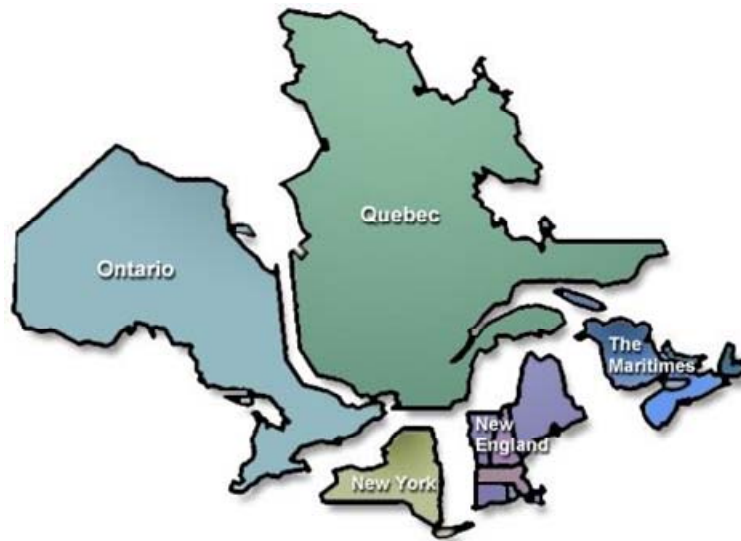




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NPCC DER Guidance Document, Distributed Energy Resources (DER) Considerations to Optimize and Enhance System Resilience and Reliability



**NPCC Regional Standards Committee (RSC)
Version 2 Approved 11/20/2020**

Note: Content of this document may not reflect the most current information¹. Periodic reviews for potential revisions of the document will be done biannually or more frequently if needed. Please send corrections or revision requests to [npccstandard@npcc.org](mailto:npscstandard@npcc.org).

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Revision History

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1	8/19/19	Effective Date	New
2	X/XX/XX	RSC and Subgroup developed revisions	Revisions, add AGIR, new title, clarifications, and Appendices

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Executive Summary

The Northeast Power Coordinating Council, Inc. (NPCC) is responsible for promoting and enhancing the reliability of the International, interconnected Bulk Power System in Northeastern North America.

Development of this document was initiated by the NPCC Board of Directors to provide regional guidance and information for voluntary use by NPCC Members and stakeholders. The guidance provided herein identifies potential reliability risks² to the Bulk Power Systems (BPS), recommendations to mitigate them, and also identifies opportunities to optimize the operational characteristics of DER to enhance reliability and resilience of the NPCC Bulk Power System (BPS). The document outlines both existing DER deployment practices and strategies as well as how a future with increased penetration of DER and internet controllable devices could be reliably coordinated ([Appendix H](#)). Links to other resources have also been provided throughout the document.

As Distributed Energy Resources (DER) continue to replace traditional industry generation resources the resource fuel mix and operational characteristics of the system will change. DER will necessitate changes to how the system is planned and operated. The North American Electric Reliability Corporation (NERC) Reliability Standards are not applicable to equipment on the distribution systems unless such equipment has a direct impact on the “reliable operation”³ of the BPS, such as Automatic Underfrequency Load Shedding (UFLS). However, as penetration of DER increases, planning and operating assessments used to assure reliable operation of the BPS will need to accurately represent how DER interacts with the BPS.

NPCC recognizes that continent-wide efforts in North America are underway at the NERC level to define DER and address some aspects related to planning and modeling. [Appendix C](#) outlines some specific reliability activities related to DER which have either been developed, or are in the process of being developed, by the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG), along with links to some of their documents. NPCC and its members have also been engaged in the work efforts at the NERC level and are leading efforts to address outstanding issues within the scope of those groups and provide expertise. With the understanding of all the efforts which are underway, NPCC can coordinate and fill a vital role in identifying additional areas where the Region may provide information and services to promote reliable deployment of DER. An example is coordination with State and Provincial Government Regulatory Authorities, and distribution utilities. Also, opportunities exist in the areas of obtaining data, models, testing and verification, observability, protection systems and other operational characteristics of DER and their effect on the distribution systems.

² An example of a reliability risk not addressed is remote dispatch of DER. A significant challenge that has been found by some NPCC members is that DER Operators can be anywhere in the world and that as a result, communications can be significantly delayed, leading to reliability risks. This includes time zone challenges and language challenges,

³ “reliable operation” is defined in 16 U.S. Code § 824o and means “operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.”

NPCC has also been conducting DER Forums, the purpose of which is to promulgate DER related information, educate, and inform. NPCC's Regional Standards Committee (RSC) and Reliability Coordinating Committee (RCC) have also developed a joint process and a form to report DER related impacts (i.e. during or following an event both enhancing reliability or causing a reliability risk) and analyze and determine if any further actions are needed. The Form and process may be found in [Appendix A](#) and on the NPCC website.

NPCC is not creating new Criteria or Standards through this guidance document. The intent of this document is informational and as NERC's SPIDERWG, and other groups develop their respective guidance documents it will be revised to achieve continued alignment and avoid duplication.

This guidance document contains [DER Recommendations](#), and information provided by NPCC's Members, NERC, the industry, the US National Renewable Energy Labs, the Electric Power Research Institute (EPRI) and information from NPCC Staff. Also, it is important to note that specific distribution utility requirements within NPCC at the local level will supersede any suggested approaches in this document.

Introduction and Objective

A consistent defined term for what type of generating, demand or storage resources are included in DER is not broadly accepted by industry stakeholders. Also, DER is not currently a term that is defined by NERC.

For the purpose of this NPCC guidance document, DER refers to:

Any non-BPS connected real or reactive power resources (generating units, multiple generating units at a single location, distributed generation installations, battery storage systems, etc.) located within the boundary of any distribution utility's service territory, regardless of capacity, allowing individual DER to be captured if they are not aggregated. Some DER technologies are more intermittent in their production characteristics than resources which operate based on a controllable fuel input.

Initially, in the first version of this guidance document, NPCC specified a threshold for inclusion of DER in any regional guidance that would not include individual rooftop solar or individual wind turbines or other DER net metering installations. However, the aggregate effect of these types of DER can have a significant effect on the power system and if not properly understood can impact the reliable operation of the BPS, as we have seen in California subsequent to their Rule 21⁴. NPCC is now beginning to observe aggregations of DER entering into the capacity wholesale markets within the NPCC Region. This

⁴ <https://www.cpuc.ca.gov/Rule21/> Electric Rule 21 is a tariff that describes the interconnection, operating and metering requirements for generation facilities to be connected to a California utility's distribution system. The tariff provides customers wishing to install generating or storage facilities on their premises with access to the electric grid while protecting the safety and reliability of the distribution and transmission systems at the local and system levels.

document will continue to be modified as emerging issues related to DER's deployment, interconnection, planning and operations are identified and technology improves.

This document identifies opportunities for DER related process improvements and addresses potential reliability risks, promotes good utility interconnection practices necessary for reliability, and promulgates information on how DER can enhance reliable operation at the Transmission Distribution interface by providing essential reliability services. In addition, during the development of this document, a review of existing DER related documents was performed and NPCC is working with the NY Interconnection Technical Working Group (ITWG) as well as the Joint Utilities group of NY to align processes where possible. As other related groups and endeavors are identified within the Region, NPCC will monitor and review their activities going forward and will coordinate with the NPCC Areas and its Members, as necessary.

International standards are established to address DER impact on system reliability. IEEE 1547-2018 as amended by IEEE 1547a-2020 brings significant potential benefits to the BPS by requiring that DER provide essential reliability services to ensure stability, reliability, and security. State and Provincial requirements for DER interconnection should also require compliance with IEEE 1547-2018 through inclusion in their respective jurisdictional interconnection agreements.

As DER continues to proliferate on the electric system at the "grid edge" or distribution system, and replace conventional transmission grid connected resources, there is an increasing reliability related need to understand the effect of DER resources on the BPS. It is important to understand how DER is interconnected, planned, operated and how DER interacts with the transmission system.

Reliably and securely integrating DER into the electric system requires a comprehensive multi-pronged approach utilizing perspectives from different disciplines. DER design, modeling, planning, and relay coordination require consideration of jurisdictional issues. The importance of Members working with their respective national, state, and provincial regulatory authorities to help them understand the consequences of and the development of effective DER interconnection requirements is critical. While there may be some broad universal guidelines, the details of effective DER interconnection requirements should be reconciled with the characteristics of the system where the interconnection is taking place. [Appendix B](#) of this document provides a comparison of NPCC's Area requirements, at the time of the Version 1 writing, to help identify opportunities for guidance.

Many, if not most, of the current DER being deployed is theoretically capable of bringing several enhancements to reliability, provided that there are sufficient design specifications and interconnection requirements to implement the benefits. Inverter based DER may use fast, programmable responses to provide benefits to reliability if properly configured and coordinated with the host utility. Coordination must consider effects both on the distribution system and the BPS. The sections below address DER impact on the BPS including aspects of:

- Interconnection guidance
- Voltage response
- Frequency support

- Reconnecting to the utility following faults
- Underfrequency load shedding

While DER presents opportunities to enhance reliability, they also introduce challenges at the Transmission Distribution interface if not deployed correctly. Interoperability with the transmission system is not solely determined at the point of interconnection. Visibility and a level of controllability of DER is essential for transmission operators to maintain situational awareness for reliable operation of the BPS, and for short-term forecasting. Additionally, characteristics of DER such as capacity, intermittent production, location, protection settings, and other parameters must be known for long-term operational performance forecasting and system planning to ensure BPS reliability is maintained. Additionally, the local distribution utility overseeing the interconnection of DER needs to be able to ensure that the DER doesn't cause safety issues for distribution line workers.

Presently there are limited study tools in general use to perform fully integrated studies of transmission and distribution which would allow both systems to be modeled and studied (in steady-state and dynamically) together, although work is underway in this regard. In the shorter term, visibility of the variability of DER capacity could dramatically affect the quality of state estimator information, and methods of improving data and forecasting need to be explored. The U.S. Department of Energy Argonne National Laboratory has a project underway to develop a tool that would Co-simulate Transmission and Distribution systems. The tool being developed will utilize Siemen's Power System Simulator "PSS®E" transmission system analysis tool with EPRI's open sourced distribution system smart grid tool "OpenDSS" ([Smart Grid Simulation Tool](#)) using a Python interface. A detailed presentation on this project may be found in the October 2019 NPCC DER Forum meeting materials on NPCC's website. Additionally, some planners in the NPCC Region are moving to composite load models for their simulations and planning activities.

In recognition of both the benefits and challenges associated with DER, the approach taken with this second version of the NPCC DER Guidance Document is to continue to collect interconnection related information within the NPCC Region as well as in other areas of the NERC Electric Reliability Organization (ERO) Enterprise. There are some specific situations where opportunity exists to ensure better coordination across the NPCC Region. The intent of this document is to identify any emerging reliability issues, provide general guidance and information where possible, and offer support to NERC and others North America wide to promote reliable interconnection and operation practices for DER. It is also recognized that DER may not be located optimally and/or in areas where deliverability to load may not be ideal. In this respect any specific information in this document must be considered in conjunction with the requirements of the interconnecting distribution utility.

NPCC DER Impact Reporting

In order to ensure the reliability and resilience of the interconnected BPS in Northeastern North America as DER, both aggregated and single installations, continue to proliferate throughout the distribution systems within the NPCC Region, it is important to have a regional DER impact reporting mechanism. The NPCC Regional Standard Committee (RSC) created an impact reporting form and process that allows entities to report DER impacts and to seek guidance regarding emerging issues and reliability risks that

affect or could affect the reliable performance of the BPS (see [Appendix A](#)). The Word version of the form also is available on the NPCC website at:

[BES Impact Reporting Form](#)

Impact reporting and its associated process provide an orderly mechanism for NPCC to review reliability impacts submitted. A Report will initiate a collaborative review by the Reliability Coordinating Committee and the Regional Standards Committee.

DER BPS Impact Considerations

NPCC's Regional Standards Committee (RSC) and Task Forces (i.e. Task Force on System Studies) reviews of DER as it pertains to the NPCC Region's BPS performance have identified several areas which, going forward, may warrant further and continual monitoring and analysis. NPCC has identified the following items that should be carefully considered as DER levels (total MWs) increase.

