-site or remote interrogation. Where the MPs mutually agree to the need for joint access to this recorded data, remote communications equipment is recommended to be installed
   - An RTU at the meter location scanned hourly by a centrally located dispatch or data acquisition computer. The computer must periodically retrieve accumulated pulses via coded digital transmission for all hours
   - A solid-state multifunction meter equipped with a modem and interval data recorder capable of storing at least 60 days of interval data and an internal clock. Data shall be retrieved from the meter by remote interrogation. Where the MPs mutually agree to the need for joint access to this recorded data the meter's program shall be secured appropriately

   Off-site accumulation of continuous pulse signals received from metering equipment does not satisfy the recording device requirement. These existing installations shall be upgraded to include either of the types of equipment listed above.

6. All data recorders shall be synchronized in time, within an accuracy of +/- 2 minutes, with the National Institute of Standards and Technology (NIST) periodically and when they are installed or returned to service after maintenance or repair.

7. The pulse rates selected for input to the data recorder shall be sized such that the pulse rates utilize the resolution capabilities of the recorder.

8. Compensation for line and/or transformer losses, when used, shall be accomplished by using Level I or Level II metering accuracy standards as defined in Section IV.B.7 of this OP.

VIII. POWER SUPPLY REQUIREMENTS FOR DATA COMMUNICATIONS EQUIPMENT

Upon the occurrence of a partial or system-wide blackout, substations, control centers and communications systems will be dependent upon backup systems and/or internal power sources. The availability of data communications circuits will be critical to effective restoration.

To ensure that reliable data communications paths are available should a blackout occur, criteria have been developed, against which existing circuits should be measured. When existing facilities do not meet the criteria, appropriate steps should be taken to correct the situation. The following are the criteria for the RTU and related equipment located at substations rated at 115 kV and above, generating stations and for the communications equipment between these stations and the SCADA centers or LCCs.

All data communications equipment shall meet the following standards:

1. The equipment should not be dependent on alternating current (ac) as a power source. The basic power source should be the station battery or an independent battery, as appropriate. The battery should be capable of supporting the anticipated load for at least eight hours.

2. If for some reason the substation or generating station equipment must be powered by an ac source, the equipment must be able to operate independently from the ac power source for the rest of the facility. An auxiliary power source would be required.

3. The basic power source for the communications terminal equipment, including the modem, at the substation or generating station, should be a battery. If this equipment is dependent on an ac power source, it must be able to operate independently from the ac power source to the rest of the facility or operate without a power source.

4. Diagnostic (loop back schemes) and protective devices on communication circuits must be passive or fail into a safe, communicating mode upon loss of station service power.

5. Whenever possible, utility owned facilities should be available as the primary or backup means of data communication.

6. At stations where two batteries are provided, it is desirable that each should be made capable of being a power source for the equipment.

7. The equipment should operate over the normal range of temperatures that could exist when the ac power source is lost and as a result, air conditioning or heating is lost.

8. The configuration/connection of communication circuits should be designed so that a problem on one circuit does not cause a problem on another (should not be propagated).

9. Alarms should be provided to an appropriate location indicating the status of batteries, backup equipment, etc.

10. Dedicated telephone circuits or a secure communication network should be used. Any collection points where circuits terminate should have a backup or independent power source.

11. All microwave/fiber optic sites should have a battery rated for at least eight hours and a suitable backup power source for extended periods.

IX. TESTING, CALIBRATION AND MAINTENANCE STANDARDS

A. OVERALL REQUIREMENTS

Each MP is responsible for properly maintaining its metering, recording and telemetering equipment in accordance with applicable ANSI standards as amended from time to time. The specific standards for testing, calibration and maintenance are put forth in this Section. The accuracy standards to be observed are summarized in Appendix C and Appendix B.

B. OVERALL TELEMETERING SYSTEM TEST

Whenever transducers and/or telemetering systems are tested, an overall system test should also be conducted. This system test includes the use of the calibrated transducers output as input to the telemetry system. All receiving devices (e.g. meters, chart recorders, computer outputs) shall be verified against the applied input. Testing of all circuit breakers or switches OPEN/CLOSED position status telemetered by other than SCADA RTUs shall be performed once every four years if the device has not had a confirmed operation. This testing does not require the operation of the circuit breaker or switch. Repair and/or calibration at all locations should be done as required.

C. TELEMETRY COMPONENT TESTS

To ensure the accuracy of telemetered data, MPs shall do one of the following:

1. Use manual or computerized routines to check telemetered quantities against each other to identify unreasonable values at least once every six months. Appropriate calibrations and/or repairs will be made as necessary. State estimators or similar software packages that detect and individually identify inconsistent data values may be used for this purpose.

