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

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5. ISO New England Manual for Measurement and Verification of Demand Reduction Value from Demand Resources (M-MVDR)

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I. INTRODUCTION

A. Background

1. This Operating Procedure (OP) describes the minimum technical requirements for defined Generators, Settlement Only Generators (SOGs) Demand Response (DR), Asset Related Demands (ARDs) and Alternative Technology Regulation Resources (ATRRs) under the control/jurisdiction of ISO New England Inc. (ISO). For the purposes of this procedure, under the control/jurisdiction of ISO is defined as: a) an individual or aggregated asset/resource/unit/facility classification meeting the technical criteria as stipulated in Sections II, III, IV, V, VI or VII as applicable and b) participating in the wholesale electric market. This OP addresses technical requirements, and not the Offer and Bid Data associated with these resources for submission to the Market, that may include parameters of a technical nature. This OP is meant to assure, in conjunction with the market structures that the Bulk Electric System (BES) of the New England Reliability Coordinator Area/Balancing Authority Area (RCA/BAA) conforms to proper standards of reliability. This OP is also meant to establish technical requirements to verify that each Generator, Demand Resource, ARD and ATRR has accurate metered data available for ISO dispatch control and Settlement.

B. Standards

1. Compliance with all applicable ISO Operating Procedures (OPs) is the responsibility of the Lead Market Participant for the Asset (Lead MP). The Lead MP is responsible for identifying a Designated Entity (DE) or a Demand Designated Entity (DDE) for a given Asset, as applicable. However, a Lead MP is always ultimately responsible for all requirements and obligations assigned to a DE or DDE that is performing functions for that Lead MP. Each MP must also comply with all applicable Northeast Power Coordinating Council Inc. (NPCC) and North American Electric Reliability Corporation (NERC) requirements. It is also expected that all elements specified in this OP will be operated utilizing Good Utility Practice including making resources available for service as soon as possible after failures of equipment.
II. TECHNICAL REQUIREMENTS FOR GENERATING UNITS

This section describes the basic technical requirements that a Generator must meet to be considered for offer, dispatch and Settlement. However, Generators must also meet the eligibility requirements of ISO New England - ISO New England Inc. Transmission, Markets and Services Tariff Section III, ISO New England Market Rule 1 - Standard Market Design (Market Rule 1) and ISO Manuals to offer into the Markets.

Requirements outlined in Sections II.C.4 and II.E.1 shall be implemented no later than June 1, 2011 unless agreed to by ISO on a case by case basis based on a demonstration that there is good cause to allow for a delay in implementation for a specified period, and the DE has demonstrated to ISO satisfaction that DE staff will be sufficiently alerted to Emergency Dispatch Instructions (Dispatch Instructions accompanied by an Emergency Message) prior to the full implementation of these requirements. Requirements outlined in Sections II.I.1 through II.I.3 shall be implemented no later than December 1, 2016 unless agreed to by ISO on a case by case basis based on a demonstration that there is good cause to allow for a delay in implementation for a specified period.

Criteria used to define registration options outlined in Section II.A.2 shall be used for all generating facilities on or after May 2, 2014. A Registered SOG completed prior to May 2, 2014 remains as SOG.

A. Generator Defined

1. A Generator must be defined consistently for all ISO applications for the purposes of offers, dispatch and Settlement. Defined Generators are represented in the ISO Energy Management System (EMS) and shall communicate with ISO through its approved DE registered in accordance with ISO Manual for Registration and Performance Auditing (M-RPA) having satisfied all requirements of a DE as defined in this OP in Section II.C - Designated Entity - Performance, Communication and Control.

   a. To define a new Generator, a minimum of one hundred and twenty (120) calendar days advance notice to ISO is required. To change data for an existing Generator definition, a minimum of seven (7) calendar days advance notice to ISO is required. The advance notice period commences upon ISO receipt of the data detailed in Section II.A.6 of this OP.

2. The registration options for a generating facility and eligibility for each option depend on the size and interconnection of each generating facility.

   a. A generating facility (of any size) interconnected at 115 kV or above shall register as a Generator.

   b. A generating facility of five (5) MW or greater interconnected below 115 kV shall register as a Generator.

   c. A generating facility between one (1) MW and less than five (5) MW...
interconnected below 115 kV:

- May register as a Generator
- May register as a SOG or
- May elect to not register if not participating in any Wholesale electric markets other than as a load reducer

d. A generating facility less than one (1) MW interconnected below 115 kV:

- May register as a SOG or
- May elect to not register if not participating in any Wholesale electric markets other than as a load reducer

e. For the purpose of this Operating Procedure, the aggregated maximum net output at or above 0 degrees F and interconnection voltage of a generating facility measured at the point at which the generating facility interconnects to the existing transmission system are used to determine registration options.

f. For dispersed power generating facilities or distributed energy resources the following applies:

(1) For purposes of this Operating Procedure, a common collector is a system, usually operating at distribution or sub-transmission voltage levels, designed primarily for interconnecting capacity to a common point of connection on an existing Transmission Owner/Market Participant Distribution Provider transmission or distribution element. Where the existing point of connection is a substation, the interconnection facilities are commonly referred to as an express feeder. An express feeder by definition serves no load other than that associated with the interconnected dispersed power generating facilities or distributed energy resources.

(2) Multiple resources connected to the same common collector system will be aggregated for the determination of the less than five (5) MW eligibility threshold.

(3) In such cases where the common collector is a dedicated or express feeder serving only generation, all Generators/generator units will be considered in the determination of the less than five (5) MW eligibility threshold.

(4) The timing of interconnection requests will be considered in the determination of the less than five (5) MW eligibility threshold. A separate request by an unaffiliated entity to connect to an existing common collector will not be aggregated with the existing generation in the determination of the less than five (5) MW eligibility threshold.
(5) ISO will consider project information included in the Proposed Plan Application submitted pursuant to Section 1.3.9 of the Tariff to determine if multiple points of connection are present.

3. A Lead MP may combine generator units to form a defined Generator subject to the below Section II.C - Designated Entity - Performance, Communication and Control. Examples of a defined Generator, composed of multiple generator units, include: multi-unit hydro stations, solar farms, wind farms and most combined cycle units. A Lead MP’s right to combine physical generator units to create a Generator for bidding, dispatch and Settlement is governed by the following rules:

   a. Generator units being combined must either be at the same physical site or be part of a project that, by its technical nature, requires coordinated control of the various units being combined to form a Generator.

   b. For a Generator that is a composite of multiple physical generator units, only the defined Generator will be represented, acted upon or allowed to transact in the various Markets.

   c. ISO will determine if generator units located on different electrical buses may be combined and defined as a Generator.

   d. ISO will consider if such a combination of generator units interferes with effective control of probable constraints or accurate determination of system losses, Operating Reserve and Regulation capabilities. The appropriateness of these combinations will be reviewed on a continuing basis.

4. Price offers may only be submitted for a defined Generator.

5. ISO will only perform Settlement functions for defined Generators and SOG.

6. To define a Generator, the Lead MP is required to submit any technical data with respect to a Generator that ISO determines to be necessary for ISO to carry out its responsibility of reliably and efficiently operating the power system. The Lead MP is required to submit the technical data for each physical component of a unit irrespective of whether it is modeled as a single unit or as multiple aggregations of the physical components of the unit, such as the case with some hydro units and combined cycle units. The Lead MP is responsible for submitting and maintaining all requested data of the Generator. A defined Generator must have an approved DE, provide all required data and have all required communications equipment in place and tested in accordance with ISO Procedures prior to being available for dispatch. The Lead MP is responsible for identifying the DE. The Lead MP communicates to ISO through their identified DE for dispatch related matters. The data includes, but may not be limited to, the following, as necessary:
o Generator Technical Data per Appendix A of this Procedure

o Form NX-12D, Generator Reactive Data, per Appendix B of this OP and as summarized in Appendix B of ISO New England Operating Procedure No. 12, Voltage and Reactive Control (OP-12)

o NX-9 data per ISO New England Operating Procedure No. 16, Transmission System Data (OP-16)

o Form NX-9B, Transformer-fixed/GSU/TCUL per OP-16

o Form NX-9D, Capacitor/Reactor per OP-16

o Station one-line diagrams

o Dynamics models for Generators of 5MW or greater compatible with PSS/e including:
  - Generator, including Wind Turbines, Photovoltaic Systems, Fuel Cells and any other resource that delivers MW to the BES and meets the definition of a Generator per this Operating Procedure.
  - Excitation System
  - Governor
  - Power System Stabilizer (if equipped)

Generator dynamics models shall be provided to ISO prior to making changes to generator equipment. Changes to the above listed facilities shall be made in accordance with Tariff Section I.3.9 and Generator Interconnection Procedures. Updates to existing and proposed modeling changes shall be sent to ISO using the e-mail address: geninterconn@iso-ne.com. ISO will initiate recertification of models for existing Generators annually in March. Lead Market Participants for Generators will indicate that the model represents the Generator as configured including Automatic Voltage Regulator and Governor response or that change has been made. Recertification or information showing changes shall be provided to ISO within 45 calendar days of the initial ISO request. Responses shall be sent to ISO as directed in the recertification request letter. The ISO request for recertification will include the modeling information currently maintained by ISO. Refer to ISO Compliance Bulletin MOD-032 for additional information on generator characteristics located at:

http://www.iso-ne.com/participate/rules-procedures/nerc-npcc

PSCAD models for generators using power electronic equipment (e.g., Wind Generators, Power Inverter Equipment)

Designated Entity registration per M-RPA

Nuclear Generator MPs shall provide proposed Nuclear Plant Interface Requirements (NPIRs) in accordance with Master/Local Control Center Requirements.
7. Equipment Requirements:
   

b. A defined Generator shall be connected to only one (1) ISO Communications Front End (CFE) connected Remote Terminal Unit (RTU).
   
   (1) **No** RTU shall control more than five (5) dispatchable Generators without the review and approval of an exemption by ISO.
   
   (2) New exemptions are required for each additional Generator beyond five (5) as previously granted.

   
c. For Generators that are participating in the Market and/or are dispatchable in Real-Time, communications equipment, hardware and software sufficient to enable the DE to receive, acknowledge receipt, and implement ISO Dispatch Instructions electronically and, if necessary, verbally in a timely manner as required by ISO Manuals and Administrative Procedures. The points of contact between ISO and each DE for verbal Dispatch Instructions shall **not** exceed the number of ISO CFE connected RTUs installed for receipt of electronic Dispatch Instructions without prior approval of ISO. Participation in the Energy Market and Reserve Markets is conditioned upon having Electronic Dispatch Capability (EDC) installed. EDC is the ability, through the installation and maintenance of adequate hardware and software and communications infrastructure within the Continental United States, to provide for the electronic transmission, receipt, and acknowledgment of data relative to the dispatch of Generators to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of dispatchable Generators. Generators are considered to have EDC when they are capable of receiving, responding to, and changing output in response to electronic Dispatch Instructions issued to the ISO CFE connected RTU of its DE.

   
d. In the event of a failure of the ISO CFE connected RTU or the failure of communications or other equipment between the ISO CFE connected RTU and the Generators connected to the ISO CFE connected RTU, the DE acting on behalf of the Lead MP shall convey the Dispatch Instructions issued by ISO to the generating unit(s) impacted by the equipment failure within the time and other constraints established by ISO Manuals and OPs, and to diligently pursue the repair and/or replacement of failed facilities on an expedited basis.