- DER performance with respect to voltage and frequency ride through
- DER ability to provide regulation and reserves
- DER dispatch and controllability
- DER availability, quality of forecasting, and verification
- Observability and situational awareness of DER, and the importance of implementing Advanced Metering Infrastructure (AMI) if telemetry is not deployed
- DER impacts on Underfrequency Load Shed programs
- Impacts of DER on System Restoration and Black Start Plans

Although DER markets, both wholesale and dual participation models, are not the focus of this document, due consideration should be given to their structure. Market rules that allow aggregation also vary across the NPCC Region. Some Areas allow injection of the aggregation across their market area while other Areas require specific aggregations to be injected nearest to a transmission node. DER are capable of providing ancillary services that are necessary to support reliability, if there are appropriate market mechanisms and incentives that allow and encourage them to do so. Wide-area aggregation and injection may create challenges for the system planners and operators as well as raise deliverability and operations concerns.

NPCC Interconnection Guidance

This document and any detailed specifications which follow, are intended to provide examples of general information regarding DER interconnection. The examples do not constitute a Regional Criteria (which can only be implemented through NPCC Directories and approval of NPCC's Full Members). There are numerous efforts underway in many forums and regulatory bodies that are expected to create new, more specific guidance⁵. The level of detail and specificity provided is intended to be used as

⁵ At the time of this guidance document development, these include but are not limited to: NERC (e.g. SPIDER WG, Inverter- Based Resources Task Force (IRPTF), Events Analysis, Modelling and Standards process), IEEE (IEEE Std

information and guidance for any NPCC Member Area which may not have yet seen the need to establish detailed operating parameters. This document shares the practices of some Members of NPCC which have already established detailed DER requirements, even in advance of upcoming applicable industry standards due to the rate of penetration of DER in their Area. NPCC Members considering improving or adding to their respective DER guidance documents are encouraged to reach out directly to other NPCC Members which may have already addressed DER related reliability risk issues.

NERC and NPCC have criteria for resource and transmission planning. For transmission, criteria require transmission planners to simulate different transmission system events and ensure the transmission system remains reliable by meeting performance characteristics for these events. If the transmission system does not remain reliable, the planners are required to identify remediation, including upgrades or expansions of the transmission system. One aspect of the simulation is to account for the loss of generation resources. If a significant amount of DER trips or ceases to inject current for the simulated transmission event, the transmission system could become unreliable for that event and require remediation. This can occur in several scenarios such as a peak load day with maximum output from DER like solar PV or a light load spring day where PV solar and small hydro make up a significant percentage of the generation. IEEE Std. 1547-2018 “Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power System Interfaces” addresses this issue by setting the default DER trip settings for Category II at a level that coordinates with NERC standard PRC-024-2 “Generator Frequency and Voltage Protective Relay Settings.” This is the standard that defines ride-through capability for generators connected to the transmission system. Requiring DER to ride-through disturbances, similarly to large generators, would be a significant step towards achieving a robust level of reliability in a cost-effective manner.

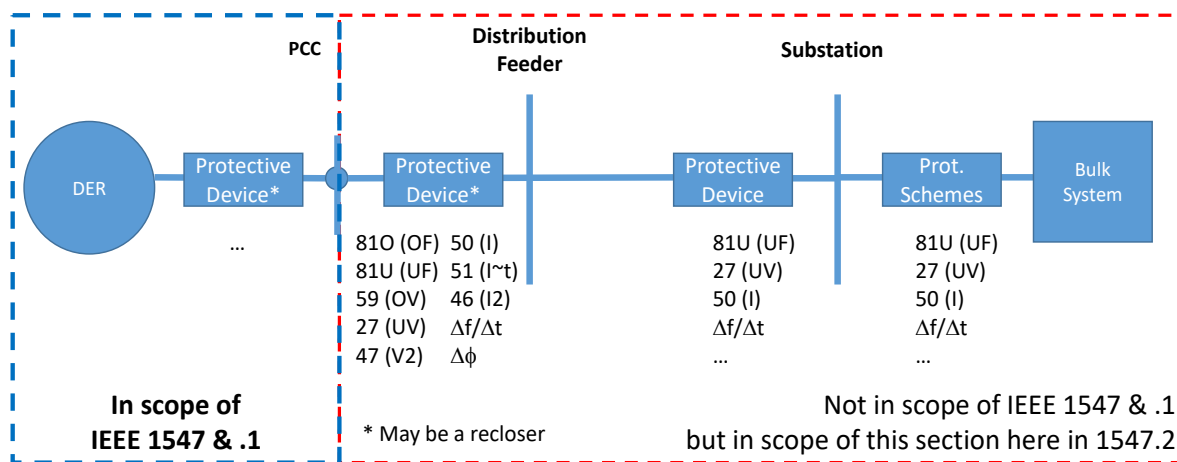


Figure 1: Scope of IEEE 1547 series of standards and guidelines and list of distribution protective functions that may interfere with DER ride-through. Source: Provided courtesy of EPRI⁶

1547.1-2020, P2800), and various state initiatives such as the New York Interconnection Technical Working Group (ITWG), Other regional, Provincial and State initiatives.

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IEEE 1547-2018 was unanimously adopted by the National Association of Regulatory Utility Commissioners (NARUC) in 2019. The standard outlines the technical specifications and performance requirements which are universally needed for interconnection and interoperability of DER and should be sufficient for most installations. Implementation guidance for IEEE 1547-2018 may be found here: [Guideline IEEE 1547-2018](#). The applicability of certain specifications and requirements are dependent on specific application considerations. For these, the requirements are provided in terms of a limited number of technology-neutral performance categories, for which it is the responsibility of the authority governing interconnection requirements (AGIR) to consider. Within New England, interconnection requirements vary by state, and further, by Distribution Provider. In New York a common set of DER interconnection requirements exists and there is a Coordinated Electric System Interconnection Request (CESIR) which outlines and initiates the process. Several other State and Provincial AGIR have developed local interconnection requirements which are listed in [Appendix E](#) of this document along with links which will be helpful to access specific interconnection information. These requirements are then supplemented by individual Distribution Provider interconnection agreements, specifications, and requirements.

The DER owner, responsible for its operation, must follow Interconnection Agreements and any AGIR requirements for fault ride-through. Distribution Providers and other AGIR entities should ensure that their requirements describe necessary DER performance with ride-through capabilities for frequency and voltage excursions events. Interconnection Agreements and local requirements generally have provisions to provide documentation upon request.

In addition, NERC developed three NERC Disturbance Reports related to system disturbances in California which resulted in significant inverter-based resource interruptions. The reports may be found on NERC's Major Events Analysis Reports page: <https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx>. Some of these past events emphasize the importance of fault ride-through.

In terms of generation resource adequacy and resource management there is also the possibility of over generation, as has been demonstrated in the state of California when the system operator runs out of load to absorb the available generation. Operating procedures for selecting which generation to curtail should be in place requiring System Operator visibility of DER either individually or in aggregate. In lieu of operating procedures, some areas of the country are planning to use market mechanisms to address this issue. Interconnection agreements or other state or local requirements may require DER installations to provide communication channels so that generation can be coordinated with a central dispatch authority.

The DER owner's protection and control equipment also should be capable of ceasing to inject current, or automatically disconnecting the generation from the system to which it is directly connected upon detection of frequency or voltage excursion conditions outside of the applicable ride-through requirements. Note that those interconnection agreements, specifications, and requirements should account for both distribution protection and the reliability of the BPS. For three-phase installations, the over and under voltage function should be implemented on each phase and the over and under frequency protection on at least one phase. All phases of a generator or inverter interface should

disconnect or cease to inject current for appropriate voltage or frequency excursion conditions sensed by the protective devices. Voltage protection should be wired as specified by IEEE 1547-2018. Automatic disconnect devices must be sized to meet all applicable local, state, and federal codes.

The specified size of the generation facility or energy storage system should be based on electrical generator or inverter AC nameplate ratings. The specific design of the protection, control, and grounding schemes will depend on the size and characteristics of the DER owner's generation, as well as the DER owner's expected load level. Dynamic protection systems may be needed based on the characteristics of the particular portion of the utility's system where the DER owner is interconnecting.

The settings referenced herein are generally intended for single-phase and three-phase applications using wye grounded- wye grounded service transformers or wye grounded-wye grounded isolation transformers. For applications using other transformer connections, a site-specific review should be performed by the utility and the revised settings identified in the DER Application Process⁷.

The guidance set forth in this document is intended to be consistent with those specifications contained in the most current version of IEEE Std. 1547-2018. It is recommended that the requirements in IEEE 1547-2018 be referenced in the interconnecting utility requirements as well as any further state interconnection requirements as appropriate.

Voltage Response

Within IEEE-1547-2018 and in NY State Public Service Commission Interconnection Requirements, the operating range for the generators is generally intended to be from 0.88 to 1.10 per unit of nominal voltage magnitude. In addition, the generator should not cause the system voltage, at the Point of Common Coupling (PCC), to deviate from a range of 0.95 to 1.05 per unit of the utility system voltage. For excursions outside these limits with a duration longer than the applicable fault ride-through requirements, the protective device generally automatically initiates a disconnect sequence from the utility system as detailed in the most current version of IEEE Std. 1547-2018. Planning Coordinators and Transmission Planners should also be aware that DER installed with older interconnection agreements may reference prior versions of IEEE Std. 1547 and may not meet current ride through requirements. Clearing time is defined as the time the range is initially exceeded until the DER owner's equipment ceases to energize the PCC and includes detection and intentional time delay. Other static or dynamic voltage functions may be permitted or required as agreed upon by the utility and DER owner. The industry is now in the process of promoting ride-through via several different standards initiatives which NPCC is tracking through its DER Forum.

As described above, ensuring that DER can respond appropriately for various voltage conditions is critical for system reliability, as well as avoiding equipment damage and protecting personnel safety. Continuous operation over a wide range of voltage levels will ensure that DER do not prematurely trip or cease to inject current and further deteriorate system conditions. IEEE Std. 1547-2018 includes ranges of

⁷ Currently there has not been an assessment of potential change in sensitivity (increase or decrease) to the effects of Geomagnetic Disturbance (GMD) from the presence of high DER penetration. This is a potential reliability risk to be aware of and evaluated in the future.

trip settings. For inverter-based DER, the “shall trip under” voltage setting should be chosen to meet the requirements of NERC PRC-024-2, as described in Annex B of IEEE Std.1547-2018.

Quebec Interconnection

Ride-through during system disturbances is of primary importance for resources connected to the grid, with the objective of maintaining system reliability⁸. IEEE-1547-2018 addresses the topic, however, for voltage and frequency, what is required in the IEEE standard does not match the requirements in Quebec.

DER should have voltage related operational capability and protection settings set as prescribed by the area Electric Power System (EPS)operator and in accordance with IEEE Std. 1547-2018.

This subject area is a matter of facility installation and personnel policy of the asset owner, balancing both reliability and safety. This information should be communicated to the interconnecting utility for proper protection system coordination.

In the Quebec interconnection voltage ranges and regulation requirements vary from the Eastern Interconnection. The requirements of the AGIR having jurisdiction should be followed (typically the Régie de l'énergie and Hydro-Québec). Details for Quebec’s process may be found in [Appendix E](#).

Frequency Support

Frequency support is provided through the combined interactions of synchronous inertia and frequency response. Working in a coordinated way, these characteristics and services arrest the decline in frequency after a disturbance and eventually return the frequency to the desired level. As increased levels of DER are introduced to the system, synchronous inertia will be displaced, which may have an impact on the frequency response performance of the system. With increased penetration of DER it is becoming desirable for DER to remain connected even outside the prescribed frequency range if there is no risk to the DER equipment. The ride-through curves are “shall not trip within the acceptable range,” not “must trip immediately outside of the acceptable range.”

Interconnection Agreements should require DER to have a frequency and voltage operating range that is equivalent to BPS connected resources consistent with the most limiting of PRC-006-NPCC, PRC-024 and the latest version of IEEE 1547 (IEEE 1547-2018 as amended by IEEE 1547a-2020). The sequence for a protective device to automatically initiate a disconnect sequence from the utility system is also detailed in the IEEE-1547-2018. Clearing time is defined as the time the range is initially exceeded until the DER owner’s equipment ceases to energize the point of common coupling (PCC) and includes detection and intentional time delay. Other static or dynamic frequency functionality may be permitted or required as agreed upon by the utility and DER owner. There should be a mechanism to ensure that the Distribution Provider transmits any necessary information pertaining to capacity, operational characteristics, etc. to system planners and system operators for DER facilities.

Note that in the Quebec Interconnection the frequency operating range is wider than in the Eastern Interconnection. In Quebec, the acceptable steady-state frequency range is from 59.4 Hz to 60.6 Hz, and

⁸ NERC report on Loss of Wind Turbines During System Disturbances : [NERC Report-Loss of Wind Turbines](#)

DER must be capable of riding through frequency as low as 55.5 Hz (for a short time period). Therefore, in Quebec, UFLS systems must operate outside this operating range in accordance with the Quebec variance to the PRC-006-NPCC UFLS-1 regional standard table 4.

