July 24, 2020

Via Electronic-Mail

Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, N.H. 03301-2429

RE: IR 20-004, Investigation of Electric Vehicle Rate Design Standards, Electric Vehicle Time of Day Rates for Residential and Commercial Customers
July 14, 2020 Hearing Follow-Up Comments of Unitil Energy Systems, Inc.

Dear Secretary Howland,

Unitil Energy Systems, Inc. ("Unitil" or the "Company") appreciates the opportunity to provide supplementary comments following the Commission's July 14, 2020 hearing regarding the Staff Recommendation in the investigation of electric vehicle (EV) rate design standards and electric vehicle time of day rates for residential and commercial customers as part of the investigation docketed in IR 20-004. In the comments which follow, responses to specific questions raised by the Commission are provided that were directed to Unitil during the hearing. Within the broader context of the topical areas listed below, these comments serve to provide a more complete portrayal of the other considerations which Unitil believes will influence specific areas of concern that should be addressed by the Commission.

<u>Cost of Service:</u>

Traditional Cost of Service Regulation provides that the utility's revenue requirement "reflects the total amount that must be collected in rates for the utility to recover its costs and earn a reasonable return."[1] The Company's rates for delivery service are designed on an embedded cost basis consistent with how the utility's total revenue requirement is determined. As such, EV-specific rates also should conform to this principle to the maximum extent practicable.

In developing rates for new loads such as EVs, there should be recognition that an EV rate must be based on a combination of sunk, or embedded costs, and marginal costs. In order to avoid undue inter-class subsidization, certain costs that support the offering of an EV-specific time-of-use (TOU) rate (e.g., operations and maintenance (O&M), administrative and general (A&G), etc.) should be recognized and allocated to these loads so they do not burden non-EV customers. Some costs will be marginal in nature

[1] Tariff Development I: The Basic Ratemaking Process, Darryl Tietjen, Public Utility Commission of Texas (Accessed February 20, 2020). Available at: https://pubs.naruc.org/pub.cfm?id=538E730E-2354-D714-51A6-5B621A9534CB

related to incremental investments such as metering and make-ready infrastructure that are specific to the EV class (or loads) and may not be assigned to other rate classes. The Commission should consider the appropriate allocation of the fully-loaded costs of providing EV charging to a customer within each rate offering.

More specifically, for those EV loads that are treated as an addition to the customer's existing electric utility service,[2] it would be appropriate to view that load as incremental to the existing load and to recognize that the utility rate for the existing load already reflects a full complement of embedded costs when deriving the rate. However, if there are additional costs created by this load, the utility must be able to recover those costs through the rates that apply to the customer's total load. In contrast, for an EV load that is separately metered in the same facility or an EV load that is served as a standalone facility,[3] it is appropriate to consider a combination of marginal (incremental) costs and embedded costs to derive the rate so that it fairly recovers the costs incurred by the utility to serve this new service.

Unitil believes it is appropriate to develop EV rates within the context of a general rate case to ensure the level of the rate reflects the utility's most current and representative level of embedded costs (i.e., the utility's total revenue requirement) and that it can be properly aligned with the class revenues and rates for all of the utility's other rate classes to avoid the creation of inter-class subsidies. In addition, the rate structure and rate level of an EV service should be established using the same types of cost and non-cost considerations that are used in determining the level of class revenues and rates for the utility's other rate classes and tariff offerings.

"Sunk costs" are equivalent to the embedded cost of service, or total revenue requirement, used by the utility to set distribution rates within the context of a general rate case. A variety of cost components included in the utility's revenue requirement must be recoverable in potential EV rates so that the distribution portion of the EV rate (i.e., costs related to the delivery service charges) is derived on a fully-loaded basis to avoid the creation of any inter-class subsidies among the utility's rate classes. At the same time, there are other costs that are properly characterized as marginal in nature related to the utility's power supply costs (i.e., costs related to the energy service charges) along with the cost of potential separate metering and make-ready infrastructure specific to EV customers.

By definition, a full cost of service study presented by a utility in a general rate case reflects an assignment, or allocation to each of its rate or customer classes, of the utility's total revenue requirement derived on an embedded or sunk cost basis. To properly align the utility's cost of service study with its total revenue requirement, each sunk cost component included in the total revenue requirement also should be included in the cost of service study.

Some examples of sunk costs that should be included in the cost of providing service to EV loads are: (1) sub-transmission and substation costs; (2) primary circuit costs; (3) engineering and supervision costs; (4) load dispatch and balancing costs; (5) general plant costs; and (6) customer service and A&G costs.

[2] For example, a residential customer offered an EV TOU rate on a whole-facility basis.
[3] For example, a commercial EV charging station facility.

Unitil believes it is necessary to understand the full cost of serving EV customers even if rates are set on a basis other than cost for policy reasons.

Time of Day Rates:

Unitil supports the availability of time of day/TOU rates for EV charging. While TOU structures may not be suitable for all charging applications (such as public commercial and Direct Current Fast Charging (DCFC)), the Company believes that a suite of rate offerings tailored for different customer types and use cases may be appropriate, potentially including but not limited to whole-facility TOU designed for EV customers, separately-metered EV TOU, or clustered and DCFC EV charging.

The off-peak hours to use in a TOU rate for EV loads should be established in recognition of the time varying cost components which form the basis for the rate design. In general, the process would be to determine the time period (i.e., the number of hours) for the off-peak period that maximizes the cost difference between the peak and off-peak periods being evaluated for the rate so the corresponding peak to off-peak rate differential can be maximized in the TOU rate.

Off-peak periods used in TOU rates typically can start between 8:00 p.m. and 10 p.m. and may last until between 4:00 a.m. and 8:00 a.m. depending on the utility's particular energy resource mix and system load curve. Any TOU rate designed for EV loads should offer a long enough off-peak time period to provide a sufficient opportunity for customers to shift load through changes in EV charging behavior. The rate design should consider that the typical timeframe for an EV to charge overnight. However, providing the customer with a long charging window should not be the sole consideration in designing a TOU rate for EV loads. As stated earlier, the basic purpose of the TOU rate is to provide proper price signals to customers; it is well within the range of reasonable consumer behavior if the customer decides to charge its EV during a higher cost time period out of convenience or necessity.

The utility's TOU rate design philosophy should focus on allowing customers to make independent consumption decisions based on proper price signals provided through the rate rather than trying to artificially influence customer behavior. As a fundamental proposition, Unitil believes that TOU rates for any type of electric load should be designed to promote efficient use of the utility's fixed system resources, leading to reduced costs for all utility customers. The TOU rate must provide price signals and influence customer behavior in a manner creating beneficial outcomes for the customer (through lower rates and electric bills) and for the utility (through a reduction in system costs over time). To achieve this objective, the design of the TOU rate should only reflect the utility's system costs that are time varying in nature so that customers will be presented with a cost-based price signal through the TOU rate structure. The time varying costs should drive the desired shape of the utility's load curve and not simply a preconceived idea of what may constitute a desirable outcome based on non-cost or qualitative presumptions.

With the utility's time varying costs as a foundation, the underlying costs of providing energy and delivery services influenced by the utility's system load curve, design, and operational characteristics should be the primary determinants in designing the TOU rate. For example, when the utility's costs are higher during certain seasonal and daily time periods, the TOU rate should reflect that result so that customers receive a price signal indicating the added costs of electricity consumption during those times. In other words, the utility's underlying time varying costs dictate how the system load shape should be modified over time as customers respond to the rate by reducing their peak electric usage and/or shifting their peak electric usage to off-peak periods. The desired load shape for the utility and its customers will be reflective of the more efficient use of electricity and observed through a flattening of the system load curve as measured by an increase in the utility's system load factor.

At the same time, it is also necessary to understand and evaluate how customers are responding to the utility's TOU rate so that periodic refinements can be made to the TOU rate design to identify that the utility's load shape and resulting costs likely will change over time. For example, the Company understands that other industry participants have recognized past TOU rates as having been designed with overly long peak time periods, precluding customers from responding to the TOU rate in a meaningful way.[4] In addition, some jurisdictions have designed TOU rates to create a significant peak-to-off peak rate differential to increase the likelihood of a positive customer response without recognizing that such a large rate differential may not be supported by the underlying time varying costs of the utility. In that case, a rate benefit is afforded to customers who can change their electric usage patterns even though the utility does not experience a corresponding reduction in cost. Ultimately, the utility's non-TOU customers will be required to absorb in their rates the mismatch of the changes in revenues and costs associated with the TOU rate.