8. Whenever a Lead MP wishes to establish or change the DE responsible for managing dispatch for its Generator(s), the Lead MP and DE are responsible for demonstrating to ISO that the proposed DE meets the technical requirements set forth in this procedure prior to the ISO
9. Generators are required to provide and maintain up to date contact information to the applicable Local Control Center (LCC).

B. Telemetering and Revenue Metering

1. Telemetering for the Generator must meet the requirements for speed and accuracy per OP-18. Telemetering must be maintained and calibrated by the Lead MP on an ongoing basis per OP-18.

2. Revenue metering must meet ISO accuracy requirements per OP-18. Meter readings must be forwarded to ISO for Settlement, in a timely manner, as required per ISO Manuals and Administrative Procedures. The Lead MP is responsible for the maintenance and calibration of revenue metering per ISO requirements as contained in OP-18.

3. Metering requirements and modeling options in the EMS and Market Systems for units less than five (5) MW will depend on their registration choice:
   a. Each Generator that is represented in the EMS and Market Systems must meet the telemetering and revenue metering requirements described in II.B.1 and II.B.2 above.
   b. Each generating facility that registers as a Settlement Only Generator must only meet the revenue metering requirements described in II.B.2 above; there are no telemetering requirements.
   c. Each generating facility that is not registered does not need telemetering.

C. Designated Entity - Performance, Communication and Control

1. Each DE provides dispatch services from a single physical location for a defined Generator and shall be the single point of contact to receive, acknowledge receipt, and implement ISO Dispatch Instructions and related communications. If prior approval from the ISO Control Room has been obtained, the operation from a single physical location allows for exigent conditions, as well as for infrequent, periodic testing & training needs.

   - No Entity shall be recognized as a DE unless it meets the requirements in this OP and has been registered pursuant to ISO M-RPA.
   - All DE contact information shall be confirmed and/or updated by the DE on an annual basis or upon change.

2. Each DE shall comply with all requirements of the ISO Operating Documents to the same extent as if the Lead MP were carrying out the functions of the DE.
3. ISO shall communicate with the DE via electronic dispatch through an ISO connected RTU or voice communications through an Auto Ring Down telephone circuit or one of the dedicated 24x7 phone numbers identified during DE Registration in accordance with M-RPA.

4. The DE shall have the knowledge and authority to act on ISO Dispatch Instructions for all ISO registered assets it manages for dispatch, as defined in Section II.F Dispatch Instructions of this OP.

   a. Any control equipment used to start, stop or vary the output of the Generator, from a remote location, must meet the requirements set in OP-18, relative to speed, accuracy and data channel requirements. Such equipment must be maintained by the Lead MP according to ISO requirements contained in OP-18 and ISO New England Operating Procedure No. 2 - Maintenance of Communications, Computers, Metering and Computer Support Equipment (OP-2). ISO System Operators must be notified as soon as practicable if the equipment is incapable of meeting the requirements of OP-18. Steps should be taken to restore the equipment to normal operating conditions as soon as possible in accordance with OP-2.

   b. Each DE must have a dedicated voice communication telephone (assigned public switched network land line phone number) for ISO dispatching purposes unless otherwise agreed on a case-by-case basis by ISO.

5. In addition to the dedicated voice communication telephone, each DE is required to have a dedicated Auto Ring Down telephone circuit to the ISO Control Room for any of the following unless otherwise agreed on a case-by-case basis by ISO.

   a. Each DE managed dispatchable Generator or aggregate of dispatchable generation greater than or equal to fifty (50) MW (net)

   b. A Generator providing Regulation service

   c. Other instances as determined on a case-by-case basis by ISO

   Further, certain Generators are critical to the BES under emergency conditions. These Generators are listed in Appendix D of this OP and are required to install, maintain, operate, test and fund a voice communication system that is independent of the public switched network for the purposes of communicating with its Local Control Center (LCC) during system emergencies such as a system restoration event. The installation, maintenance, testing and operation of the communications system must be coordinated with, and acceptable to, the Generator’s LCC. Each LCC is responsible in turn for providing the requirements for the communications system and coordinating with each Generator to effect the installation, operation and testing of the communications system.

6. Each DE for a Generator that participates in the ISO Markets is required to have equipment capable of reliably receiving and acknowledging receipt of...
Dispatch Instructions sent electronically by ISO as frequently as necessary and to implement Dispatch Instructions in a timely manner as required by ISO Manuals and Administrative Procedures.

7. Each DE is required to display to their DE Operator, the following parameters for each dispatchable Generator, as defined in Section II.A.7 of this OP, in New England that is under their responsibility.
   - ACK Required (i.e., Acknowledgement Required)
   - Message Type
     - (1) Normal
     - (2) Emergency
     - (3) Start Up
     - (4) Shut Down
   - DDP
   - Actual Generation
   - Economic Minimum Limit
   - Economic Maximum Limit
   - Emergency Minimum Limit
   - Response Rate
   - Regulation High Limit (where applicable)
   - Regulation Low Limit (where applicable)
   - Unit Control Mode
   - Heartbeat

8. Acknowledgement and response to Electronic Dispatch via the Human Machine Interface (HMI) of the RTU shall also be performed at the same location as the voice communications unless otherwise agreed on a case-by-case basis by ISO.
   a. Each DE is required to maintain staff on duty to communicate with ISO System Operators at all times.
   b. Each ISO CFE connected RTU shall be connected to one and only one DE. This verifies Electronic Dispatch can be acknowledged by a single, approved DE.
   c. Each DE is required to have equipment capable of reliably receiving and displaying to its operators the data in accordance with Section II.B. - Telemetering And Revenue Metering for each Generator it manages for dispatch

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d. In instances where Dispatch Instructions or any other orders must be issued verbally by ISO System Operators, the verbal communication shall take precedence over all other forms of communication.

D. Designated Entity - Modifying DE Details

1. ISO evaluates all submitted DE change, registration or modification requests according to the required lead times with the requirements stated in this OP. ISO will coordinate with each applicable Lead MP, transitioning DE, communication vendor, and any other authorized party in order to process requests.

2. A Lead MP shall provide at least thirty (30) calendar days notice to change the DE, as defined in M-RPA.
   a. The effective date of the transfer is contingent on the proposed DE meeting the technical requirements and being registered and approved in accordance with M-RPA.
   b. Change requests concerning the DE communications infrastructure, moving the DE location, or changing the contact details can only be submitted by a DE, in accordance with the following:
      1) Changes to dedicated telephone numbers require at least thirty (30) calendar days advance notice.
      2) Modifications to dedicated communications circuits (e.g., for ARD and/or RTU) require at least ninety (90) calendar days advance notice.
      3) Contact details including person performing a role, their phone number and/or email address require at least seven (7) business days advance notice.
   c. ISO approval of the change is contingent on the verification by ISO of the successful implementation and testing of the technical capabilities.

E. Emergency Message Indications

1. Emergency messages shall be displayed to each DE with visual and audible indications:
   a. Each Generator must have a specific Message Type indicator.
   b. Each DE must not employ visual messages that are common to multiple Generators.
   c. Emergency messages must have an audible alarm that is unique to Emergency messages and cannot be disabled.
   d. Emergency messages are Message Type 2 (Emergency).
   e. Messages that require acknowledgement have an ACK Required = 1
1. All Dispatch Instructions (Includes Normal and Emergency)
   a. If a DE is not capable of controlling the delivery of energy in accordance with its Offer Data, the DE is required to notify the ISO System Operators as soon as practicable. Efforts should be made to forecast Generator capabilities based on daily local conditions and submit those parameters appropriately.

2. Normal Dispatch Instructions
   a. Normal Dispatch Instructions are transmitted electronically to each DE every five minutes or less, depending on system conditions.
   b. Manual acknowledgement of a Normal dispatch is not required; however compliance with the Dispatch Instruction is required in accordance with Offer Data without delay.
   c. Fast Start Generators will receive Start Up and Shut Down messages which must be acknowledged by the DE within sixty (60) seconds. This acknowledgement requires physical action by staff at the DE. This item may be waived on a case by case basis by the ISO. Acknowledgement of a Start Up or Shut Down message shall indicate the DE intent to immediately comply with the Dispatch Instruction.
   d. Fast Start Generators shall not be shut down without receiving a Shut Down message. A Desired Dispatch Point (DDP) below the Economic Minimum Limit that is not accompanied by a Shut Down message is considered a dispatch to the Generator’s Economic Minimum Limit.
   e. Under normal Dispatch Instructions, voice communications to ISO Control Room related to the Dispatch Instructions should be limited to only those pertaining to clarifying the Dispatch Instructions.

3. Emergency Dispatch Instructions
   a. Emergency messages will be issued by the ISO System Operators when an emergency issue requires an immediate response by Generators outside of the normal dispatch protocol.
   b. Emergency Dispatch Instructions are transmitted electronically to each DE every five minutes or less, depending on system conditions.
   c. Emergency messages shall be acknowledged by the DE within sixty (60) seconds of the receipt of the message. This acknowledgement requires physical action by staff at the DE. This item may be waived on a case by case basis by ISO New England. Acknowledgement of the Emergency message shall indicate the DE intent to immediately comply with the Dispatch Instruction.
d. Emergency Dispatch Instructions shall be followed in accordance with Offer Data without delay.

e. In an emergency, off-line Fast Start Generators that are called on to start will receive an Emergency message and a non-zero DDP in lieu of a Start Up message. The DDP that accompanies the Emergency Message dictates the desired response from the Fast Start Generator. The DE must take action to comply with the Dispatch Instructions in accordance with their Offer Data.

f. Fast Start Generators shall not be shut down without receiving a Shut Down message. A DDP below the Economic Minimum Limit that is not accompanied by a Shut Down message is considered a dispatch to the Generator Economic Minimum Limit.

g. Any generator providing Regulation when an Emergency message is received shall remove the Generator from Regulation and follow the DDP. Following an Emergency message, the Generator will not be placed on Regulation unless called for by ISO System Operators.

h. While the Emergency message is active, voice communication to the ISO Control Room related to the Dispatch Instructions should be limited to only those pertaining to clarifying the Dispatch Instructions.

G. Operational Considerations

1. A Generator will be dispatched as directed by ISO in accordance with ISO New England Operating Procedure No. 1 - Central Dispatch Operating Responsibilities and Authority (OP-1), and the operating characteristics submitted by the Lead MP. The safety of operating personnel and prevention of damage to equipment are the sole responsibility of the Lead MP, and must take priority at all times.

2. Each Generator that is treated as a Settlement Only Generator may have additional responsibility under ISO New England Operating Procedure No. 4 - Action During a Capacity Deficiency (OP-4).