Reconnection to the Utility System

If the DER is disconnected as a result of the operation of a protective device, the DER owner's equipment should remain disconnected until the utility's service voltage and frequency have recovered to acceptable voltage and frequency limits for an acceptable amount of time. Interconnection Agreements or local standards should address times for reconnection to the utility system. Per IEEE 1547-2018 Clause 4.10.3, the allowable range of settings is 0-600 seconds with a default setting of 300 seconds. IEEE 1547-2003 in clause 4.2.6 allows an adjustable delay or a fixed delay of 5 minutes. The time specified by the interconnection agreement should be coordinated to support BPS reliability as well as distribution requirements.

DER systems greater than 25 kW that do not utilize inverter-based interface equipment should not have automatic recloser capability unless otherwise approved by the utility. If the interconnecting utility determines that a facility must receive permission to reconnect, then any automatic reclosing functions must be disabled and verified to be disabled during verification testing.

Utilities in other parts of the Eastern Interconnection who have experienced increased levels of DER have determined that during system restoration, DER should not be allowed to return to service until the system has been reestablished and is in a stable operating state. Interconnection Agreements and standards should address necessary communications and SCADA requirements. As traditional resources on the BPS are retired and the grid becomes increasingly reliant on grid edge DER on the Distribution system, Black Start, and System Restoration plans will have to be adjusted accordingly.

Inverters

A power inverter, or inverter, is a power electronic device or circuitry that converts direct current (DC) to alternating current (AC). The inverter itself does not produce power. The power is provided by the DC source. Inverter design and/or configuration should be capable of ride-through for specified utility system events and are grouped into three separate performance Categories.

- Category I is based on minimal BPS reliability needs and is reasonably attainable by all DER technologies that are in common usage today.
- Category II covers minimum BPS reliability needs, and coordinates with NERC Reliability Standard PRC-024-2, which was developed to avoid adverse tripping of BPS generators during system disturbances.
- Category III provides the longest duration and widest range (band) for voltage ride-through capabilities that are attainable by inverter-based systems where very high levels of DER penetration are expected or where momentary cessation requirements are seen as a desirable solution for coordinating with distribution system protection and safety. This category is intended to address DER integration issues like power quality and system overloads caused by DER tripping in the local Area Electric Power System and to provide increased BPS reliability by further reducing the potential loss of DER during bulk system events.

Power Conversion	Prime Mover / Energy Source	Category
Inverter	Solar PV, Battery Energy Storage	Category III ¹ (amended)
	Wind	Category II
	Hydrogen Fuel Cell	Mutual Agreement
Synchronous generator	Bio-/landfill gas, fossil fuel, hydro, combined heat & power	Category I
Induction generator	Hydro	Mutual Agreement
¹ was Category II prior to Amendment		

Figure 2: Example assignment of IEEE 1547 abnormal performance categories to various types of DERs. Source: Provided courtesy of EPRI⁹

Inverters intended to provide local grid support during system events that result in voltage and/or frequency excursions as described in this document should be provided with the required functionality to allow for the equipment to remain online for the duration of the event.

It is recommended that all applicable inverter-based applications should:

- be certified per the requirements of UL 1741 SA as a grid support utility interactive inverter
- have the voltage and frequency trip settings as specified by the interconnecting utility
- have the abnormal performance capabilities (ride-through)
- provide interactive inverter functions status

In New York State it is recommended that equipment be selected from the Department of Public Service “Certified Interconnection Equipment list” maintained on the NY Public Service Commission’s website. Interconnected DG systems utilizing equipment not found in such list should meet all functional requirements of the current version of IEEE Std. 1547-2018 and be protected by utility grade relays (as defined in these requirements) using settings approved by the utility and verified in the field. The field verification test in New York State must demonstrate that the equipment meets the voltage and frequency requirements detailed in this section. Individual New England State interconnection

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standards and agreements also typically refer to IEEE Std. 1547-2018 functional requirements and include protection setting review requirements.

ISO-New England also has developed a technical bulletin, contained in [Appendix F](#), which outlines required settings for inverters in New England.

Certification per UL 1741 SA and UL 1741 SB as grid support utility interactive inverters

Because Inverters currently certified for IEEE 1547-2003 do not currently provide adequate grid support functionality, in the interim period until DER that have been certified as meeting IEEE Std. 1547-2018 in accordance with IEEE Std. 1547.1-2020 (IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces) and UL 1741 SB (September, 2020) become available, certification of all inverter-based applications is needed. For example, in one NPCC Area the following approach was taken to assure having inverters installed with a standardized set of grid support functionality to ensure the reliability of the BPS (e.g. maintaining acceptable system frequency and voltage):

- Should be compliant with only those parts of Clause 6 (Response to Area EPS abnormal conditions) of IEEE Std. 1547.1-2018 (2nd ed.) that can be certified per the type test requirements of UL 1741 SA (September 2016).
- May be sufficiently achieved by certifying inverters as grid support utility interactive inverters per the requirements of UL 1741 SA (September 2016) with either CA Rule 21 or Hawaiian Rule 14H as the Source Requirement Document (SRD). Such inverters are deemed capable of meeting the requirements of this document.
- Applications should have the voltage and frequency trip points and abnormal performance capabilities consistent with IEEE 1547-2018, PRC-024-2 and PRC-006-NPCC “Automatic Underfrequency Load Shedding.”
- For abnormal performance, Category III inverters should be recommended for use. (There may be some circumstances, such as certain types of fuel cells) where the primary energy source may not allow practical implementation of Category III performance. Specification of Category II performance in abnormal conditions may be acceptable in these limited cases.)

UL Standard 1741 Supplement B (UL 1741 SB) implements the test requirements for compliance with IEEE 1547-2018 DER performance requirements in accordance with the test specifications of IEEE 1547.1-2020. With the approval of this UL standard in September 2020, it is anticipated that inverters compliant with IEEE 1547-2018 grid support requirements will be widely available by 2022. Substantial availability of compliant inverters can be anticipated somewhat prior to that date as inverter manufacturers complete their design modifications and move their products through the UL certification process. Once UL 1741 SB inverters become pervasive, the measures in the first and second bullets above are no longer applicable or necessary.

Protective Functions

Protective system requirements for distributed generation facilities result from an assessment of many factors, including but not limited to:

- Type and size of the DER facility
- Voltage level of the interconnection
- Location of the DER facility on the distribution circuit
- Distribution transformer
- Distribution system configuration
- Available fault current
- Load that can remain connected to the DER facility under isolated conditions
- Amount of existing DER on the local distribution system.

Local Interconnection Agreements and standards should require that synchronous, induction and inverter based DER include protection functions for Under/Over Voltage (27/59), Over/Under Frequency (81O/81U), Overcurrent (50P/50G/51P/51G) and Anti-Islanding Protection. Reverse power protection should also be considered as appropriate for BPS support. Interconnection Agreements and standards should require that inverter based DER should be certified according to UL 1741SA as grid supportive. DER protection equipment should utilize a non-volatile memory design such that a loss of internal or external control power, including batteries, will not cause a loss of interconnection protection functions or loss of protection set points. Interconnection Agreements and standards should require that DER protective devices utilize their own current transformers and potential transformers for protection and not share electrical equipment associated with utility revenue metering.

The need for additional protective functions will be determined by the utility on a case- by-case basis. If the utility determines a need for additional functions, it will notify the DER owner of the requirements. The notice should include a description of the specific aspects of the utility system that necessitate the addition, and ideally, explicit justification for the necessity of the enhanced capability. The connecting utility should specify and provide settings for those functions that the utility designates as being required to satisfy their individual protection practices. Any protective equipment or setting specified by the utility is not to be changed or modified at any time by the DER owner without consent from the utility.

The DER owner is responsible for ongoing compliance with all applicable local, state, and federal codes and standardized interconnection requirements as they pertain to the interconnection of DER.

All interface protection and control equipment should operate as specified by state and local interconnection agreements and standards.

In New England, for monitoring and control of new DG projects, [Appendix E](#) lists current interconnection documentation and standards for DER by State. The DER communications hardware, protocols, and data models must comply with these state and local interconnection utility standards.

In New York, for monitoring and control of new DER projects, the most current version of the Monitoring and Control Criteria should be employed by the utilities to evaluate the need for such

equipment in New York. The New York Monitoring and Control Criteria document was developed and agreed to through a collaborative process as part of the Interconnection Technical Working Group (ITWG)¹⁰. The communications hardware, protocols, and data models must comply with local interconnection utility standards.

Also, and fundamentally, existing over-current protections in distribution system are typically designed to clear line and ground faults occurring downstream from their location, as the only source feeding the fault is the transformer station. Connecting a DER provides another source supplying the fault, and the fault contribution from the facility might cause protection to operate non-selectively for reverse faults, out of the protected zone. If the maximum reverse fault current through a non-directional fault-interrupting device exceeds the setting of the device, the fault-interrupting device should be considered with a directional feature to prevent tripping for reverse fault current flow. For instance, phase protection could be replaced with an impedance relay (function 21) if required.

Metering

Advantages and Opportunities of Implementing Advanced Metering Infrastructure (AMI):

IEEE 1547-2018 interoperability requirements specify that the DER have communication capabilities and shall measure specific quantities and have this information available at the communications interface. Most utilities, however, do not have and are not requiring DER owners to provide the communications needed to connect all DER to a grid SCADA system. Such requirements tend to be placed only on large DER. Most utilities do not have the information infrastructure necessary to interoperate with large numbers of small DER; however, implementation of AMI will help in this regard.

Depending on the level of analytics utilized by an Electric Distribution Company (EDC), AMI can provide varying levels of intelligence and operability about the electric distribution system. Even if no analytics are implemented, value can be gained by reviewing and having access to the data provided by AMI. If a full-fledged data analytics package is implemented, then significant benefits can be realized.

Without an analytics package, engineers or analysts can still review basic voltage information provided from AMI. Using SAS, Excel or other simple tools, the voltage data provided, on a daily basis, can be quickly filtered down to exhibit meters that have high or low voltages exceeding the limits set by local Regulatory bodies. With minimal research, it can be determined if high voltage is caused by the presence of DER, either for the meter affected or a nearby neighbor on the same secondary transformer. The transformer can be evaluated by engineering to determine if new, larger equipment is needed.

With reports of abnormal voltage, Distribution Planning can evaluate the data and determine if voltage regulators need to be added towards the end of a circuit, if switching needs to occur to change circuit topology, or if other actions are needed. If the low voltage only occurs at certain times of the day, then perhaps load tap changers at the substation may be used to address the issue.

¹⁰ This document can be found on the Department of Public Service website (www.dps.ny.gov) at the Distributed Generation/Interconnections tab under Interconnection Technical Working Group Information.

If implementing a data analytics package, whether off-the-shelf or home grown, more details on system operating conditions can be found. For instance, by evaluating the sum of meter usage for a specific transformer, secondary transformers can be determined to be over or under loaded. If voltage interval data is available, the GIS model of the system can be evaluated to identify meters that are incorrectly assigned to transformers; the model can be corrected to properly assign meters to transformers.

With data analytics and near real-time data transfer from the head-end system then volt-var optimization can occur. As LTCs, capacitor banks or voltage regulators are adjusted, live feedback from the system can be evaluated to ensure the expected responses are occurring. If something unexpected is happening, then operators receive evidence of this quickly and can take remedial actions.

The specific benefits of AMI are still evolving, and as more analytical tools are made available, and as meters become more advanced, the data will be leveraged to provide more insights into the operation of the distribution network.

Metering requirements for SCADA purposes are usually determined by the local connecting utility and based on the configuration of the DER system prior to energization. Whether SCADA metering can be integrated with revenue metering is a matter for the local connecting utility and connecting DER facility to decide. New metering or modifications to existing metering should be reviewed on a case-by-case basis and be consistent with metering requirements specified by the local connecting utility and any overarching requirements adopted by the local regulatory authority that has jurisdiction (e.g. state commission for example for revenue metering).

IEEE-1547-2018 requires DER to be capable of providing monitoring of connection status, real power output, reactive power output, and voltage either at the point of connection or some agreed upon point if multiple DER facilities are involved. Going forward, member utilities should consider developing IT Infrastructure plans to aggregate and report critical DER Status to BPS Operators, i.e. aggregate DER output within a given area and map those to individual transmission nodes. This information should be available to the system operator as required by the connecting utility. The monitoring equipment should be installed at the time of interconnection and meet the technical requirements of the connecting utility. The DER metering and monitoring communications will allow interoperability and the capability to provide system operators with situational awareness necessary for reliable operation of the interconnecting utility facilities. As more DER is employed and base load generation is replaced with DER resources, it will be important for the Distribution Provider (DP) or interconnecting utility to be able to monitor the availability and production of electricity (power output and energy delivered) from the DER resources.