The PUC Staff recommendation suggested that the Commission require the following:

> *Time of Use Rate Proposal Filings for Separately Metered EV Chargers: Open an adjudicative proceeding and direct each electric utility to file within 120 days, consistent with the guidance above: (1) an electric vehicle time of use rate proposal for separately-metered residential and small commercial customer applications; (2) an electric vehicle time of use rate proposal for separately metered high demand draw commercial customer applications that may incorporate direct current fast charging or clustered level 2 chargers. Both proposals should be accompanied by testimony explaining how those rates were developed, any plans for marketing residential electric vehicle time of use rates, and how the rate is consistent with the Commission guidance.*[5]

It is unclear how much time would be needed to develop meaningful EV TOU rates but the Company would recommend developing such rate offerings in the context of a rate case as stated above. A variety of considerations would need to be addressed including but not limited to cost of service, billing and customer service, infrastructure deployment. With these considerations in mind, Unitil would recommend that the Commission afford the utilities more flexibility than the PUC Staff's recommendation would require.

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[4] Some customers were unable to shift their electric usage during the rate's defined peak period to the off-peak period to take advantage of a lower rate because the shift in electric usage was not sufficient to move the usage into the off-peak period.

[5] IR 20-004 April 3, 2020 NHPUC Staff Recommendation at 3.

Unitil additionally notes that the large general service class of its Massachusetts subsidiary Fitchburg Gas and Electric Light Company's has simple on and off peak distribution rates and an on peak demand rate. The on peak period is from 10AM to 10PM on non-holiday weekdays.

Demand Charges:

Demand charges are typically designed to directly reflect the characteristics of and recover fixed costs by matching cost causation to the subsequent rate design. Not all utility costs are time varying in nature. Demand charges allow the utility an opportunity to recover those costs as opposed to being exposed to increased recovery risk through variable charges. For customers that have the ability to improve their load factor, they may actually benefit from demand charges and lower their costs over time.

It is difficult to conceive of a "bright line" customer size necessitating the use of demand charges that would have broad applicability across utilities and jurisdictions. The determination of demand charge applicability should be a function of the utility's customer mix, how the level of fixed demand or capacity costs compare to the utility's other costs, and whether other ratemaking mechanisms exist that could provide the utility with a reasonable opportunity to recover the fixed costs of utility service. While utilities have traditionally utilized demand charges in the pricing of electricity for their larger commercial and industrial customers, with the advent of advanced metering infrastructure (AMI), some utilities have proposed and received regulatory approval to implement demand charges for smaller customers, including residential customers.[6] With that being said, Unitil is not advocating for residential EV TOU demand charges at this time.

Demand charges based on customers' coincident peak demands do not align with distribution-related cost causation principles (i.e., non-coincident peak demands cause distribution capital-related costs and O&M costs to be incurred by the utility). A utility's engineering and system planning standards should remain as the principal criteria to determine the capacity needed to reliably support the utility's distribution system through examination of localized electric loads irrespective of when the system peak occurs. Demand charges based on the utility's coincident peak and each customer's contribution to that peak are more suitable for power supply and transmission-related costs rather than distribution costs.

[6] For example, electric utilities such as Arizona Public Service, NV Energy, and Westar Energy have voluntary tariffs that include demand charges for customers with PVs on their roofs, Salt River Project (SRP) in Arizona, a municipally owned system, has instituted such a tariff for DG customers and the Kansas Corporation Commission has ordered that DG customers be considered a separate class and be offered three-part rates, among other options.

Distribution, Energy, and/or Transmission:

Power supply procurement should be based upon Locational Marginal Prices (LMPs), day-ahead energy prices, and other wholesale power market considerations that are properly characterized as marginal costs (as opposed to sunk or embedded costs).

Metering, Communication, and Billing Costs:

The PUC Staff recommendation suggested that the Commission require the following:

> *"Direct the electric distribution companies to file a feasibility assessment within 90 days relating to opportunities for offering an electric vehicle time of use rate for residential and commercial facilities that utilizes interval metering capability of devices other than a utility owned meter. If an electric distribution company finds such an offering would not be feasible at this time, the assessment should nonetheless include a quantification of costs that would need to be incurred to deploy such a strategy, an explanation of any other barriers that may exist, and a roadmap for overcoming those barriers."*[7]

Unitil does not support utilizing interval metering capability of devices (i.e., 3rd party metering) other than a utility-owned meter for revenue and billing purposes. In considering whether to allow 3rd party metering for EV charging customers, Unitil submits that the Commission must establish rules that require utility and 3rd party metering to meet the same customer data accuracy and security protections, and determine that it has sufficient oversight and enforcement authority to ensure 3rd party compliance with these requirements. Additionally, the Commission must ensure utilities that the prudent and reasonable costs they incur for 3rd party meter integration and data management with their own systems are recoverable.[8] Unitil submits that the Commission require the following protections before approving 3rd party metering applications:

NH PUC 300 Rules for Electric Service

- 303 Service Provisions
    - 303.03 Meter Reading: 3rd party metering must provide compatible reads with utility metering and billing systems. Unitil's basic systems and processes are described below for

[7] IR 20-004 April 3, 2020 NHPUC Staff Recommendation at 2.

[8] Unitil respectfully suggests that the following questions be considered: 1. Why should 3rd party meters be subject to lessor standards of customer and data accuracy and security protections than those for utility-owned meters? 2. If it is determined that 3rd party meters may be subject to such lessor standards, then why it is necessary that utility-owned meters be subject to higher standards? 3. Why should 3rd party meters not be subject to the same Commission oversight and enforcement authority as are utility-owned meters? 4. If it is determined that 3rd party meters need not be subject to the same Commission oversight and enforcement authority, then why is it necessary that utility–owned meters be subject to that oversight and enforcement authority? 5. Why should customers not be entitled to the same protections, security and data accuracy, and afforded a process to complain to the Commission if such standards are not met, from both 3rd party and utility-owned meters? 6. If 3rd party meters are allowed, who will be responsible to respond to customer inquiries regarding such meters?

reference. Section 303.03 also implies the meter should clearly indicate how someone can determine usage based on reading the meter and any multiplication factors.

    - Unitil utilizes meters and equipment that are compatible with internal AMI systems and capable of providing the readings as required by Section 303.03.
    - The majority of Unitil's meters are read through the Landis + Gyr powerline carrier system (PLC). The PLC system reads the meter at a minimum daily and is capable of reading the meters three times per day.
    - The remaining small percentage of Unitil's meters not read through PLC utilize the phone system to gather readings on a daily basis.
    - In both cases, specific endpoints and communication protocols are required to allow the reading systems to accept and process the meter readings. These systems provide Unitil with a means of reading meters through an automated system rather than having to read them manually.
    - The meter data is processed through the reading systems and the data is transferred to the meter database management system where it is verified before it is transferred to the billing system.
    - 3rd party meter reading systems would need to be compatible with current and future utility meter reading systems so as not to add manual intervention for reading, data transfer or data validation.
    - All Unitil meters have the ability to be manually read as well, either through visual means or physical data downloaded to a mobile device.
  - 303.04 Change in Character of Service
    - Typically, the cost of changes to metering and metering equipment associated with upgrades or changes to system voltages are covered by the Company, unless otherwise stated in the customer's service agreement.
    - The owner of a 3rd party meter may be responsible for the specification of equipment and the cost to upgrade 3rd party metering if there is a change of character in service.
- 305 Meter Accuracy and Testing: Procedures for meter inspections and testing that meet this requirement must be adopted by customers and/or 3rd parties.
  - 305.01 Inspection of Meters
    - Meter manufacturers provide test data to ensure accuracy of all new meters before they are installed at a customer's service location.
    - Before a meter that has been removed from service is placed back into service, it is tested for accuracy and compliance with NH PUC 305.02 (a).
    - Unitil has test equipment and software that are integrated with the meter inventory system so all tested data is stored with meter records.
    - The watt-hour working standards used for testing electric meters are tested against an annually certified master standard.
    - Unitil inspects all meters and performs an electrical test of all instrument transformer connections upon installation. This test verifies polarity, phasing, ratios and correct wiring. An electronic record of the test (constant verification form) is

filed with the electronic work order and can be accessed through Unitil's Mobile Data System (MDS) repository.
    - Prior to installation, all current and potential transformers are tested to ensure the transformer ratios are as specified on the nameplate.
  - 305.02 Test and Calibration of Meters
    - 3rd party meters must be tested to the same accuracy standards as provided by the rule.
    - Before a meter can be placed in service it must test within the following tolerance outlined in PUC 305.02
      - At full load, +/- 1 %
      - At light load, +/- 1 %
      - At power fact load, +/- 2 %
  - 305.03 Test Schedules
    - 3rd party meters must meet the test frequency as provided in the rule.
    - 1% or 500 meters must be tested annually, whichever is greater. The owners of 3rd party meters should be responsible for testing their meters annually if they have fewer than 500 meters.
    - 3-phase, self-contained meters are tested on a 12 year cycle.
    - Unitil tests its single-phase, transformer-rated meters on an 8 year cycle.
  - 305.05 Customer's Bill Adjustments
    - When a 3rd party meter is responsible for an under- or over-billing error, the 3rd party must be responsible for the refund or invoice of the billing difference. Moreover, where the 3rd party meter error results in unbilled kilowatt hours, the period "look back" restrictions should not apply, so that the utility and its other customers are protected from any financial responsibility for unbilled payments.
- 306 Equipment and Facilities: Unitil tests its 3-phase, transformer-rated meters on a 4 year cycle. If the 3rd party has employees who work on their metering equipment, they must develop procedures for the following:
  - 306.05 Resuscitation
    - All individuals and entities who engage in work on electrical equipment must receive instruction on safety procedures for resuscitation from electric shock.
  - 306.06 Notifications of Accidents and Property Damage
    - All individuals and entities must have procedures in place to notify the Commission in the event of applicable accidents and significant events as required by this section.
  - 306.07 Commission Inspection
    - Metering associated with EV charging must be inspected from time to time by the Commission to ensure such equipment has conformed and presently conforms to PUC rules.
  - 306.10 Physical and Cyber Security Plans, Procedures and Reporting

