DISTRIBUTED ENERGY RESOURCES (DERS)
Reliability Impacts and Recommended Changes

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1 EXECUTIVE SUMMARY

Distributed Energy Resource (DER) penetration in the Electric Reliability Council of Texas (ERCOT) region continues to trend upward. Based on annual reports filed at the Public Utility Commission (PUC) of Texas by Transmission & Distribution Service Providers (TSDPs) located in the competitive choice areas, nearly 900 Megawatts (MW) of Distributed Generation[1] — ranging from large fossil fuel-fired reciprocating units to small rooftop solar systems — were interconnected as of Dec. 31, 2015. An estimated additional 200-plus MW are deployed in the Non-Opt In Entity (NOIE) territories.

Based on installed capacity and current rates of growth, these resources do not pose an immediate or near-term reliability concern for the transmission grid. The environment for DERs in ERCOT is characterized by a combination of low energy prices and an absence of region-wide regulatory incentives, leading to a penetration growth rate that is much slower than has been witnessed in other regions such as Germany, California and Hawaii.

Nevertheless, many factors — including customer desire for independence, environmental consciousness, and declining costs of DER acquisition — point to continued growth. Thus far within ERCOT, additional drivers for DER growth have included participation in Emergency Response Service (ERS), demand-charge avoidance in the form of Four Coincident Peak (4CP) response, and Load Zone-level wholesale price response in the Real-Time Energy Market. The ERCOT Independent System Operator (ISO) would like to be prepared for a future scenario in which a larger share of the regional generation mix may come from the distribution system.

ERCOT has been evaluating the potential reliability impacts of increasing DER activity. This paper is submitted to stakeholders in order to identify the areas of concern, and to support a goal identified in ERCOT's DER Concept Paper published in August, 2015[2] —

[1] Based on submissions in PUC Project NO. 45513. This document uses the terms Distributed Generation and Distributed Energy Resource interchangeably. In practice, DERs may include both generation and storage devices which are a combination of generation and Load. Also note that the 900 MW includes a number of DG units that provide backup power only and do not inject energy to the grid.
[2] Posted at http://www.ercot.com/calendar/2015/8/25/72783-DREAMTF.

namely, collection of data that ERCOT will eventually need to perform reliability and planning studies and ensure the reliability of the bulk power grid.

There are two distinct categories of DERs in the region today, each posing its own set of challenges and opportunities:

- Self-dispatched generation. Currently, these are primarily units that use diesel fuel, natural gas, or landfill gas as their fuel type and are typically capable of starting quickly and running for widely varying periods of time without incurring extensive wear and tear. A significant number of these units are providing backup power to critical infrastructure, and may also be providing Emergency Response Service and/or responding to price signals in the Real-Time Market. There are fewer than 200 of these units in operation today, and approximately 70 that inject power onto the grid and accordingly are registered with ERCOT. Nonetheless, self-dispatched DG comprises a sizeable majority of the total DG Connected Capacity in the region. In the future, self-dispatched generation could also include distribution-connected energy storage technologies.
- Intermittent generation, primarily rooftop solar. These units typically generate automatically when their energy source is present, and are typically offsetting native Load and exporting excess generation during light Load conditions. While comprising perhaps one-fifth of total DER Connected Capacity, they represent the vast majority of total installed units, with over 11,000 unregistered DER facilities in competitive choice territories and over 12,000 unregistered DER facilities[3] in NOIE territories. Importantly, data suggests that rooftop solar adoption tends to concentrate in neighborhoods, creating clusters on various distribution feeders which in turn are connected to single transmission Load points.

Local integration of DERs is the responsibility of the Distribution Service Provider (DSP). As DER penetration levels increase, especially in concentrated clusters, the DSPs can

[3] Source: Energy Information Administration reports (Forms 826 and 861) for TDSPs in ERCOT competitive choice areas, and published reports from NOIEs..

be expected to see the first level of impact to their systems such as voltage and feeder capacity, which are not visible to ERCOT.

However, real-time operations of both types of DERs currently affect the grid as non-conforming power on individual transmission Load points. At higher penetration levels, this DER activity has the potential to affect grid operations in multiple ways, including:

- Increased error in Load Forecasting, which could result in excessive reliance on Regulation Service and other Ancillary Services to mitigate the potential frequency excursions caused by the output of both variable and self-dispatched DER;
- Less accurate inputs to the State Estimator and Load Adaptation. These ISO functions are critical for managing transmission-level line loading and maintaining single contingency ("N-1") reliability. Potentially impacted are:
    - Load Distribution Factors (LDFs) which are among the key inputs to numerous studies conducted in both the ERCOT Energy Management System (EMS) and Market Management System (MMS), and which can be affected by DERs;
    - Reactive power, voltage control, and dynamic response to faults; and
    - Transmission-level congestion management.
- Uncoordinated system restoration, potentially involving large voltage or frequency swings, in the event of a load shed event.

Many of the concerns associated with larger self-dispatched DERs could be alleviated if the ISO were to acquire real-time visibility of the units' locations and real-time or near-real-time data in the form of telemetry from the unit's Qualified Scheduling Entity (QSE). Other concerns could be addressed by allowing self-dispatched DERs the option of active wholesale market participation. ERCOT's August 2015 DER White Paper proposed a way to enhance markets by allowing DERs the option of being settled on local (Nodal) prices, which are already being produced every five minutes at more than 4,000 Load points on the transmission grid.[4] While this paper focuses on power system management

[4] See "DER Light" and "DER Heavy" concepts in the August 2015 ERCOT DER white paper.

rather than market-based issues, delivering existing Nodal prices from the transmission system to resources at the local distribution level could be a valuable component of an efficient and reliable grid.[5]

This document provides more detail and background on the above challenges, and suggests ways for ERCOT and stakeholders to collaborate on addressing these issues going forward in order to ensure a continued reliable bulk power grid.

ERCOT believes the foundation to the reliable and efficient management of this future distributed grid is visibility, in the form of more detailed collection of static DER data from Distribution Service Providers (DSPs) and Transmission Service Providers (TSPs) to support various ERCOT grid monitoring functions. ERCOT does not propose to model or operate the distribution system; that remains the sole province of the DSPs. Rather, ERCOT proposes a collaborative process involving DSPs and TSPs in which the locations of large DERs or large clusters of small DERs are mapped to their appropriate modeled transmission loads (Common Information Model, or CIM Loads) in the ERCOT Network Operations Model (NOM). ERCOT acknowledges that these entities do not currently have processes in place to map DERs to CIM Loads, and therefore proposes the following transition:

1. ERCOT in 2017 will work with TSPs and DSPs to develop a standardized method of providing and collecting appropriate data for mapping current and future registered[6] DER units to their CIM Loads, considering the normal circuit operating configuration of the DER. TSPs will retain their current flexibility in determining how to model the CIM Loads in their networks, and will have the ability to relocate a mapped DER to a different CIM. This will affect approximately 85 existing units, all of which have at least 1 MW in rated capacity and export power to the grid. The vast majority of this capacity falls into the "self-dispatched" category; mapping

[5] Note that active market participation which contributes to price formation may require the DG facility owner to register with the Public Utility Commission as a Power Generation Company, and to follow applicable rules associated with PGCs.

[6] Distributed Energy Resources in both competitive choice and Non Opt-In Entity (NOIE) territories are required to register with ERCOT if they are 1 MW or greater in Connected Capacity and inject energy to the grid at any time.

these units to their CIM Loads will provide the ISO with locational awareness for more than 80% of total DER Connected Capacity.

2. ERCOT will work with stakeholders to develop a process for competitive choice and NOIE DSPs to monitor the accumulation of clusters of unregistered (<1 MW) DER units connected to specific CIM Loads. When the combined Connected Capacity of these smaller units associated with a specific CIM Load exceeds an agreed-upon threshold, the DSP and TSP can work with ERCOT to determine the best process for providing the data necessary to map these DERs to the CIM. This will provide the ISO with locational awareness for CIM Loads that may be subject to reliability issues due to larger than normal weather-related swings or load swings due to large DER accumulation, while avoiding the need to map thousands of individual DERs (mainly rooftop solar arrays) to the transmission grid. ERCOT does not propose the actual thresholds herein, but rather looks forward to working with TSPs and DSPs to identify them.

As noted above, responsibility for operation of the distribution grid resides with the DSPs. ERCOT does not propose to alter this structure; rather, ERCOT proposes to enhance the visibility of DERs connected to the distribution system for the ISO and market participants to assure the continued reliable operation of the ERCOT System.