3. Both the Planned and Maintenance Outages of the Generator will be done in accordance with ISO Generator maintenance scheduling procedures per ISO New England Operating Procedure No. 5 - Generator, Dispatchable Asset Related Demand and Alternative Technology Regulation Resource Maintenance and Outage Scheduling. (OP-5)

4. The Lead MP must, at all times, comply with all applicable switching and tagging procedures in effect by the authorities governing switching and tagging operations in the field.

H. Voltage Control

1. The MVAR production of a Generator is an important factor in the reliable operation of the New England RCA/BAA. Each Lead MP is to support system voltage and reactive needs at the direction of ISO and the LCC per
Op-12. Each Generator in the New England RCA/BAA normally follows a schedule of bus voltages, which is specified for both On-Peak and Off-Peak load periods as contained in OP-12, Appendix B, or as otherwise specified by ISO or LCC. ISO and the LCC have the authority to direct the Lead MP to deviate from the normal voltage schedule to address operating situations. Each Generator is expected to participate, to the limit of their capability as documented in its NX-12D and as summarized in OP-12, Appendix B, to maintain their assigned voltage schedule as directed by ISO or the LCC and to comply with any variations that ISO or the LCC may request.

2. The Lead MP must keep and maintain an automatic voltage regulator (AVR) in service and regulating to the voltage schedule on all generating units comprising a Generator unless granted an exemption under the provisions in Section 5 of Master/Local Control Center Procedure No. 8 - Coordination of Generator Voltage Regulator and Power System Stabilizer Outages (M/LCC 8). Generators that have applied for and received an exemption will be listed in M/LCC 8, Attachment A - Generators Exempted From AVR Requirements.

3. It is the responsibility of each Lead MP (except those for whom an exemption has been granted, as described in Section II.H.2) to maintain the AVR in good operating condition.

4. Each Lead MP shall provide to ISO on ISO Form NX-12D - Generator Reactive Data Form, in accordance with Appendix B of this Operating Procedure, information describing the periods of time when conditions occur (if any) where the Lead MP routinely expects that its Generator will not operate with the AVR in service and controlling voltage (such as during Start Up or Shut Down).

5. Actual or expected changes in AVR Operating status must be reported in Real-time in accordance with OP-12 and M/LCC 8, unless the requirement for such real-time reporting of AVR operating status is automatically waived during the periods of time when Real-time conditions occur that are as described by the Lead MP on Form NX-12D pertaining to when the Lead MP routinely expects that its Generator will not operate with the AVR in service and controlling voltage (such as during Start Up or Shut Down). When such conditions occur that match the conditions described on Form NX-12D, this serves as advance standing notification and Real-time reporting is not required.

I. Governor Control

1. Each Lead MP is obligated to provide, maintain and operate a “functioning governor” on each Generator with a capability of ten (10) MW or greater. For the purposes of this procedure a “functioning governor” includes hardware or software that provides autonomous frequency-responsive power control. This requirement applies to all conventional Generators and non-conventional power sources including but not limited to: defined Generator Assets, aggregated Generator Assets, wind turbine Generator...
Assets, all elements of a photo-voltaic Generator Asset, etc. The equipment providing “governor functionality” shall be set such that:

a. It has a speed droop based on nameplate capability or the value determined in Section II.A.2 of this document set between a minimum of four percent (4%) and a maximum of five percent (5%);

b. It has a frequency response deadband of no greater than 59.964-60.036 Hz; and

c. The real power response is not inhibited by effects of outer loop controls (such as operator set point controls and load control but excluding AGC control) that would override the governor response (including blocked or nonfunctioning governors or modes of operating that limit Frequency Response). Meeting this requirement results in providing primary frequency response.

2. Upon ISO request, the Lead MP shall verify that actual governor operation in response to load control and/or active power/frequency control approximates the specified droop. Verification will be in the form of Plant Information (PI) data indicating MW response to frequency events during a fifteen (15) minute interval (MW and Hz timestamp data five (5) minutes prior and ten (10) minutes post an identified frequency event).

3. The DE, acting on behalf of the Lead MP, shall inform ISO of actual or expected changes in governor operating status per Master/Local Control Center Procedure No. 10 - Generator Governor Control and Operation (M/LCC 10). Each Lead MP is responsible for periodic testing and maintenance of the Generator governor.

4. All Generators within the ISO RCA with a capability of ten (10) MW or greater are expected to have a functioning governor and provide primary frequency response and support to the New England transmission system. ISO will consider a well documented and reasoned request to be exempt from this requirement. All requests shall be submitted through “Ask ISO” and should include “Governor Exemption Request” with the asset name and ID number in the issue summary. Any such request will be reviewed by ISO technical staff for acceptability. Any Generator whose exemption is accepted will be listed on a governor exemption list in M/LCC 10 Attachment A - Generators Exempted from Governor Requirements. A Generator listed in M/LCC 10 Attachment A either does not have a governor or does not operate its governor in conformance with the requirements in this procedure. For all such Generators, ISO has reviewed the impact of this and has determined that this status is acceptable from a reliability perspective. If evaluation is needed ISO will undertake evaluation under the Proposed Plan Application Process (Section I.3.9 of the ISO Tariff). All governor exemption requests will be reported to the Reliability Committee; if accepted by ISO, the Generator Asset and unit, if applicable, will be listed in M/LCC 10 Attachment A. The exemption process will only consider a full exemption from all requirements.
Addition to the exemption list does not preclude reevaluation required with changes processed through the Large Generator Interconnection Procedure (LGIP) / Small Generator Interconnection Procedure (SGIP) Schedules 22 and 23, respectively. These exemption criteria do not relieve that resource from adhering to any other ISO operating document or program requirements.

J. Interconnection

5. A Generator wishing to connect its facilities to transmission facilities must have a valid interconnection agreement(s) in place with the Transmission Owners(s) with which the Generator is wishing to interconnect, or whose facilities are impacted. The terms and conditions of said interconnection agreement(s) shall be negotiated between the entities that are parties to the interconnection agreement(s) and may or may not contain additional and/or more stringent requirements than those prescribed by ISO.

K. System Protection

1. At a minimum, each Lead MP must install and maintain protection systems in accordance with the NPCC Regional Reliability Reference Directory # 4 - Bulk Power System Protection Criteria (NPCC Directory #4) on each unit that is large enough to affect the systems of others. Each Lead MP is responsible for maintaining and upgrading the protection system such that it continues to meet the reliability criteria of NPCC.

2. Relay maintenance and testing that would in any way degrade the level of system protection or system reliability provided by the unit should not occur while the unit is on-line. All requests for such maintenance must adhere to the requirements of ISO New England Operating Procedure No. 3 - Transmission Maintenance Outage Scheduling (OP-3), and local scheduling procedures at the lower voltage levels.

3. Under frequency relays for a unit must be set lower than under frequency relays used to disconnect customers for the purpose of balancing load and generation unless compensatory load shedding has been arranged for by the Generator Lead MP. Section 5.4 of the NPCC Regional Reliability Reference Directory # 12 - Under Frequency Load Shedding Program Requirements (NPCC Directory #12), identifies the frequencies at which owners of generation can unilaterally disconnect from the power system.

L. Power System Stabilizers

1. Where Power System Stabilizer (PSS) equipment is installed on a Generator for the purpose of maintaining system stability, it is the responsibility of the Lead MP to maintain the PSS equipment in good operating condition, and promptly report to ISO any problems interfering with PSS proper operation. The Lead MP should normally operate the PSS out of service unless directed otherwise per the unit’s System Impact Study (SIS) or as directed by other studies as may be performed by ISO. A listing of Generators required to have a PSS in service can be found in...
M/LCC 8, Attachment B - Generators Requiring PSS Devices In/Out of Service. Each Lead MP must promptly report to ISO or the appropriate dispatch center, if and when the PSS is intended to be either placed into or removed from service prior to taking such action unless warranted by emergency plant conditions.

M. Blackstart Capability

1. Each Lead MP that provides blackstart capability from one of their Generators and that Generator has been incorporated in the ISO system restoration plan and/or as defined by ISO New England Operating Procedure No. 11 - Blackstart Resource Administration (OP-11) must maintain that Generator in good operating condition. Each Lead MP must promptly report to ISO, or the appropriate dispatch center, any problems interfering with the black start capability of each such Designated Blackstart Resource (DBR) Generator.

N. Additional Requirements for Wind Powered Generators

1. Due to the unique nature and operating parameters associated with wind powered generation, additional specific requirements for these resources are necessary. Wind Plants modeled and defined in the ISO New England Energy Management System are required to telemeter additional Reliability data. Appendix F - Wind Plant Operators Guide details the criteria and requirements for wind powered generators and shall be used by MPs for interconnected operation. The requirements are in effect and become enforceable upon installation of the communications equipment necessary to perform the data transfer.
III. TECHNICAL REQUIREMENTS FOR ALTERNATIVE TECHNOLOGY REGULATION RESOURCES

This section describes the basic technical requirements that must be met by each Alternative Technology Regulation Resource (ATRR) to be considered in the regulation market offer process. However, each ATRR must meet other eligibility requirements of ISO New England - ISO New England Inc. Transmission, Markets and Services Tariff Section III, ISO New England Market Rule 1 - Standard Market Design (Market Rule 1) and ISO Manuals to offer into the Market.

A. ATRR Defined

1. Each ATRR must be defined consistently for all ISO applications. That is, it must be defined in the same manner for the purposes of Regulation offers, dispatch and Settlement. Each ATRR shall communicate with ISO through its approved DE registered in accordance with ISO Manual for Registration and Performance Auditing (M-RPA) having satisfied all requirements of a DE as defined in this OP in Section III.C - Designated Entity - Performance, Communication and Control. Registration of an ATRR will be subject to the provisions of Section I.3.9 of the ISO New England Transmission, Markets and Services Tariff to the extent that the operation of the proposed ATRR may have a significant effect on the stability, reliability or operating characteristics of the New England RCA/BAA. A defined ATRR can only be dispatched via Electronic Dispatch for Regulation service.
   a. A defined ATRR is subject to the below Section III.C - Designated Entity - Performance, Communication and Control.

2. The Lead MP right to aggregate sub-resources to define an ATRR for bidding, dispatch and Settlement is governed by the following rules:
   a. Individual sub-resources must be less than one (1) MW of Regulation Capacity. If greater than or equal to one (1) MW of Regulation Capacity, it must register as a separate ATRR.
   b. ISO will determine if sub-resources may be combined and defined as one ATRR.
   c. ISO will consider if such a combination of sub-resources interferes with effective control and/or system reliability.