        - Compliance with Rule 306.10 must be required for all 3rd parties owning meters critical to the delivery of power to NH customers if they are storing and transmitting sensitive data.
        - A Physical Security Plan must be developed to protect critical equipment and facilities from security breaches.
        - A Cyber Security Plan must be developed to protect critical cyber assets, if such assets exist. Critical cyber assets in the context of meter reading would include equipment used to transmit and store meter read data. A comprehensive Cyber Security Plan must include the following for both on premise and cloud environments:
            - Disaster Recovery
            - Incident Response Plan with Detailed Breach Reporting
            - Security Awareness Training
            - Vendor Assessment and Management
            - Auditable IT Controls for Risk Mitigation
            - Vulnerability Management
            - Change Control
            - Asset Management
            - Hardening Standards
            - User Access Security
            - Protection of Personally Identifiable and Sensitive Information
            - Data Loss Protection
            - Intrusion Detection
        - Both of these plans must be annually offered to the PUC for review.
        - Form E-37 Quarterly Report of Equipment Theft, Sabotage and Breaches of Security must be submitted to the PUC.
- 307 Records and Reports
    - 3rd party metering must be subject to record and report rules regarding the operation and performance.
    - Such records should be kept or made available in New Hampshire.
    - The Commission must have access to such records for examination.
    - Reports made to the Commission must be filed in conformance with procedures developed by the Commission including but not limited to the E-2 Quarterly Report, E-3 Annual Report, E-3A Report, E-4 Monthly Report, and E-5E Accident Report.
- 308 Forms Required: 3rd Parties must provide the appropriate records and reports to ensure procedures are being followed.
    - 308.03 E-3 Annual Report of Total Electric Meter Test
        - The E-3 Annual Report of Total Electric Meter Tests must contain test data for all the meters that were tested as part of the annual testing program as well as miscellaneous meter tests that were performed that year.
    - 308.04 E-3A Report on Selective Sample Tests of Weighted Average Accuracy on Self-Contained Single-Phase Meters and Network Meters

    - This report must be filed annually and contain the weighted average accuracy test data for the 1% of total meters that were selected for sample tests of self-contained single-phase and network meters.
  - 308.05 E-4 Monthly Report on Electric Meter Complaint Tests
    - Monthly reports must be filed detailing electric meter complaint tests using Form E-4.
  - 308.17 Quarterly Report of Equipment Theft, Sabotage and Breaches of Security
    - Quarterly reports must be filed detailing equipment theft, sabotage, and breaches of security using Form E-37.

<u>ISO New England (ISO-NE) Operating Procedure No. 18, Metering and Telemetering Criteria (OP-18)</u>[9]

ISO-NE Operating Procedure No. 18 may serve as a useful example of shared metering services. If 3rd party metering is to be used for utility purposes, the Unitil recommends that the PUC develop a 3rd party meter reading procedure that addresses operational and applicable standards. This procedure must highlight the complexities and requirements to ensure meter readings can be relied upon for operational and/or billing purposes. In addition to this procedure, the PUC must consider 3rd party metering governance regarding approval and rejection of 3rd party metering entities, contract requirements, and problem escalation. The March 5, 2020 revision of ISO-NE Operating Procedure No. 18 has been included at the end of these comments for reference by the Commission.

<u>Meter Man Handbook</u>

Another useful reference for metering considerations is the Meter Man Handbook. It is used by meter personnel as a reference to theory, processes and procedures associated with the metering field.

<u>Privacy and Security Requirements of 3rd Party Service Providers: Privacy and Security (NH RSA 363:38)</u>

Compliance with NH PUC 363:38 Privacy Policies for Individual Customer Data - Duties and Responsibilities of Service Providers must be required.

For all 3rd parties storing and transmitting customer data:

- Customer consent must be required for sharing of individual customer data with limited exceptions.
- Customer data must not be sold without express customer consent.
- 3rd parties must not incentivize a customer for access to their data.
- 3rd parties must only collect, store, use and disclose the amount of data required to accomplish primary purposes and use the data only for that such purposes.
- Customers must be allowed to access their own data without being required to disclose it.
- 3rd parties must use reasonable security procedures and practices to protect individual customer data.
- Aggregated and anonymized customer data may be used for analysis, reporting or program management.

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[9] https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op18/op18_rto_final.pdf

- Any entity that receives shared customer data must be subject to a service contract requiring implementation and maintenance of reasonable security procedures and practices to protect the data and prohibition of secondary commercial use.
- All 3rd parties requesting access to individual customer data from a utility for system, grid, or operational needs, or the research, development, and implementation of new rate structures and tariffs, demand response, customer assistance, energy management, or energy efficiency programs must be subject to a service contract requiring implementation and maintenance of reasonable security procedures and practices to protect the data and prohibition of secondary commercial use.
- Data sharing required by law or subject to warrant or subpoena or PUC order must be supplied.

Communications/Networking, Integrations, Data Processing Considerations

No single common standard exists for the format, transmission or quality assurance of the types of 3rd party metering data being considered for integration with the utility backend systems. This lack of data standardization across 3rd party devices will introduce considerable cost, complexity and risk to the utilities and could make some integrations untenable to support or even impossible to implement.

Similar discontinuities exist across the communication protocols leveraged by 3rd party devices which would necessitate time consuming and complex connectivity testing and potential development of multiple incompatible interface types.

Unitil recommends that a standard, similar to the ISO OP-18 Operating Procedure, be developed to ensure consistent and maintainable interfaces with utility systems. Such operating procedures would provide both technical specifications for data integration as well as outline the potentially complex and broad human processes that surround the technology and enable the actual onboarding of a 3rd party device and "turning on" the data flows.

These operating and data sharing procedures would cover the following broad topic areas, amongst others:

- Acceptable application protocol interface (API) standards supported by the utilities with a documented list of API protocols and methodologies supported by the utilities and the 3rd party devices.
- Data quality standards and guidance.
- Integration and communication testing requirements.
- Data security considerations in transit and while at rest.
- Change control processes and governance.
- Problem reporting and resolution procedures.

Meter Work Coordination

Operating procedures for meter changes and inspections are tracked for coordination and reporting purposes. 3rd parties must be required to develop procedures for coordinating meter work that consider utility requirements for reporting and assurance. Unitil's procedures are outlined below for reference and consideration:

- Meter work is tracked through a work order system.

- Work orders are created though the customer information system, automatically transferred to the mobile data system, and then assigned to field technicians to their mobile technician application.
- The work performed is recorded on an electronic work order.
- When the work is complete, the technician changes the work order status to complete and the account in the customer information system is updated to reflect that the work order was completed and the account is updated with the technicians' notes.

Utilities Uses of Metering Data Other than Billing and Measurement

Unitil's metering systems also provide useful power quality and reliability information in real-time which is used in live outage determination and reporting. The use of 3rd party metering will reduce this capability and operational value. Preference should be given to metering that provides this information without adding additional integration costs.

Management and Processing Costs

The management and associated processing of 3rd party meter data for billing purposes will likely result in additional costs to validate and integrate into utility systems and processes. It is currently unknown what form 3rd party metering data for EV charging would take; Unitil recommends standardization for EV charging metering data to strengthen interoperability and reduce potential costs.

Programming of Different Rate Designs

Unitil believes that a suite of rate options should be offered for EV customers with varying rate designs, structures, time blocks, etc., in order to accommodate differing customer types, charging, and travel needs. 3rd party charging metering equipment should be capable of supporting a variety of such rate designs with programming changes that do not limit customers' ability to leverage future options.

Unitil appreciates the opportunity to provide these comments regarding EV TOU charging rates and infrastructure development efforts. Please do not hesitate to contact me if you have any additional questions concerning this matter.

Sincerely,

Carleton B. Simpson

Carleton B. Simpson
Attorney for Unitil Service Corp.

