DECEMBER 16, 2013 | MILLFORD, MA

Impacts of Transmission System Contingencies on Distributed Generation - Overview

DG Forecast Working Group Meeting

Mike Henderson

DIRECTOR, REGIONAL PLANNING AND COORDINATION

Overview

- ISO concerned about the response of distributed generation (DG) to transmission system contingencies
- Existing interconnection standards for DG may exacerbate potential fault-related problems for the overall power system (the focus is on solar photovoltaics or PV)
- New analysis shows the nature of these potential problems
- ISO will be working with the DGFWG, Transmission Owners, Distribution Owners, and the states to address concerns
- Next steps

PV Interconnection Requirements

- DG interconnections must be consistent with distribution system requirements
  - IEEE 1547 is the technical standard that has been accepted by most states and must be met
- Meeting protection and control requirements
  - Ensures the health and safety of the public and utility workers
  - Protects equipment
- At low levels of development, PV interconnections have little effect on the transmission system response to contingencies
  - IEEE 1547 was developed for low levels of DG on the system

In Large Quantities, PV Affects the Bulk System

- The variable nature of production affects the systemwide ramping and regulation requirements
- The use of power electronics means large MW amounts of PV can respond very rapidly to contingencies
  - Current PV unit protection practices could increase the need for under frequency load shedding (that is necessary when there is insufficient generation to serve load)
  - PV units could trip due to faults on the high voltage system and exacerbate the system response to contingencies
  - PV units can be restored to service in large quantities within very fast timeframes and at very fast ramp rates

What Others Have Learned

- The interconnection issue was discussed at the RSP Public Meeting
- IEEE 1547 is now being modified
  - A vote is scheduled by early 2014 that will allow local entities to impose interconnection requirements that better meet ***both*** transmission system performance needs and distribution system requirements
  - Further work is being initiated to better coordinate distribution system and transmission system interconnection requirements (expected completion no sooner than 2018)
- Germany is investing up to ½ billion dollars to retrofit PV interconnection controls on their system to deal with transmission system faults and other interconnection issues
  - PV manufacturers have indicated modifying the interconnection controls for new installations adds little cost, but that retrofits are very expensive
- California is reviewing the state interconnection requirements and is scheduled to modify them in approximately two years
- DOE national labs recognize the problem and are initiating studies

Immediate ISO Concerns

- DG is now poised to reach significant levels in the region
- New England may lose significant amounts of PV/DG due to transmission faults
  - Affects post contingency thermal, voltage, and stability system response
  - Could increase the size of loss of source contingencies in New England
    - Includes the loss of a large source plus PV that trips as the result of the fault
  - Studies are complicated by different amounts of PV that could be lost for different locations and types of contingencies
    - 3-phase, line-to-line-ground faults, single-line-to –ground faults, and loss of elements without a fault
- PV sources of MW could be lost for low frequency conditions
  - Causes greater loss of sources supplying the network resulting in a even greater degradation of frequency
  - Could trigger greater use of under frequency load shedding
  - Could negate the ability of under frequency load shedding to prevent widespread blackouts

Addressing ISO Concerns

- Short circuit simulation results show the possible extent that PV resources could be lost for system faults
- ISO will be working with the DGFWG, transmission owners, distribution owners, and the states to meet both the distribution system interconnection requirements and the transmission system performance needs
- Modifications to new PV protection and control system interconnection requirements will be requested of the states
  - Low voltage ride through (the ability to sustain PV operation for system faults)
  - Low frequency ride through (the ability to sustain PV operation consistent with the practices of existing central station generating units)
  - Other requirements for restoring PV to service, such as ramp rates

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Impacts of Transmission System Contingencies on Distributed Generation – Technical