As higher levels of DER penetration begin to impact the power grid, the need for DERs to provide reactive power and improved response to disturbances and faults on the electrical system will become important. Efforts are already underway to address some of these reliability concerns via new standards being developed by the Underwriters Laboratory (UL) and the Institute of Electrical and Electronic Engineers (IEEE). Many provisions have already been adopted by the California Public Utilities Commission (see Rule 21[7]). Over time, these initiatives should result in modernized DER interconnection standards.

[7] https://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf

2 DEFINITIONS

The following working definition of DER is based on language from ERCOT's August 2015 DER Concept Paper:

> **Distributed Energy Resource:** Generation, energy storage technology, or a combination of the two that is interconnected at or below 60 kV and operates in parallel with the distribution system.
>
> (Note that further discussion will be required if the DER definition is to be expanded to include demand response.)

This paper differentiates between Distributed Generation (DG) "Connected Capacity" and DG "Operating Capacity," with the terms defined as follows:

> **Connected Capacity:** The output capability of a Distributed Generation (DG) facility before applying any protective or operational limitations. This is most often the nameplate capability of the generating system or the rated capability of the inverter.
>
> **Operating Capacity:** The output capability approved by the Distribution Service Provider for parallel operations with the utility system. In some cases, customers operate their DG Facilities with only a portion of the Connected Capacity at a given point in time. Other customers may have spare generating capacity and limit what is used at a given point in time.

3 RELIABILITY IMPACTS WITH HIGH DER PENETRATION

Distributed Energy Resources (DERs) can include batteries and other evolving storage technology, rooftop photovoltaic (PV) solar arrays, fossil fuel reciprocating generators, or combinations of these resources. Experiences in several markets show that large amounts of DER installed capacity, especially rooftop PV, can be installed in a very short time. Germany alone added 7,400 MW of solar PV on its low-voltage distribution grid in one year [reference 1][8]. There are examples of similar fast-paced growth of DERs elsewhere as well, including California and Hawaii. While the rapid DER growth in these jurisdictions can be attributed to public policy and/or economic factors that are not currently present in Texas, with continually reducing costs all three major U.S.-Canadian power grids are expected to see greater amounts of DER penetration in the future.

This document focuses on the reliability impacts that both major categories of DERs — self-dispatched DERs and intermittent DERs — could pose to the operation of the ERCOT grid if current software, systems, and regulatory and market rules remain unchanged. At a high level, the ISO's lack of DER visibility potentially impacts ISO operations as follows:

- Inaccuracies in forecasting net load;
- A need to change Ancillary Service reserve requirements to support added uncertainty;
- Invalid State Estimation (SE) results brought about by incorrect handling of energy injection data from distribution circuits;
- Inaccurate Load Adaptation and invalid LDFs in Operational Studies;
- Reduced or limited reactive power, voltage control, and dynamic response to faults
- Lack of coordination during system restoration;
- Over-operation of voltage control equipment not properly coordinated with active output of solar PV facilities reacting to clouds and weather; and

[8] References throughout this document are listed in Section 5.

- Risks of damage to transmission surge arresters when interconnected with delta-wye transformers.

Three North American Electric Reliability Corporation (NERC) task forces — the Variable Generation Task Force, the Essential Reliability Task Force, and the Distributed Energy Resources Task Force — have worked on similar efforts to identify the reliability impacts that significant amounts of DER may pose to bulk electric systems, and have assessed the performance of DERs relative to voltage and frequency disturbances [references 2, 4, 4 and 5]. Additionally, over the past few years, several stakeholders across the industry have conducted studies to assess the impact of DERs to Bulk Electric System reliability and their ability to support transmission network stability [references 7, 8, 10 and 11].

3.1 Visibility

ERCOT's objective is to collaborate with TDSPs and other stakeholders to advance the protocols and rules related to DER activity before reliability challenges to the bulk power grid emerge. This dialogue should seek to identify appropriate standards for interconnected equipment and resources, and to provide the ISO with visibility to assure that system planning, load forecasting and Ancillary Service (AS) requirements are sufficient to manage the benefits and risks of large scale DER deployment. This visibility, coupled with appropriate resource information, will support ERCOT's ability to manage or mitigate reliability issues as DERs become a significant part of the resource mix. ERCOT anticipates the need to account for intermittent DERs in procuring AS and to build models correlating weather conditions and DER output.

ERCOT has experienced events where the net load has fluctuated, and later discovered that a contributing factor was self-dispatched DER generation coming online and going offline in response to Load Zone prices during scarcity conditions. These events illustrate the increasing importance to ERCOT of visibility of self-dispatched DERs.

ERCOT anticipates a need for a more advanced toolset for forecasting the impacts of intermittent DERs such as rooftop solar whose behavior is influenced by weather.

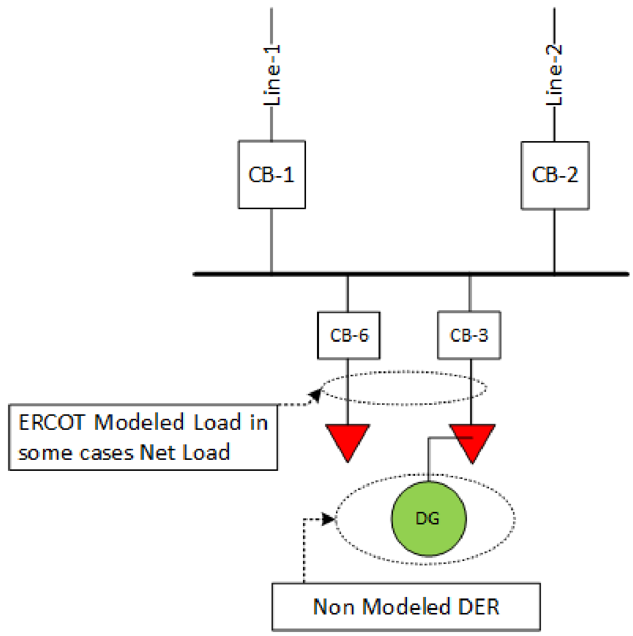
ERCOT does not seek to acquire the ability to control intermittent DERs. If future DER penetration levels start to rival those seen in other regions, the ability to curtail such DERs for transmission constraint management, via new DSP communications and control systems, may be necessary. A thorough discussion of the eventual responsibilities of DSPs and/or QSEs for remote monitoring and control, which are key functions included in the new IEEE and UL standards for distributed generation, will be complementary to ISO operations.

3.2 Power Flow & State Estimation

The State Estimation (SE) application within the ERCOT EMS determines the best estimate of the system state (bus voltage magnitude & angle, and transformer taps), given the network model and available measurements. The State Estimator is equipped with processing logic that detects gross errors in measurements and filters out bad values. Its results are used in creating a power flow study case describing the current state of the system which is used in real-time reliability analysis programs, and detecting structural errors in network configurations and erroneous breaker status.

In ERCOT, a process of load adaptation uses the state estimated value for each Load modeled in the Network Operations Model (NOM) to update each Load's corresponding Load schedule — i.e., Load Distribution Factor (LDF). These schedules in turn feed into numerous future studies conducted using the ERCOT EMS, including outage coordination, day-ahead studies and real-time studies; and the MMS, including the Day Ahead Market (DAM), Day Ahead Reliability Unit Commitment (DRUC), Hourly Reliability Unit Commitment (HRUC) and Congestion Revenue Rights (CRR).

ERCOT's concern is that a significant increase in the penetration of DERs — either larger self-dispatched DERs or clusters of small intermittent DERs — could result in more bi-directional flow of energy from the distribution system. Since the NOM tracks loads at the transmission level, with DERs in ERCOT's footprint, the SCADA measurements telemetered by TSPs for their associated transmission Loads represent a net value where the actual demand is offset by the DER injection. This net load telemetry affects the transmission load's adapted LDF — resulting in a smaller number than the maximum demand possible with no DER injection[9]. With today's quantity of DERs, this is not an issue; however, this becomes a concern when the DER injection is driven by a factor other than time of day — for example, cloud cover over clustered solar PV sites — leading to erroneous results for some studies but not others



Incorrect LDFs are difficult to identify but are nonetheless used as inputs in all operations studies. The primary goal of most of these future studies in the Operations and Operations Planning horizon is to detect potential thermal or voltage reliability issues on

[9] ERCOT experienced similar effects in the past at a facility with significant behind-the-meter generation for which ERCOT had no visibility. Typically, the facility relied on the ERCOT grid to serve about a third of its total load, and served the rest with its local generation. The LDF for this facility was based on the historical net consumption data, which assumed the on-site generation was always present. A reliability concern arose on a day when the behind-the-meter generation was forced out of service, unknown to ERCOT's studies, concurrent with an ERCOT-approved planned transmission outage in that area. As a result, the load served from the grid was magnified threefold, leading to transmission overloads in real-time. In such cases, because all LDFs from the State Estimator are used "as-is," the effects of such a scenario cannot be identified ahead of time. (Note that ERCOT has adapted to this facility's specific case in current practice by gaining visibility into the behind-the-meter generation.)

an expected future (for example, worst case Load, high/no wind, etc.) scenario. Erroneous LDFs could mask potential reliability issues in these studies.