ISO New England Operating Procedure No. 18
Metering and Telemetering Criteria (OP-18)

Effective Date: March 5, 2020

REFERENCES:

ISO New England Inc. Transmission, Markets, and Services Tariff Section I - General Terms and Conditions Section I.3.9 Review of Market Participant's Proposed Plans

ISO New England Market Rules and Procedures

ISO New England Planning Procedure No.11 - Planning Procedure to Support Geomagnetic Disturbance Analysis (PP11)

ISO New England Operating Procedure No. 14 - Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources (OP-14)

ISO New England Operating Procedure No. 17 - Load Power Factor Correction (OP-17)

ISO New England Manual for Market Rule 1 Accounting Manual M-28 (Manual M-28)

ISO New England Manual for Definitions and Abbreviations Manual M-35 (Manual M-35)

ISO New England Manual for Registration and Performance Auditing Manual M-RPA (Manual M-RPA)

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I. PURPOSE

This Operating Procedure (OP) establishes standards for metering (measurement) and telemetering (data transmission) for the purposes of ISO New England (ISO) dispatching, market settlement, Transmission Owner (TO) and Market Participant (MP) peak load determination, factors that impact voting shares and load power factor (lpf) measurement. This OP identifies the power system parameters that each TO and MP are to meter and/or telemeter. This OP also establishes standards to verify that the equipment that each TO or MP installs can provide an appropriate level of accuracy and/or appropriate recordings for audit purposes. This OP further prescribes maintenance procedures and schedules to be followed by each TO and MP so that the attainable level of accuracy may be realized.

There may be additional metering and telemetering requirements established by local state utility control and distribution utilities.

II. IMPLEMENTATION

A. Applicability

1. Each TO and/or MP shall have in-service all the metering, recording and telemetering equipment necessary to meet the requirements of this OP as described in Sections II.A.2 and II.A.3 of this OP.
2. For new and Non-Emergency Replacement Equipment, all requirements described in this OP shall be met on or before the date when the asset, line, or system commences operation.
    a. The operational commencement date shall include all test power activities unless the ISO determines that compliance with the requirements is not necessary during test power activities.
    b. Starting on the operational commencement date, each TO and/or MP shall meet all testing, calibration, and maintenance requirements established in this OP.
    c. If any requirement of this OP cannot be met by the operational commencement date, then, prior to the operational commencement date, the TO and/or MP shall submit a mitigation plan request or an exemption request pursuant to, respectively, Section II.B or Section II.C of this OP.
3. Equipment existing prior to the effective date of the current version of this OP (i.e., March 5, 2020) ("Pre-existing Equipment") shall meet the requirements of this OP as described in this Section II.A.3.
    a. Pre-existing Equipment shall meet the currently effective version of the requirements in Sections III, IV, V, and VI of this OP.
    b. Pre-existing Equipment shall be required to be compliant with the version of the requirements in Sections VII and VIII of this OP that was in effect when the equipment commenced operation.
    c. For any Pre-existing Equipment that is found to not meet the requirements of this OP as described above in Sections II.A.3.a and II.A.3.b, the TO/MP shall submit a mitigation plan request or an exemption request within 30 calendar days of the finding.

d. If the ISO observes that the Pre-Existing equipment shows a severe anomaly, then the ISO may require that the equipment be replaced or repaired in order for it to meet the currently effective version of all the requirements of this OP.

B. Mitigation Plan Requests

1. A TO and/or MP shall submit a mitigation plan request for one or more of the requirements of this OP when a non-compliant condition is identified (as described in Sections II.A.2.c and II.A.3.c of this OP), if such condition may be corrected in order to meet the requirements of this OP.
2. Included with the request, the TO and/or MP shall provide:
    a. A list of the requirement(s) for which the mitigation plan request is being submitted.
    b. A proposed mitigation plan that describes the actions that will be taken to comply with any outstanding requirements as well as the deadlines for each of those actions.
3. The mitigation plan request shall be submitted to the ISO Customer Service and Training staff.
4. The ISO may request supporting documentation after it reviews the mitigation plan request.
5. The ISO, at its sole discretion, may grant or deny the mitigation plan request.
    a. If the ISO grants the mitigation plan, then the TO and/or MP shall meet the deadlines for compliance with the requirements of this OP as established in the accepted mitigation plan.
    b. For new and Non-Emergency Replacement Equipment, if the ISO does not accept the mitigation plan, then the TO or MP shall comply with the requirements of this OP on the operational commencement date described in Section II.A.2.a of this OP.
    c. For existing equipment, if the ISO does not accept the mitigation plan, then the TO or MP shall revise the mitigation plan as directed by ISO.
6. Upon completion of the accepted mitigation plan, the TO and/or MP shall notify the ISO Customer Service and Training staff, which shall confirm that the mitigation plan has been completed.

C. Exemption Requests

1. A TO and/or MP shall submit an exemption request for one or more of the requirements of this OP if a non-compliant condition is identified (as described in Sections II.A.2.c and II.A.3.c of this OP).
2. Included with the exemption request, the TO and/or MP shall provide:
    a. A list of the requirement(s) for which the exemption is being requested.
    b. An explanation of how the unique configurations of an asset, line, or system would justify the exemption.
3. The exemption request shall be submitted to the ISO Customer Service and Training staff.

4. The ISO may request supporting documentation after it reviews the exemption request.
5. The ISO, at its sole discretion, may grant or deny the exemption request.
   a. If the ISO grants the exemption request, then the TO and/or MP shall not be required to meet the requirements of this OP for which the exemption is granted. ISO may grant exemptions for up to five years from the date of the exemption approval. Before the exemption reaches its end date, the ISO shall review the exemption to determine whether significant changes that warrant revocation of the exemption have occurred. If no such changes have occurred, then the ISO may, at its sole discretion, renew the exemption for up to five years from the date of renewal. The ISO shall review the renewed exemption before it reaches its end date.
   b. For new and Non-Emergency Replacement Equipment, if the ISO denies the exemption request, then the TO or MP shall comply with the requirements of this OP on the operational commencement date described in Section II.A.2.a of this OP.
   c. For existing equipment, if the ISO denies the exemption request, then the TO or MP may submit a mitigation plan pursuant to Section II.B of this OP.

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 High Voltage Direct Current (HVDC) interconnection])
   - Metering, recording and telemetering of megawatt hours (MWh) per hour (i.e. energy per hour)
2. MW and 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 TO/MP and the non-TO/MP who own the line.
4. Wherever feasible, both technically and economically, data transmission in the ISO Reliability Coordinator Area/Balancing Authority Area (RCA/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 MWh 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 applicable TO/MP Local Control Center (LCC) or Supervisory Control And Data Acquisition (SCADA) Control Center (CC), which has responsibility for the particular interconnection line.
3. The watt-hour data shall be compensated for line losses to the ISO RCA/BAA boundary.
4. MWh 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. 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 Inc. Transmission, Markets, and Services Tariff Section I - General Terms and Conditions (Tariff Section I) There is an option for Generator Assets, Tie-line Assets and Load Assets, subject to appropriate authorization[1], to have metering data submitted at the subhourly 5-minute interval. The 5-minute data reported is calculated by measuring the generation or consumption energy in units of MWh in the 5-minute interval and multiplying that value by 12 (resulting in an average generation or consumption in units of MW during the interval). This 5-minute subhourly data reporting option also applies to all other settlement Watt-hour (Wh) and MWh requirements.
2. In order for an Asset to be eligible to participate in one or more of the Markets, the Asset must have 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 Demand Response Resources (DRR), MWh per 5-minute interval data is required for each Demand Response Asset (DRA). 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 a DRA to be eligible to participate in one or more of the Markets, the DRA must have a 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 pursuant to Manual M-RPA.

1 See ISO New England Manual for Registration and Performance Auditing Manual M-RPA (M-RPA_, Section 1

B. Wh Metering and 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 (Manual M-28).
3. For Tie-Line Assets: 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 an hourly interval in accordance with Section VII.B.5 of this OP. If the option for submitting 5-minute interval data is used, the quantities must be automatically recorded at **no** greater than the 5-minute interval.
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. (See section IX.D.5 for required energy comparison)
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 or subhourly 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 TOs/MPs or,

   iii.) the agreed upon point of interconnection between a TO/MP and a non-MP.

   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 is **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 DRAs, the 5-minute (MWh) data submitted to the ISO in accordance with Manual M-28 shall be either energy billing quality as defined in OP-18, Appendix C - Minimum Accuracy Standards For New And Upgraded Metering, Recording And Telemetering Installations And For Calibration Of Existing Equipment (OP-18 App C) or in the case where metering is installed specifically for the DRA (and will **not** be used for utility billing purposes), a metering system with an overall accuracy as defined in App C may be used. Metering used for utility billing purposes is also known as revenue quality metering.