3. To define an ATRR, the Lead MP is required to submit any technical data with respect to an ATRR and any sub-resources that ISO determines to be necessary for ISO to carry out its responsibility of reliably and efficiently operating the BES. The Lead MP is required to submit the technical data for each sub-resource irrespective of whether it is a single unit or an aggregation. The Lead MP is responsible for submitting and maintaining all requested data of the ATRR. A defined ATRR must have an approved DE, provide all required data and have all required communications equipment in place and tested in accordance with ISO Procedures prior to being available for dispatch. The Lead MP is responsible for identifying the DE. The Lead MP communicates to ISO through their identified DE. The data...
may include, but not be limited to, the following, as necessary:

a. ATRR Technical Data per Appendix G of this Procedure
b. Textual description of the technical and operational characteristics of each sub-resource
c. One-line diagrams
d. Registration per M-RPA, includes DE registration as necessary

4. Equipment Requirements:

a. Telemetering as defined by OP-18
b. A defined ATRR shall be connected to only one (1) ISO Communications Front End (CFE) connected Remote Terminal Unit (RTU). No RTU shall control more than five (5) ATRRs without the review and approval of an exemption by ISO.
c. New exemptions are required for each additional ATRR beyond five (5) as previously granted.
d. Communications equipment, hardware and software sufficient to enable the DE to receive, acknowledge receipt, and implement ISO Dispatch Instructions electronically and, if necessary, verbally in a timely manner as required by ISO Manuals and Administrative Procedures. The points of contact between ISO and each DE for verbal Dispatch Instructions shall not exceed the number of ISO CFE connected RTUs installed for receipt of electronic Dispatch Instructions without prior approval of ISO. Participation in the Regulation Market is conditioned upon having Electronic Dispatch Capability (EDC) installed. EDC is the ability, through the installation and maintenance of adequate hardware and software and communications infrastructure within the Continental United States, to provide for the electronic transmission of data relative to the dispatch to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in injection or consumption of ATRR(s). An ATRR is considered to have EDC when it is capable of receiving, responding to, and changing output in response to electronic Dispatch Instructions issued to the ISO CFE connected RTU of its DE.

5. To define a new ATRR, a minimum of one hundred and twenty (120) calendar days advance notice to ISO is required.

To change data for an existing ATRR definition:

- A minimum of seven (7) calendar days advance notice to ISO is required. The advance notice period commences upon ISO receipt of the criteria detailed in Section III.A.3 of this OP.
- Dispatch methodology may be changed to be effective at the start of every calendar quarter. Requests to change the dispatch method of
an ATRR must be received no later than thirty (30) business days before the requested effective date of the change. There are three (3) dispatch methodology selections:

- Continuous - energy neutral
- Trinary - energy neutral
- Continuous - non-energy neutral

6. Whenever a Lead MP wishes to establish or change the DE responsible for managing dispatch for its ATRR(s), the Lead MP and DE are responsible for demonstrating to ISO that the proposed DE meets the technical requirements set forth in this procedure prior to ISO approving the proposed change to become effective.

B. Telemetering and Revenue Metering

1. Telemetering must be maintained and calibrated by the Lead MP or their designee on an ongoing basis per OP-18. ISO does not specify how the DE will communicate with or obtain telemetering data from the sub-resource(s). However, the telemetering requirement for the ATRR to provide data to ISO must meet the requirements for speed and accuracy per OP-18. Metering requirements for ATRRs and any/all sub-resource(s) less than five (5) MW will depend on their modeling option in the EMS and Market Systems:

- Each ATRR, whether as single or aggregate, greater than five (5) MW at a single node is represented in the EMS and must meet the telemetering requirements described in III.B.1 above

C. Designated Entity - Performance, Communication and Control

1. Each DE provides dispatch services from a single physical location for a defined ATRR and shall be the single point of contact to receive, acknowledge receipt, and implement ISO Dispatch Instructions and related communications. If prior approval from the ISO Control Room has been obtained, the operation from a single physical location allows for exigent conditions, as well as for infrequent, periodic testing & training needs.

- No Entity shall be recognized as a DE unless it meets the requirements in this OP and has been registered pursuant to ISO M-RPA.
- All DE contact information shall be confirmed and/or updated by the DE on an annual basis or upon change.

2. Each DE shall comply with all requirements of the ISO Operating Documents to the same extent as if the Lead MP were carrying out the functions of the DE.

3. ISO shall communicate with the DE via electronic dispatch through an ISO connected RTU or voice communications through an Auto Ring Down telephone circuit or one of the dedicated 24x7 phone numbers identified.
during DE Registration in accordance with M-RPA.

4. The DE shall have the knowledge and authority to act on ISO Dispatch Instructions for all ISO registered assets it manages for dispatch, as defined in Section III.F Dispatch Instructions of this OP.

   a. Any control equipment used to start, stop or vary the output of the ATRR, from a remote location, must meet the requirements set in OP-18, relative to speed, accuracy and data channel requirements. Such equipment must be maintained by the Lead MP according to ISO requirements contained in OP-18 and ISO New England Operating Procedure No. 2 - Maintenance of Communications, Computers, Metering and Computer Support Equipment (OP-2). ISO System Operators must be notified as soon as practicable if the equipment is incapable of meeting the requirements of OP-18. Steps should be taken to restore the equipment to normal operating conditions as soon as possible in accordance with OP-2.

   b. Each DE must have a dedicated voice communication telephone (assigned public switched network land line phone number) for ISO dispatching purposes unless otherwise agreed on a case-by-case basis by ISO.

5. In addition to the dedicated voice communication telephone, each DE is required to have a dedicated Auto Ring Down telephone circuit to the ISO Control Room for any of the following unless otherwise agreed on a case-by-case basis by ISO.

   o Each DE managed ATRR or aggregate of ATRRs greater than or equal to fifty (50) MW capacity (net)

   o Other instances as determined on a case-by-case basis by ISO

6. Each DE for an ATRR is required to have equipment capable of reliably receiving and acknowledging receipt of Dispatch Instructions sent electronically by ISO as frequently as necessary and to implement Dispatch Instructions in a timely manner as required by ISO Manuals and Administrative Procedures.

7. Each DE is required to display to their DE Operator, the following parameters for each ATRR, as defined in Section III.A.4 of this OP, in New England that is under their responsibility.

   a. AGC Setpoint
   b. Actual Injection / Consumption
   c. Response Rate
   d. Regulation High Limit
   e. Regulation Low Limit
f. ATRR Availability

g. On Regulation Status

h. Heartbeat

ATRR parameter display shall be at the same location as the voice communications unless otherwise agreed on a case-by-case basis by ISO.

8. Each DE is required to maintain staff on duty to communicate with ISO System Operators at all times.

9. Each ISO CFE connected RTU shall be connected to one and only one DE. This verifies Electronic Dispatch can be acknowledged by a single, approved DE.

10. Each DE is required to have equipment capable of reliably receiving and displaying to its operators the data in accordance with Section II - Telemetering And Revenue Metering for each ATRR it manages for dispatch.

11. Dispatch Instructions or any other orders issued verbally by ISO System Operators shall take precedence over all other forms of communication.

D. Designated Entity - Modifying DE Details

1. ISO evaluates all submitted DE change, registration or modification requests according to the required lead times with the requirements stated in this OP. ISO will coordinate with each applicable Lead MP, transitioning DE, communication vendor, and any other authorized party in order to process requests.

2. A Lead MP shall provide at least thirty (30) calendar days notice to change the DE, as defined in M-RPA.

   a. The effective date of the transfer is contingent on the proposed DE meeting the technical requirements and being registered and approved in accordance with M-RPA.

   b. Change requests concerning the DE communications infrastructure, moving the DE location, or changing the contact details can only be submitted by a DE, in accordance with the following:

   c. Changes to dedicated telephone numbers require at least thirty (30) calendar days advance notice.

   d. Modifications to dedicated communications circuits (e.g., for ARD and/or RTU) require at least ninety (90) calendar days advance notice.

   e. Contact details including person performing a role, their phone number and / or email address require at least seven (7) business days advance notice.
f. ISO approval of the change is contingent on the verification by ISO of the successful implementation and testing of the technical capabilities.

E. AGC Dispatch Instructions

1. All AGC Dispatch Instructions (Includes Normal and Emergency)
   a. If a DE is not capable of controlling the delivery of Regulation service in accordance with its Regulation Offer Data, the DE is required to notify the ISO System Operators as soon as practicable. Efforts should be made to forecast ATRR capabilities and submit those parameters appropriately.

2. Normal AGC Dispatch
   a. Normal AGC setpoints are transmitted electronically to each DE every four seconds or less.

3. Emergency Dispatch Instructions
   a. Emergency messages will be issued by the ISO System Operators when an emergency issue requires an immediate response by ATRRs outside of the normal dispatch protocol.
   b. While the Emergency message is active, voice communications to the ISO Control Room related to the Dispatch Instructions should be limited to only those pertaining to clarifying the Dispatch Instructions.

F. Operational Considerations

1. An ATRR will be dispatched as directed by ISO in accordance with OP-1, and the operating characteristics submitted by the Lead MP. The safety of operating personnel and prevention of damage to equipment are the sole responsibility of the Lead MP, and must take priority at all times.

2. Both the Planned and Maintenance Outages of the ATRR will be done in accordance with ISO Generator maintenance scheduling procedures per ISO New England Operating Procedure No. 5 - Generator, Dispatchable Asset Related Demand and Alternative Technology Regulation Resources Maintenance and Outage Scheduling (OP-5).

3. The Lead MP must, at all times, comply with all applicable switching and tagging procedures in effect by the authorities governing switching and tagging operations in the field.

G. Voltage Control

1. An ATRR shall not adversely impact the voltage control performance at the point of Interconnection.

H. Interconnection

1. An ATRR needs to follow the interconnection requirements for the type of
facility(ies) that will be participating as part of the ATRR. The terms and conditions of said interconnection agreement(s) shall be negotiated between the entities that are parties to the interconnection agreement(s) and may or may not contain additional and/or more stringent requirements than those prescribed by ISO.

I. System Protection

1. Operation as an ATRR, either by an individual facility or aggregate of sub-resources, shall have system protection appropriate to the classification of that facility or sub-resource for each interconnection.
IV. TECHNICAL REQUIREMENTS FOR DISPATCHABLE ASSET RELATED DEMANDS (DARDS)

This section describes the basic technical requirements that must be met by each DARD in order for it to be considered in the bidding process. However, each DARD must meet other eligibility requirements of Market Rule 1 and ISO Manuals to bid into the Markets.

Requirements outlined in Sections IV.C.4 and IV.E.1 shall be implemented no later than June 1, 2011 unless agreed to by ISO on a case by case basis based on a demonstration that there is good cause to allow for a delay in implementation for a specified period, and the DE has demonstrated to ISO satisfaction that DE staff will be sufficiently alerted to emergency Dispatch Instructions (Dispatch Instructions accompanied by an Emergency Message) prior to the full implementation of these requirements.

A. DARDs

1. Each DARD must be defined consistently for all ISO applications. That is, it must be defined in the same manner for the purposes of bidding, dispatch and Settlement. Each DARD shall communicate with ISO through its approved DE registered in accordance with ISO Manual for Registration and Performance Auditing (M-RPA) having satisfied all requirements of a DE as defined in this OP in Section IV.C - Designated Entity - Performance, Communication and Control.

2. A bid may be submitted for only a defined DARD. Bid parameters for a DARD are submitted by the Lead MP.

3. ISO will only perform Settlement functions for a defined DARD.

4. Each DARD is eligible to provide Operating Reserve in accordance with ISO New England Operating Procedure No. 8, Operating Reserve and Regulation (OP-8).