Additionally, high DER penetration could cause the telemetry from an affected transmission Load to become negative (i.e., a net injection scenario). ERCOT's State Estimator currently filters out all negative load telemetry values, effectively treating them as bad data. ERCOT sees a need today to anticipate these trends and change the current framework in order to avoid high residuals and mismatches in the SE solutions, many of which will be false positives.

In other words, if ERCOT doesn't know the existence of or the associated capacities of DER(s) at a Load modeled in the NOM, large DER power injections could degrade the accuracy of the solutions analysis from ERCOT's reliability assessment tools (State Estimator, Network Security Analysis) as well as studies conducted in preparation for real time.

To maintain acceptable quality of ERCOT's reliability studies in a future with high DER penetration, DERs' withdrawal and injection components will need to be known or estimated for accurate load adaptation.

3.3 Short-Term and Mid-Term Load Forecast

ERCOT's Hourly Load Forecast (LF) application — the Mid-Term Load Forecast (MTLF) and the Short-Term Load Forecast (STLF) — forecasts Load across eight ERCOT Weather Zones. The MTLF uses a neural network and linear regression-based algorithm every hour to create a forecast for the next 168 hours. The STLF is configured to use a "similar day"-based analysis every five minutes to create a forecast for the next hour. The ERCOT System-wide Load forecast is then calculated as the sum of the Load forecasts across these eight Weather Zones.

The LF application has a self-training mode which recalibrates the STLF and MTLF based on actual Load trends in each weather zone. The accuracy of this forecasting logic is highly dependent on the consistency of the changes in Load. With higher penetration of DERs across various geographic locations in ERCOT, net Load reductions caused by DERs will look sporadic and could be expected to hinder the application's ability to properly project demand, causing larger Load forecast errors. Within geographic regions DER penetration can be expected to be inconsistent, due to the observed tendency for DER adoption to occur in clusters, leading to concentrations of DER activity at specific substations and CIM Loads. These inconsistencies will affect the accuracy of ERCOT's load forecast and any downstream operational or planning studies based off the forecast.

In real time, the ERCOT Load forecast factors into ERCOT's Reliability Unit Commitment (RUC) application and in the Generation-To-Be-Dispatched (GTBD) logic employed in Security Constrained Economic Dispatch (SCED). An inaccurate MTLF and STLF — e.g., an over-forecast of Load — will degrade decisions on the commitment of units for RUC, and could result in price spikes caused by a magnified GTBD when the actual demand may not be as high; conversely, an under-forecast could depress market prices. Accordingly, from a RUC perspective, accurate load forecasting is both critical to integrating high amounts of intermittent Resources, and also subject to increased error due to activity by those very resources if they remain invisible to ERCOT. If forecasting accuracy degrades, then reliable integration of DERs, especially intermittent DERs, becomes increasingly difficult.

ERCOT over time has steadily improved its MTLF, and is currently working on STLF improvements to operate the grid more reliably with higher amounts of intermittent Resources. To ensure the continued accuracy of these key applications, detailed and granular information related to DERs will need to be shared within the Load Forecasting applications and correctly accounted for.

ERCOT anticipates that DERs may eventually impact the Region's Ancillary Service requirements. DERs can offset local load, thereby causing significant changes in the System's apparent demand patterns. These unanticipated load variations in real time can be expected to result in additional reliance on ancillary services. ERCOT will deploy Regulation Service to maintain the balance of supply and demand; however, as the penetration of DERs continues to grow, current levels of Regulation Service may not be sufficient.

Higher penetration of DERs may result in displacing the amount of conventional synchronous generation used to meet real time demand, thus resulting in a decline of total online system inertia. Low inertia can require more conventional generation reserves to be kept online to respond to the loss of another Resource. In today's world, this may create a need to procure additional Responsive Reserve Service (RRS) during such hours. And since the degree of variability from DERs may not be fully known, more Non-spinning Reserve Service may also be needed to compensate for fast ramps and higher variation in output by large number of DERs, especially intermittent DERs.

If ERCOT lacks visibility to the quantity and availability of DERs on the system in near-real time conditions, ERCOT's Ancillary Service requirements will need to have higher safety margins to manage this uncertainty. The California ISO (CAISO), which operates a System with high levels of DER penetration, has examined the effects of DERs on its reserve requirements and quantified benefits and costs associated with gaining visibility and control of DERs. The CAISO study observes that with higher DER penetrations and no added visibility in the longer term, the ISO's Regulation-Up requirements could triple. Conversely, the same study found that with improved visibility, forecasting and monitoring, at conservative error margins Regulation-Up requirements could actually *decrease* by as much as 8%, even in a high DER penetration scenario [reference 6].

3.4 Long Term Load Forecast

The Long Term Load Forecast is one of the critical inputs to the Capacity, Demand and Reserves report and also one of the primary assumptions in the studies conducted in the Planning horizon. The forecasted growth of DER will have an impact on planning decisions. Inaccuracies in the Long Term Load Forecast due to over- or under-forecasting of DER in an area could lead to building too little or too much transmission. Further, the dynamic behavior of DERs can affect stability study results which could also lead to less than optimal transmission planning decisions. Hence, the Operational Capacity, location, and type of DER is important data that should be included in the Planning horizon.

3.5 Reactive Power And Response To Abnormal Conditions

The ability to provide reactive power support, voltage control and capability to ride through abnormal system disturbances (voltage and frequency ride-through) are critical to support ERCOT grid reliability.

The IEEE-1547 standard as published in 2003 did not require DERs to have the ability to regulate feeder voltage [reference 14]. With higher DER penetration levels, this lack of reactive control could significantly alter bulk electric system's response for voltage control during disturbances. This requirement has been amended in the addendum published in 2014 in response to Hawaii and California's needs for reactive power [reference 15]. The full revision of IEEE1547 expected to be implemented in 2017 now also includes the capability for both volt/var and watt/var support algorithms for providing grid level support during voltage and frequency events.

Similar to the reactive control, the IEEE-1547 standard as published in 2003 [reference 14] had very narrow operating range requirements for voltage or frequency beyond which DERs were mandated to trip thus effectively restricting DERs from riding through system disturbances. Recognition of the reliability concerns of these narrow operating ranges were also addressed in the IEEE1547a-2014 addendum, which significantly widened these mandatory trip limits. These limits are proposed to be widened even further in the forthcoming 2017 update to IEEE1547.

Technical provisions in PUCT Substantive Rules governing distributed generation, which have not been revised since their adoption in 1999, require competitive TDSPs in the ERCOT market to follow these narrow operating ranges, which means that during loss of significant levels of bulk generation resulting in drops in voltage or frequency, this distributed generation is expected to trip offline as well.

This mandatory trip requirement is not coordinated with reliability requirements for Generation Resources in the ERCOT Protocols and Operating Guides.

At higher DER penetration levels, a significant amount of DER disconnecting from the system just when their energy is needed could potentially cause cascading effects. The voltage and frequency ride-through requirements in IEEE 1547 were amended in 2014 and continue to be a focus in the ongoing revision of this standard (Section 5 provides more insights on the draft IEEE 1547).