C. Generator Assets

1. Generator Assets directly connected to the 345 kV (or above) 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. Generator Assets directly connected to the PTF system at 230 kV or below where PTF boundary metering is utilized shall be metered at the PTF boundary or compensated to the PTF boundary in accordance with Section IV.B of this OP.
3. Generator Assets directly connected to the PTF system at 230 kV or below where PTF boundary metering is **not** utilized 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. Generator Assets **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-Line Assets connect a TO/MP to another TO/MP, a non-MP or the 345 kV (or above) PTF system. Tie-Line Assets are also used to connect different sections of a TO/MP system that is divided by a Load Zone boundary.
2. Tie-Line Assets shall have a Wh meter or in the case of intra-TO/MP tie-lines an instantaneous watt meter to calculate Wh at the Interconnection Point or compensated to the Interconnection Point with the other TO/MP or non-MP unless otherwise agreed to by the parties involved or the PTF boundary as appropriate and in accordance with Section IV.B of this OP.
3. Intra-TO/MP tie-lines are Tie-Line Assets used to connect different sections of a TO/MP system that is divided by a Load Zone boundary. For these Tie-Line

Assets, MWh per hour data derived from integrating instantaneous MW data used for Dispatch purposes (Section V.) is acceptable provided the metering equipment meets the minimum accuracy standards defined in App C.

E. Load Assets

1. Every Load Asset except DRAs shall have a Wh meter or be determined on an hourly basis as an allocation of Wh meters. The 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 TO/MP 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 State Estimator (SE) in accordance with the procedures embodied in Manual M-28, will be supplied to the TO/MP by ISO, and will be subtracted from the total load as metered, to determine a TO/MP non-PTF demand.

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

A. Generator Asset, Alternative Technology Regulation Resources (ATRR) and Load Telemetering Criteria

Metering, as set forth below, is required for all Generator Assets and Load Assets (excluding DRAs) which are modeled and defined in the ISO Energy Management System (EMS) and are eligible to participate in the hourly markets. The metering must measure the Generator Asset or Load Asset as it is offered or bid in the Market in accordance with OP-14. Additionally any major change to modify an existing facility shall also conform to the procedures set forth below.

The following quantities are to be telemetered:

1. Market Requirements:
   a) Generator Asset net (Net_1) MW, net (Net_1) MVAr and Generator Step-Up (GSU) transformer high and low-side breaker status must be telemetered. Refer to OP-18, Appendix D - OP-18 Metering and Telemetering Diagrams (App D) 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.
   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 OP-18, Appendix E - OP-18 Metering and Telemetering for Pseudo Combined Cycle Generator (App E) for definition of Net_3.
   d) **No** telemetering is required for Generator Assets receiving “Settlement Only” treatment and generators **not** registered in accordance with OP-14**.**
   e) ATRR MWs must be telemetered. MVAr must be telemetered for non-aggregated ATTRs with a maximum regulation capacity of 20 MW injection/consumption or larger and for aggregated ATTRs with a maximum Regulation capacity of 75 MW injection/consumption or larger.

NOTE

OP-18, Appendix G - Price Responsive Demand RTU Specification (App G), is a Confidential document and distributed in accordance with the ISO New England Information Policy. If document access is required, contact ISO Customer Support as detailed on the ISO external website.

f) For DRAs, MWh per 5-minute interval must be telemetered and meet the requirements specified in OP-18, App G. The MWh per 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 Manual for Definitions and Abbreviations Manual M-35 (Manual M-35). In addition to 5 minute data, any DRA providing TMSR or TMNSR shall supply 1 minute or less MW telemetry at the retail delivery point.

g) Other data may be required to be telemetered, as determined on a case-by-case basis based on bulk power system (BPS) monitoring and operations requirements and also based on how ISO models the Asset. The determination of the data that must be telemetered will be made jointly by ISO, the LCC/SCADA CC and the MP.

h) Geomagnetically induced current (GIC) in DC neutral amperes (ANDC) from each GSU transformer subject to the requirements of Section 3.11 of ISO New England Planning Procedure No. 11- Planning Procedure to Support Geomagnetic Disturbance Analysis (PP11). The measured GIC value shall have the following direction convention: a positive sign shall indicate the GIC flows from ground into the transformer neutral, and a negative sign shall indicate the GIC flows from the transformer neutral into ground.

2. Reliability Requirements:

   a) Generator Asset Net MW, and Net MVAr, as measured at the low side of the GSU transformer. Refer to OP-18, App D for definition of Net. Combined cycle plants are required to supply measurements for each unit.

   b) Automatic voltage regulation (AVR) indicator, which indicates whether the unit(s) and/or Flexible Alternating Current Transmission System (FACTS) device(s) is/are in automatic voltage regulating mode and regulating voltage. This includes AVR status for individual generators or synchronous condensers, that are part of a composite Asset, except for wind plants which are described in (i) below.

      i. For a wind plant, the AVR status indicates the combined status of all the various pieces of equipment that make up the voltage regulation system. That equipment may include Dynamic Volt-Amp Reactive (D-VAr) devices, capacitor banks, master control computers, breakers, Static VAR Compensators (SVCs), FACTS, Special Protection System (SPS) equipment, or any other equipment that contributes to the functioning of the full specified voltage regulation capability. If any of these contributing pieces of equipment are degraded or out of service then the

AVR status indicator should indicate OFF

c) Power system stabilizer status shall be provided if installed.

d) MW and MVAr station service load values may also be requested.

e) Generator Asset terminal voltage measurements may also be requested.

f) Other telemetered data to be determined on a case-by-case basis which are required for ISO BPS monitoring and operation based on how ISO models the Asset. The determination of the data that must be telemetered will be made jointly by ISO, the LCC/SCADA CC and the MP.

g) OP-18 Appendix A - ISO New England ICCP CNP Node Requirement (App A) defines the binary representation expected for status data types.

B. TRANSMISSION SYSTEM TELEMETERING CRITERIA

The following quantities are to be telemetered. Any major change to modify an existing facility shall conform to the procedures set forth below.

1. Transmission substation voltage from the following:

    a) Each generating station 50 MW or larger that connects to the 69 kV and above transmission system.

    b) Each 115 kV and above substation where two (2) or more line sections terminate with protective circuit interruption capability, such as a circuit breaker.

NOTE

The preferred measurement of bus voltage is phase-phase. In the event that phase-phase measurement is **not** provided, a phase-phase value calculated from a phase-ground measurement will be acceptable.

2. Substation frequency from the following:

    a) Each station that either (i) has a Designated Blackstart Resource **OR** (ii) has generation capability that is 50 MW or larger (nameplate).

    b) Each 230 kV and above substation.

    c) Each 115 kV substation where two or more line sections terminate with protective circuit interruption capability, such as a circuit breaker.

    d) On or before October 1, 2020, each Transmission Owner shall submit to the ISO a list of its substations that do not already provide substation frequency as of the date of submission of such list. Transmission substations included in each Transmission Owner’s list shall be exempt from meeting the requirements of this Section V.B.2. Transmission substations that already provide substation frequency and are therefore not included in a Transmission Owner’s list shall continue to provide substation frequency as required under this Section V.B.2. For any new transmission substations, a Transmission Owner may request an exemption pursuant to Section II.C of this OP. ISO may require that a transmission substation included in a Transmission Owner’s exemption list meet the requirements of Section V.B.2 if a reliability need for the data from that transmission substation arises.

3. MW and MVAr from each terminal of all non-radial inter-LCC lines.

4. MW and MVAr from every terminal of all 230 kV and above lines and at least one end of each non-radial 115 kV line.
5. MW and MVAr from each transformer connected to 115 kV and above.
6. MW and MVAr from one end of each intra-LCC line which is necessary for reliable transmission operation, to support BPS transfers, or is otherwise needed.
7. The status of each breaker 115 kV and above.
8. Any transformer with voltage regulation capability that has a low side voltage of 115 kV or above shall provide the status of its voltage regulating state. This is commonly referenced as a load tap changer (LTC) AVR status.
9. The on-load tap changer (OLTC) tap positions of each autotransformer connected to 230 kV and above and each phase-shifting transformer connected to 115 kV and above.
10. Other telemetered data to be determined on a case-by-case basis which are required for ISO-NE BPS operation (i.e., synchronous condensers, HVDC terminals, SVC, capacitor/reactor status, frequency, FACTS devices, Northeast Power Coordinating Council Inc. [NPCC] Type I BPS SPS equipment and selected 69 kV switching devices). The determination of the data that must be telemetered will be made jointly by ISO, the LCC/SCADA CC and the MP.
11. GIC in ANDC from each transformer subject to the requirements of Section 3.11 of PP11. The measured GIC value shall have the following direction convention: a positive sign shall indicate the GIC flows from ground into the transformer neutral, and a negative sign shall indicate the GIC flows from the transformer neutral into ground.