5. To define a DARD, each Lead MP is required to submit any technical data with respect to a DARD that ISO determines to be necessary for ISO to carry out its responsibility to reliably and efficiently operate the power system. Each Lead MP is responsible for submitting and maintaining all requested data. The Lead MP is responsible for identifying the DE. The Lead MP communicates to ISO through their identified DE for dispatch related matters. The technical data includes, but is not limited to, the following:

   a. Dispatchable Asset Related Demand Technical Data, per Appendix E of this Procedure

   b. NX-9 data as applicable, per OP-16

   c. Form NX-9B as applicable, Transformer-fixed/GSU/TCUL, including each physical component, per OP-16
ISO New England Operating Procedure  

OP-14 - Technical Requirements for Generators, Demand Resources, Asset Related Demands and Alternative Technology Regulation Resources

6. Equipment Requirements:

   a. Telemetering as defined by OP-18

   b. Each DARD requires communications equipment, hardware and software, sufficient to enable the DE to receive, acknowledge receipt, and implement ISO Dispatch Instructions electronically and, if necessary, verbally in a timely manner as required by ISO Manuals and Administrative Procedures. The points of contact between ISO and each DE for verbal Dispatch Instructions shall not exceed the number of ISO CFE connected RTUs installed for receipt of electronic Dispatch Instructions without prior approval of ISO.

   c. Participation in the Energy Market is conditioned upon having Electronic Dispatch Capability (EDC) installed. EDC is the ability, through the installation and maintenance of adequate hardware and software and communications infrastructure within the Continental United States, to provide for the electronic transmission, receipt, and acknowledgment of data relative to the dispatch of each DARD to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of each dispatchable DARD. Each DARD is considered to have EDC when it is capable of receiving, responding to, and changing output in response to electronic Dispatch Instructions issued to the ISO CFE connected RTU of its DE. Participation in the ISO Energy and Reserve Markets is conditioned upon having EDC installed.

   d. It is the responsibility of the DE in the event of a failure of the ISO CFE connected RTU or the failure of communications or other equipment between the ISO CFE connected RTU and the each DARDs connected to the ISO CFE connected RTU, to convey the Dispatch Instructions issued by ISO to the DARD impacted by the equipment failure within the time and other constraints established by ISO Manuals and OPs, and to diligently pursue the repair and/or replacement of each failed facility on an expedited basis.

   e. Communications equipment, hardware and software, sufficient to enable the DE to receive, acknowledge receipt, and implement ISO Dispatch Instructions electronically and, if necessary, verbally in a timely manner as required by ISO Manuals and Administrative Procedures. ISO may issue Dispatch Instructions as frequently as needed.

   f. A DARD shall be connected to only one (1) ISO CFE connected RTU. No RTU shall control more than five (5) DARDS without the review and approval of an exemption by the ISO.
g. New exemptions are required for each additional DARD beyond five (5) as previously granted.

7. Each DARD definition must be submitted to ISO in accordance with the following advance notice requirements:
   a. To define a new DARD, a minimum of one hundred and twenty (120) calendar days advance notice is required. The one hundred and twenty (120) calendar day period commences upon ISO receipt of the criteria detailed in Section IV.A.5 of this OP.

8. Whenever a Lead MP wishes to establish or change the DE responsible for managing dispatch for its DARD(s), the Lead MP and DE are responsible for demonstrating to ISO that the proposed DE meets the technical requirements set forth in this procedure prior to the ISO approving the proposed change to become effective.

B. Telemetering and Revenue Metering

1. Telemetering from each DARD must meet the requirements for speed and accuracy per OP-18. The Lead MP is required to telemeter the instantaneous MW value of the DARD. Telemetering must be maintained and calibrated by the Lead MP on an ongoing basis per OP-18.

2. Revenue metering must meet ISO accuracy requirements per OP-18 for all DARDs. Meter readings must be forwarded to ISO for Settlement in a timely manner as required per ISO Manuals and Administrative Procedures. The Lead MP is responsible for the maintenance and calibration of revenue metering per ISO requirements as contained in OP-18.

C. Designated Entity - Performance, Communication and Control

Each DE provides dispatch services from a single physical location for a DARD and shall be the single point of contact to receive, acknowledge receipt, and implement ISO Dispatch Instructions and related communications. If prior approval from ISO Control Room has been obtained, the operation from a single physical location allows for exigent conditions, as well as for infrequent, periodic testing & training.

   a. No Entity shall be recognized as a DE unless it meets the requirements in this OP and has been registered pursuant to ISO M-RPA.

   b. All DE contact information shall be confirmed and/or updated by the DE on an annual basis or upon change.

Each DE shall comply with all requirements of the ISO Operating Documents.
ISO shall communicate with the DE via electronic dispatch through an ISO connected RTU or voice communications through an Auto Ring Down circuit or one of the dedicated 24x7 phone numbers identified during DE Registration in accordance with M-RPA.

The DE shall have the knowledge and authority to act on ISO Dispatch Instructions for all ISO registered assets it manages for dispatch, as defined in Section IV.F Dispatch Instructions of this OP.

1. Any control equipment used to start, interrupt, restore or vary the output of each DARD, from a remote location, must meet the requirements set in OP-18, relative to speed, accuracy and data channel requirements. Such equipment must be maintained by the Lead MP according to ISO requirements contained in OP-18 and OP-2.

2. The DE of each DARD must have a dedicated voice communication telephone (assigned public switched network land line phone number) for ISO dispatching purposes unless otherwise agreed on a case-by-case basis by ISO.

In addition to the dedicated voice communication telephone, each DE is required to have a dedicated Auto Ring Down telephone circuit to the ISO Control Room for any of the following unless otherwise agreed on a case-by-case basis by ISO.

   a. DE managed dispatchable DARD(s) singly or in aggregate greater than or equal to 50 MW (net).

   b. Other instances as determined on a case-by-case basis by the ISO.

3. Further, certain DARDs are critical to the BES under emergency conditions. These DARDs are listed in Appendix D of this OP and are required to install, maintain, operate, test and fund a voice communications system that is independent of the public switched network for the purposes of communicating with its LCC during system emergencies such as a system restoration event. The installation, maintenance, testing and operation of the system must be coordinated with, and acceptable to, the DARD LCC. Each LCC is responsible in turn for providing the requirements for the communications system and coordinating with the DARD owner to effect the installation, maintenance, operation and testing of the communication systems.

Each DE for a DARD that participates in ISO Markets is required to have equipment capable of reliably receiving and acknowledging receipt of Dispatch Instructions sent electronically by ISO as frequently as necessary and to implement Dispatch Instructions in a timely manner as required by ISO Manuals and Administrative Procedures. Each DARD is required to have equipment in place to reliably receive and carry out Dispatch Instructions received by their DE from ISO within the timing and other constraints required.
4. Each DE is required to display to their DE Operators the following parameters for each DARD that is dispatchable, as defined in Section IV.A.6 of this OP, in New England and is under their responsibility:

   a. ACK Required (i.e. Acknowledgement Required)
   b. Message Type
      (1) Normal
      (2) Emergency
      (3) Start Up
      (4) Shut Down
   c. DDP
   d. Actual Consumption
   e. Minimum Consumption Limit
   f. Maximum Consumption Limit
   g. Response Rate
   h. Unit Control Mode
   i. Heartbeat

Acknowledgement and response to electronic dispatch via the Human Machine Interface (HMI) of the RTU shall also be performed at the same location as the voice communications unless otherwise agreed on a case-by-case basis by ISO.

5. Each DE is required to maintain staff on duty to communicate with ISO System Operators at all times.

6. Each ISO CFE connected RTU shall be connected to one and only one DE. This verifies Electronic Dispatch can be acknowledged by a single, ISO-approved DE.

7. Each DE is required to have equipment capable of reliably receiving and displaying to its operators the data in accordance with Section IV.B. - Telemetering And Revenue Metering for each DARD it manages for dispatch.

8. In instances where Dispatch Instructions or any other orders must be issued verbally by ISO System Operators, the verbal communication shall take precedence over all other forms of communication.
D. Designated Entity - Modifying DE Details

1. ISO evaluates all submitted DE change, registration or modification requests according to the required lead times with the requirements stated in this OP. ISO will coordinate with Lead MPs, transitioning DEs, communication vendors, and any other authorized parties in order to process requests.

2. A Lead MP shall provide at least thirty (30) calendar days notice to change the DE, as defined in M-RPA.
   a. The effective date of the transfer is contingent on the proposed DE meeting the technical requirements and being registered and approved in accordance with M-RPA.

3. Change requests concerning the DE communications infrastructure, moving the DE location, or changing the contact details can only be submitted by a DE, in accordance with the following:
   a. Changes to dedicated telephone numbers require at least thirty (30) calendar days advance notice.
   b. Modifications to dedicated communications circuits (e.g., ARD / RTU) require at least ninety (90) calendar days advance notice.
   c. Contact details including person performing a role, their phone number and / or email address require at least seven (7) business days advance notice.

Approval of the change by ISO is contingent on the verification by ISO of the successful implementation and testing of the technical capabilities.

E. Emergency Message Indications

1. Emergency messages shall be displayed to each DE with visual and audible indications
   a. Each DARD must have a specific Message Type indicator.
   b. Each DE must not employ visual messages that are common to multiple assets.
   c. Emergency messages must have an audible alarm that is unique to Emergency messages and cannot be disabled.
   d. Emergency messages are Message Type 2 (Emergency).
   e. Messages that require acknowledgement have an ACK Required = 1 on the RTU.

F. Dispatch Instructions

1. All Dispatch Instructions (Includes Normal and Emergency)
2. Normal Dispatch Instructions

   a. Normal Dispatch Instructions are transmitted electronically to each DE every five minutes or less, depending on system conditions.

   b. Compliance with the Dispatch Instruction is required in accordance with Offer Data without delay. Dispatch Instructions below Minimum Consumption Limit or above Maximum Consumption Limit shall be followed at the discretion of the DE, in cooperation with ISO System Operators.

   c. Under Normal Dispatch Instructions, voice communications to the ISO Control Room related to the Dispatch Instructions should be limited to only those pertaining to clarifying the Dispatch Instructions.

3. Emergency Dispatch Instructions

   a. Emergency messages will be issued by the ISO System Operators when an emergency issue requires an immediate response by DARDs outside of the normal dispatch protocol.

   b. Emergency Dispatch Instructions are transmitted electronically to each DE every five minutes or less, depending on system conditions.

   c. Emergency messages shall be acknowledged by the DE within sixty (60) seconds of the receipt of the message. This item may be waived on a case by case basis by ISO New England. This acknowledgement requires physical action by staff at the DE. Acknowledgement of the Emergency message shall indicate the DE intent to immediately comply with Dispatch instruction.

   d. Emergency Dispatch Instructions shall be followed in accordance with Offer Data without delay. Dispatch Instructions below Minimum Consumption Limit or above Maximum Consumption Limit shall be coordinated with the ISO System Operators.

   e. In an emergency, DARDs will receive an Emergency message in lieu of a Shut Down message. The DDP that accompanies the Emergency message dictates the desired response from the DARD. The DE must take action to comply with the Dispatch Instructions.

   f. While the Emergency message is active, voice communications to the ISO Control Room related to the Dispatch Instructions should be limited to only those pertaining to clarifying the Dispatch Instructions.
G. Operational Considerations

1. Each DARD shall be dispatched as directed by ISO in accordance with OP-1, and the operating characteristics submitted by the Lead MP. The safety of operating personnel and prevention of damage to equipment are the sole responsibility of the Lead MP, and must take priority at all times.