DG Forecast Working Group Meeting

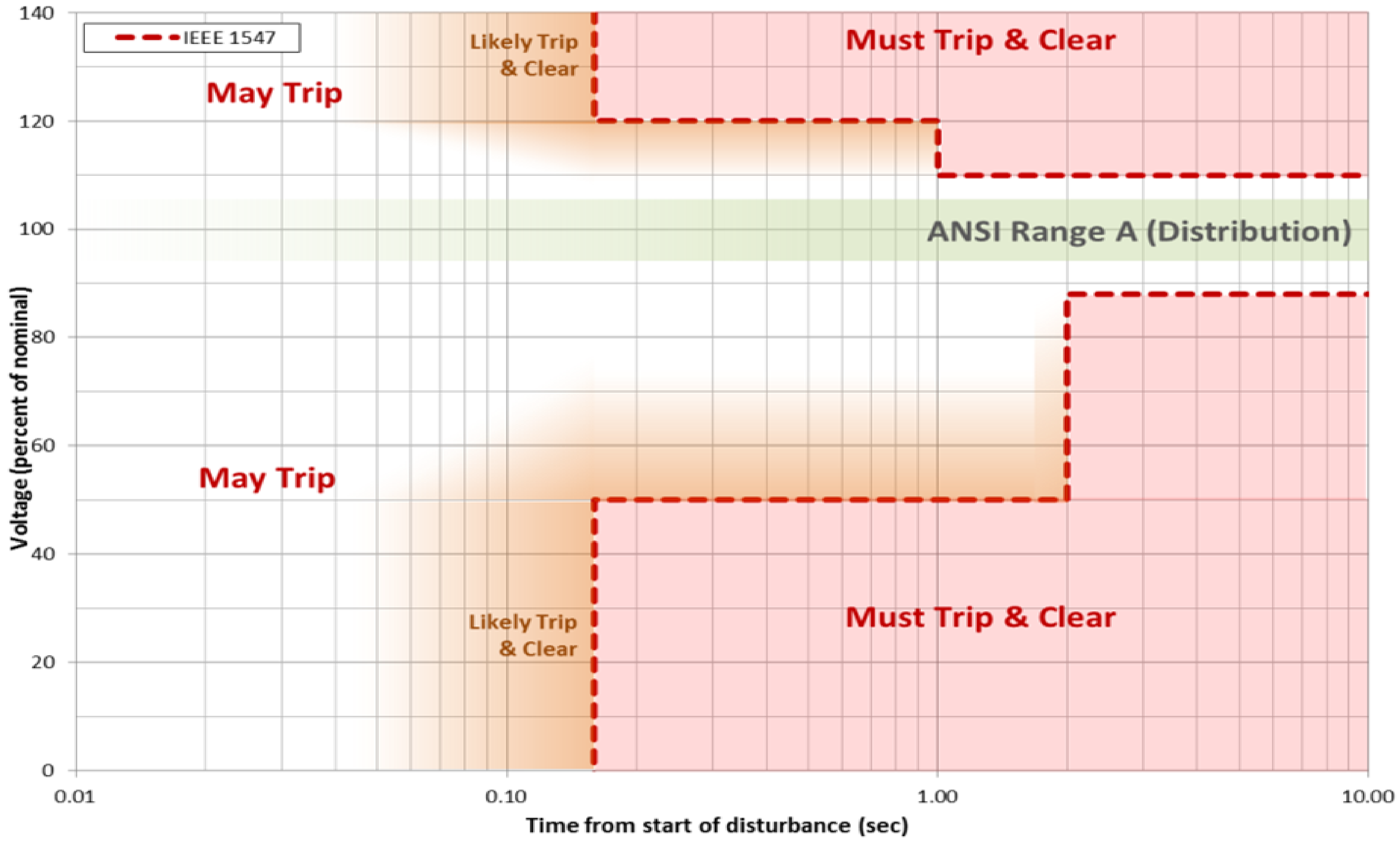
Dave Forrest

MANAGERENGINEERING AND STUDY COORDINATION

Existing Interconnection Standards

- DG is now poised to reach significant levels in the region
- New England may lose significant amounts of PV/DG due to transmission faults unless states adjust DG interconnection standards
- State jurisdictional interconnection standards for DG are generally consistent with IEEE Standard 1547
- IEEE 1547 originally developed with the assumption that DG would not reach significant levels with regards to the regional power system
- IEEE 1547 has a "don't ride through" requirement
  - The standard requires DG to trip soon after detecting low voltage conditions that are not severely depressed
  - The standard requires DG to trip soon after detecting a low frequency conditions that are not severely depressed

IEEE 1547 Standard Voltage Sensitivity



Source: Draft NERC IVGTF Task 1-7 report

DG Is Likely to Trip for Normal Fault Clearing

- NERC and/or NPCC require that the transmission system remain secure for a permanent three-phase fault with normal fault clearing on any
  - Generator
  - Transmission circuit
  - Transformer
  - Bus section
  - Series or shunt compensating device
- Normal clearing of a three-phase fault on the 345 kV system is approximately 0.1 seconds
- Normal clearing of a three-phase fault on a the 115 kV system can range from 0.1 seconds to over 0.5 seconds depending on the protective relay scheme
- The times to clear both the 345kV system and the 115kV system faults are within the “likely to trip” times of distributed generation