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 and ATRR Regulation Service providers, 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 ISO CFE.
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 all DRAs, data shall be submitted in 5-minute intervals. For a DRR to provide TMSR or TMNSR, DRA telementry values shall be submitted at least every one minute. This data requirement recognizes the change detection logic employed by some RTUs is telemetered to the SCADA system only after a change in the data 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. Telemetered Data Criteria

The following communication paths shall be established to make the required telemetered data available. Some paths are dependent upon the Asset being defined as dispatchable per OP-14.

1. Generation data (Section V.A) shall be made available to the LCC or SCADA CC in which the Asset resides. The LCC/SCADA CC shall make this data available to the Intrapool ICCP network.
    a. If the Asset is dispatchable the generation data shall also be made available to ISO via the CFE (see OP-18, Appendix F - ISO Communications Front End (CFE) Interface Specifications (App F). Some dispatchable types have additional data requirements as specified in OP-14 that shall also be provided to ISO. ISO will make all of this data available to the ICCP network.
    b. If the Asset is dispatchable and the Asset nameplate generation capability as defined by the NX-12 technical data is less than 15 MW, the LCC/SCADA CC may request an exemption to providing this data. The LCC/SCADA CC should submit the exemption request to ISO and provide a technical explanation as to why the data **cannot** be obtained. ISO reserves the right to deny the exemption.
2. Transmission system data (Section V.B) shall be made available by the LCC/SCADA CC to the Intrapool ICCP network. This data shall also be made available to the ISO via the CFE if applicable.
3. The following Asset types from Section V.A shall connect directly to ISO per OP-18, App F or OP-18, App G requirements as applicable to supply data:
    a. DARDs
    b. ATRRs
    c. DRAs

E. Non-Telemetered Data Criteria

Additional data has been defined as necessary for the overall operation of the ISO/LCC/SCADA CC/TO/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/SCADA CC/TO/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 (UCMs).
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.

F. Telemetered Data Identification

NOTE
OP-18 App F is a Confidential document and distributed in accordance with the ISO New England Information Policy. If document access is required, contact ISO Customer Support as detailed on the ISO website.

ISO, each LCC/SCADA CC, each TO and each MP shall uniquely and correctly identify the data being supplied to the network using the format described in OP-18, App A for CNP sourced data and in OP-18, App F and OP-18, App G for ISO CFE data.

VI. METERING FOR POWER FACTOR MEASUREMENT PURPOSES

Each TO/MP shall submit to ISO the quantities necessary to calculate TO/MP lpf as prescribed in ISO New England Operating Procedure No. 17 - Load Power Factor Correction (OP-17). A sufficient number of the necessary quantities must be metered and recorded so that the resulting lpf is a valid calculation.

VII. EQUIPMENT STANDARDS FOR NEW AND UPGRADED INSTALLATIONS

This section specifies standards for metering, recording and telemetering equipment that each TO/MP installs in all new and upgraded installations. A TO/MP is **not** precluded from maintaining or repairing existing equipment with like or improved components, but each TO/MP is required to choose equipment that meets all standards of this OP and the ISO New England Inc. Transmission, Markets, and Services Tariff Section I - General Terms and Conditions Section I.3.9 Review of Market Participant’s Proposed Plans when the equipment is replaced for purposes other than maintenance or repair (i.e., an upgraded installation).

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. HVDC metering devices shall meet or exceed the accuracy requirements of ANSI standards as noted below in 1, 2, and 3.

1. Integrated metering quantities, such as watt-hours and the associated demand components should conform to ANSI standard C12.
2. Instruments or transducers for the analog or digital measurement of telemetered quantities, such as MW, 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

1. The design accuracy of individual components as well as overall systems shall conform to the standards contained in App C.
2. Electro-mechanical Wh meters shall **not** be installed.
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. The requirement for data recorders and for integrated metering quantities shall be satisfied with the types of equipment listed below. Either type may be used internally or on interconnections with systems outside ISO.
   - A data recorder shall be installed at the metering location. Data shall be retrieved from recorders by on-site or remote interrogation. Where the TOs/MPs mutually agree to the need for joint access to this recorded data, remote communications equipment is recommended to be installed
   - A multifunction meter shall be equipped with an 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 TOs/MPs mutually agree to a need for joint access to this recorded data, the meter program shall be secured appropriately.
   - The data recorder or multifunction meter equipped with an interval data recorder shall **not** be dependent on the alternating current (ac) voltage that it is metering as the sole power source if an alternative power source exists at the metering location (such as an ac station service emergency panel feed, a direct current (dc) battery or “street power”).
5. All data recorders shall be synchronized in time, within an accuracy of +/- 15 seconds, with the National Institute of Standards and Technology (NIST) periodically and when they are installed or returned to service after maintenance or repair.
6. 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 OP-18 Section IV.B.7.

VIII. REQUIREMENTS FOR DATA COMMUNICATIONS EQUIPMENT FOR TELEMETERING SYSTEMS

To ensure reliable data communications for telemetry, the telemetry equipment (RTU, Digital Metering, communication equipment etc.) located at and between stations [owned by an MP or Designated Entity (DE)], the LCCs/SCADA CCs and ISO, supporting telemetry data is required by this OP:

1. The equipment shall **not** be dependent on a single ac power source. The power source shall be a station battery or an uninterruptible power source capable of supporting the anticipated load for at least eight hours.
   - Communication only facilities (terminal or intermediate) should have a battery rated for at least eight (8) hours and a suitable backup power source for extended periods.
   - This includes telephone company equipment co-located with MP or DE equipment.
2. Dedicated communication circuits or a utility-owned communication network shall be used. Utility-owned communication facilities should be used as the preferred means of data communication. Tie-Line Asset telemetering with external ISO ties must use “electric utility-owned” communication facilities.
   - The intent of “electric utility-owned” is to exclude commercial telecom providers for Tie-Line Asset communication circuits. Tie-Line Asset

communication circuits, if redundant, shall have at least one (primary or backup) that must be electric utility-owned.

- "Electric utility-owned" may also be jointly owned as a communication circuit that may traverse multiple utility service territories.
- "Communication facilities" noted above refer to all components (i.e.,: terminal & intermediate equipment & communication media)

3. At stations where two battery systems are provided, it is desirable that each should be made capable of being a power source for the equipment.
4. The equipment shall be capable of operating in a temperature range of -20°C to +50 °C for equipment within the control building or -40 °C to +50 °C for equipment installed in other outdoor enclosures. This temperature range is based upon the conditions that could exist when the ac power source is lost and as a result, air conditioning or heating is lost.
5. 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).
6. Alarms shall be provided to the appropriate LCC/SCADA CC indicating the status of equipment covered by this section.

IX. TESTING, CALIBRATION AND MAINTENANCE STANDARDS

A. Overall Requirements

Each TO/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 App C.

B. Overall Telemetering System Test

Whenever transducers and/or telemetering systems are tested, an overall system test shall also be conducted. This system test includes the use of the calibrated transducers output as an input to the telemetry system. All receiving devices shall be verified against the applied input.

C. Telemetry Component Tests

To ensure the accuracy of telemetered data, each TO/MP shall do one of the following:

1. Use manual or computerized routines to check telemetered quantities (MW, MVAr & kV) against each other, revenue meter quantities and/or against derived values of an SE, to identify unreasonable values at least one day once a calendar month as detailed in Section IX.C.1.a below. This option can only be used for equipment after the initial installation (or replacement) test where IX.C.2 (below) would apply for initial installation (or replacement).

   a. Each single day check shall include 24 data samples for each telemetered point, 1 for each hour of the day.

      - While individual hour samples might have variations that exceed tolerances, noted below, where six or more consecutive samples exceed the tolerance in 1-day appropriate calibration, repairs or replacement actions shall be taken.

- Each sample may be from a single point in time within the hour or averaged/integrated over the hour interval.
- Voltage variance, as compared against below tolerances, is each telemetered phase-phase voltage compared against at least one of the two below:
  - The SE resultant bus voltage associated with the telemetered voltage, given in, or corrected to, phase-phase

> **NOTE**
>
> Concerning average of telemetered voltages, when less than three voltages (of comparable phase relationship) are measured at the same substation bus, additional points of reference are needed for comparison. Other points of reference could include, but are **not** limited to, adjacent bus voltages, nearby scheduled voltages, or bus voltage in an SE.

  - The average of all non-zero telemetered voltages that are phase-phase on the same nominal voltage level at the substation. Busses at the same voltage level that are **not** tied should be treated separately.

b. The tolerances for acceptable MW, MVAr and kV telemetered quantities are as follows:

- Watts: +/- 10 MW or +/- 4.5% of the largest fiducial value (whichever is smaller)
- VArs: +/- 30 MVAr
- Voltage: +/- 5 kV for 345 kV systems
  +/- 4 kV for 230 kV systems
  +/- 3 kV for 115 kV systems
  +/- 2 kV for 69 kV systems

c. MVAr quantities will **not** require the above check if the MVAr quantities are measured from the same device that measures the telemetered MW quantities.