Power Quality

In practice, DER-related power quality issues are exclusively distribution issues and have little impact or relevance to the bulk power system, or to power quality in other distribution systems. Therefore, this topic is not addressed in this document.

Power Factor

IEEE 1547-2018 requires new DER to have the capability to produce or absorb reactive power from 0.95 pf leading to 0.95 pf lagging¹¹. The standard also specifies that DER have a number of different control functions to regulate this reactive power capability. Legacy DER are typically operated at unity power factor.

Because of the low reactance to resistance (X/R) ratio of distribution systems, the general impact of DER active (kW) power at high penetration is to elevate distribution voltages, potentially to excessive levels. Utilization of DER reactive power capabilities will generally mean that these DER will be absorbing reactive power during high output in order to hold down the distribution voltage to acceptable levels.

Transmission system voltage are generally decoupled from distribution system voltage levels by on-load tap changers in primary distribution substation transformers. The increased reactive power demand that can be brought about by deployment of DER reactive power to mitigate distribution overvoltage issues, however, can directly impact the transmission system unless that additional reactive power demand is compensated by capacitor banks at the distribution substation bus. This can increase total reactive power demands on the transmission system and could potentially have adverse impacts on bulk system voltage stability.

Islanding

Although an entire distribution substation along with some transmission assets could become islanded in a very high DER penetration scenario, islanding is primarily a distribution system concern. IEEE Std 1547.1-2020 tests certified DER for islanding detection with the most insensitive trip settings and with the most aggressive grid support functions. Because DER must pass the islanding detection tests despite these settings and functions, islanding concerns should not be a constraint on implementing trip settings and disturbance ride-through requirements that are necessary for protecting the bulk system security from the impacts of widespread DER resource tripping due to transmission level disturbances.

Some of the anti-islanding algorithms that are implemented in DER intentionally destabilize islanded systems in order to force voltage or frequency tripping. There is some concern that, at high regional DER penetration, these functions may also have adverse impact on the dynamic stability of the bulk system. This potential issue is in need of research to define its extent and severity.

Automatic Underfrequency Load Shedding (UFLS) Programs

UFLS is implemented to restore power system frequency stability if system frequency drops below the UFLS operational set point. Significant deviations in system frequency typically occur during major disturbances such as a loss of generation or events in excess of design contingencies used for planning purposes. UFLS is considered the “safety net” for the BPS and a last resort automatic operation designed to stabilize BPS islands for a generation deficiency. Various fractions of load are shed in multiple stages, up to about 31% of peak net load¹², in order to stabilize frequency. UFLS is primarily installed on distribution feeders, where DER is increasingly being deployed.

¹¹ Certain DER, such as rotating generators, may be allowed to meet slightly less stringent reactive power requirements.

¹² Peak net load shall be calculated as an average of the peak net load from the previous 3 years, excluding the

NERC has a set of requirements in the PRC-006 standard and NPCC has more stringent requirements in NPCC's Regional Standard, PRC-006-NPCC¹³ which outline expected UFLS performance. Approved and effective versions of these standards may both be found on the NERC website.

SS-38 is the NPCC working group responsible for inter-Area dynamic analysis. The SS-38 Working Group regularly studies the UFLS performance within the Region and has recently completed sensitivity analysis showing that a moderate increase of DER penetration anticipated in the short term will not result in any significant degradation in the UFLS program performance based on the conditions and assumptions used in the analysis.

In the future, adopting a more flexible approach to UFLS may be necessary as DER penetrations reach higher levels. There are utilities that are reviewing the feasibility of "Adaptive UFLS" which uses real time monitoring of distribution feeder loads and their DER to determine how much additional load may need to be tripped when DER has increased output. Some utilities, such as Duke Energy avoid choosing those distribution feeders for the UFLS program that have DER interconnected to them.

Effective Grounding for DER

The subject of Effective Grounding may not, in many cases, be impactful to BES reliability it will potentially have an impact on Substation equipment, particularly substation class metal oxide varistor (MOV) arrestors due to overvoltages during faults. With the onset of high penetrations of DER, such as photovoltaic (PV) generation, utilities should consider interconnection of DER similarly to how they would interconnect synchronous generators.

Conventional generators are considered voltage sources as the magnetic flux within the generator tends to provide a constant voltage source during faults. In contrast, inverter-based DER are considered voltage-controlled current sources during faults. Inverter-based facilities generally provide less short-circuit current than similarly sized synchronous units.

Solidly grounding a transformer neutral for a DER plant eliminates a possible phase overvoltage stemming from a single-line-to-ground fault. A potential problem with the solid grounding in the distribution line is that large fault currents can flow through the transformer neutral, which can desensitize the overcurrent protection coordination. In order to mitigate this issue, impedance grounding can limit the fault current and potential equipment damage, while allowing overvoltage to some limited magnitude. Some utilities protect their distribution from overvoltage by using overvoltage protection so Effective Grounding isn't a concern. Further investigation on the how specific installations are grounded is warranted and being pursued by the Interconnection Technical Working Group (ITWG) in New York.

current year. See NPCC's Regional Standard for further details on UFLS requirements, PRC-006-NPCC-2 [Automatic Underfrequency Load Shedding](#)

¹³ Effective Date of the Standard is 4/1/2020 subject to the Implementation Plan and specific area regulatory approvals

Resource Adequacy

Forecasting resource adequacy is an important system reliability planning function¹⁴. The reporting of generation capability and related performance data is integral to this activity. Specific modelling information of intermittent DER resources is critical to planning and understanding system performance. Information related to DER in-service dates, capacity value, availability, emergency assistance, scheduling, and deliverability should be available to the planners. Modeling, data, and other necessary information should be defined and made available to those needing it, such as system planners and system operators. Any requirements associated with this information should be in Interconnection Agreements or Tariffs prior to any commissioning of the DER. Mechanisms for DER entities to provide this information are evolving, depending on locality, and subject to change as DER penetration increases.

Energy Storage Systems for DER

Battery storage technology is undergoing a rapid evolution from Lead Acid to Absorbent Glass Mat to Li-Ion due to the expanding application of batteries to transportation and other sectors. Li-Ion batteries have been and continue to be deployed in a wide range of electric energy-storage applications, ranging from energy-type batteries of a few kilowatt-hours in residential systems with rooftop photovoltaic arrays to multi-megawatt containerized batteries for the provision of grid ancillary services. The Energy Storage Association (ESA) anticipates at least 35 GW of new energy storage will be deployed in the United States by 2025.

NPCC is also observing marked increases in Hybrid Resources which are combinations of multiple technologies that are physically and electronically controlled by the Hybrid Owner/Operator behind the point of interconnection (“POI”) and offered to the grid as a single resource at that POI. This arrangement usually involves energy storage at a photo-voltaic or wind turbine site. It optimizes the use of DER and enables normally clipped energy (energy beyond the rating of an inverter or unneeded by the BPS) to be stored on-site and released in the future. It also allows low outputs of DER which may be outside the operational range of an inverter to be harvested for charging on-site storage allowing better utilization of the total resource. In the figure below the red curve represents the capability of an inverter and the blue is the capability of the DER. Areas between the curves may be used to charge or be “harvested.” This leads to a more efficient utilization of the DER and supports grid reliability and state of charge of the energy storage. As shown in Figure 3 below, the capability of an inverter can be exceeded by the capability of the DER behind it. Figure 3 below also displays a typical daily capability curve associated with a PV inverter with the maximum power capability delivered during mid-day. DER in many instances is designed with due consideration of the degradation of capability, such as a solar panel’s capacity over time.

¹⁴ For background on resource adequacy metrics see: [“Resource Adequacy Metrics and their Applications”](#) prepared by the New York State Reliability Council.

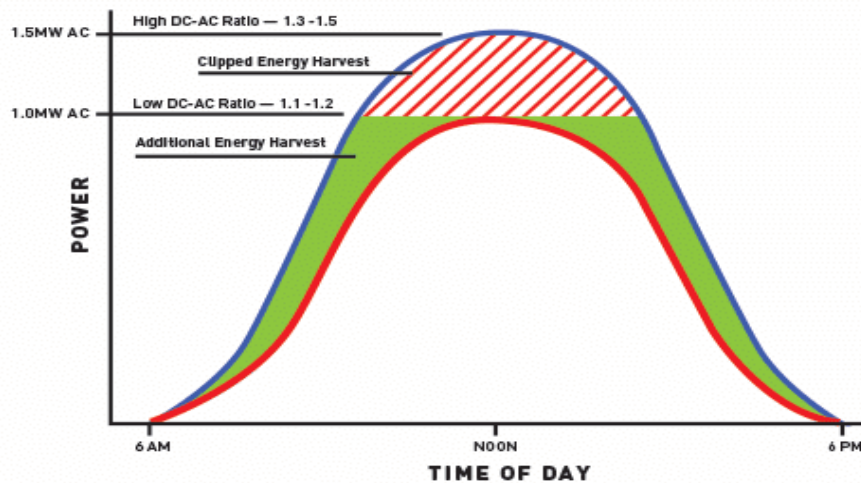


Figure 3- Storage showing Clipped and Unused Energy

The ESA has an online report to manage any risks associated with Energy Storage. Their report may be found here, [Energy Storage, Operational Risk Management](#). Care should be used in placement of batteries and should avoid physical proximity (due to the risk of fire or explosion) and electrical proximity (due to harmonics and other power electronic interaction concerns) to other facilities that may be critical to the reliable operation of the BPS.

System Control and Data Acquisition (SCADA) and Communications

As DER penetration increases all DER above a certain MW level, as determined by the interconnecting utility or System Operators, should be required to provide SCADA telemetry data to a control center to monitor their output. It might be beneficial to have DER data be communicated to a Distribution System Operator, distribution system platform or similar, to provide analysis and aggregation of data for a concise summary to the transmission system operator. IEEE-1547-2018 has a communication port requirement. This ensures that the output remains visible to the system operator. It allows the system operator to observe DER status when working on a feeder in emergency or planned outage situations. Some NPCC Members have encountered difficulty with obtaining information and data from DER operators. DER owners should be encouraged to keep their end of any SCADA equipment functional and reconnect their telemetry devices when they have been disabled and this can be done through interconnection requirements. The operator should be alerted by the DER when telemetry is interrupted. Scan rates equivalent to the scan rates used by the system operator are preferred (typically in the 6 second range). Although IEEE 1547-2018 defines and requires a communication port, the path that a utility may use for data from that communication port may pose a cyber-security risk if not adequately secure. It is suggested that full consideration be given to cyber security risks when transferring data until such time as the IEEE 1547 has been amended to require cyber security protections.

Going forward many areas and utilities are either in the process of or determining the value of adding distribution system platforms to deal with DER aggregation, observability, availability and status of DER. NPCC will continue to monitor the development and deployment of these Distributed Energy Resource Monitoring Systems (“DERMS”).

DER Recommendations

As DER continues to proliferate within the NPCC Region we suggest the following initial activities:

Participation in National DER Forums

- 1) Participate in efforts to fully understand the issues and best practices associated with DER.
- 2) Engage NPCC and its members to address the issues and provide expertise.
- 3) As the understanding of the issues and best practices matures, then NPCC will be well positioned to understand the regional differences that need to be considered.

Process and Risk Management Recommendations

- 1) Continue with sensitivity analysis at the Transmission level for various levels of penetration of DER on the distribution facilities to determine effects of increased penetration levels of DER on BPS performance.
- 2) Pursue further opportunities to coordinate distribution and transmission requirements for DER, share Member best practices, and promote consistency regarding DER installations where possible within the NPCC region.
- 3) Continue to review and identify approaches to coordinate NPCC AGIR and utility interconnection requirements relative to DER to identify dissimilarities between Areas which may negatively impact reliability.
- 4) Identify opportunities to share information regarding DER related reliability risk problems and solutions and promote sharing.
- 5) Encourage consideration of developing IT Infrastructure plans to aggregate and report critical DER Status to BPS Operators.
- 6) Continue to solicit and address observable reliability related issues of DER using NPCC's DER Impact Reporting Forms and its associated process.
- 7) Continue to discuss any changes required for System Restoration and Blackstart Plans, as a result of increased DER.
- 8) Continue to follow DER related ESA ESS safety issues and associated recommendations and share the results with NPCC stakeholders.
- 9) Avoid placement of UFLS on distribution feeders which have a significant amount of DER relative to the feeder's load if possible, unless sufficient telemetry exists to ensure proper functionality of the UFLS program as a whole.