DG Is Likely to Trip for Delayed Fault Clearing

- Planning criteria also requires analyzing a three-phase fault with delayed clearing
- Delayed clearing of a three-phase fault on the 345 kV system is approximately 0.1-0.2 seconds
- Delayed clearing of a three-phase fault on a the 115 kV system can range from 0.3 seconds to over a second depending on the protective relay scheme
- The times to clear both the 345kV system and the 115kV system faults are within the "likely to trip" times of distributed generation

Transmission Planning Criteria

- Stability criteria requires limitations on the amount of sources that be lost
- The times to clear both the 345kV system and the 115kV system faults are within the “likely to trip” times of distributed generation
- The additional tripping of distributed generation would increase the size of loss of source contingencies in New England
- The loss of DG in addition to other sources for common contingencies could necessitate
  - The need for transmission upgrades
  - Further restrict the loss of source limits for existing facilities
- See the Appendix for the criteria

Modeling Trips of DG Adds Complexity to System Studies

- Different amounts of DG could trip for single phase and multiple phase faults
- Tripping DG increases the net load that is simulated post contingency
  - Affects thermal, voltage, and stability performance
- Planning and Operating Criteria require consideration of loss of elements without a fault
  - These contingencies would not trip DG

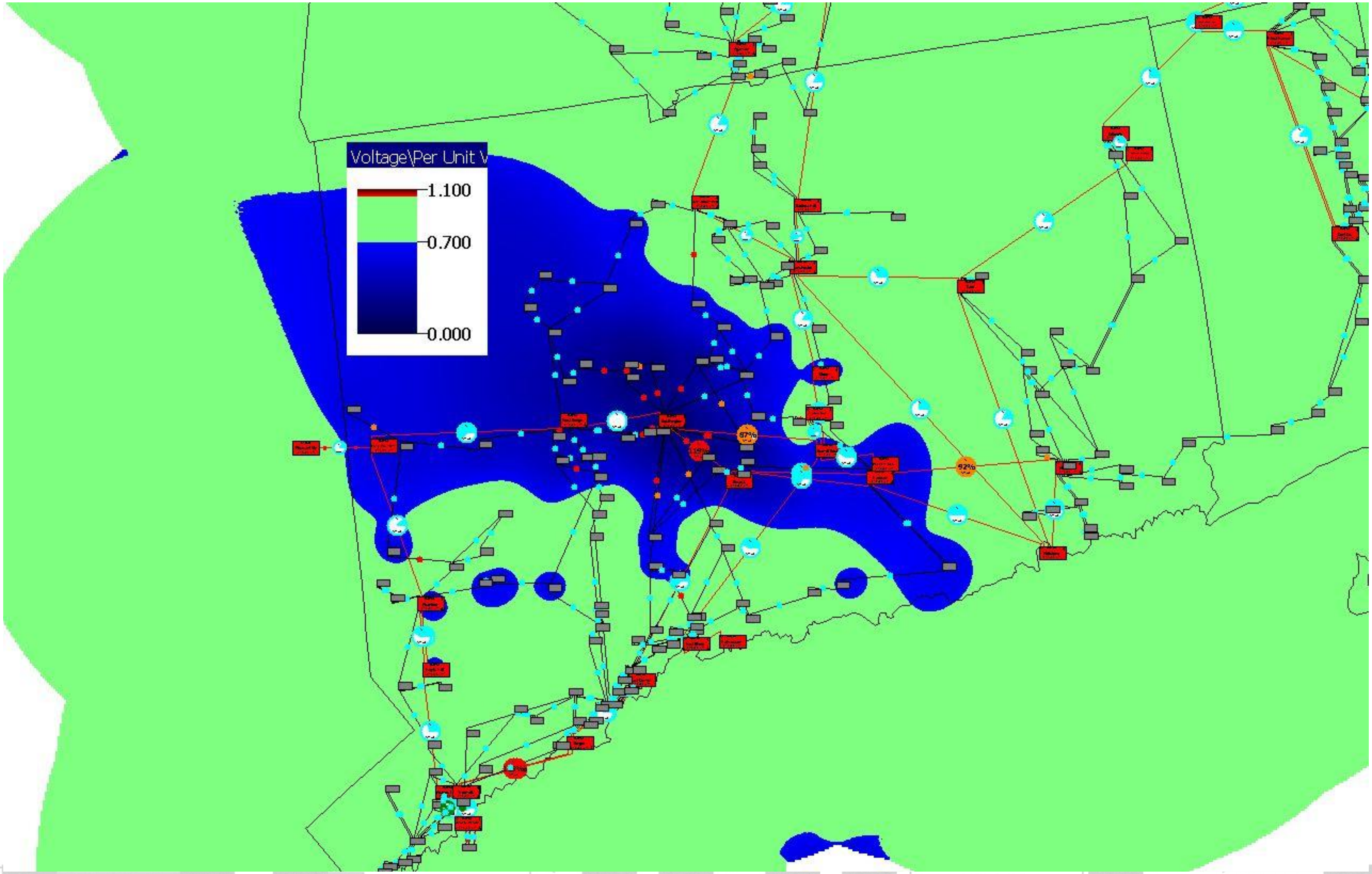
Short Circuit Analysis

- To understand how transmission faults might impact DG in New England, the ISO had a consultant and a transmission owner test several three-phase short circuits on the transmission system
- Testing was done with a model of the existing transmission system and with all existing generation on line
- A sensitivity test was done with a number of generators off line to simulate a light load period (a spring day with high levels of solar and wind generation)