The Electric Power Research Institute (EPRI) in its studies has demonstrated that in the case of small isolated power systems, adding frequency ride-through ability improves the frequency nadir, rate-of-change-of frequency (precluding subsequent stages of under frequency load shedding) and also improves the settling frequency — reducing the secondary reserves required to return frequency to nominal [reference 8]. Similarly, another study analyzed the potential impact this lack of voltage ride-through capability could pose on the voltage and frequency performance in the Southwestern U.S. transmission system in a high distributed PV penetration scenario. This study observed that voltage recovery in cases where distributed PVs trip due to lack of voltage ride-through is in many cases worse than cases without distributed PV, and that voltage recovery in cases where distributed PVs don't trip is much better than cases without distributed PV [reference 10]. Germany has also analyzed the possible frequency stability (primarily high frequency) challenges posed to the German grid during abnormal system conditions. In such cases, system frequency can violate the high operating frequency threshold for DERs which were a mix of equipment that were built under different rules — some requiring immediate trip and others that removed the trip requirement.[10]

PUC Substantive Rules §25.211 and §25.212 [reference 12] address the technical and procedural aspects of interconnecting DG and specify that DG should follow the voltage and frequency imposed by the interconnecting utility, including a requirement to disconnect under abnormal conditions identified in the table below.

Table 3-1: Voltage/Frequency Disturbance Delay & Trip Times

Range		Trip Time[2]	
Percentage	Voltage[1]	Seconds	Cycles
<70%	<84	0.166	10 (Delay) & 10 (Trip)
70%-90%	84 – 108	30.0 & 0.166	1800 (Delay) & 10 (Trip)
90% - 105%	108 – 126	Normal Operating Range	
105% - 110%	126 – 132	30.0 & 0.166	1800 (Delay) & 10 (Trip)
>110%	>132	0.166	10 (Delay) & 10 (Trip)
	Frequency (Hz)		
	<59.3	0.25	15 (Trip)
	59.3 – 60.5	Normal Operating Range	
	>60.5	0.25	15 (Trip)

[1] Voltage shown based on 120V, nominal.

[2] Trip times for voltage excursions were added for completeness by the PUCT Project No. 22318 Pre-certification Working Group as the intent of 25.212.

While the ranges and trip times take into account the fact that losing any generation (including DER) when the system voltage or frequency is decreasing can exacerbate generation-related problems, these rules were based on the assumption of relatively low

[10] Two thirds of PV power in Europe is connected to the low voltage (i.e., distribution) network. Operating frequency range for such DERs is extremely close to nominal frequency with the requirement that the DERs trip immediately should these be violated (note that the immediate trip requirements were introduced in 2005/2006 when PV penetration was relatively low and has since 2011/2012 been altered to a transitional strategy). The study notes that conditions under which frequency could exceed these thresholds are a rarity under normal operations but were experienced during a European power grid failure in 2006 and during the blackout in Italy in 2003 (~N-1-1 condition). The study further extrapolates that similar conditions were subject to occur on days with high DER penetration (worst case 9000 MW); the European grid, which is designed for the sudden loss of 3000 MW, could face significant frequency stability problems and recommends retrofitting the existing distribution connected DERs [reference 11].

DG penetration and have not been fully vetted for a higher DER penetration scenario. It is worthwhile noting that these ranges and trip times do not align with the voltage and frequency ride-through requirements for Generation Resources specified in ERCOT's Protocols and Operating Guides. (See Appendix A for additional information on this). These misaligned ranges are of concern as these could cause DERs to trip in frequency/voltage ranges during periods when ERCOT expects these to be operating. ERCOT envisions a need either to change these ranges or to modify standards for distribution network voltage control to maintain voltage within these ranges.

At higher penetration levels, the impacts of DERs on system protection requirements will require evaluation. As the penetration levels of inverter-connected generation (e.g., solar PV) increase, displacing conventional synchronous generation, the available short circuit current on the system can be expected to decrease correspondingly, making it difficult to detect and clear system faults [reference 2].

ERCOT will need to develop detailed dynamic models to conduct studies that analyze DERs' voltage and frequency ride-through capabilities, frequency response and under-voltage load shedding abilities, akin to the characteristics of other generators. A key aspect to conducting these studies is to have knowledge of the location of the DER relative to its CIM Load. This paper does not attempt to address what additional information ERCOT may need to develop detailed dynamic models or the sources of any such information.

3.6 COORDINATION OF SYSTEM RESTORATION

System restoration after a major outage event is another issue that requires attention in the case of high DER penetration [reference 4]. Bulk power system restoration is a controlled procedure whereby generation restart is coordinated with transmission network energization and staged load restoration. In contrast, a DER restart is typically automatic — meaning there is no provision for staggered restarts to avoid possible problems during a system recovery. During the November 2006 European Blackout [reference 13], approximately 8,000 MW of wind energy, mainly from distribution-connected turbines, auto-restarted despite the fact that the system was still islanded and the frequency was at 50.3 Hz (on a 50 Hz system). This auto restart further increased frequency to about 50.45 Hz, causing significant overloads of facilities and nearly causing a collapse of the system by tripping generation due to over-frequency. In the Oahu, Maui, and Hawaii Island grids, automatic reconnection of the large amounts of distributed solar PV is already of significant concern for restoration from potential island-wide outages.

IEEE 1547-2003 standard for reconnection requires "either an adjustable delay (or a fixed delay of five minutes) that may delay reconnection for up to five minutes after the Area EPS steady-state voltage and frequency are restored…" PUCT rule §25.212 included the provision "*The customer may reconnect when the utility system voltage and frequency return to normal range and the system is stabilized*."

The IEEE standard allows for an adjustable reconnection setting; however, most manufacturers simply set the default values of their equipment to 5 minutes (300 seconds) and utilities typically do not require any change. This may result in complications during system restoration efforts in areas with high DER penetration. In such a case, when a circuit is restored following an outage, the Load comes back immediately, but the generation is delayed for 5 minutes. The simultaneous return of all DG can cause power quality issues. New features in the proposed IEEE1547-2017 standard include both randomization and ramping functions. These settings should all be reviewed and optimized for areas with high DER penetration.

4 RECOMMENDATIONS

Based on Energy Information Administration data, today there are over 11,000 unregistered DER facilities in competitive choice territories and over 12,000 unregistered DER facilities[11] in NOIE territories. ERCOT will need to adopt certain system and policy changes to support larger scale integration of DERs and ensure continued reliable operations of the grid. It is also worth recognizing that the breadth and depth of changes ERCOT needs are dependent on the amount of DER penetration. As a result, this section starts by identifying at a high level the system changes, process and methodology amendments, and studies and analyses that may be necessary to ensure reliable grid operations while supporting large DER penetration levels. ERCOT then proposes an approach based on active monitoring of the penetration levels of DERs for prioritizing implementation of these changes.

ERCOT believes the foundation to the reliable and efficient management of this future distributed grid is visibility, in the form of more detailed collection of static DER data from Distribution Service Providers (DSPs) and Transmission Service Providers (TSPs) to support various ERCOT grid monitoring functions. ERCOT does not propose to model or operate the distribution system; that remains the sole province of the DSPs. Rather, ERCOT proposes a collaborative process involving DSPs and TSPs in which the locations of large DERs or large clusters of small DERs are mapped to their appropriate CIM Loads in the ERCOT NOM. ERCOT acknowledges that these entities do not currently have processes in place to map DERs to CIM Loads, and therefore proposes the following transition:

1. ERCOT in 2017 will work with TSPs and DSPs to develop a standardized method of providing and collecting appropriate data for mapping current and future registered[12] DER units to their CIM Loads, considering the normal circuit operating configuration of the DER. TSPs will retain their current flexibility in determining

[11] Source: Energy Information Administration reports (Forms 826 and 861) for TDSPs in ERCOT competitive choice areas, and published reports from NOIEs.

[12] Distributed Energy Resources in both competitive choice and Non Opt-In Entity (NOIE) territories are required to register with ERCOT if they are 1 MW or greater in Connected Capacity and inject energy to the grid at any time.

how to model the CIM Loads in their networks, and will have the ability to relocate a mapped DER to a different CIM. This will affect approximately 85 existing units, all of which have at least 1 MW in rated capacity and export power to the grid. The vast majority of this capacity falls into the “self-dispatched” category; mapping these units to their CIM Loads will provide the ISO with locational awareness for more than 80% of total DER Connected Capacity.

2. ERCOT will work with stakeholders to develop a process for competitive choice and NOIE DSPs to monitor the accumulation of clusters of unregistered (<1 MW) DER units connected to specific CIM Loads. When the combined Connected Capacity of these smaller units associated with a specific CIM Load exceeds an agreed-upon threshold, the DSP and TSP can work with ERCOT to provide mapping data for these DERs. This will provide the ISO with locational awareness for CIM Loads that may be subject to reliability issues due to larger than normal weather-related swings or load swings due to large DER accumulation, while avoiding the need to map thousands of individual DERs (mainly rooftop solar arrays) to the transmission grid. ERCOT does not propose the actual thresholds herein, but rather looks forward to working with TSPs and DSPs to identify them.