Planning Related Recommendations Due to Changing Resource Mix

- 1) Identify and consider new methods to obtain and facilitate collection of DER modeling and performance data to enable Long-Term Resource, Long-Term Transmission and Operational Planning of the BPS¹⁵
- 2) Clearly identify DER in the NPCC Region's Area interconnection queues or forecasts where DER is being proposed for installation, including the magnitude and location relative to the existing resource base and load projections.
- 3) Address masking of load by DER at the distribution level to ascertain its impact on the behavior of load, as well as the assumptions that underpin UFLS programs.
- 4) Determine the appropriate entities responsible for providing DER data to the Planning Coordinator for the purposes of model building and maintenance and ensure that this data is provided.

Analytics and simulation recommendations to deal with increased system complexity

- 1) Support interconnection wide inertia loss study efforts, to determine potential reliability impacts, as DER replaces conventional synchronous generation resources.
- 2) Obtain DER modelling data to be able to model, predict and examine system behavior and assess the interactions between the new resources and the existing reliability preserving systems and programs. Examples include:
 - a. Dynamic behavior of the transmission system
 - b. Sudden loss of large amounts of DER due to transmission system events
 - c. Under Frequency Load Shedding,
 - d. Under Voltage Load Shedding,
 - e. Frequency response sharing mechanisms (BAL standards).
 - f. Analysis of system protection systems (both T and D) so that the parameters to set protection systems and other control systems are known to permit the most reliability benefits to be garnered from the new resources.
- 3) Determine the transmission and distribution benefits and challenges of DER fault-related dynamic voltage support.
- 4) Determine the value to the transmission and distribution systems of the different DER steady-state voltage/reactive power control.

Implementation of IEEE-1547-2018

- 1) Work with the AGIR to assign abnormal performance categories for DER certified as meeting IEEE Std. 1547-2018. For example, synchronous generators could be Category I. All inverter-based generation could be Category III. Exceptions could be allowed for inverter-based technologies that could not meet category III and did not constitute a significant penetration. Exceptions could need to be agreed to by both the distribution and transmission entities.
- 2) Develop standard voltage trip settings (1547-2018 Clause 6.4.1) that provide for BPS reliability. For example for Category III, UV1 could be set at 0.88 p.u. & 3.5 seconds to coordinate with PRC-

¹⁵ Questions exist regarding which entities should be responsible for providing DER data to the Planning Coordinator for the purposes of model building. NERC is working on this issue.

024-2 at 0.88 p.u. & 6 seconds to coordinate with PRC-024-2 with margin for Fault Induced Delayed Voltage Recovery (FIDVR) or at 0.88 p.u. & 10 seconds which conforms with the default setting of Category II I. UV2 could be set at 0.5 p.u. and 2 seconds which conforms with the default setting of Category III.

- 3) Develop standard frequency trip settings (1547-2018 Clause 6.5.1) that provide for BPS reliability. For example, use the default setting which were chosen to coordinate with under frequency load shedding.
- 4) Develop standard frequency droop settings (1547-2018 Clause 6.5.2.7) that provide for BPS reliability. For example, use the default settings that are consist with the requirements for generators connected to the BPS
- 5) Develop standard Enter Service settings (1547-2018 Clause 4.10) that can be used in black start studies. The default delay time is 300 seconds. However, distribution entities may require a shorter delay to reduce the impact of cold load pickup. Also, distribution entities may require different delay times when several large DER are connected to the same feeder
- 6) Develop requirements that ensure protective relay settings on the distribution system coordinate with the voltage and frequency ride-through capabilities established by the selected trip settings. Any exceptions shall be discussed with the transmission provider.

Appendix A, NPCC DER Impact Reporting Form and Process



NORTHEAST POWER COORDINATING COUNCIL, INC.
 1040 AVE. OF THE AMERICAS, NEW YORK, NY 10018 (212) 840-1070 FAX (212) 302-2782

Please Complete and email this form and email to; [npccstandard@npcc.org](mailto:npscstandard@npcc.org)

Distributed Energy Resource (DER), BES Impact Reporting Form

Name		Date	
Email		Company	
Impact on Bulk Electric System		Area (NY, NE, State or Province etc.)	

Equipment Impacted

Equipment	Location (substation name, etc.)	Impact (Positive reliability impact? Negative reliability impact-Protection System failure, Misoperation, load affected or lost?, power quality issue?, etc.)	Duration of Impact, (start and stop times, length of impact, ongoing? etc.)

Description of Impact on BES- What Happened or was observed?

Please describe below the details of all the impacts of the DER as it pertains to this report, such as load loss, loss of life, equipment failure or potential reliability improvement. A sequence of events showing the impact is helpful. Attach supporting information to this form if necessary.

Root Cause or additional Analysis

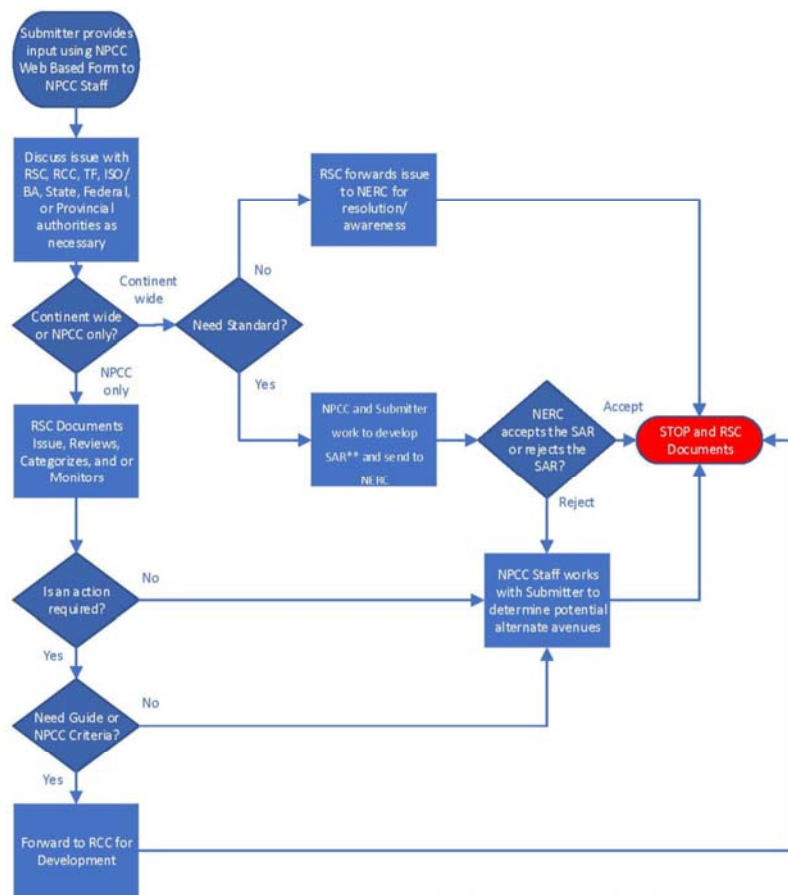
Please describe below the details of any investigation your company may have already done to identify causes or contributing factors to the incident. This will help NPCC route the issue properly to address it.

NPCC Review of Issue and Recommendations (i.e. refer to NERC, develop a Criteria, Guideline, Already Addressed or Identified, etc.)

NPCC Date of Resolution of Issue _____

Evaluation Process

Impacts from Distribution Level* Distributed Energy Resources on the BES



*Distribution Level, Not behind the Meter, utility scale DER

** Standards Authorization Request (SAR)

Regional Standards Committee, Approved 8/22/18 (GVZ)

Appendix B, NPCC Areas-Comparisons

Key Inverter based specification extracts

	ISO-NE Inverter Requirements	NG ESB 756 B, C, D	NY SIR ¹⁶	IESO F2 Technical Requirements
Inverter Certification	yes	yes	yes	yes
Voltage and frequency trip settings for inverter-based applications	yes	yes	yes	yes
Voltage Response	yes ¹⁷	yes	yes	yes
Frequency Response	yes ¹⁸		yes	yes
Abnormal performance capability (ride-through) requirements for inverter-based applications	yes	yes		
Other grid support utility interactive inverter functions statuses	yes			
Minimum protection functions		yes	yes	
Monitoring and Control		yes	yes	yes
Reconnection to the System		yes	yes	
Distribution Protection Coordination		yes		yes
Inverter Certification		yes	yes	
Power Quality			yes	

¹⁶ NY SIR is the [New York Standardized Interconnection Requirement](#).

¹⁷ The functionality is required to be present, but the default state is to have this functionality disabled unless otherwise directed by the area EPS operator

¹⁸ The functionality is required to be present, but the default state is to have this functionality disabled unless otherwise directed by the area EPS operator

Appendix C – SPIDER Working Group Reliability Guidelines & Activities

The NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) was formed to focus on the impacts that aggregate amounts of DER can have on transmission planning and BPS reliability. This SPIDERWG is seeking to provide high-level, technical recommended practices for ensuring BPS reliability in the face of growing penetrations of DER across North America. The recommended practices and guidance provided by SPIDERWG, in many cases, will need to be adapted to specific utility and regional planning and operating practices. The following DER-related topics are covered, as described in NERC Staff’s “Summary of Activities: BPS-Connected Inverter-Based Resources and Distributed Energy Resources”¹⁹:

Modeling: Representing aggregate DER in BPS reliability studies, advancing industry capabilities and expertise with representing DER in these reliability studies, developing robust and reasonable data sets for power flow and dynamic simulations

Verification: Ensuring that the models used in studies provide a reasonable and suitable representation of the actual aggregate performance of these resources, benchmarking software platforms to ensure uniformity in tools, recommending analysis techniques for accounting for aggregate DER during large BPS disturbances

Studies: Improving study techniques and methods to ensure the most stressed operating conditions are chosen for BPS reliability studies, identifying key operating conditions and sensitivities to perform, improving software tools and study capabilities

Coordination: Supporting coordination between transmission and distribution entities for improved data exchange and coordinating with IEEE to support the application of IEEE Std. 1547- 2018 across North America

A list of SPIDERWG Reliability Guidelines and other activities is provided in Table 1 and Table 2, respectively.

¹⁹ Available here: https://www.nerc.com/comm/PC/Documents/Summary_of_Activities_BPS-Connected_IBR_and_DER.pdf

Table 1. SPIDER Working Group Reliability Guidelines

Subgroup	Title	Description	Status
Modeling	DER Data Collection for Modeling	Guideline providing recommended practices for collecting DER data for the purpose of developing aggregate DER models for BPS reliability studies.	In Review – Draft Posted for Comment (here)
	DER_A Model Parameterization	Guideline providing recommendations for using state-of-the-art aggregate DER dynamic models in BPS reliability studies.	Published (here)
Verification	DER Performance and Model Verification	Guideline providing recommended practices for performing model verification for aggregate DER dynamic models including placement of measurement devices, execution of verification simulations, and how to use the data collected through these practices.	In Development
	DER Forecasting Practices and Relationship to DER Modeling for Reliability Studies	Guideline providing how forecasting practices are linked to DER modeling for reliability studies, specifically on how DER are accounted for in future reliability assessments.	In Development
Studies	Bulk Power System Planning under Increasing Penetration of Distributed Energy Resources	Guideline providing recommended practices for performing planning studies considering the impacts of aggregate DER behavior.	In Development
	Recommended Approaches for Developing Underfrequency Load Shedding Programs with Increasing DER Penetration	Guideline regarding how to study UFLS programs and ensure their effectiveness with increasing penetration of DER.	Under Consideration
Coordination	BPS Reliability Perspectives on the Adoption of IEEE 1547-2018	Guideline providing industry recommendations and BPS reliability perspectives on the implementation and adoption of IEEE 1547-2018.	Published (here)
	Communication and Coordination Strategies for Transmission Entities and Distribution Entities regarding Distributed Energy Resources	Guideline recommending strategies to encourage coordination between Transmission and Distribution entities on issues related to DER such as information sharing, performance requirements, DER settings, etc.	In Development

Table 2. SPIDER Working Group Other Activities

Subgroup	Title	Description	Status
Modeling	Modeling Notification: Dispatching DER off Pmax in Case Creation	Notification of accounting for DER in powerflow and dynamics cases, particularly regarding accounting for power output levels with DER utilizing advanced grid-supportive features.	Posted (here)
	DER Modeling Survey	Survey of SPIDERWG member organizations regarding the use of DER models in BPS planning studies.	Compiling Results
Studies	White Paper: Review of TPL-001-5 for Incorporation of DER	White paper discussing technical review of NERC TPL-001-5 in the context of increasing DER and their impacts to the BPS. Possible SAR development following completion of white paper, as needed.	In Review
	White Paper: Recommended Simulation Improvements and Techniques	White Paper recommending simulation software improvements to enhance the ability to accurately account for and model DER.	In Development
	White Paper: DER Impacts to Undervoltage Load Shedding	White Paper briefly discussing how DER may impact UVLS program development.	In Development
	White Paper: Beyond Positive Sequence RMS Simulations for High DER	White Paper highlighting the use of tools that provide additional technical detail to DER studies beyond just positive sequence RMS simulation tools.	In Development
Coordination	Coordination of DER Terminology	Development and ongoing review of definitions and terminology pertaining to DER and related topics.	In Development
	NERC Reliability Standards Review	White Paper reviewing NERC Reliability Standards and the impacts that increasing penetrations DER may have on BPS reliability and standards compliance/implementation. Possible SAR development following completion of white paper, as needed.	In Development
	Tracking and Reporting DER Growth	Coordinated review of information regarding DER growth, including types of DER, size of DER, etc. Consideration for useful tracking techniques for modeling and reliability studies.	In Development

Appendix D, NPCC Reliability Principles

Using its membership structure and governance authority to create and apply Regional Criteria²⁰, NPCC Member adherence to Regional Criteria contributes to a more robust level of reliability beyond NERC ERO reliability “results-based” standards / requirements. For example, NPCC Criteria mandate specific design requirements for NPCC Member facilities. NPCC’s approach to reliability and Resilience can be summarized in Principles that guide NPCC Members in their effort to meet or exceed NERC requirements. NPCC’s core Reliability Principles²¹ and activities support the NERC Bulk Electric System and NPCC’s Bulk Power System reliability.