- The purpose for this is that measurement drift of a device measuring both would cause errors in both MW and MVAr. Also MVAr variances are often obscured by transformer losses or SE solutions that are **not** perfect.
- With the bus-net method, MVAr quantities that originate from a different device than the associated MW telemetry would **not** be exempt from a MVAr bus-net even if the other telemetry on the bus had its MW and MVAr quantities measured from the same device.
- If a MVAr bus-net is needed, VAr losses can be estimated based upon transformer test data to mitigate bus-net VAr error.

2. Calibrate or test the accuracy of 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 accuracy limits stated in App C. If during the test, errors exceed this value the device shall be recalibrated, repaired or replaced as necessary to attain that accuracy.

Digital Telemetry employing analog to digital converter(s) (ADC), the gain and offset characteristics of which are continuously monitored, and reported to SCADA, by ADC reference values that are within accuracy limits stated in App C, shall be exempt from periodic calibration requirements. When accuracy limits stated in App C are exceeded, the equipment shall be recalibrated, repaired or replaced as necessary to attain that accuracy. This digital telemetry test exemption can only be used for equipment after the initial installation (or replacement) accuracy test.

D. Watt-hour Meters

1. All Wh meters shall be tested by comparison to a solid-state Wh standard that 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. DC Wh meters - dc Wh metering equipment utilizing voltage inputs for current and voltage sensing shall conform to the following requirements. See Figure 9-1.
   a. DC test voltage source equipment for generating current and voltage inputs to the meter shall be traceable to NIST for accuracy.
   b. Voltmeters used for monitoring the input voltages to the dc meter during the test shall be traceable to NIST for accuracy.
   c. Meter nominal test voltage shall be the meter input voltage corresponding to the nominal operating voltage of the metered line.
   d. Meter “full load test amperes” shall be the meter input voltage corresponding to the nominal operating current of the metered line.
   e. The test points for the meter shall be as follows:
      - Full load test amperes
      - 10% of full load test amperes
      - 50% of full load test amperes
      - 150% of full load test amperes
   f. Where meter pulse outputs are compared to calculated target values, and pulses from a standard, to determine meter accuracy, worksheets detailing the test conditions and target pulse counts will be made available prior to testing the meter. See Table 9-1, below.
   g. If the meter is compensated to account for different operating modes of the metered circuit the meter shall be tested with compensation activated at each of the test points defined above. The operating modes that represent the normal operating conditions shall be tested as a part of periodic testing. All operating modes shall be tested upon commissioning.

h. For engineered (custom) metering systems a hard copy of the current meter program will accompany the meter test documentation.

i. Where both revenue meter data and telemetry data are provided by the same meter, provision must be made to continue the telemetry while the meter is out of the measurement circuit during the test.

j. Where redundant meter schemes are utilized the generation of any alarms or status flags due to differences in measurement between the meters caused by the testing must be documented. Where redundant recorders are used differences in recorded pulse totals due to the testing must also be documented.

k. Where redundant meter schemes are utilized the start and stop time as well as the accumulated test energy for the meter under test will be documented. Likewise, the start and stop time as well as the accumulated energy during the test period will be noted for the in-service meter.

l. A field standard meter that has been programmed identical to the meter under test may be used for certification provided that it meets the accuracy and certification requirements of Section IX.F.

Example Test Scheme for a DC Meter with Voltage Inputs.

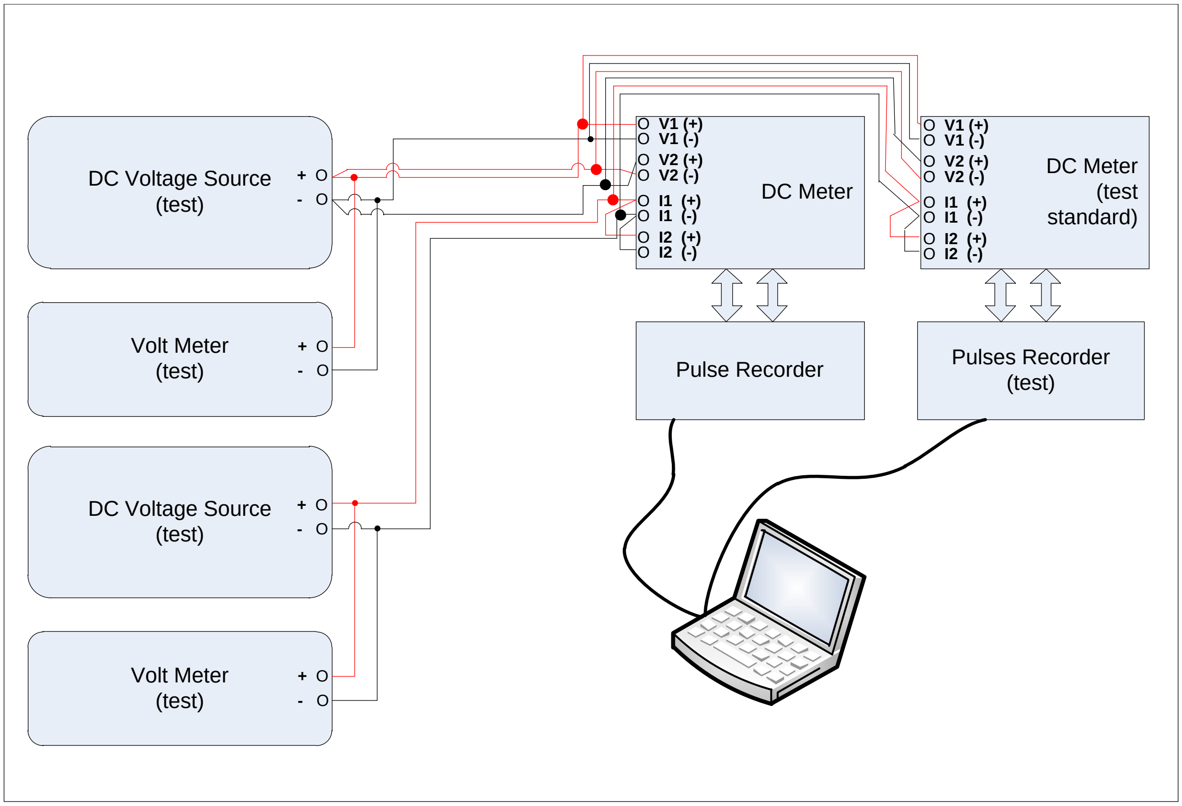

Figure 9-1

Example Pulse Target Worksheet

Test Conditions - Equation 1 (Import / South)		Uncompensated Reference Energy	Meter Reading	Meter Standard Reading	Meter error
Voltage	**Current**	**Pulses***	**Pulses***	**Pulses***	**(%)**
V1: 5V(450kV) V2:-5V(-450kV)	I1:0.5V(225A) I2:0.5V(225A)	506.25			
V1: 5V(450kV) V2:-5V(-450kV)	I1:2.222(1000A) I2:2.222(1000A)	1125			
V1: 5V(450kV) V2:-5V(-450kV)	I1:5V(2250A) I2:5V(2250A)	2531.25			
V1: 5V(450kV) V2:-5V(-450kV)	I1:7.5V(3375A) I2:7.5V(3375A)	3796.88			
* Pulses are 0.2 MWh / pulse. 225A (10%) test uses pulse over 30 min, all other test conditions use pulses for 15 min.					

Table 9-1

3. 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

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 Wh 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 practical to 0.0% error. The final “As-Left” test results shall be within the stated accuracy limits.

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

b) Single point three-phase test using the actual in-service load and meter uncompensated [**not** permitted for testing induction type Wh meters].

   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 light-load (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 practical to a 0.0% error or promptly replaced. The final "As-Left" test results shall be within the stated accuracy limits.

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

4. Meters with compensation for line and/or transformer losses shall be either one or the other of the following:
   - Series tested with and without the compensation activated at the test points as defined in Section IX.D.2.a.
   - Single point tested with compensation checked by comparison of compensated and uncompensated pulse data channels.
5. In-service testing of Wh 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, with noted exception, shall be tested at the frequency specified as follows: All Wh meters must be tested at least once a calendar year with the exception that non-induction type Wh meters, the operation of which is monitored daily, must be tested at least once every two calendar years. The exception is Generator Assets registered as "Settlement Only Generators" whose registered summer and winter claimed capability is less than 1 MW of which shall be tested at a frequency in accordance with the local state utility control and distribution utility requirements for retail loads.
6. Periodic Energy Comparison

   a) Data recording equipment external to the meter shall be checked monthly by comparing a summation of the hourly demand readings with the kWh registered on the Wh meters for the same period of time. When only small quantities (less than 7,200 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 kWh registered on the Wh meter should be less than the value of the Wh meter transformer ratio multiplier. When this difference is greater, the installation shall be reviewed and tested if the discrepancy is **not** explainable.

   b) For DRAs, data recording equipment external to the meter shall be checked at least annually by comparing a summation of the hourly demand readings with the kWh registered on the Wh 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.
7. 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 Wh 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 based on 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 and ANSI C57.13.