2. The Lead MP is required to maintain the DARD control equipment in good operating condition, and must promptly report to ISO any problems interfering with its proper operation.

3. Both the Planned and Maintenance Outages of DARDs will be done in accordance with ISO Generator maintenance scheduling procedures per OP-5.

4. At all times the Lead MP must comply with all applicable switching and tagging procedures in effect by the authorities governing switching and tagging operations in the field.

H. Interconnection

1. Each DARD wishing to connect its facility to transmission facilities must have a valid interconnection or Service agreement(s) in place with the Transmission Owners(s) with which the DARD is wishing to interconnect, or whose facilities are impacted. The terms and conditions of said interconnection agreement(s) shall be negotiated between the entities who are parties to the interconnection agreement(s) and may or may not contain additional and/or more stringent requirements than those prescribed by ISO.
V. TECHNICAL REQUIREMENTS FOR ASSET RELATED DEMANDS (ARDs) (NOT DISPATCHABLE)

This section describes the basic technical requirements that must be met by each ARD.

A. ARDs (Not Dispatchable)

1. Each ARD must be defined consistently for all ISO applications. That is, it must be defined in the same manner for the purposes of bidding and Settlement.

2. ISO will only perform Settlement functions for a defined ARD.

3. To define an ARD, the Lead MP is required to submit any technical data with respect to an ARD that ISO determines to be necessary for ISO to carry out its responsibility to reliably and efficiently operate the power system. Registration of an ARD will be subject to the provisions of Section I.3.9 of the ISO New England Transmission, Markets and Services Tariff to the extent that the operation of the proposed ARD may have a significant effect on the stability, reliability or operating characteristics of the New England RCA/BAA. Each Lead MP is responsible for submitting and maintaining all requested data. The Lead MP is responsible for identifying the DE. The Lead MP communicates to ISO through their identified DE for dispatch related matters. The data includes, but is not limited to, the following:
   a. Asset Related Demand Technical Data, per Appendix E of this OP
   b. NX-9 data as applicable, per OP-16, Transmission System Data
   c. Form NX-9B as applicable, Transformer-fixed/GSU/TCUL, including each physical component, per OP-16
   d. Form NX-9D as applicable, Capacitor/Reactor, including each physical component, per OP-16

4. Equipment Requirements:
   a. Telemetering as defined by OP-18

5. ARD definitions must be submitted to ISO in accordance with the following advance notice requirements:
   a. To define a new ARD, a minimum of one hundred and twenty (120) calendar days advance notice is required. The one hundred and twenty (120) calendar day period commences upon ISO receipt of the criteria detailed in Section V.A.3 of this OP.
   b. The ISO Manuals should be referenced to change the capability of an existing ARD.
B. Telemetering and Revenue Metering

1. Telemetering from each ARD must meet the requirements for speed and accuracy per OP-18. The Lead MP is required to telemeter the instantaneous MW value of an ARD. Telemetering must be maintained and calibrated by the Lead MP on an ongoing basis per OP-18.

2. Revenue metering must meet ISO accuracy requirements per OP-18 for each ARD. Meter readings must be forwarded to ISO for Settlement in a timely manner as required per ISO Manuals and Administrative Procedures. The Lead MP is responsible for the maintenance and calibration of revenue metering per ISO requirements as contained in OP-18.

C. Interconnection

1. An ARD wishing to connect its facility to transmission facilities must have a valid interconnection or service agreement(s) in place with the Transmission Owners(s) with which the ARD is wishing to interconnect, or whose facilities are impacted. The terms and conditions of said interconnection agreement(s) shall be negotiated between the entities who are parties to the interconnection agreement(s) and may or may not contain additional and/or more stringent requirements than those prescribed by ISO.
VI. TYPES OF DEMAND RESOURCES

Active Demand Resources are comprised of interruptible loads. Interruptible loads are defined as any load or collection of loads which can be removed within a predetermined time period from the power system through the action (i.e., push button, telephone call, etc.) of a Demand Resource operator, in response to instructions received and accepted through the ISO CFE connected RTU. There are two (2) active Demand Resource types available for real-time interruptible loads to register and participate in. A Demand Resource can only be registered as one (1) of these types. These Demand Resource types do not provide operating reserve; however they are used by ISO to maintain operating reserve or partially restore operating reserve on supply side resources as well as maintain transmission reliability within established criteria. It is recognized that Load Serving Entities (LSEs) may have particular programs under their control specifically to manage their load. The two active Demand Resource types are listed below and further explanation is provided.

Real-Time Demand Response (RTDR) Resource - 30-minutes or less notification

Real-Time Emergency Generation (RTEG) Resource - 30-minutes or less notification

A. Real-Time Demand Response Resource - 30-Minutes or Less Notification

1. This Demand Resource type requires 30 minutes or less notification from ISO to interrupt. A Real-Time Demand Response Resource is interrupted by ISO during Real-Time Demand Resource Dispatch Hours as defined in Section I.2.2 of the Tariff. A Real-Time Demand Response Resource can be activated on a zonal or system-wide basis. When a Real-Time Demand Response Resource is activated, ISO can dispatch the Real-Time Demand Response Resource to any reduction level of their obligation. All Real-Time Demand Response Resources in the same zone will be activated for an event on a pro-rata basis represented by the Real-Time Demand Response Resource obligation in that zone to the total Real-Time Demand Response Resource obligations in that zone. Each Real-Time Demand Response Resource is eligible to qualify as an FCM Resource subject to the performance criteria identified within Market Rule 1 and the ISO manuals.

B. Real-Time Emergency Generation Resources - 30-Minutes or Less Notification

1. This Demand Resource type requires thirty (30) minutes or less notification from ISO to interrupt, (interrupting load includes both reducing load by stopping a process or by shifting the load to a generator at the facility) and is composed of distributed generation resources that have environmental air permits that limit their operation to situations involving loss of external power or the imminent loss of external power. A Real-Time Emergency Generation Resource is interrupted by ISO during
capacity deficiencies when OP-4 Actions activating manual voltage reduction requiring more than ten (10) minutes are implemented. A Real-Time Emergency Generation Resource can be activated on a zonal or system-wide basis. When a Real-Time Emergency Generation Resource is activated, ISO can dispatch these resources to any reduction level of their obligation. All Real-Time Emergency Generation Resource in the same zone will be activated for an event on a pro-rata basis represented by the resource obligation in that zone to the total demand resources obligations in that zone. A Real-Time Emergency Generation Resource must be available for interruption during the period hour ending 0800 through hour ending 1900 on all non-holiday weekdays per Appendix C of this OP. A Real-Time Emergency Generation Resource is eligible to qualify as an FCM Resource subject to the performance criteria identified within Market Rule 1 and ISO manuals.
VII. TECHNICAL REQUIREMENTS FOR REAL-TIME DEMAND RESPONSE RESOURCES AND REAL-TIME EMERGENCY GENERATION RESOURCES

A. Technical Requirements

1. This section describes the basic technical requirements that must be met by each Real-Time Demand Response Resource and Real-Time Emergency Generation Resources. Real-Time Demand Response Resources and Real-Time Emergency Generation Resources involves any resource which contains load or a collection of loads that are associated with an active Demand Resource that may or may not have a Capacity Supply Obligation for the current Obligation Month which can be used to remove or supply energy, within a predetermined time period, through the action (i.e., push button, telephone call, etc.) of a power system operator. Real-Time Demand Response Resources and Real-Time Emergency Generation Resources are defined by the following:

   a. A Real-Time Demand Response Resource and Real-Time Emergency Generation Resource must be defined in the same manner for the purposes of dispatch and Settlements. A Real-Time Demand Response Resource and a Real-Time Emergency Generation Resource may include:

      (1) Individual or aggregated loads of end-use customers

      (2) Other operator controlled demand-reducing actions

2. A Demand Reduction Offer may be submitted for a Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource.


3. A Real-Time Demand Response Resource or a Real-Time Emergency Generation Resource must be greater than or equal to one hundred (100) kW and be aggregated in a single Dispatch Zone.

4. ISO will perform Settlement functions for a Real-Time Demand Response Resource and a Real-Time Emergency Generation Resource meeting the technical rules of this section and in accordance with the ISO Manuals and Administrative Procedure.

5. To define a Real-Time Demand Response Resource and Real-Time Emergency Generation Resource, the Lead MP is required to submit any technical data with respect to the resource that ISO determines to be necessary for ISO to carry out its responsibility to reliably and efficiently operate the power system. The Lead MP is responsible for submitting and maintaining all requested data. The Lead MP is responsible for identifying the DDE. The Lead MP communicates to ISO through their identified DDE.
for dispatch related matters. The technical data includes, but is not limited to, registration through the ISO Customer Asset Management System (CAMS) application which is accessible at https://smd.iso-ne.com.

6. A Real-Time Demand Response Resource and a Real-Time Emergency Generation Resource definition must be submitted to ISO in accordance with the following advance notice requirements:

   a. Seven (7) calendar days advance notice is required to define a new Real-Time Demand Response Resource or change its definition.

   b. The seven (7) calendar day period commences upon ISO receipt of the criteria detailed in Section VII.A.5 of this OP.

7. Equipment Requirements:

   a. Telemetering as defined by OP-18

   b. A Real-Time Demand Response Resource and a Real-Time Emergency Generation Resource requires communications equipment, hardware and software, sufficient to enable DDEs to receive, and implement ISO Dispatch Instructions electronically and, if necessary, verbally in a timely manner as required by ISO Manuals and Administrative Procedures. Participation in the FCM for active DR is conditioned upon having communication systems installed meeting the communication requirements. Communication requirements provide the ability, through the installation and maintenance of adequate hardware and software and communications infrastructure within the Continental United States, to provide for the electronic transmission and receipt of data relative to the dispatch of a Real-Time Demand Response Resource and a Real-Time Emergency Generation Resource to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of a Real-Time Demand Response Resource and Real-Time Emergency Generation Resource. A Real-Time Demand Response Resource and a Real-Time Emergency Generation Resource are considered to have met this requirement when they are capable of receiving, responding to, and changing output in response to electronic Dispatch Instructions issued to the ISO CFE connected RTU of its DDE. Participation in the FCM is conditioned upon having such capability installed.

   c. A Real-Time Demand Response Resource and a Real-Time Emergency Generation Resource shall communicate with ISO for Dispatch through its approved DDE registered in accordance with ISO M-RPA having satisfied all requirements of a DDE as defined in this OP in Section VII.C - Demand Designated Entity - Performance, Communication and Control.

   d. It is the responsibility of the DDE in the event of a failure of the ISO CFE connected RTU or the failure of communications or other equipment between the ISO CFE connected RTU and the Real-Time
Demand Response Resource and Real-Time Emergency Generation Resource connected to the ISO CFE connected RTU, to convey the Dispatch Instructions issued by ISO to the Real-Time Demand Response Resource and Real-Time Emergency Generation Resource impacted by the equipment failure within the time and other constraints established by ISO Manuals and OPs, and to diligently pursue the repair and/or replacement of any failed facility owned by the DDE on an expedited basis.