The NPCC Reliability Principles include:

1. **Focus on the most important system components:** In order to focus resources to those portions of the power delivery system most important (critical) to overall reliability, NPCC Members employ mechanism(s) for identifying those facilities that are most critical to the reliable planning and operation of the power delivery assets in the NPCC region²². These critical facilities collectively are identified as the NPCC Bulk Power System^{23,24}.
2. **Application of Criteria beyond NERC requirements to identified critical facilities:** Where, in the opinion of NPCC’s Membership, the NERC standards do not adequately specify a necessary performance or design outcome in a given technical, operation or planning area, NPCC Criteria govern the design of their respective portions of the NPCC Bulk Power System planning and operation²⁵ activities.
3. **NPCC Members support the Criteria:** NPCC’s Full Members in accordance with the NPCC Bylaws are committed to designing and operating their systems to meet the NPCC Criteria under peer review of the NPCC Full Members.
4. **No conflict with NERC Requirements:** The NPCC Criteria supplement, improve upon where necessary, benefit, and do not conflict with or duplicate the results-based performance

²⁰ See NERC Rule of Procedure #313 on page 15 of the [NERC Rules of Procedure 3-9-2018](#).

²¹ The Reliability Principles were summarized in the NPCC 2018 Strategic Review Report.

²² The method of identifying critical facilities is currently embodied in the [NPCC A-10 Classification of bulk power system Elements](#) document, currently under review by the CP-11 Working Group with a due date of October 31, 2018.

²³ The NPCC bulk power system is identified by a specific list of facilities in the NPCC region deemed critical by the NPCC A-10 classification process. This list is not determined based on the definition of the ERO bulk power system, which is defined in the US 2005 EPACT as:

“(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and

“(B) electric energy from generation facilities needed to maintain transmission system reliability.

The term does not include facilities used in the local distribution of electric energy.

²⁴ There are other documents which supplement the Directories, for instance the NPCC Compliance Guidance Statements. These documents usually refer to NERC standards applicability and can be found here: [NPCC CGS](#)

²⁵ NERC [Rule of Procedure](#) #313 (page 15) permits the following: “Regional Entities may develop Regional Criteria that are necessary to implement, to augment, or to comply with NERC Reliability Standards, but which are not Reliability Standards. Regional Criteria may also address issues not within the scope of Reliability Standards, such as resource adequacy.”

requirements of NERC standards where they apply to the NPCC Bulk Power System. NPCC adjusts its Regional Criteria to retire or adapt to any new NERC requirements as they come into effect as necessary.

5. **Include design specifications where needed:** The NPCC Criteria and related guidelines and procedures provide design criteria and practices to assure implementation. NPCC Directories go into greater detail regarding how to accomplish a given reliability result, where NERC standards may simply require a “reliability result.”
6. **Resilience has always been an element of NPCC Criteria:** Based on experience, resilience^{26 27} is a necessary constituent component of reliability and it is important both to electricity consumers and regulatory authorities in NPCC’s Region. NPCC Criteria provide substantial resilience benefits to the NPCC Bulk Power System by providing:
 - a. Robustness – The ability to withstand disturbances by supporting operations in a more secure state.
 - b. Resourcefulness – The ability to detect and manage a crisis as it unfolds.
 - c. Rapid recovery – The ability to get services back as quickly as possible in a coordinated and controlled manner.
 - d. Adaptability – The ability to absorb new lessons from events

²⁶ Reference NERC’s recent [filing](#) with FERC regarding Resilience for a more complete discussion of the relationship between resilience, the NERC standards and the NAICS Resilience Framework. FERC is expected to define resilience in the course of its current examination of electric system resilience concepts.

²⁷In the US, [Presidential Policy Directive – 21](#) defines resilience as “The ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents”.

NERC, Model of Resilience

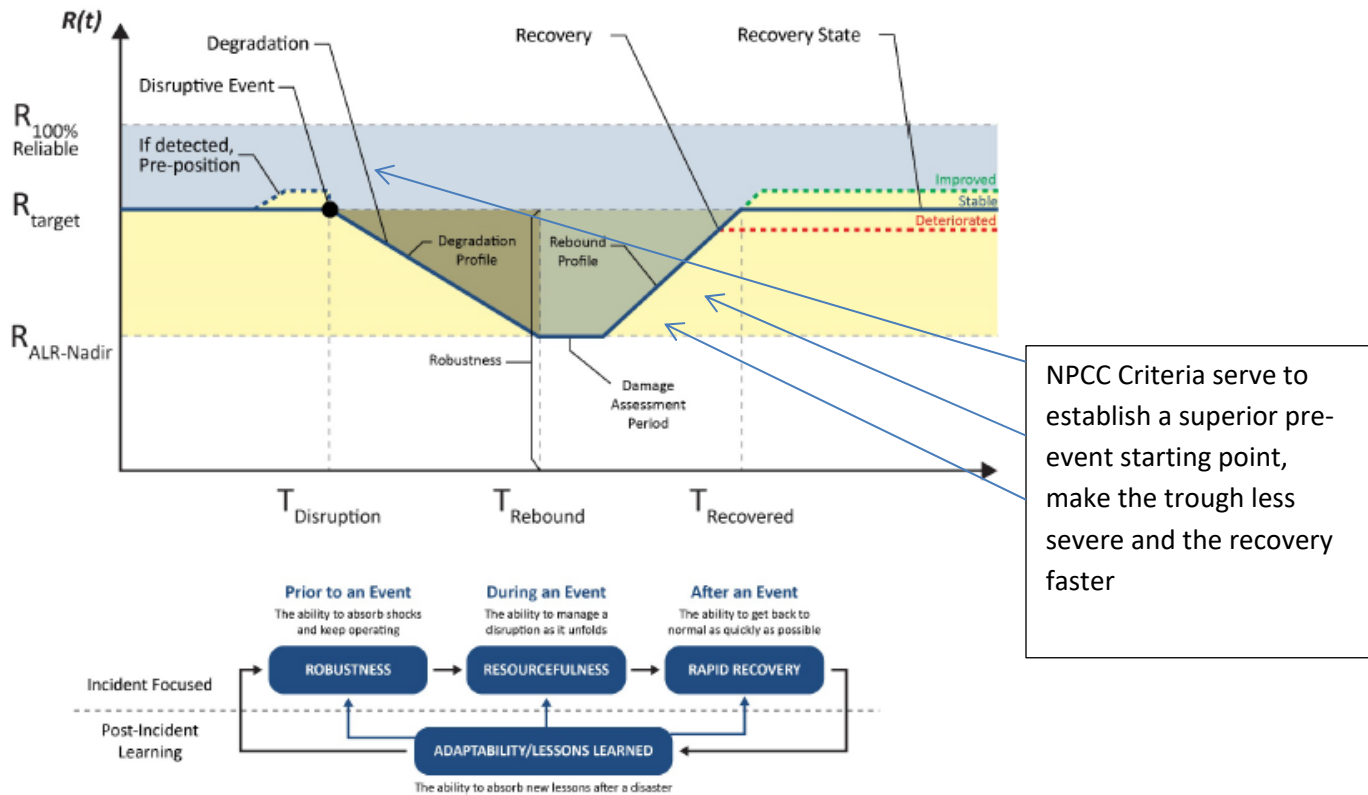


Figure 2.1

Figure 2.1 depicts a typical disruptive event and maps how the systems responds in a qualitative fashion. The y-axis above is meant to represent a relative level of reliability and system response is plotted temporally. DER will increasingly fill a critical role with respect to reliability and Resilience of the Bulk Electric System. Specifically, DER can contribute to the overall robustness of the system and provide increased resource support within islands during system separations. As DER continues to penetrate the system, changes to NPCC's Underfrequency Load Shedding program may be required.

Appendix E, State and Provincial AGIR Information

New York State

Statewide Interconnection Technical Documents may be found at:

[Interconnection Technical Working Group Webpage](#)

New England, by State

Inverter Source Requirement Document of ISO New England (ISO-NE)

Connecticut –

Department of Energy and Environmental Protection, Public Utilities Regulatory Authority (PURA)

Eversource Energy – Connecticut Interconnection Standard

<https://www.eversource.com/content/general/about/about-us/doing-business-with-us/builders-contractors/interconnections/connecticut-application-to-connect>

Summary of Facility Connection Requirements for Generation, Transmission and End Users Connecting to UI Transmission Facilities, Revision 4.0, December 7, 2015:

<https://www.uinet.com/wps/wcm/connect/89138d72-c4a0-403b-9871-937a00f91c42/NERC%2BFAC-001%2BInterconnect%2Bsummary%2BDocument%2BRevision%2B4.pdf?MOD=AJPERES&CACHEID=ROOTWORKSPACE-89138d72-c4a0-403b-9871-937a00f91c42-mkr0qCb>

Eversource/United Illuminating Guidelines for Generator Interconnection, Fast Track and Study Processes, April 5, 2019:

https://www.uinet.com/wps/wcm/connect/bd802aec-1e83-4051-8a6e-58f0cb98d1fd/Guideline_for_Generator_Interconnection_Fast_Track_and_Study_Process_5-12-10_doc_1577.pdf?MOD=AJPERES&CACHEID=ROOTWORKSPACE-bd802aec-1e83-4051-8a6e-58f0cb98d1fd-miUZQ4n

Maine –

Maine Public Utilities Commission

Chapter 324 Small Generator Interconnection Procedures

Central Maine Power Transmission and Distribution Interconnection Requirements for Generation, December 15, 2018:

<https://www.cmpco.com/wps/wcm/connect/dee5fbf1-7af0-40ec-b06c-af3ec015e0be/SchB-TransmissionDistributionInterconnectionRequirementsforGeneration.pdf?MOD=AJPERE&CACHEID=ROOTWORKSPACE-dee5fbf1-7af0-40ec-b06c-af3ec015e0be-mwfmMCK>

Emera Maine Interconnection Agreement:

<https://www.emeramaine.com/energy-solutions/connecting-renewable-resources/small-generator-interconnection-process/>

Massachusetts –

MA Department of Public Utilities (MADPU) interim guidance (DPU 19-55)

MADPU Massachusetts Department of Energy Resources

MADPU Interconnecting Renewable Energy webpages with links to: resources, past and present proceedings before the DPU, each electric distribution companies' tariff, and the Ombudsperson dispute resolution process: <https://www.mass.gov/interconnecting-renewable-energy-facilities>

MADPU is currently conducting a large-scale investigation into the rules and procedures by which distributed generation is interconnected in Massachusetts in docket D.P.U. 19-55. This investigation includes implementation of IEEE 1547-2018. Documents and information can be found in our online file room: <https://eeaonline.eea.state.ma.us/DPU/Fileroom/dockets/bynumber> (enter "19-55")

Massachusetts Technical Standards Review Group:
<https://sites.google.com/site/massdgc/home/interconnection/technical-standards-review-group>

Renewable energy generally: <https://www.mass.gov/topics/renewable-energy>

MADPU Net Metering Information: <https://www.mass.gov/net-metering>

MADOER SMART Program Information: <https://www.mass.gov/info-details/solar-massachusetts-renewable-target-smart-program>