2. Calibrate transducers and telemetering systems according to manufacturer's procedures, on the following schedule:

Transducers:	at least once every four years
Analog Telemetry:	at least once every twelve months
Digital Telemetry:	at least once every four years

When tests are performed on transducers, errors should not exceed 0.25% of full scale. If during the test, errors exceed this value, the transducer should be recalibrated, repaired or replaced as necessary to attain that accuracy.

When tests are performed on the telemetering system (excluding the transducer), errors should not exceed 0.25% of full scale. If during the test, errors exceed this value, the equipment should be recalibrated, repaired or replaced as necessary to attain that accuracy.

SCADA RTUs employing analog to digital converter(s) (ADC), the gain and offset characteristics of which are continuously monitored by ADC Reference Values that are within 0.25% of full scale, shall be exempt from periodic calibration requirements.

D. WATT-HOUR METERS

1. All watt-hour meters shall be tested by comparison to a solid-state watt-hour standard which is traceable to the NIST as outlined in Section IX.F. of this document. Testing should include an inspection, verification, and analysis of the metering system excluding Instrument Transformers.

2. As a minimum, watt-hour meters shall be tested by one of the following two methods:

   a) Series test with external loads applied [permitted for testing either induction or solid-state watt-hour meters].

      i. "As-Found" series tested at operating or nameplate voltage under the following three conditions:

         - Full Load (FL) at the meter Test Ampere (TA) rating and unity power factor
         - Light Load (LL) at 10% of the meter TA rating and unity power factor
         - Power Factor (PF) at the meter TA rating and 0.5 power factor lag

         NOTE: Solid-state meters used in bi-directional applications shall be tested for both forward (delivered) and reverse (received) accuracy.

         The series test results must be within the following accuracy limits:

Test Condition	Accuracy Limit
FL	+/- 0.2% error
LL	+/- 0.3% error
PF	+/- 0.5% error

      ii. In addition to the "As-Found" series tests, all induction watt-hour meters shall have an "As-Found" individual element balance test performed. The individual elements shall be tested at operating or nameplate voltage, at FL test amps, and unity power factor. The individual element test results must be within 1.0% of each other.

      iii. If the "As-Found" test results are outside the stated accuracy limits, then the meter shall be adjusted as closely as practicable to 0.0% error. The final "As-Left" test results shall be within the stated accuracy limits.

      iv. Any induction watt-hour meter found outside of +/- 2.0% error or any solid-state watt-hour meter found outside the +/- 0.5% error (at any test condition) shall be adjusted and scheduled for replacement as soon as practicable.

b) Single point three phase test using the actual in-service load and meter uncompensated [permitted for testing solid-state watthour meters only].

i. "As- Found" three phase tested at actual in-service voltage, current, and power factor; provided:

- voltage is within the range specified by the meter manufacturer
- current is within the meter's load range between LL and Class Amps of the meter, and
- power factor is between unity and 0.5 lagging or leading

The single point three phase test results must be within the following accuracy limits:

Test Condition	Accuracy Limit
Actual In-service Load	+/- 0.2% error

ii. If the "As-Found" test results are outside the stated accuracy limits, then the meter shall be adjusted as closely as practicable to 0.0% error or promptly replaced. The final "As-Left" test results shall be within the stated accuracy limits.

iii. Any solid-state watt-hour meter found outside the +/- 0.5% error shall either be adjusted and scheduled for replacement as soon as practicable; or, promptly replaced.

3. Meters with compensation for line and/or transformer losses shall be:

a) Series tested with and without the compensation activated at the test points as defined in Section IX.D.2.a. or

b) Single point tested with compensation checked by comparison of compensated and uncompensated pulse data channels.

4. In-service testing of watt-hour meters shall be tested at a frequency in accordance with the local state utility control and distribution utility requirements for retail loads such as Asset Related Demands (ARDs). All other assets shall be tested at the frequency specified as follows: Solid-state meters, the operation of which is monitored daily, must be tested at least once every two calendar years. All other meters must be tested at least once a calendar year.