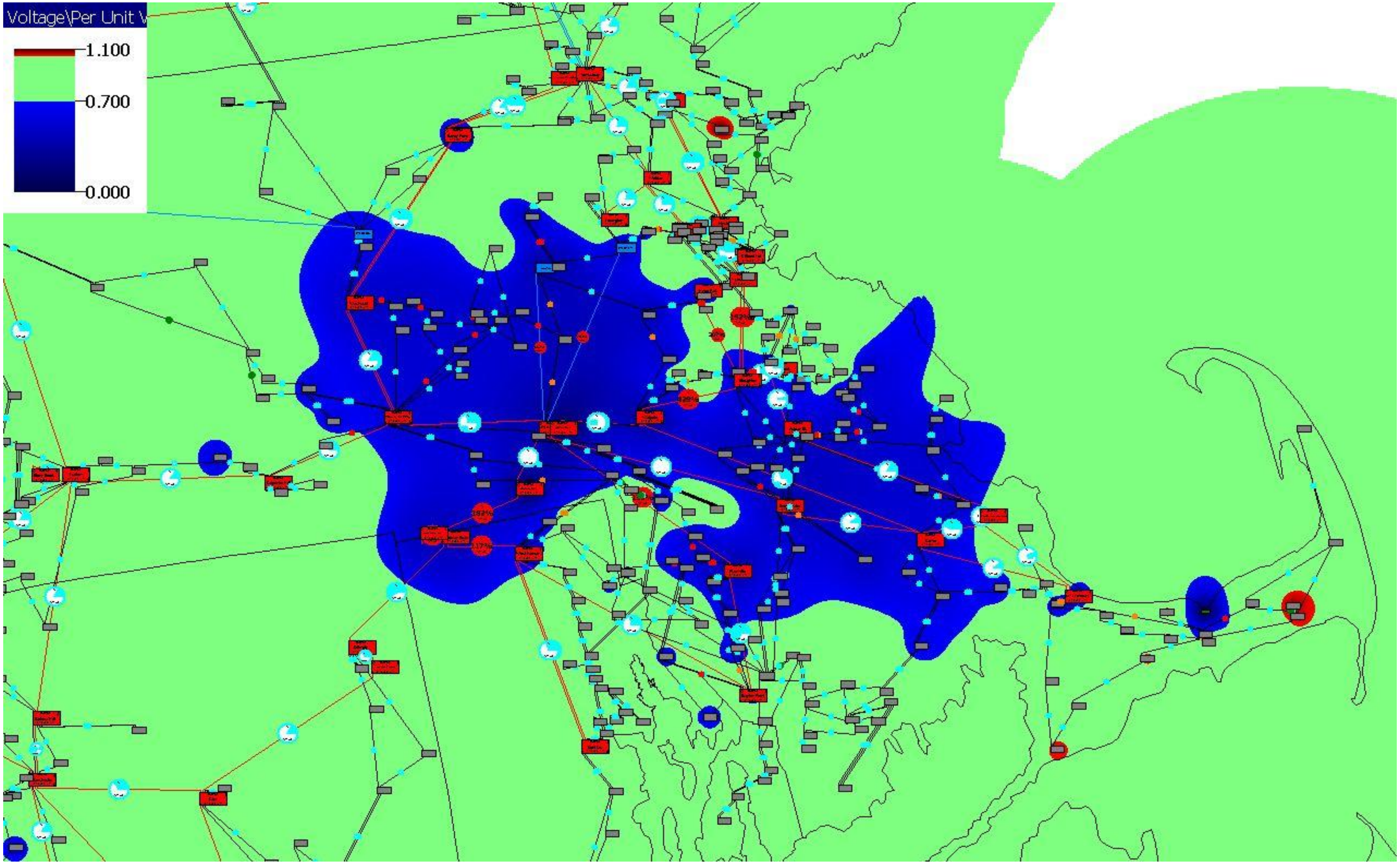
Short Circuit Analysis

- Limited testing indicates that three-phase faults on the 345 kV transmission system can result in low voltages over a significant area
- Sensitivity testing indicates that low voltages can extend to a wider area during light load periods when local generation is off line
- The following plots show the extent of low voltages that could occur for faults on the 345 kV systems in central Connecticut and Central Massachusetts
- These low voltages could result in trip of DG

Low Voltage for 345 kV Fault in Connecticut



Low Voltage for 345 kV Fault in Massachusetts