Who to contact in MA for your renewable energy question: <https://www.mass.gov/info-details/who-to-contact-about-my-renewable-energy-question-or-concern>

Massachusetts Utilities

National Grid / Supplement to Specifications for Electrical Installations / ESB 756-2019 ver. 5.0 (Section 7.8 includes voltage and frequency ride through and control requirements);

https://www9.nationalgridus.com/non_html/shared_constr_esb756.pdf

NSTAR ELECTRIC COMPANY d/b/a EVERSOURCE ENERGY STANDARDS FOR INTERCONNECTION OF DISTRIBUTED GENERATION, M.D.P.U. No. 55, Effective: February 1, 2018:

https://author.eversource.com/content/docs/default-source/rates-tariffs/ma-electric/55-tariff-ma.pdf?sfvrsn=8582c462_6

Unitil Energy Systems, Inc. Interconnection Standards for Inverters Sized up to 100 kVA:

https://unitil.com/sites/default/files/pdfs/UES%20100%20KVA%20Interconnect%20Standard%202009_08_21_1.pdf

Individual Massachusetts Municipal Electric Utility Entity Interconnection Requirements:

<https://www.mass.gov/guides/net-metering-guide>

New Hampshire –

New Hampshire Public Utilities Commission

Liberty Utilities Electricity Delivery Service Tariff – NHPUC No. 20:

https://www.puc.nh.gov/Regulatory/Docketbk/2018/18-183/INITIAL%20FILING%20-%20PETITION/18-183_2018-12-10_GSEC_TARIFF.PDF

New Hampshire Electric Co-op Net Metering Requirements:

<https://www.nhec.com/wp-content/uploads/2017/02/2017-Interconnection-Application-Package.pdf>

Public Service Company of New Hampshire Interconnection Standards for Inverters Sized Up to 100 KVA, August 2009:

https://www.eversource.com/content/docs/default-source/builders-contractors/eversource's-interconnection-standards-for-inverters.pdf?sfvrsn=2dd9cf62_0

Unitil Energy Systems, Inc. Interconnection Standards for Inverters Sized up to 100 kVA:

https://unitil.com/sites/default/files/pdfs/UES%20100%20KVA%20Interconnect%20Standard%202009_08_21_1.pdf

Rhode Island –

State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers

Block Island Power Company Net Metering Application:

<https://blockislandpowercompany.com/net-metering-application-2/>

The Narragansett Electric Company Standards for Connecting Distributed Generation, Effective September 6, 2018:

https://www9.nationalgridus.com/non_html/RI_DG_Interconnection_Tariff.pdf

Pascoag Utility District – Electric Net Metering Policy, Requested Effective Date: June 1, 2010:

<https://www.pud-ri.org/wp-content9999/uploads/2015/07/Net-Metering-Policy.pdf>

Vermont –

Vermont Public Utility Commission

The Vermont Public Utility Commission issued an interconnection rule in 2006 that was largely modeled on the FERC Small Generator Interconnection Procedures at that time. The rule has not been updated since 2006.

Links to the current rule as well as an application form and application instructions:

PUC Rule 5.500 – Interconnection Rule

https://puc.vermont.gov/sites/psbnew/files/doc_library/5500-electric-generation-interconnection-procedures_0.pdf

PUC Rule 5.500 – Application Form

https://puc.vermont.gov/sites/psbnew/files/doc_library/5500-revised-application_0.pdf

PUC Rule 5.500 – Application Instructions

https://puc.vermont.gov/sites/psbnew/files/doc_library/5500-revised-application-instructions_0.pdf

In addition, the Department petitioned the PUC to initiate a rulemaking to make adjustments to the interconnection rule in 2016. As of the date of this DER Guidance document there were some filings and a workshop, but the process recently ended without resolution. The PUC has indicated that they are likely to take up the process again in the near future however has not provided NPCC with a date. Information regarding this process can be found here: <https://puc.vermont.gov/about-us/statutes-and-rules/proposed-changes-rule-5500>

Province of Quebec (some references are only available in French)

Section 112 of the [Act respecting the Régie de l'énergie](#) (chapter R-6.01) (the Act) reads as follows:

112. THE GOVERNMENT MAY MAKE REGULATIONS DETERMINING

[...]

(2.1) for a particular source of electric power supply, the corresponding energy block and maximum price established for the purpose of fixing the cost of electric power referred to in section 52.2 or for the purposes of the supply plan provided for in section 72, or for the purposes of a tender solicitation by the electric power distributor under section 74.1;

(2.2) the timeframe applicable to a public tender solicitation by the electric power distributor under section 74.1;

(2.3) the maximum production capacity referred to in section 74.3, which may vary with the source of renewable energy or the class of customers or producers specified;

[...]

In cases where energy needs are to be supplied out of an energy block, a regulation may provide that only certain classes of suppliers may be invited to tender by the electric power distributor and that the quantity of electric power required under each supply contract may be limited.

Consequently, the Government has taken the following regulations, regarding Distributed Energy Resources (or DER), between 2003 and 2013:

- [CONCERNANT le Règlement sur l'énergie produite par cogénération](#) (Décret 1319-2003, 10 décembre 2003);
- [CONCERNANT le Règlement sur l'énergie éolienne et sur l'énergie produite avec de la biomasse](#) (Décret 352-2003, 5 mars 2003);
- [CONCERNANT le Règlement modifiant le Règlement sur l'énergie produite par cogénération](#) (Décret 298-2004, 29 mars 2004);
- [CONCERNANT le Règlement sur le second bloc d'énergie éolienne](#) (Décret 926-2005, 12 octobre 2005);
- [CONCERNANT le Règlement sur l'énergie produite par cogénération à la biomasse](#) (Décret 916-2008, 24 septembre 2008);
- [CONCERNANT le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets autochtones](#) (Décret 1043-2008, 29 octobre 2009);
- [CONCERNANT le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets communautaires](#) (Décret 1045-2008, 29 octobre 2008);
- [CONCERNANT le Règlement modifiant le Règlement sur l'énergie produite par cogénération à la biomasse](#) (Décret 9-2009, 7 janvier 2009);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets communautaires](#) (Décret 179-2009, 4 mars 2009);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets autochtones](#) (Décret 180-2009, 4 mars 2009);
- [CONCERNANT le Règlement sur la capacité maximale de production visée dans un programme d'achat d'électricité pour des petites centrales hydroélectriques](#) (Décret 336-2009, 25 mars 2009);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets autochtones](#) (Décret 520-2009, 29 avril 2009);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets communautaires](#) (Décret 521-2009, 29 avril 2009);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets communautaires](#) (Décret 468-2010, 2 juin 2010);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets autochtones](#) (Décret 469-2010, 2 juin 2010);
- [CONCERNANT le Règlement sur la capacité maximale de production visée dans un programme d'achat d'électricité produite par cogénération à base de biomasse forestière résiduelle](#) (Décret 1085-2011, 26 octobre 2011);
- [CONCERNANT le Règlement sur un bloc de 450 mégawatts d'énergie éolienne](#) (Décret 1149-2013, 6 novembre 2013).

The following regulations, or modified regulations (marked in yellow highlight in the section above) have led to four tender solicitations, targeting precise quantities, or energy blocks, of wind Energy:

- [CONCERNANT le Règlement sur l'énergie éolienne et sur l'énergie produite avec de la biomasse](#) (Décret 352-2003, 5 mars 2003);

- [CONCERNANT le Règlement sur le second bloc d'énergie éolienne](#) (Décret 926-2005, 12 octobre 2005);
- [CONCERNANT le Règlement modifiant le Règlement sur un bloc de 250 MW d'énergie éolienne issu de projets communautaires](#) (Décret 468-2010, 2 juin 2010);
- [CONCERNANT le Règlement sur un bloc de 450 mégawatts d'énergie éolienne](#) (Décret 1149-2013, 6 novembre 2013).

The Régie considers the results of these tenders when examining Hydro-Québec's supply plan, as per section 72 of the Act:

72. *With the exception of private electric power systems, a holder of exclusive electric power or natural gas distribution rights shall prepare and submit to the Régie for approval, according to the form, tenor and intervals fixed by regulation of the Régie, a supply plan describing the characteristics of the contracts the holder intends to enter into in order to meet the needs of Québec markets following the implementation of the energy efficiency measures. The supply plan shall be prepared having regard to*

- (1) *the risks inherent in the sources of supply chosen by the holder;*
- (2) *as concerns any particular source of electric power, the energy block established by regulation of the Government under subparagraph 2.1 of the first paragraph of section 112; and*

[...]

When examining a supply plan for approval, the Régie shall consider such economic, social and environmental concerns as have been identified by order by the Government.

Sections 74.1 and 74.2 of the Act provide that the Régie oversees the process of such tender solicitations:

74.1. *To ensure that suppliers responding to a tender solicitation are treated with fairness and impartiality, the electric power distributor shall establish and submit for approval to the Régie, which shall make its decision within 90 days, a tender solicitation and contract awarding procedure and a tender solicitation code of ethics applicable to the electric power supply contracts required to meet the needs of Québec markets in excess of the heritage pool, or the needs to be supplied out of an energy block determined by regulation of the Government under subparagraph 2.1 of the first paragraph of section 112.*

The tender solicitation and contract awarding procedure shall, in particular,

- (1) *allow all interested suppliers to tender by requiring the tender solicitation to be issued in due time;*
- (2) *grant equal treatment to all sources of supply and energy efficiency projects unless the tender specifications provide that all or part of the needs met by a particular source of supply must be supplied out of an energy block determined by regulation of the Government;*
- (3) *favour the awarding of supply contracts based on the lowest tendered price for the required quantity of electric power and in keeping with the required conditions, taking into account the applicable transmission cost and, where the tender specifications provide that all or part of the needs met by a particular source of supply must be supplied out of an energy block, taking into account the maximum price established by regulation of the Government; and*
- (4) *provide that, following a tender solicitation, contracts may be awarded to two or more suppliers, in which case a supplier offering the required quantity of electric power may be invited to reduce the quantity offered without modifying the tendered unit price.*

An energy efficiency project to which a tender solicitation applies under subparagraph 2 of the second paragraph must meet the stability, sustainability and reliability requirements that apply to conventional sources of supply.

The Régie may dispense the electric power distributor from soliciting tenders for short-term contracts or where urgent needs must be met.

For the purposes of this section, the promoter of an energy efficiency project is deemed to be an electric power supplier.

74.2. *The Régie shall monitor the implementation of the tender solicitation and contract awarding procedure and code of ethics provided for in section 74.1 and ascertain whether they are complied with. To that end, the Régie may require any document or information it considers useful. The Régie shall report its findings to the electric power distributor and to the supplier chosen.*

The electric power distributor may not enter into an electric power supply contract unless it has obtained the approval of the Régie, under the conditions and in the cases determined by regulation by the Régie.

The Régie's Website lists every docket related to this jurisdiction over Québec's electricity distributor (in French only): [Approval of supply contracts](#).

The Régie also considers DER when adopting specific reliability standards. Sections 85.2 and 85.7 of the Act read as follows:

85.2. *The Régie shall ensure that electric power transmission in Québec is carried out according to the reliability standards it adopts.*

85.7. *The Régie may request the reliability coordinator to modify a standard filed or submit a new one, on the conditions it sets. It shall adopt reliability standards and set the date of their coming into force.*

The reliability standards may

(1) subject to section 85.10, provide for a schedule of sanctions, including financial penalties, that apply if standards are not complied with; and

(2) refer to reliability standards set by a standardization agency that has entered into an agreement.

Docket [R-4070-2018](#) (in French only) relates to a request by the reliability coordinator (HQCME) and is still under examination by the Régie. It aims the adoption of reliability standards associated with Special Protection System (Remedial Action Scheme) and Dispersed Power Producing Resources.

The following sections of Québec' electricity distributor and transmitter's web site might be useful, since they list the applicable technical codes, standards and requirements:

- http://www.hydroquebec.com/transenergie/fr/commerce/raccordement_distribution.html ;
- http://www.hydroquebec.com/transenergie/fr/commerce/raccordement_transport.html

Province of Ontario

The current connection requirements for all resources can be found in Chapter 4 appendices 4.2 and 4.3 of the Market Rules. <http://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-rules/mr-chapter4appx.pdf?la=en>

The Independent Electric System Operator (IESO) is in the process of making updates to these requirements to be more specific about the requirements that apply to all DERs (not just storage). <http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Updates-to-Performance-Requirements-Market-Rule-Appendices-4-2-and-4-3>

The IESO is working on several white papers. The one that was posted in 2019 called "**Exploring Expanded DER Participation in the IESO-Administered Markets**" sets out the participation models that exist for DER in wholesale markets in general and in the IESO-Administered Markets (IAM) today and

also identify the range of options that exist for expanded participation in the future. In addition, this paper provides a working definition of DER, sets out principles for integrating them into wholesale markets, offers an initial review of participation models in other jurisdictions, and identifies key barriers that may limit DER participation in the IAMs.