5. Data recording equipment external to the meter shall be checked monthly by comparing a summation of the hourly demand readings with the kilowatt-hours registered on the watt-hour meters for the same period of time. When only small quantities (less than 7200 MWh in one month) have been registered, comparison is required every two months using two months of data. The difference in the sum of hourly demand readings and the kilowatt-hours registered on the watt-hour meter should be less than the value of the watt-hour meter transformer ratio

multiplier. When this difference is greater, the installation shall be reviewed and tested if the discrepancy is not explainable. For Real-Time Demand Response Resource Assets and Real-Time Emergency Generation Assets, data recording equipment external to the meter shall be checked at least annually by comparing a summation of the hourly demand readings with the kilowatt-hours registered on the watt-hour meter for at least one month. If hourly data is available from the pulse source meter, then comparison should take place at the hourly level.

6. The continuity of meter readings should be maintained during tests either by use of a portable meter or other suitable methods. Note: use of the single point test method will insure continuity of both readings and data. A watt-hour meter test may be made during a period of no load or when the load is constant and the reading adjusted upon completion of the test. Pulse data should likewise be adjusted upon completion of the test. When this is not practical, other methods must be used to segregate pulses registered due to the test from pulses due to registration of power flow.

E. INSTRUMENT TRANSFORMERS

Scheduled tests of instrument transformers are not required unless all other tests fail to explain a discrepancy; then testing shall be performed. The testing procedure shall conform to the manufacturer's specifications.

F. TEST EQUIPMENT

Test equipment used in the calibration of instrument transformers or transducers should be certified to values of accuracy and precision which are at least twice as accurate as the required accuracy of the equipment under test. Solid-state watt-hour standards of 0.1% or better accuracy shall be used in the testing of watt-hour meters. All watt-hour standards should be certified correct every twelve months.

All watt-hour standards should be certified by comparison with laboratory standards whose accuracy is traceable to the NIST. The standard certification values may be determined by the use of data obtained through round-robin procedures between MPs, provided at least one of the laboratories maintains standards traceable to NIST. Standards utilized for the purpose of calibrating voltage and current transducers should be of the same sensing type (e.g. Root Mean Square (RMS) or average) as the transducers under test.

NOTE: Traceability refers to relating individual measurement results to NIST measurement systems through an unbroken chain of comparisons.

The tests and calibrations should be performed at ambient temperatures recommended by the manufacturers of the test equipment and the equipment under test.

Instrumentation used to check the tone modulating frequency for data transmission should have a minimum definition of 0.001 Hertz. The dc ammeter or voltmeter used to measure input signals shall have a minimum accuracy of +/- 0.05%.

G. RECORD KEEPING AND AUDITING

The MPs are to maintain records of the testing and calibration of all metering and telemetering equipment which is required to be installed according to the provisions of this OP. The records are to include such information as the dates of testing and calibration, whether the equipment was found to be within accuracy standards without recalibration, whether recalibration was performed and accuracy achieved by recalibration. These records are to be retained for a minimum of the two most current calibration cycles and are to be available to ISO and the LCC upon request.

H. NOTIFICATIONS

When metering and telemetering equipment associated with MP interconnections is scheduled for maintenance, test or upgrade, interconnected MPs shall be notified at least two weeks in advance in order to have the opportunity to participate in or witness the maintenance, test or upgrade.

X. SECURITY OF METERED AND RECORDED DATA

Security shall be addressed to prevent unlawful, unintentional or unauthorized access to those portions of the firmware, software and data being collected that would have an effect on the metered and recorded quantities. This may be done using primary and secondary security codes or other appropriate means. This does not preclude the MP from allowing read-only access to the data.

XI. COMPLIANCE

Periodically, ISO may conduct an audit survey of metering, recording devices and telemetering criteria to determine the degree of MP compliance with all OP 18 requirements.

OP 18 REVISION HISTORY

Document History (This Document History documents action taken on the equivalent NEPOOL Procedure prior to the RTO Operations Date as well revisions made to the ISO New England Procedure subsequent to the RTO Operations Date.)

Rev. No.	Date	Reason
Rev 0	04/13/99	
Rev 1	10/21/99	
Rev 2	06/21/2002	
Rev 3	10/01/04	
Rev 4	02/01/05	Updated to conform to RTO terminology
Rev 5	05/06/05	Update for initiation of VELCO Local Control Center
Rev 6	01/06/06	Incorporate recommendations from the OP 18 Working Group
Rev 7	10/01/06	Updated for ASM Phase 2
Rev 8	11/15/07	Revised for Pseudo Combined Cycle Generator requirements and added Appendix E
Rev 9	09/05/08	Change frequently used terms to defined acronyms (e.g., ISO for ISO New England, LCC for Local Control Center, MP for Market Participant, etc., Revised for RIG upgrade project:
Rev 10	06/01/10	Updated to reflect the new communications infrastructure requirements for the Demand Response Integration Project under FCM