As noted above, responsibility for operation of the distribution grid resides with the DSPs. ERCOT does not propose to alter this structure; rather, ERCOT proposes to enhance the visibility of DERs connected to the distribution system for the ISO and market participants to assure the continued reliable operation of the ERCOT System.

As higher levels of DER penetration begin to impact the power grid, the need for DERs to provide reactive power and improved response to disturbances and faults on the electrical system will become important. Efforts are already underway to address some of these reliability concerns via new standards being developed by the Underwriters Laboratory (UL) and the Institute of Electrical and Electronic Engineers (IEEE). Many provisions have already been adopted by the California Public Utilities Commission (see

Rule 21[13]). Over time, these initiatives should result in modernized DER interconnection standards.

4.1 System Changes And Additional Analysis

In evaluating the reliability impacts outlined in Section 1, listed below are system changes that ERCOT believes it will eventually need for addressing the reliability impacts of significant DER penetration levels.

- Sections**Error! Reference source not found.**, 3.1 and 3.4 of this paper shed light on the importance for ERCOT to know the type, Operational Capacity, location and operational abilities of the DERs in its footprint. These sections also recognize that this need for DER-related information is not a call for distribution-level modeling at the ISO, but is limited to knowing the nature of the load/resources that are being served by a substation transformer. The following proposed process and system changes address the concerns identified:

  1. Gather DER-specific data from NOIE DSPs and TSPs, similar to that currently provided by investor-owned TDSPs via Load Profiles, which includes Electric Service Identifiers (ESI ID), fuel type, Connected Capacity, inverter data, and other relevant information for interconnected DERs. Note that ERCOT's internal systems allow it to map ESI IDs to substations, but not to the individual transmission Loads modeled in ERCOT's NOM (CIM Loads) within the substations.

  2. As described above, map DERs to their specific transmission Loads modeled in ERCOT's NOM (CIM Load) using a two-phase collaborative process that involves the DSP, the TSP and ERCOT.
     a. ERCOT does not envision a need to track short-term distribution switching that may cause individual DERs to move from one load

[13] https://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf

transformer to another. A periodic, perhaps annual, readjustment approach could be adopted to capture long-term CIM-Load mapping changes.

3. Revise the SE to allow it to recognize energy injections at CIM Loads as valid inputs into the estimation algorithm in cases where energy flow from DERs can be expected to significantly affect net telemetered load. In addition, modify the SE's load adaptation to track and estimate DER schedules at CIM Loads where DERs are mapped, via the mapping process described above. These changes will assist in developing acceptable representations of the LDF for a CIM Load. (A similar process is currently under investigation with ERCOT's EMS vendor, based on an implementation in Denmark). Improving the accuracy of LDFs will enable downstream applications and studies to better account for the effects of DERs.

4. Incorporate additional contingency definitions into studies to simulate loss of or reduction in DER energy output. This will likely be dependent on the magnitude of DER penetration at a substation or, more accurately, a CIM Load.

- Sections 3.3 and 3.4 raise concerns that the lack of DER visibility could impact ERCOT's Load Forecast accuracy. These inaccuracies would affect both planning and operational studies. Preserving the accuracy of ERCOT's net load forecast will be critical to address these concerns and support larger scale integration of DERs. The following list captures some recommendations to address these concerns:

5. Forecast intermittent DER (e.g., rooftop PV) for visibility, based on irradiance forecasts in defined areas such as Weather Zones or other defined areas, with input from analysis and stakeholder feedback.
6. Update the Load Forecasting tools (STLF and MTLF) to include DER information similar to its other inputs. Enhance the Load Forecasting model to include irradiance or intermittent DER forecast when forecasting net ERCOT load. It is expected that as this model gains a few years of history that correlate

irradiance with the Weather Zone forecasts, the performance of the Load Forecast will continue its current improvement trend.

7. Develop a separate forecasting tool to project the participation of self-dispatched DERs that are deemed to be responsive to wholesale market prices or other signals. This will likely require inputs from other sources, potentially including the Outage Scheduler.
8. Integrate the DER forecast to Real-Time SCED dispatch in the form of a GTBD input, similar to how the STLF is incorporated.
9. Update the procedure used to compute Long Term LF to include DERs.

4.2 Monitoring DER Growth And Developing Triggers For Implementation

ERCOT reiterates that DERs do not pose a system reliability problem today. The urgency needed for implementation of the changes identified in Section 4.1 should be predicated on the rate of growth of DERs in ERCOT's footprint. Based on the DG Interconnection Reports filed with the PUC[14] by the five competitive choice TDSPs,[15] as of December 31, 2015, the following table represents a snapshot of existing DERs[16] with 10 MW or less of Connected Capacity in those territories:[17]

	Self-Dispatched		Intermittent	
Unit Size	Installations	Megawatts	Installations	Megawatts
1 ≤ 10 MW	113	593.4	3	7.8
< 1MW	43	16.0	8,484	75.5
Totals	**156**	**609.4**	**8,487**	**83.3**

[14] Project No. 45513.
[15] Oncor, CenterPoint Energy Houston Electric, LLC, Texas-New Mexico Power, Sharyland, and AEP. (AEP North and AEP Central were submitted as a joint filing.)
[16] Reports including 2016 DG installations will be filed at the PUC by the TDSPs by March 31, 2017.
[17] Does not include any data from NOIEs.

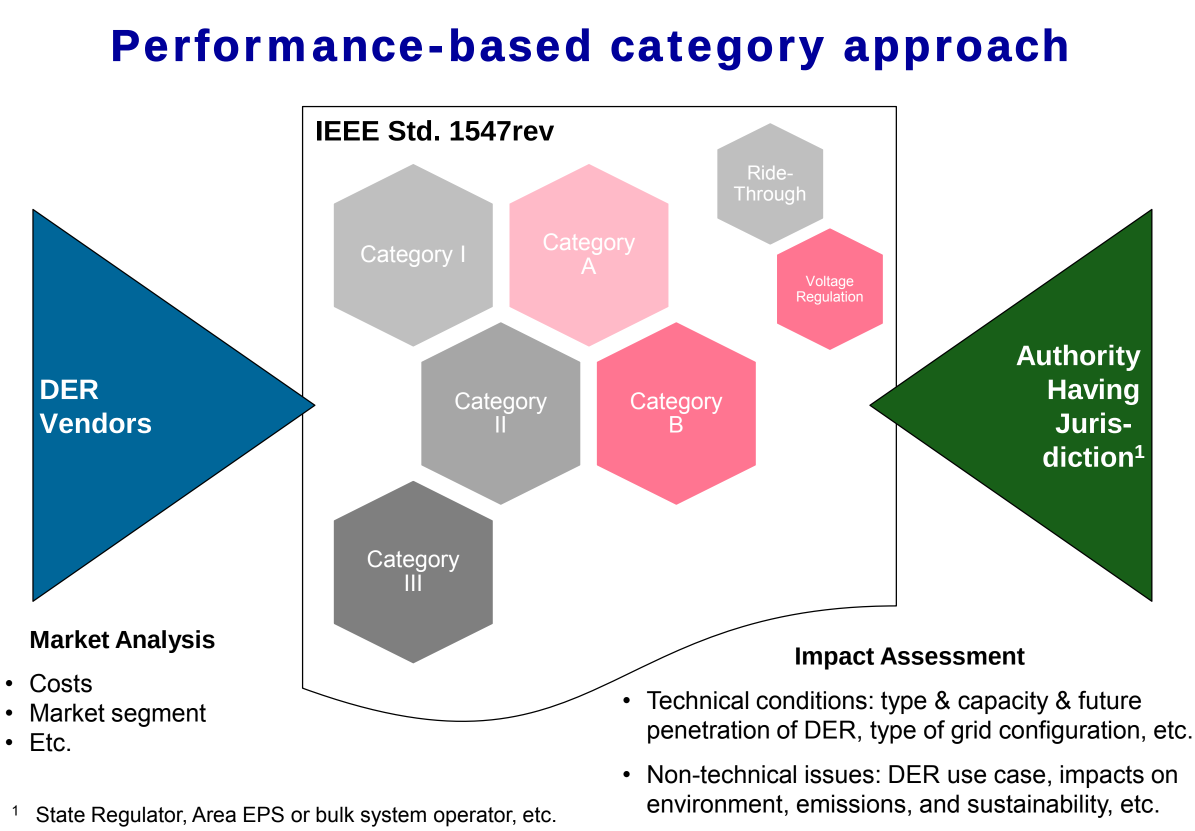
As noted earlier (in Items 1 and 2 from Section 4.1) ERCOT's proposal to acquire data mapping registered DERs (≥1 MW) to their appropriate transmission Loads (CIM Loads) will provide ERCOT with increased awareness and could provide a stronger basis for market participation by DERs electing to be settled at local (Nodal) energy prices. In parallel with this effort, ERCOT proposes to collaborate with Stakeholders, primarily DSPs, to develop monitoring criteria and a set of thresholds for identifying clusters of smaller DERs that are large enough to impact the transmission grid, and to put in place a process for mapping those clusters. Collection of this data will enhance the ability of ERCOT to report relevant DER data to the Market.