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. Non-induction type Wh standards of 0.1% or better accuracy shall be used in the testing of Wh meters. All Wh standards shall be certified correct every twelve months.

NOTE

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

All Wh standards should be certified by comparison with laboratory standards whose accuracy is traceable to NIST. The standard certification values may be determined by the use of data obtained through round-robin procedures between TOs/MPs, provided that 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. All telemetry standards shall be certified at least once every 24 calendar months.

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

Each TO/MP is to maintain records of the testing, calibration and verification of all metering and telemetering equipment which is required to be installed according to the provisions of this OP. The records are to include:

- Entity name
- Element (line, bus, transformer, etc.) name covered by telemetry
- Name of telemetering device (or system)
- The dates of testing, calibration or verification
- % error of as-found (and as-left if recalibrated or replaced)

- A note, if as-found is **not** within accuracy tolerance
- Action(s) taken (if applicable) including date(s) of action(s)

These records are to be retained for a minimum of the two most current testing (or verification) cycles or since the last audit (whichever is greater) and are to be available to ISO and the LCC upon request.

H. NOTIFICATIONS

When metering and telemetering equipment associated with TO/MP interconnections is scheduled for maintenance, test or upgrade, interconnected TOs/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.

XI. COMPLIANCE

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

XII. DEFINITIONS

- **Fiducial Value -** A value to which reference is made in order to specify the accuracy of a transducer. The Fiducial Value is the span except for transducers having a symmetrical reversible input and output. In this case, the Fiducial Value is half the span. (Reference: ANSI/IEEE 460-1988, lapsed) Examples below:
    - Above the term “symmetrical reversible” means that the positive and negative full scale are equal in magnitude while opposite in polarity and halfway in the span is zero (0).
    - An ac Watt and/or VAr transducer where the inputs (voltage and current) are bidirectional (due to their nature of being ac) and where the values Watts and VArs that would be derived from them based upon magnitude and angle difference are also bidirectional would therefore mean the Fiducial Value half span (the value of positive full scale). Given an example scale of -810 MW to 0 to +810 MW and an absolute error of 7 MW would yield a % error of 0.86% (7 MW / 810 MW) meaning the Fiducial Value would be 810 MW.
    - A transmitter device (such as the RFL 9800 series transmitter) that takes a signal representing a telemetered MW and outputs a frequency shifted by the input would have a Fiducial Value of the full span independent of the input since the output is between a min and max frequency. Given an example input scale of -300 MW to 0 to +300 MW via a -5V to 0 to +5V input signal and the associated output scale being 10 Hz to 20 Hz to 30 Hz, because the output is **not** reversible the Fiducial Value of the output is 20 Hz (Span = 30 Hz – 10 Hz). In that example if the absolute error in frequency was 0.5 Hz, the % error would be 2.5% (0.5 Hz / 20 Hz). The Receiver would similarly have its input as **not** being

symmetrically reversible and so the Fiducial Value would be the full span.

- An ac Volt transducer has a symmetrical reversible input due to it being ac but the output would be unidirectional (zero to full scale) and as such, the Fiducial Value would be the full span but in that case, the full span is equal to the positive full scale as there is **no** negative side to the scale. Therefore, effective accuracy is similar to the Watt/VAr transducer example where the positive full scale ends up being in the denominator.

- **Telemetering (telemetry)** - Transmission of measurable quantities using telecommunication techniques. (reference: IEEE 610.2-1987, including analog and digital below)
  - **Analog -** Telemetering in which some characteristic of the transmitter signal is proportional to the quantity being measured.
  - **Digital -** Telemetering in which a numerical representation is generated and transmitted, the number being representative of the quantity being measured.
- **Transducer** - A device that takes a signal or signals (Volts, Amps, etc.,) and converts it into another signal or signals (milli-Amps, Volts, etc.). Most often used to convert secondary Volts and/or Amp quantities into a scaled signal usable by an RTU (mA or Volt) representing system Volts, Amps, Watts, VArs or Frequency values. Digital meters and digital relays that convert signals into numerical values used for OP-18 compliance will be treated as transducers for this OP.
- **Non-Emergency Replacement Equipment** is any equipment that does not interrupt or alter the flow of data critical to system operation when it fails and that, as such, does not need to be returned to service immediately. This equipment has been categorized as maintenance priorities B and C in Table 1 of Appendix A to ISO New England Operating Procedure No. 2 (OP-2A). As provided for in OP-2A, the maintenance priority of any equipment not included in Table 1 shall be determined on a case-by-case basis by the ISO, the LCC, and SCADA Centers.

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
- -	04/10/17	For previous revision history, refer to Rev 10 available through Ask ISO;
Rev 11	08/03/12	Biennial review by procedure owner; Change font to Arial, changed pagination to “X of Y” and added Hardcopy disclaimer in footer; Added “Confidential to titles of Appendices F & G; Globally used defined acronyms RCA/BAA, BES and MVAr; Added NOTEs in Section V on how to request access to confidential Appendices F & G ; Section IV deleted superseded reference to Manual 35; Globally added a dash between OP and procedure number; Section V.B.2 replaced “bulk power system” with “Bulk Electric System (BES)”; Global replaced “Real Time Demand Response Resource Assets” with Real-Time Demand Response Assets”; Global Capitalized “Asset” in Real-Time Emergency Generator asset”;
Rev 12	08/06/13	Created cover page and inserted standard Hardcopy disclaimer ; In Appendices section retired Appendix B and deleted the OP-18 App B reference in Section IX.A;
Rev 13	05/02/14	Biennial review completed by procedure owner; Added language to Section V.A.1.e to address ATRR telemetering requirements; Globally added responsibilities for Transmission Owners (TO); Minor editorial changes for consistency with current practices and management expectations and administrative changes required to publish a new Revision;
Rev 14	10/05/15	Revised per review by OP-18 working group. Reviewed from Section I “purpose” through Section V “INTERNAL NEW ENGLAND METERING AND TELEMETERING FOR DISPATCH, MARKET, AND RELIABILITY PURPOSES” subsection V.C “Telemetered Data Scan Rates” as well as targeted subjects such as: • Section IX.C.1 to note that it is only for systems already in service. Initial installation requires a calibration test (IX.C.2) • Section IX.C.2 revised language to be more in-line with current equipment and practices as well as referring to Appendix C for accuracy limits instead of having redundant language. • Section IX.D.4 the exception for SOGs <1 MW to this subsection was added • Section XII “Definitions” was added to clarify the applicability of “transducer” and “analog” vs “digital” telemetry equipment
Rev 15	04/10/17	Biennial review completed by procedure owner; Added required corporate document identity to all page footers; updated title of OP-18 Appendix A; Revised per review by OP-18 working group. Various small revision plus more significant revisions in the following sections: • Added specifications for HVDC metering to Sections VII & IX.D • Communication data paths clarified in new Section V.D • Section VIII brought up to date with current practices and terminology • Section IX.C revised with specific testing instructions for manual or computerized routines • Section IX.G expanded with more specific record keeping instructions • Section XII added Fiducial Value definition Truncated the Revision History per SOP-RTMKTS.0210.0010 Section 5.6;
Rev 16	12/08/17	Processed updates related to subhourly settlements: • Section IV updated with references about a 5-minute subhourly option; • Section VII.B updated time synching accuracy requirements;
Rev 17	06/01/18	References Section, deleted LCC Instructions; Appendices Section, updated Appendix G title; Section V.A.f made additional clarification; Section V.C.2, modified (clarified required and optional DRA telemetry timing); Globally updated due to PRD project, where applicable deleted Real-Time Emergency Generation (RTEG) Assets, replaced “RTDR” and “RTEG” terminology and with” DR”;
Rev 17.1	01/23/19	Periodic review performed requiring no changes; Made administrative changes required to publish a Minor Revision;

Rev. No.	Date	Reason
Rev 18	05/07/19	Minor editorial changes to Rev 14, 15 and Rev 16 to be consistent with current practices; Processed conforming changes from PP11, Rev 1 to support NERC Reliability Standard TPL-007-3; • Added PP11 document to References Section • Added new Sections V.A.2.h and V.B.10 specifying GIC monitoring requirements
Rev 19	03/05/20	Changes to section I to be consistent with current practices Section 2 changed to list implementation expectations and the supporting mitigation and exemption processes. Section V.B.2 added to require frequency data along with an initial data listing/exemption process.