8. Whenever a Lead MP wishes to change the DDE responsible for managing dispatch for its Real-Time Demand Response Resource(s) and / or Real-Time Emergency Generation Resource(s), the Lead MP and DDE are responsible for demonstrating to the ISO that the proposed DDE meets the technical requirements set forth in this procedure prior to the ISO approving the proposed change to become effective.

9. Whenever a new DDE is proposed to be created, the Lead MP will provide ISO no less than ninety (90) calendar-days prior written notice of the proposed establishment of a DDE.

B. Telemetering and Revenue Metering

1. Each DDE is required to telemeter the 5-minute load and or generation value of each Real-Time Demand Response Resource or Real-Time Emergency Generation Resource. Telemetering must be maintained and calibrated by the Lead MP or their designee on an ongoing basis per OP-18. ISO does not specify how the DDE will communicate with or obtain telemetering data from the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource. However, the telemetering requirement for the DDE to provide data to ISO must meet the requirements for speed and accuracy per OP-18.

2. Revenue metering must meet ISO accuracy requirements per OP-18 for each Real-Time Demand Response Resource or Real-Time Emergency Generation Resource. Meter readings must be forwarded to ISO for Settlement in a timely manner as required per ISO Manuals and Administrative Procedures. The Lead MP (or designee) is responsible for the performance of maintenance and calibration of revenue metering per ISO requirements as contained in OP-18.

C. Demand Designated Entity - Performance, Communication and Control

1. Each DDE provides dispatch services from a single physical location for Real-Time Demand Resources or Real-Time Emergency Generation Resources and shall be the single point of contact to receive, acknowledge receipt, and implement ISO Dispatch Instructions and related communications. If prior approval from ISO Control Room has been obtained, the operation from a single physical location allows for exigent conditions, as well as for infrequent, periodic testing & training.

   a. No Entity shall be recognized as a DDE unless it meets the
requirements in this OP and has been registered pursuant to ISO M-RPA.

b. All DDE contact information shall be confirmed and/or updated by the DDE on a semi-annual basis or upon change.

2. Each DDE shall comply with all requirements of the ISO Operating Documents to the same extent as if the Lead MP were carrying out the functions of the DDE.

3. ISO shall communicate with the DDE via electronic dispatch through an ISO connected RTU or voice communications through an Auto Ring Down circuit or one of the dedicated 24x7 phone numbers identified during DDE Registration in accordance with M-RPA.

4. Each DDE shall have the knowledge and authority to act on ISO Dispatch Instructions for all ISO registered assets it manages for dispatch, as defined in Dispatch Instructions Section II.F and Section IV.F in this OP.

a. Any control equipment used to start, interrupt, restore or vary the output of Real-Time Demand Response Resource or a Real-Time Emergency Generation Resource, from a remote location, must meet the requirements set in OP-18, relative to speed and accuracy. Such equipment must be maintained by the Lead MP or their designee according to ISO requirements contained in OP-18.

b. Each DDE must have a dedicated voice communication telephone (assigned public switched network land line phone number) for ISO dispatching purposes unless otherwise agreed on a case-by-case basis by ISO.

5. In addition to the dedicated voice communication telephone circuit, each DDE having five hundred (500) MW total of Active Real-Time Demand Response Resources and Real-Time Emergency Generation Resource (measured in net CSO) or larger, is required to have a dedicated Auto Ring Down telephone circuit to the ISO Control Room unless otherwise agreed on a case-by-case basis by ISO.

6. Each DDE for a Real-Time Demand Response Resources or Real-Time Emergency Generation Resource are required to have equipment capable of reliably receiving and implementing Dispatch Instructions sent electronically by ISO as frequently as necessary and to implement Dispatch Instructions in a timely manner as required by ISO Manuals and Administrative Procedures. Each Real-Time Demand Response Resource and Real-Time Emergency Generation Resource is required to have equipment in place to reliably receive and carry out Dispatch Instructions received by their DDE from ISO within the timing and other constraints required by ISO Manuals and Administrative Procedures.

a. The Communications Infrastructure for Demand Resources must meet the requirements as detailed in OP-18.
b. Each ISO CFE connected RTU shall be connected to one and only one DDE. This verifies Electronic Dispatch can be acknowledged by a single, approved DDE.

c. Each DDE is required to have equipment capable of reliably receiving and displaying to its operators the data in accordance with Section VI.B. - Telemetering And Revenue Metering for each Resource it manages for dispatch.

d. Acknowledgement and response to electronic dispatch via the Human Machine Interface (HMI) of the RTU shall also be performed at the same location as the voice communications unless otherwise agreed on a case-by-case basis by ISO.

D. Demand Designated Entity - Modifying DDE Details

1. ISO evaluates all submitted DDE change, registration or modification requests according to the required lead times with the requirements stated in this OP. ISO will coordinate with Lead MPs, transitioning DDEs, communication vendors, and any other authorized parties in order to process requests.

2. A Lead MP shall provide at least thirty (30) calendar days notice to change the DDE, as defined in M-RPA.

3. The effective date of the transfer is contingent on the proposed DDE meeting the technical requirements and being registered and approved in accordance with M-RPA

4. Only a DDE may submit requests to change a DDE’s location and/or contact information.

5. Change requests concerning the DDE communications infrastructure, moving the DDE location, or changing the contact details can only be submitted by a DDE, in accordance with the following:

   a. Changes to dedicated telephone numbers require at least thirty (30) calendar days advance notice.

   b. Modifications to dedicated communications circuits (e.g., for ARD and/or RTU) require at least ninety (90) calendar days advance notice.

   c. Contact details including person performing a role, their phone number and/or email address require at least seven (7) business days advance notice.

6. ISO approval of the change is contingent on the verification by ISO of the successful implementation and testing of the technical capabilities.
E. Operational Considerations

1. A Real-Time Demand Response Resource or Real-Time Emergency Generation Resource will be interrupted when directed by ISO through the DDE, and implemented in accordance with the operating characteristics submitted by the Lead MP.

2. The Lead MP is required to insure that any Real-Time Demand Response Resource or Real-Time Emergency Generation Resource control equipment is maintained in good functional operation, and must promptly report to ISO any problems interfering with its proper operation.

3. A Lead MP with a Real-Time Demand Response Asset that has submitted a Demand Reduction Offer for that Operating Day, shall request permission from the ISO New England Control Room no later than fifteen (15) minutes prior to and no earlier than sixty (60) minutes prior to any increase in interruption of five (5) MW or greater over a sixty (60) minute period, unless the asset was dispatched or audited. The ISO New England Control Room may approve or deny the request to interrupt based on the impact of the interruption on system reliability. A Lead MP with a Real-Time Demand Response Asset that has submitted a Demand Reduction Offer for that Operating Day shall notify the ISO New England Control Room no later than fifteen (15) minutes prior to and no earlier than sixty (60) minutes prior to any change in consumption of five (5) MW or greater from current output over a sixty (60) minute period.

F. Interconnection

1. A Real-Time Demand Response Resource or Real-Time Emergency Generation Resource wishing to connect its facilities to transmission facilities must have a valid interconnection agreement(s) (if required) in place with the Transmission Owners(s) with which the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is wishing to interconnect, or whose facilities are impacted. The terms and conditions of said interconnection agreement(s) shall be negotiated between the entities who are parties to the interconnection agreement(s) and may or may not contain additional and/or more stringent requirements than those prescribed by ISO. It should be noted that load does not necessarily require an interconnection agreement. In all cases the need is determined by the Transmission Owner.
VIII. AUDITING AND TESTING

ISO reserves the right to conduct unannounced audits or tests of a DE, Generator, DARD, DDE, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource to verify its compliance with the technical requirements as set forth in this Procedure and in accordance with Market Rule 1. These audits may be conducted on a periodic basis or because ISO has a reason to suspect a deficiency. On site audits will be coordinated with the Lead MP, DE, or DDE (as appropriate) and scheduled during normal business hours. For audit, it will be conducted according to the following applicable ISO New England Manual(s):

- Manual for Market Operations M-11
- Manual for Registration and Performance Auditing M-RPA
- Manual for Real Time Price Response and Day-Ahead Load Response Programs M-RTPA / DALRP
- Manual for Measurement and Verification for Demand Reduction Value from Demand Resources M-MVDR

Failure to comply with the technical requirements of this OP may cause the Resource to be unable to perform in the Markets. This does **not** include compliance failures due to circumstances beyond the reasonable control of the Lead MP, such as transmission, distribution or communications outages. ISO will determine the Generator, DARD, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource ability to perform in the Markets when **not** in compliance with the requirements of this OP. Failure to perform in the Markets is Sanctionable Behavior, and subject to treatment under Market Rule 1.

A. Revenue Metering

1. ISO has the right to audit testing and calibration records, and order and witness the testing of revenue metering per OP-18. In the event that ISO-ordered testing results in metering tests occurring more frequently than once in a twelve (12) month period, ISO would pay for the reasonable expense of the extra meter testing only in the event that the metering system is found to be fully functional and in calibration per OP-18. When tested otherwise, the Lead MP will be responsible for the expenses of the extra meter testing.

B. Equipment Maintenance

1. Each Lead MP shall keep detailed records of equipment maintenance. ISO shall have the right to review the maintenance and test record for auditing purposes to insure that the equipment (voltage regulator, governor, stabilizer equipment, telemetering and communication and control equipment) is maintained in good operating condition.
C. Protection Systems

1. ISO shall have the right to review protection studies, elementary diagrams, relay setting documents, relay maintenance reports and relay calibration records in order to audit compliance with the protection criteria of NPCC and ISO.
IX. FORMS ADMINISTRATION

ISO Forms NX-12, 12E and 12G reside in the appendices to this OP. Each appendix also contains an explanation of terms and instructions for data preparation of the specific form. ISO staff will review the forms for completeness, and assign a data revision number to the form if required. Market Support Services shall also route completed forms NX-12, 12E and 12G to the ISO New England Power System Modeling & Support group for changes to the EMS. If additional or missing information is required, the ISO staff will contact the person who prepared the form to obtain the necessary information. Once ISO has determined the forms to be complete and accurate, the forms will be routed to the appropriate ISO departments.
X. DESIGNATED ENTITY (DE) AND DEMAND DESIGNATED ENTITY (DDE) TRAINING REQUIREMENTS

ISO develops and provides the training and applicable materials for the required annual Supply Resource Operator Training (SROT) and Demand Resource Operator Training (DROT) courses. This DE and DDE training provides the applicable personnel with the minimum level of knowledge of ISO procedures, processes, tasks and requirements applicable to participation in normal, abnormal and emergency communications with the ISO Control Room.