5 Ongoing Efforts At IEEE

The IEEE Standard 1547 [reference 14], *Interconnecting Distributed Resources with Electric Power Systems,* establishes criteria and requirements for the interconnection of DERs with electric power systems and associated interfaces. IEEE 1547 was first published in 2003 and reaffirmed in 2008. Some DSPs in ERCOT already require the inverters to be certified to IEEE 1547 and Underwriters Laboratories (UL) 1741 standards.

Amendment 1 [reference 15] was published in May 2014 as an outgrowth of an IEEE-hosted Workshop in May 2012. The primary purpose of this amendment was to incorporate changes based on the lessons learned from DER operations across the world (some of these are outlined in [references 4, 8, and 10]). Accordingly, Amendment 1 removed the restrictions against DERs from riding through system disturbances and altered the voltage regulation provisions to allow DERs to provide regulation.

The Amendment 1 standard allowed for broader inverter support ("smart inverter") and rotating machine support ("field and governor control"), but did not mandate increased disturbance tolerance and ride-through (ride-through may only be activated under mutual agreement between the interconnecting utility and DER operators). A full revision [reference 16] of the IEEE 1547 standard, which includes name, scope and purpose change, is currently underway with the target to complete this in 2017. The scope of the full revision includes interoperability (i.e. ability for a service provider to control DER), further amendments to voltage/frequency ride-through requirements that require more robust performance from DER during and after system disturbances, and restoration. These draft requirements are structured along the concept of "performance categories" which are technology-neutral and will have to be assigned by the Authority Having Jurisdiction (AHJ) in the area in coordination with the relevant stakeholders, e.g., the Distribution Provider, Transmission Operator, and Reliability Coordinator. The figure below gives a high-level overview of the performance-based category approach. Category II is regarded as the technical minimum requirement that considers all bulk system needs (like NERC PRC-024-2) but it may exceed current state-of-the-art performance capabilities of certain DER. Category I is a limited ride-through requirement that is attainable by all state-of-the-art DER technologies. Category III is an advanced ride-through requirement that also considers distribution system operation and is coordinated with existing interconnection requirements for very high penetration DER regions (ex. California Rule 21 and Hawaii).



The Federal Energy Regulatory Commission (FERC) recently published Notice of Proposed Rulemaking (NOPR) Docket No. RM16-8-000. This rule will require new small generating facilities (no larger than 20 MW) to ride-through abnormal frequency and voltage events, and avoid disconnecting during such events [reference 17]. (Note this rule will not be applicable to rooftop PV.)

These ongoing efforts and standards development updates will provide only a technical minimum requirement for bulk power system needs. ERCOT may need to conduct studies in collaboration with its stakeholders to develop criteria that are more representative of its system.

5.1 DEVELOP DER VOLTAGE, FREQUENCY AND STABILITY REQUIREMENTS INFORMED BY NEW IEEE STANDARDS

As DER penetration levels increase, the impacts outlined in Section 2 may require ERCOT to develop additional criteria to maintain voltage, frequency control and stability during system disturbances. The next few bullet items identify studies and other analyses that may be needed to define these requirements.

- Section 3.3 anticipates increased reliance on both Regulation Service and Responsive Reserve Service to offset the variability and system inertia reductions caused by higher penetration of specific types of DERs. Additional Non-Spinning Reserves may also be needed to offset fast ramping and higher output variability from large amounts of intermittent DER generation. The following changes will potentially be needed to manage this concern.

  10. Implement changes to the Ancillary Services Methodology document, in order to account for the uncertainties related to larger quantities of DERs.

  11. Work with DSPs to consider ramp limits for intermittent DERs. This will likely be dependent on the magnitude of clustered intermittent DERs in the same geographic location and will help in averting potential frequency control issues that may be experienced due to sudden increase or decrease in DER generation.

- Section 3.5 described the necessity for DERs to have the ability to provide reactive power support, voltage control and capability to ride-through abnormal voltage and frequency conditions. Section 3.6 raised frequency control concerns that could be caused by uncoordinated restart of DERs during a System restoration process.

  12. Establish voltage ride-through and frequency ride-through requirements for DERs.

   a. Studies with detailed dynamic models will be needed to establish DER specific requirements. Further discussion will be required to establish standards to coordinate DER voltage and frequency ride-through criteria with those that have been established in ERCOT's Protocols and Operating Guides. ERCOT anticipates that rules related to DG Interconnection may also need to be updated to coordinate with the voltage and frequency ride-through requirements that are prescribed for transmission-connected generators in the ERCOT Region.
   b. ERCOT will need to conduct studies to explore how the system will operate under current and future requirements and whether there will be a need to limit the penetration of DERs that do not have frequency ride-through capability.
13. Evaluate and develop load shed set points for DERs during abnormally low voltage and frequency conditions (i.e., Under Voltage Load Shed and Under Frequency Load Shed, respectively). Ensure these are coordinated with the low voltage and low frequency ride-through requirements for transmission-connected resources.
14. Properly-equipped DERs could potentially provide governor "droop" action to stabilize the frequency. Conduct further analysis to see establish DER parameters (DER type, Connected Capacity, penetration levels etc.) for which this functionality could be mandated.
15. Consider whether conditions for restart of DERs could be coordinated with the ERCOT ISO, along with Generation Resources during the system restoration process following an outage.

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6. Final Report for Assessment of Visibility and Control Options for Distributed Energy Resources Report-Link

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7. Technical Report dated December 30, 2015 from IEEE PES on Contribution to Bulk System Control and Stability by Distributed Energy Resources connected at Distribution Networks

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15. IEEE 1547 Amendment 1(Published in 2014) WG-Link
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APPENDIX A – VOLTAGE/FREQUENCY RESPONSE TO ABNORMAL CONDITIONS COMPARISON

This section compares the ERCOT voltage and frequency ride-through requirements for transmission-connected generators with the corresponding requirements for abnormal voltage/frequency conditions outlined for DERs in PUC's Substantive Rule §25.212(c), and to identify discrepancies between the two. The PUC requirements were loosely based on the original IEEE1547 (2003 version), which is undergoing full revision [reference 16]. This section also compares the proposed voltage & frequency ride-through requirements that are currently in the DRAFT IEEE-1547rev3 with current ERCOT requirements.

IEEE 1547-2003

Table 1—Interconnection system response to abnormal voltages

Voltage range (% of base voltage[a])	Clearing time(s)[b]
$V < 50$	0.16
$50 \le V < 88$	2.00
$110 < V < 120$	1.00
$V \ge 120$	0.16

[a]Base voltages are the nominal system voltages stated in ANSI C84.1-1995, Table 1.
[b]DR ≤ 30 kW, maximum clearing times; DR > 30kW, default clearing times.