<http://www.ieso.ca/-/media/Files/IESO/Document-Library/White-papers/White-paper-series-Conceptual-Models-for-DER-Participation.pdf?la=en>

The Ontario Energy Board is also engaging in several stakeholder activities in this area. Below are the links to those activities. The Ontario Energy Board has combined the first two initiatives into one engagement.

1. Responding to Distributed Energy Resources (DER)* - The purpose of this initiative is to develop a more comprehensive regulatory framework that facilitates investment and operation of DER based-on value to consumers and supports effective DER integration so the benefits of sector evolution can be realized.

<https://www.oeb.ca/industry/policy-initiatives-and-consultations/responding-distributed-energy-resources-ders>

2. Utility Remuneration* - The purpose of this initiative is to identify how to remunerate utilities in ways that make them indifferent to traditional or innovative solutions, better supports their pursuit of least cost solutions, strengthens their focus on long-term value and requires them to reflect the impact of sector evolution in their system planning and operations.

<https://www.oeb.ca/industry/policy-initiatives-and-consultations/utility-remuneration>

3. DER Connections Review – The purpose of this initiative to review its requirements regarding the connection of distributed energy resources (DER) by licensed electricity distributors. The purpose of this initiative is to identify any barriers to the connection of DER, and where appropriate to standardize and improve the connection process. The review will be focused on connection of electricity generation and storage facilities connected to the distribution system, either in front or behind the distributor's meter.

<https://www.oeb.ca/industry/policy-initiatives-and-consultations/distributed-energy-resources-der-connections-review>

The contact for this information would be Customer Relations (customer.relations@ieso.ca)

Province of New Brunswick

Within the province, DER is referred to as “Embedded Generation” or “Distributed Generation.” Regulation from the New Brunswick Energy and Utility Board may be found here:

<http://laws.gnb.ca/en/ShowPdf/cs/2013-c.7.pdf>

Ènergie NB Power’s embedded generation may be found here:

<https://www.nbpower.com/en/products-services/embedded-generation/>

Appendix F, ISO New England

ISO-NE specific Inverter requirements are as follows in the below table and the link

[Inverter Source Requirement Document of ISO New England](#)

The following additional performance requirements are applied in one NPCC Area and are provided as an example:

- In the Permissive Operation region above 0.5 p.u., inverters shall ride-through in Mandatory Operation mode, and
- In the Permissive Operation region below 0.5 p.u., inverters shall ride-through in Momentary Cessation mode.

Table I: Inverters' Voltage Trip Settings

Shall Trip – IEEE Std 1547-2018 (2 nd ed.) Category II					
Shall Trip Function	Required Settings		Comparison to IEEE Std 1547-2018 (2 nd ed.) default settings and ranges of allowable settings for Category II		
	Voltage (p.u. of nominal voltage)	Clearing Time(s)	Voltage	Clearing Time(s)	Within ranges of allowable settings?
OV2	1.20	0.16	Identical	Identical	Yes
OV1	1.10	2.0	Identical	Identical	Yes
UV1	0.88	2.0	Higher (default is 0.70 p.u.)	Much shorter (default is 10 s)	Yes
UV2	0.50	1.1	Slightly higher (default is 0.45 p.u.)	Much longer (default is 0.16 s)	Yes

Table II: Inverters' Frequency Trip Settings

Shall Trip Function	Required Settings		Comparison to IEEE Std 1547-2018 (2 nd ed.) default settings and ranges of allowable settings for Category I, Category II, and Category III		
	Frequency (Hz)	Clearing Time(s)	Frequency	Clearing Time(s)	Within ranges of allowable settings?
OF2	62.0	0.16	Identical	Identical	Yes
OF1	61.2	300.0	Identical	Identical	Yes
UF1	58.5	300.0	Identical	Identical	Yes
UF2	56.5	0.16	Identical	Identical	Yes

Table III: Inverters' Voltage Ride-through Capability and Operational Requirements

Voltage Range (p.u.)	Operating Mode/ Response	Minimum Ride-through Time(s) (design criteria)	Maximum Response Time(s) (design criteria)	Comparison to IEEE Std 1547-2018 (2 nd ed.) for Category II
$V > 1.20$	Cease to Energize	N/A	0.16	Identical
$1.175 < V \leq 1.20$	Permissive Operation	0.2	N/A	Identical
$1.15 < V \leq 1.175$	Permissive Operation	0.5	N/A	Identical
$1.10 < V \leq 1.15$	Permissive Operation	1	N/A	Identical

$0.88 \leq V \leq 1.10$	Continuous Operation	infinite	N/A	Identical
$0.65 \leq V < 0.88$	Mandatory Operation	Linear slope of 8.7 s/1 p.u. voltage starting at 3 s @ 0.65 p.u.: $T = 3 \text{ s} + \frac{8.7 \text{ s}}{V - 0.65 \text{ p.u.}}$ $\frac{1}{V_{VRT}} \text{ 1 p. u.}$	N/A	Identical
$0.45 \leq V < 0.65$	Permissive Operation ^{a,b}	0.32	N/A	See footnotes a & b
$0.30 \leq V < 0.45$	Permissive Operation ^b	0.16	N/A	See footnote b
$V < 0.30$	Cease to Energize	N/A	0.16	Identical

The following additional operational requirements can be used. Provided as an example:

- a. In the Permissive Operation region above 0.5 p.u., inverters shall ride-through in Mandatory Operation mode, and
- b. In the Permissive Operation region below 0.5 p.u., inverters shall ride-through in Momentary Cessation mode with a maximum response time of 0.083 seconds.

Table IV: Inverters' Frequency Ride-through Capability

Frequency Range (Hz)	Operating Mode	Minimum Time(s) (design criteria)	Comparison to IEEE Std 1547-2018 (2 nd ed.) for Category II
$f > 62.0$	No ride-through requirements apply to this range		Identical
$61.2 < f \leq 61.8$	Mandatory Operation	299	Identical
$58.8 \leq f \leq 61.2$	Continuous Operation	Infinite	Identical
$57.0 \leq f < 58.8$	Mandatory Operation	299	Identical
$f < 57.0$	No ride-through requirements apply to this range		Identical

Table V: Grid Support Utility Interactive Inverter Functions Status

Function	Default Activation State
SPF, Specified Power Factor	OFF ²
Q(V), Volt-Var Function with Watt or Var Priority	OFF Default value: 2% of maximum current output per second
SS, Soft-Start Ramp Rate	ON
FW, Freq-Watt Function OFF	OFF

Appendix G, State Renewable and Green Energy Targets

New York State

70% renewable energy by 2030
85% reduction of Greenhouse Gas emissions by 2050
6,000 MW of distributed solar by 2025
3,000 MW of energy storage by 2025
Carbon free electricity system by 2040

Connecticut

Carbon free electricity system by 2040
Renewable Portfolio Standard - <https://portal.ct.gov/PURA/RPS/Renewable-Portfolio-Standards-Overview>

Vermont

90% of Vermont's overall energy needs from renewable sources by 2050
Reduce Vermont's greenhouse gas (GHG) emissions by 50% from the 1990 baseline level by 2028, and by 75% from the 1990 level by 2050

New Hampshire

20% to 25% reduction in Greenhouse Gas emissions by 2032
25.2% renewable energy by 2025

Rhode Island

100% renewable energy by 2030
1,000 MW of new clean energy installed in 2020

Maine

80% renewable energy by 2030

Appendix H, Autonomous Energy Grids

The National Renewable Energy Laboratory (NREL) and its partners are conducting research and development of advanced techniques that would enable the optimization and control of hundreds of millions of deployed distributed energy resources (DER). The concept known as “Autonomous Energy Grids (AEGs)” are multi-layer, or hierarchical, cellular-structured power grid and control systems that enable resilient, reliability, and economic optimization²⁸. Supported by a scalable, reconfigurable, and self-organizing information and control infrastructure, AEGs are extremely secure and resilient, and can operate in real time to ensure economic and reliable performance while systematically integrating energy in all forms. AEGs rely on cellular building blocks that can self-optimize when isolated from a larger grid and participate in optimal operation when interconnected to a larger grid. The figure H-1 shows how a scalable approach to control can be built from the lowest level of individual controllable technologies (renewable energy, conventional generation, electric vehicles, storage, and loads) and used to control hundreds of millions of devices through the use of hierarchical cells. To make this idea a reality, there are control algorithms for AEGs that will need to be developed and implemented with the following characteristics:

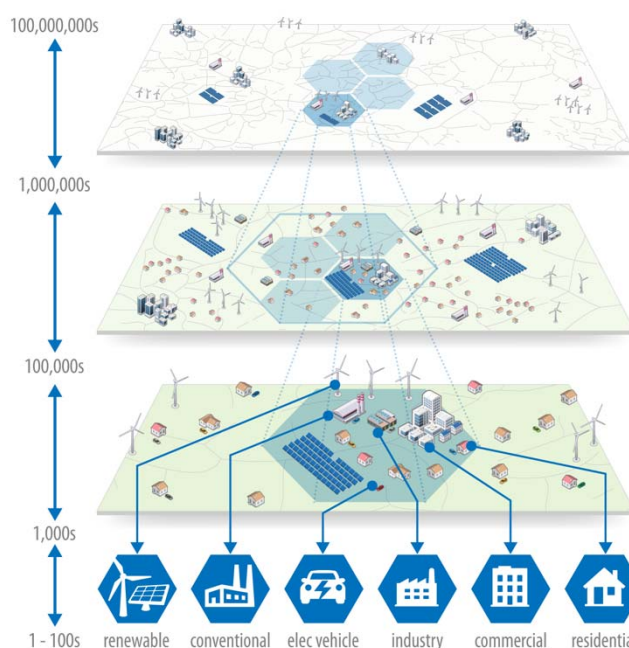


Figure H-1: Autonomous Energy Grids form a distributed hierarchical control system that integrated individual technologies in a cellular structure to the bulk power system.

- **Operate in Real Time** – Control algorithms must operate fast enough to ensure real-time operations in power grids that balance load and generation every second.
- **Handle Asynchronous Data and Control Actions** – Data needs to be used from a variety of asynchronous measurements and sources; whereas distributed decision-making leads to asynchronous control actions.
- **Robustness** – This covers both reliability and resilience, where reliability is fault tolerance and resilience are the ability to come back from a failed state. These control systems must also be

²⁸ “Autonomous Energy Grids”, B. Kroposki, E. Dall’Anese, A. Bernstein, Y. Zhang, B. Hodge, Proceedings of the 51st Hawaii International Conference on System Sciences, January 2018, <https://scholarspace.manoa.hawaii.edu/bitstream/10125/50229/1/paper0342.pdf>

robust to communications failures, prolonged communications outages, and large-scale disturbances.

- **Scalable**– Control algorithms must operate in a scalable fashion to ensure control of hundreds of millions of devices.

NREL has evaluated the AEG algorithms on both large-scale laboratory testing and small-scale real-world demonstrations. NREL evaluated the algorithms as part of the DOE ARPA-E NODES program that demonstrated the first implementation of the algorithms in hardware and successfully demonstrate real-time optimization of a single AEG cell with more than 100 controllable devices at NREL’s Energy Systems Integration Facility²⁹. The experiment includes simulation of a real distribution feeder from California with 366 single-phase connection points, more than 100 controllable assets at power (inverters, electric vehicles, and batteries), and hundreds of simulated devices. The distributed algorithms were implemented in cost-effective microcontrollers that self-optimize and communicate to the central coordinator to attain system-wide goals (voltage regulation, frequency response).

NREL has also moved out of the lab to demonstrate the deployment of AEGs in the real world. The team has been working with Holy Cross Energy (HCE), a utility cooperative near Aspen, Colorado, to deploy the AEG technology in a group of smart homes in Basalt, CO³⁰. The smart homes in Basalt Vista are a pilot for an altogether new approach to the grid. These homes optimize energy for residents and their neighbors, but the principles behind Basalt Vista go much further. Within homes, each new connected device or energy resource like a residential battery, water heater, or solar photovoltaic (PV) system, can be controlled for unprecedented energy efficiency. And at a larger scale, entire communities could rapidly share power, creating reliable energy for everyone.

²⁹ <https://www.nrel.gov/news/features/2019/from-the-bottom-up-designing-a-decentralized-power-system.html>

³⁰ <https://www.nrel.gov/news/features/2019/small-colorado-utility-sets-national-renewable-electricity-example-using-nrel-algorithms.html>