NERC Analysis

- NERC analyzed the low voltage ride through problem and made a recommendation to
  - Not trip DG until voltages are lower than those indicated in IEEE 1547
  - Allow for DG to stay on line for longer periods of time than the trip points indicated in IEEE 1547
- While the recommendation is in the right direction, ISO remains concerned that the NERC recommendation could still expose New England to transmission contingencies that could trip PV

NERC Recommendation

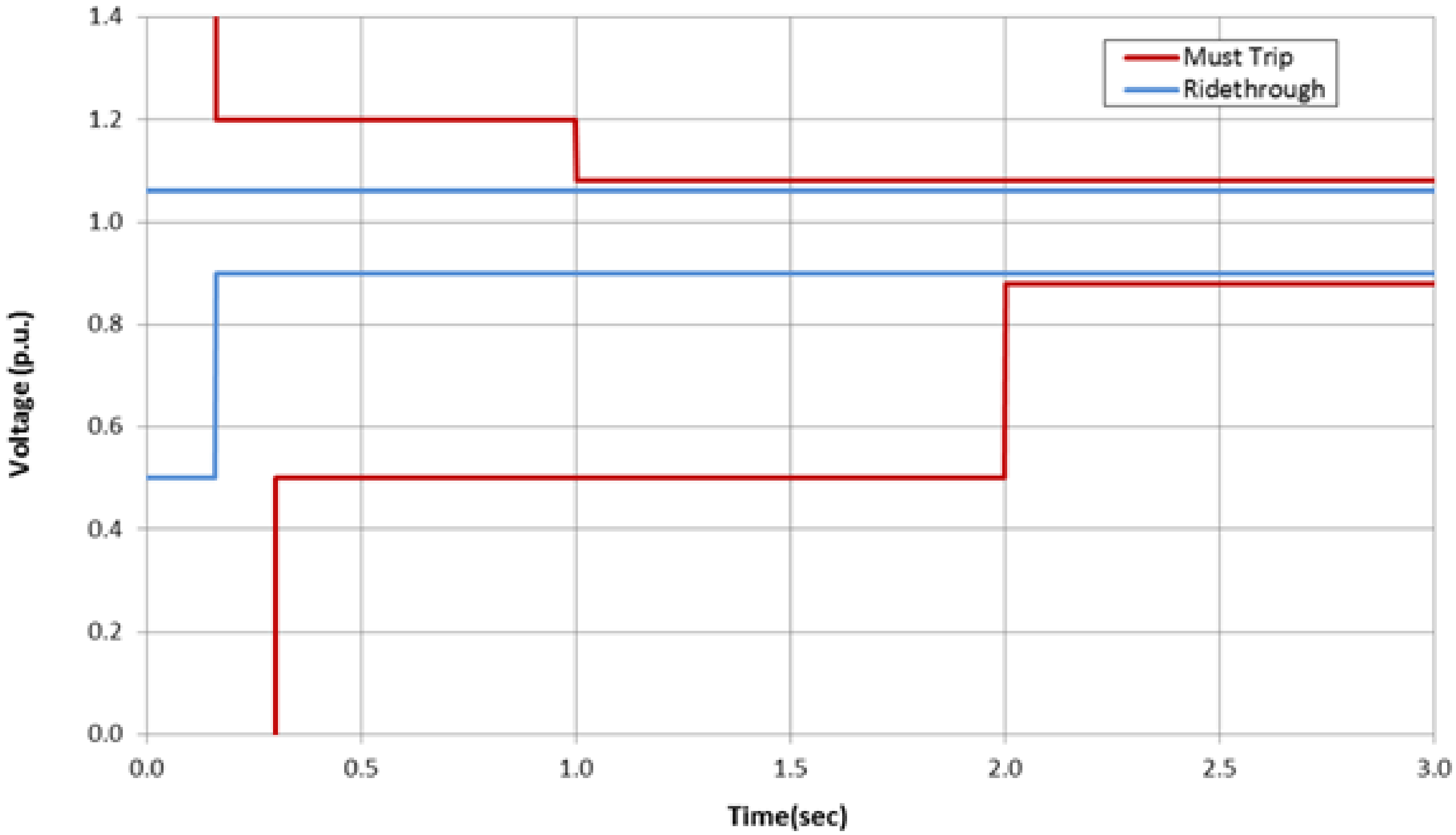
TabTable 1: Proposed changes to IEEE Standard 1547 to include VRT down to 50% voltage