Table 2—Interconnection system response to abnormal frequencies

DR size	Frequency range (Hz)	Clearing time(s)[a]
≤ 30 kW	> 60.5	0.16
	< 59.3	0.16
> 30 kW	> 60.5	0.16
	< {59.8 – 57.0} (adjustable set point)	Adjustable 0.16 to 300
	< 57.0	0.16

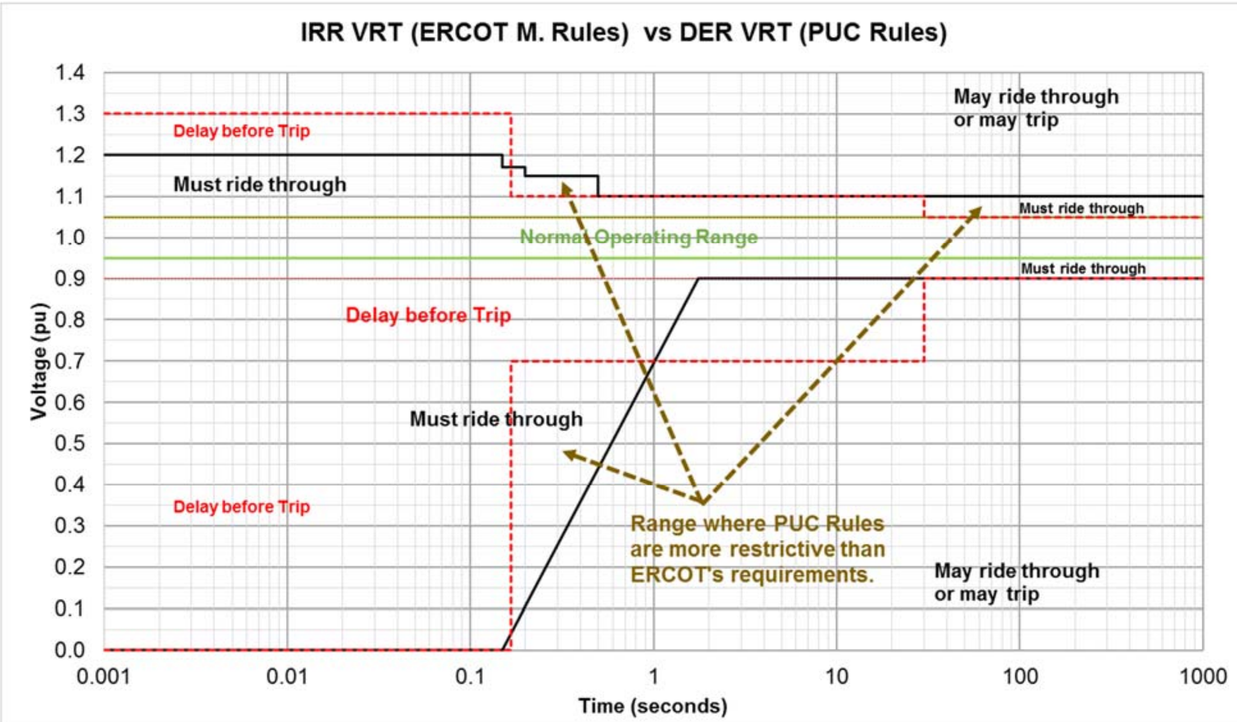
[a]DR ≤ 30 kW, maximum clearing times; DR > 30 kW, default clearing times.

The voltage ride-through requirements for Generation Resources and Intermittent Renewable Resources in ERCOT's Protocols and Operating Guides are summarized in the table below.

VOLTAGE	**GENERATION RESOURCES**	**VOLTAGE RANGE (% OF NOMINAL VOLTAGE)**	**OPERATING MODE**	**MINIMUM DELAY TIME (S)**
		110 => V > 105	Mandatory Operation	10
		95 =< V =< 105	Continuous Operation	Infinite
		90 =< V < 95	Mandatory Operation	10
	INTERMITTENT RENEWABLE RESOURCE	**VOLTAGE RANGE (% OF NOMINAL VOLTAGE)**	**OPERATING MODE**	**MINIMUM DELAY TIME (S)**
		V > 120	Cease to Energize	0.15
		117.5 =< V < 120	Mandatory Operation	0.2
		115 =< V < 117.5	Mandatory Operation	0.5
		110 =< V < 115	Mandatory Operation	1
		105 < V < 110	Mandatory Operation	Infinite
		95 =< V =< 105	Continuous Operation	Infinite
		90 < V < 95	Mandatory Operation	Infinite
		0 =< V =< 90	Mandatory Operation	Linear Slope 1.6 s/0.9 pu voltage starting at 0.15 s T_{VRT} = (1.6/0.9) * V + 0.15
FREQUENCY	**GENERATION RESOURCES**	**FREQUENCY RANGE**	**OPERATING MODE**	**MINIMUM DELAY TIME (S)**
		61.8 =< FHz	Cease to Energize	0
		61.6 =< FHz < 61.8	Mandatory Operation	30
		60.6 =< FHz < 61.6	Mandatory Operation	540
		59.4 < FHz < 60.6	Continuous Operation	Infinite
		58.4 < FHz =< 59.4	Mandatory Operation	540
		58.0 < FHz =< 58.4	Mandatory Operation	30

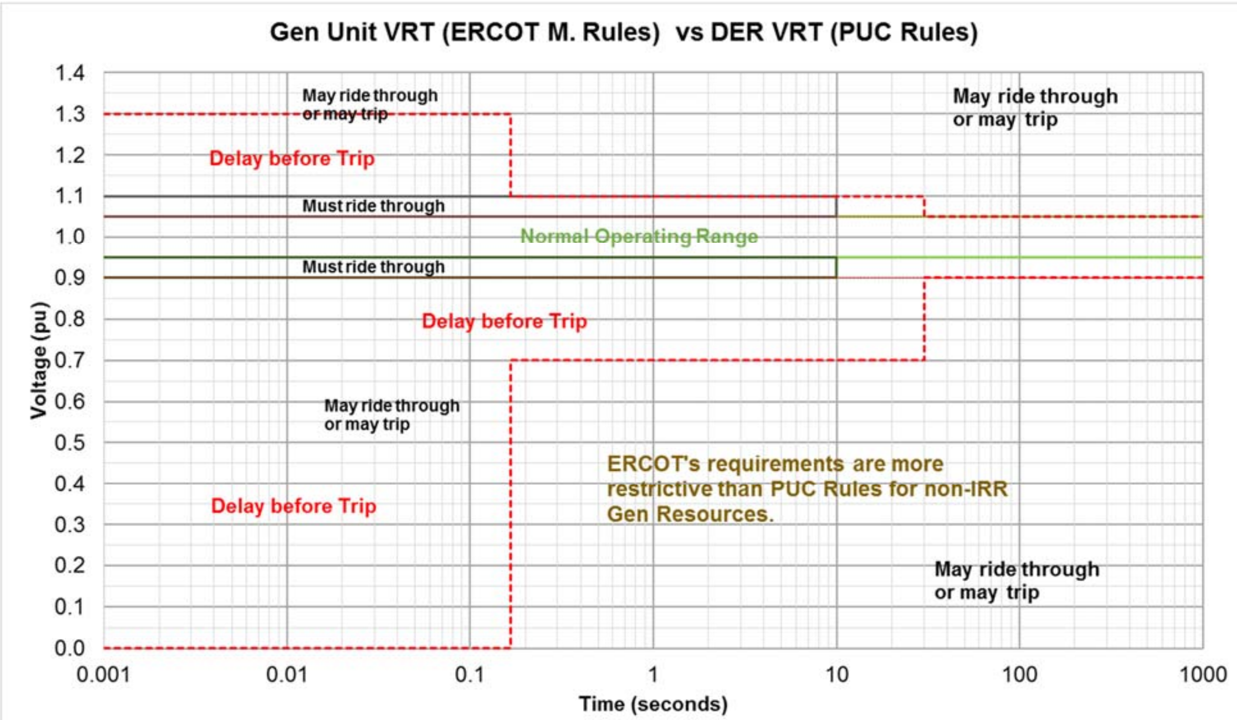
		57.5 < FHz =< 58.0	Mandatory Operation	2
		57.5 =< FHz	Cease to Energize	0

The following chart contrasts the voltage tripping requirements specified in PUC's substantive rule 25$212(c) (dashed red lines) with the voltage requirements for Intermittent Renewable Resources (IRRs) in ERCOT's Operating Guide (solid green and black lines).