A. Training Requirements for Communicating with ISO Control Room Staff in the Capacity of a DE or DDE

1. Each individual responsible for communicating with the ISO Control Room staff in the capacity of a DE or DDE must have successfully completed the required applicable SROT or DROT training courses. This training requirement is applicable to DE and DDE personnel performing the following tasks:

   a. Acknowledging and/or responding to verbal or electronic dispatch instructions from the ISO Control Room
   b. Performing redeclaration of Generator/DARD, ATRR or Real-Time Demand Response operational parameters
   c. Verbal Communications with the ISO Control Room
   d. Electronic Communication with the ISO Control Room through the receipt and acknowledgement of Emergency Notification System (ENS) messages

B. Effective Date

1. The effective date for meeting these ISO DE/DDE training requirements is January 1, 2014.

   a. As of January 1, 2014 each individual subject to this requirement shall have completed SROT/DROT training in 2013.

C. Initial Training Requirement

1. Prior to acting in the capacity of a DE or DDE as described in Section A above, Initial Training must be completed as follows:

   a. DE personnel must complete all modules of the currently available SROT course
   b. DDE personnel must complete all modules of the currently available DROT course
D. Continuing Training Requirement

1. Personnel acting in the capacity of a DE or DDE as described in Section A above and who have already satisfied the Initial Training Requirement stated in Section C above must complete Continuing Training as described below:

   a. ISO will release updated SROT and DROT courses no later than May 1st of each year.

   b. DE and DDE personnel must complete the updated applicable SROT and DROT courses to meet the Continuing Training Requirement by December 1st of each year.

   c. Each calendar year at the time the training is announced, ISO will specify which modules of the SROT and DROT courses must be completed to meet the Continuing Training Requirement

E. Exemptions

1. There are no exemptions to meeting the applicable training requirements.

F. Types of Training

1. The required DE/DDE training is developed by ISO and provided to both DE operators and DDE operators.

   a. Each applicable DE operator and DDE operator must successfully complete the required training offered for their resource type.

G. Training Delivery

1. ISO offers SROT and DROT courses in web-based and classroom training formats.

   a. Web based training is continuously available through the ISO Learning Management System (LMS).

   b. All annual SROT and DROT training material presented in the classroom training sessions is available on line and either SROT or DROT training can be selected.

   c. Upon successful completion of a required SROT or DROT module, ISO provides each applicable DE operator or DDE operator with a Certificate of Completion.

H. Tracking of Training Completion

1. Tracking the completion of the Initial and Continuing Training Requirements for all applicable Personnel acting in the capacity of a DE or DDE, as described in Section A above, is the responsibility of the DE and DDE.
### OP-14 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.)

<table>
<thead>
<tr>
<th>Rev. No.</th>
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<td>Rev 1</td>
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<td>Rev 9</td>
<td>02/01/05</td>
<td>Updated to conform to RTO terminology</td>
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<td>Rev 10</td>
<td>05/06/05</td>
<td>Update for NERC Version 0 Standards, Updated URL for LRP asset registration</td>
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<tr>
<td>Rev 11</td>
<td>10/01/06</td>
<td>Updated for ASM Phase 2</td>
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<tr>
<td>Rev 12</td>
<td>11/15/07</td>
<td>Revised for Pseudo Combined Cycle Generator Requirements</td>
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<tr>
<td>Rev 13</td>
<td>05/21/08</td>
<td>Corrected NPCC and NERC names in References. Globally defined acronym for various frequently used terms (e.g., Designated Entity = DE, Market Participant = MP) and/or used acronyms that are defined in ISO Manuals to improve readability. Section II.A. 34th bullet moved as Footnote 2, Redundant language in that a less than 1 mw unit is also a less than 5 mw unit. Removed Footnote 1 to Section II.A.3. Comment was added in preparation for implementation of 05/01/1999 ISO-NE Interim Markets. With the implementation of the Interim Markets in 1999 and subsequent implementation of Standard Market Design in 2003, ISO-NE no longer has need to limit units of &lt;1 MW from participation in the energy and capacity markets. Added Footnote 2 to Section II.A.3., Clarification that a Unit &lt; 1 MW is not represented in the ISO Energy Management System. Section II.A.7 and III.A.6, clarified current language, These changes remove language which is redundant with information already in the same sections for DARDs and Generators. The current language is not well understood nor in past or present practice. Provided the definition for the acronym RIG Section II. A.7. 1st bullet Corrected “power system operator” to now state “Demand Resource operator” and replaced “(LCC, MP)” with “(Enrolling Participant) in Section V.”</td>
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<tr>
<td>Rev 14</td>
<td>06/01/10</td>
<td>Updated document for FCM changes including: elimination of existing DR programs and new DR FCM capacity, and RIG replacement with ISO CFE connected RTU.</td>
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Deleted: January 29, 2015
| Rev 18 | 01/29/13 | Globally: changed from “MP” to “Lead MP” where appropriate, clarified any “day” reference to calendar / business day, modified “…adequate hardware and software and communications infrastructure within the…” to “Continental United States” instead of “New England RCA/BAA”
| Section II: Updated the requirements reference from “D.1” to “E.1”;
| A.1: Added expectation of DE approval and clarified location of DE requirements and registration (M-RPA);
| A.2: Updated sub-bullet with renamed Section II.C;
| Revised sub-bullet on RTU connection to clarify for when exemption needed;
| New sub-bullet regarding exemption for RTUs controlling more than 5 generators;
| A.6: Clarified Lead MP responsibility with respect to DEs prior to ISO dispatching a generator;
| Added sub-bullet regarding DE registration;
| A.8: Made 2nd paragraph into new #5. Clarified expectations regarding the LP selection of a DE (new DE or changing to an existing) and the need to demonstrate communications prior to ISO approval of the DE and dispatch;
| A.9-12: Moved to new section II.D;
| C.: Renamed section to “Designated Entity – Performance, Communication and Control” from existing “Communications and Control”; New paragraphs to clarify the definition, qualifications and limitations to define a DE prior to registration and expectations of DE performance;
| C.2.: Clarified qualification for Auto Ring Down circuit based on dispatchable generation;
| C.4: Changed from Generator Operator to DE operator. Added sentence to specify where response to Electronic dispatch is required;
| C.5, C.4 sentence moved to C.5 as a separate requirement;
| C.6, Existing C.6 moved to C.8. New C.6 specifies RTU to DE mapping;
| C.7: New requirement that the DE must be able to see the market and reliability data;
| D.: moved existing D – M to E – N;
| New section D, Designated Entity – Modifying DE Details to specify who is responsible for the DE details and the timing related to any changes;
| F.3.: Changed sub-bullet from emergency message requiring manual acknowledgement to acknowledge by the DE;
| H.2.: 2nd Paragraph created as new H.3;
| H.3.: Clarified details relating to Auto Voltage Regulator operation, responsible party (DE/LP) and reporting Section III: Updated the requirements to specify Section III references
| A.1, Added sentence regarding DE registration
| A.5, Added M-RPA reference for DE registration as a requirement for Asset registration
| A.6, New sub-bullets for RTU connection requirements and exemptions as it is for generators
| A.8, Clarified expectations regarding the LP selection of a DE (new DE or changing to an existing) and the need to demonstrate communications prior to ISO approval of the DE and dispatch.
| 2nd + 3rd paragraph info moved to III.C/D;
| C.: Renamed section to “Designated Entity – Performance, Communication and Control” from existing “Communications and Control” New paragraphs to clarify the definition, qualifications and limitations to define a DE prior to registration and expectations of DE performance;
| C.2.: Clarified qualification for Auto Ring Down circuit based on dispatchable capability
| C.4: Changed from Generator Operator to DE operator. Added sentence to specify where response to Electronic dispatch is required.
| C.5, C.4 sentence moved to C.5 as a separate requirement
| C.6, Existing C.6 moved to C.8. New C.6 specifies RTU to DE mapping;
| C.7: New requirement that the DE must be able to see the market and reliability data;
| Continued on next page
### ISO New England Operating Procedure

<table>
<thead>
<tr>
<th>Revision</th>
<th>Date</th>
<th>Changes</th>
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<tbody>
<tr>
<td>Rev 18</td>
<td>01/29/13</td>
<td>Continued from previous page</td>
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<tr>
<td></td>
<td></td>
<td>D., moved existing D – G to E – H</td>
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<td>New section D. Designated Entity – Modifying DE Details to specify who is responsible for the DE details and the timing related to any changes.</td>
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<td>Section VI – Demand Response</td>
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<td>A.7, Added sub-bullet regarding communication through the registered DDE for DR resources</td>
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<td>Clarified expectations regarding the LP selection of a DE (new DE or changing to an existing) and the need to demonstrate communications prior to ISO approval of the DE and dispatch. Moved some details to III.C/D. 2nd and 3rd paragraph info moved to III.C/D</td>
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<td>C., Renamed section to “Demand Designated Entity – Performance, Communication and Control” from existing “Communications and Control”</td>
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<td>New paragraphs to clarify the definition, qualifications and limitations to define a DDE prior to registration and expectations of DDE performance</td>
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<td>C.4, New requirement specifies RTU to DDE mapping</td>
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<td>New section D. Demand Designated Entity – Modifying DDE Details to specify who is responsible for the DDE details and the timing related to any changes.</td>
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<tr>
<td>Rev 19</td>
<td>03/04/13</td>
<td>Added M/LCC 1 to Reference Section; Modified Section II.A.6 for relocation of NPIRs to MLCC 1; clarified responsibilities associated with NPIRs</td>
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<tr>
<td>Rev 20</td>
<td>10/08/13</td>
<td>Global, minor modifications, format changes, etc., consistent with current practices and management expectations; References: corrected title of OP-11, deleted ISO New England Manual for Real-Time Price Response and Day-Ahead Load Response Programs (M-RTPRD/DALRP); Appendices: changed title of Appendix C; Part II M.: corrected terminology for current usage; Section IX: modified to include DE and DDE training requirements and criteria for SROT and DROT.</td>
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<tr>
<td>Rev 21</td>
<td>05/02/14</td>
<td>Added new section for Alternative Technology Regulation Resource criteria and requirements; modified Section II language clarifying description and criteria of SOGs</td>
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<tr>
<td>Rev 21.1</td>
<td>05/23/14</td>
<td>Clerical change (due discovery or a typographical error) to restore committee approved language inadvertently deleted during reformatting of document in Rev 21.</td>
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<tr>
<td>Rev 22</td>
<td>11/07/14</td>
<td>Clarify language in Section II and II.I, Governor Control;</td>
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<tr>
<td>Rev 23</td>
<td>01/29/15</td>
<td>Added language to Section III.A.5 regarding notification timing criteria for change requests to ATRR dispatch methods.</td>
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</table>

### Deleted

- p.17.
- January 29, 2015