Proposed changes to IEEE Standard 1547 to include VRT down to 50% voltage

Voltage Range (% of nominal voltage)	Minimum Ride-through time(s)	Maximum Clearing time(s)
V < 50	-	0.30
50 ≤ V < 88	0.16	2.00
88 ≤ V < 90	0.16	-
90 ≤ V < 108	No tripping	-
108 ≤ V < 110	-	-
110 ≤ V < 120	-	1.00
V > 120	-	0.16

Source: Draft NERC IVGTF Task 1-7 report

NERC Recommendation for Low Voltage Ride Through

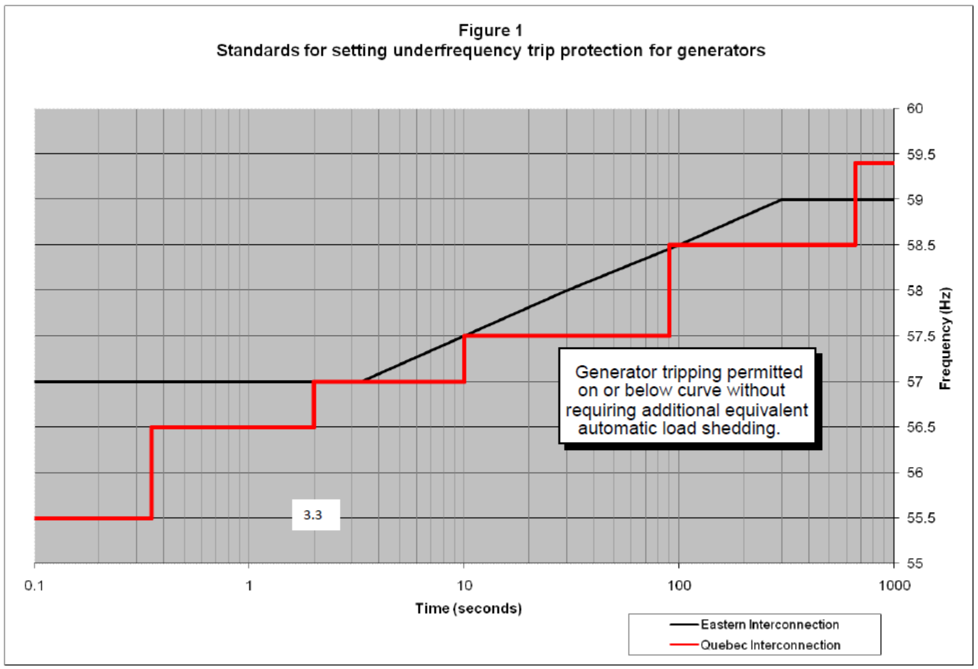


Source: Draft NERC IVGTF Task 1-7 report

DG Frequency Ride Must Be Coordinated with Under Frequency Load Shedding

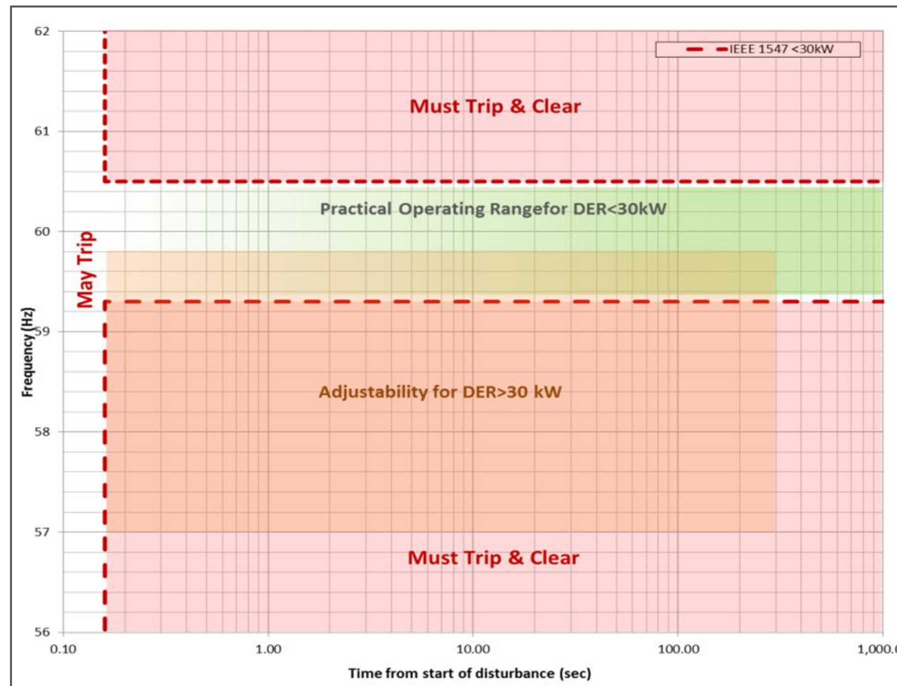
DG Frequency Tolerance: NPCC Directory 12 UFLS vs. IEEE 1547

NPCC Directory 12 – UFLS Requirements



Source: NPCC Directory 12, p. 11, available at: https://www.npcc.org/Standards/Directories/Directory12%20Full%20Member%20Approved%2020130709%20GJD.pdf

IEEE 1547



Source: Draft NERC IVGTF Task 1-7 report

Next Steps

- The ISO will participate in the revision of IEEE Standard 1547™ to address mandatory low voltage ride-through capability of DG and low frequency ride through capability of DG
- ISO will work with the DGFWG, Transmission Owners and Distribution Owners to ensure that recommendations for both under frequency ride-through and under voltage ride-through interconnection requirements of DG meet both distribution and transmission system needs
- ISO, the Transmission Owners, and the Distribution Owners will work with the states to consider revisions to DG interconnection requirements

Questions

Appendix

Transmission Planning Criteria

- New England's planning criteria requires generator unit stability for all Normal Design Contingencies as defined in Planning Procedure PP-3. This criterion applies when the fastest protection scheme is unavailable at any BPS substation involved in the fault clearing. This criterion applies if the fastest protection scheme is available at any non-BPS substation involved in the fault clearing. If the fastest protection scheme is unavailable at a non-BPS substation, unit instability is permitted as long as the net source loss resulting from the Normal Design Contingency is not more than 1200 MW, and the net source loss is confined to the local area (i.e. no generator instability or system separation can occur outside the local area).

Transmission Planning Criteria

- The following response can be considered acceptable to an extreme contingency involving a three phase fault with Delayed Clearing:
- A net loss of source above 1400 MW and up to 2200 MW, resulting from any combination of the loss of synchronism of one or more generating units, generation rejection initiated by a Special Protection System, or any other defined system separation, if supported by studies, on the basis of acceptable likelihood of occurrence, limited exposure to the pre-contingent operating conditions required to create the scenario, or efforts to minimize the likelihood of occurrence or to mitigate against the consequence of the contingency. The loss of source is net of any load that is interrupted as a result of the contingency.