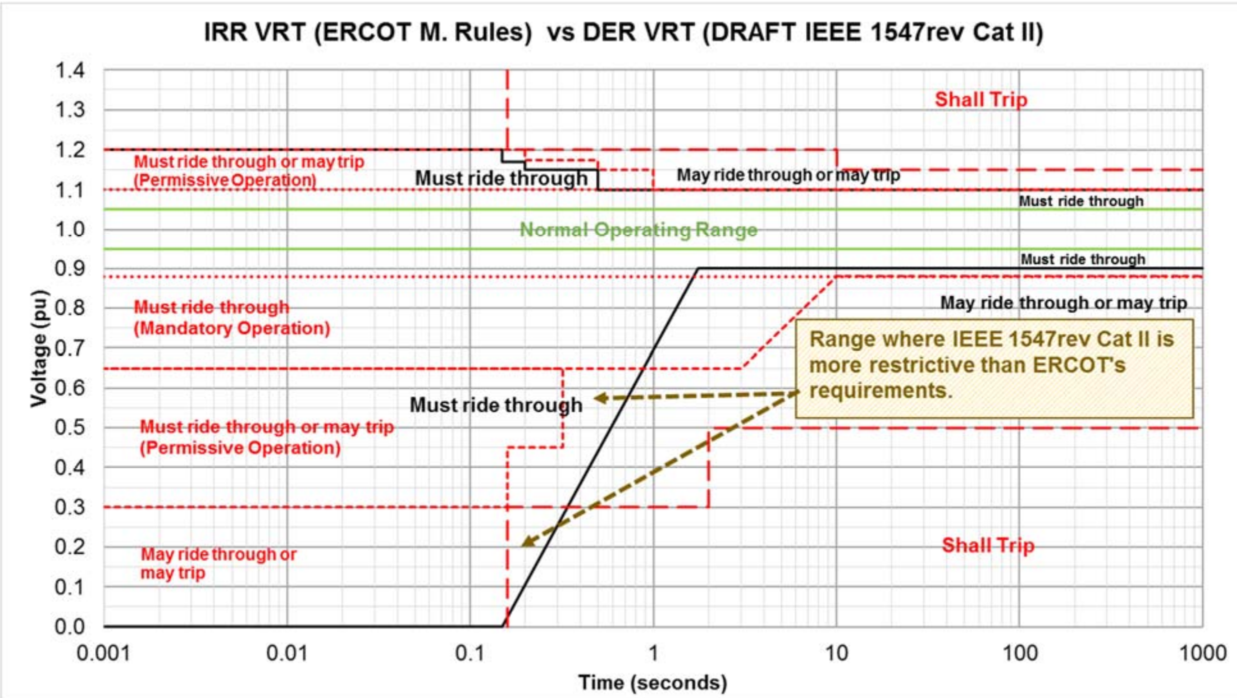
There are a few ranges where the requirements in the PUCT rules are more restrictive than ERCOT's requirements which could cause DERs to trip when ERCOT needs these to operate.

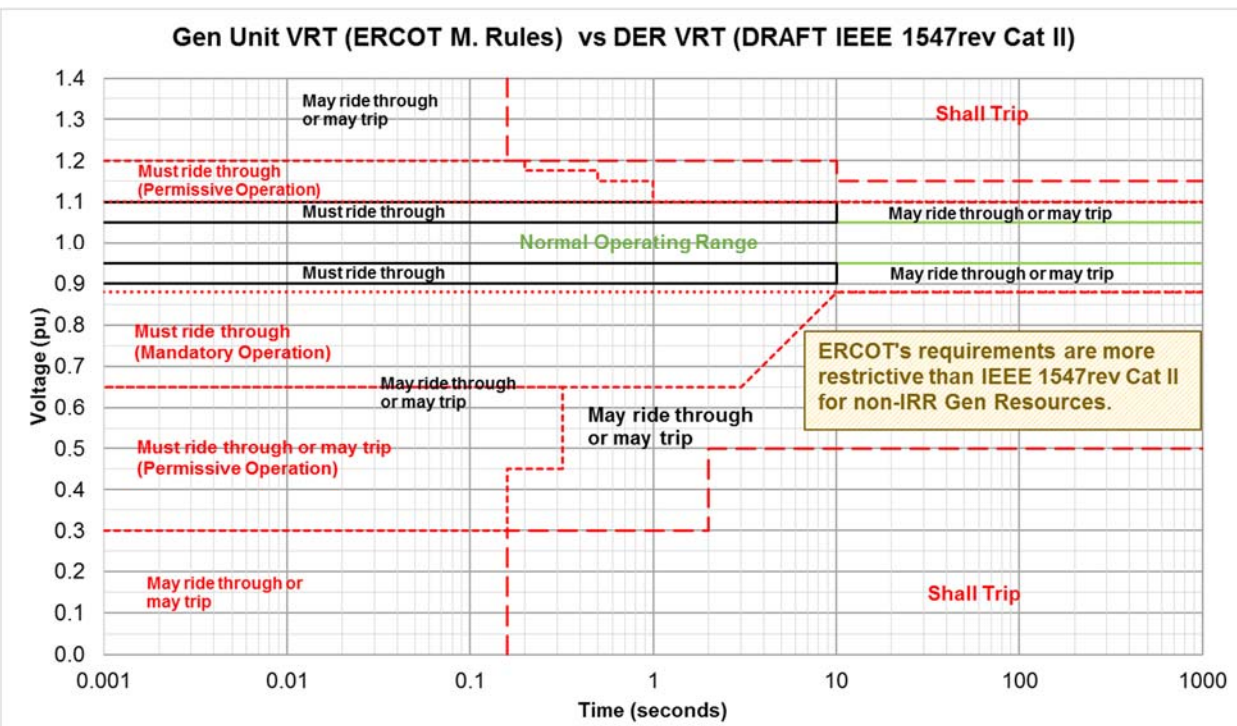
The following chart overlays the voltage requirements specified in PUC's Substantive Rule §25.212(c) (dashed red lines) with the voltage requirements for non-IRR Generation Resources in ERCOT's Operating Guide (solid green and black lines).



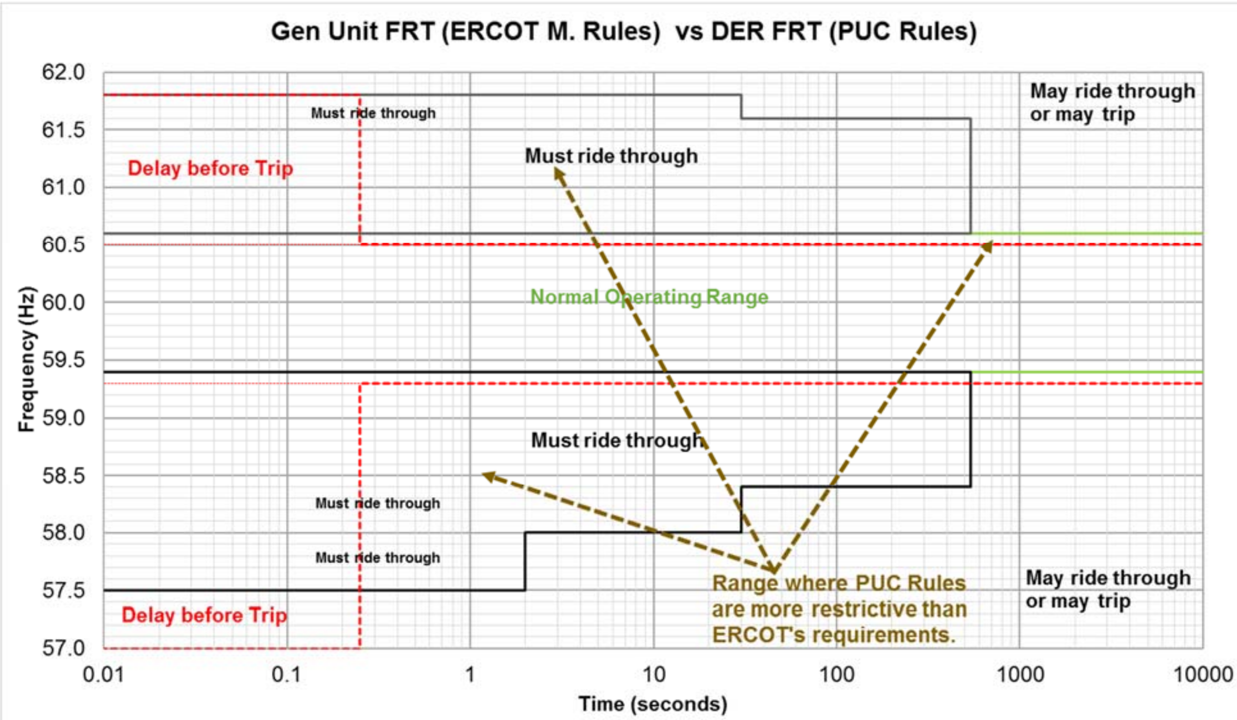
In this case, ERCOT's requirements are more restrictive than the PUC rules.

However, the proposed IEEE1547-2017 standard (as of the writing of this paper) includes ride-through provisions (dashed red lines) that better match the corresponding ERCOT's requirements (solid green & black lines).

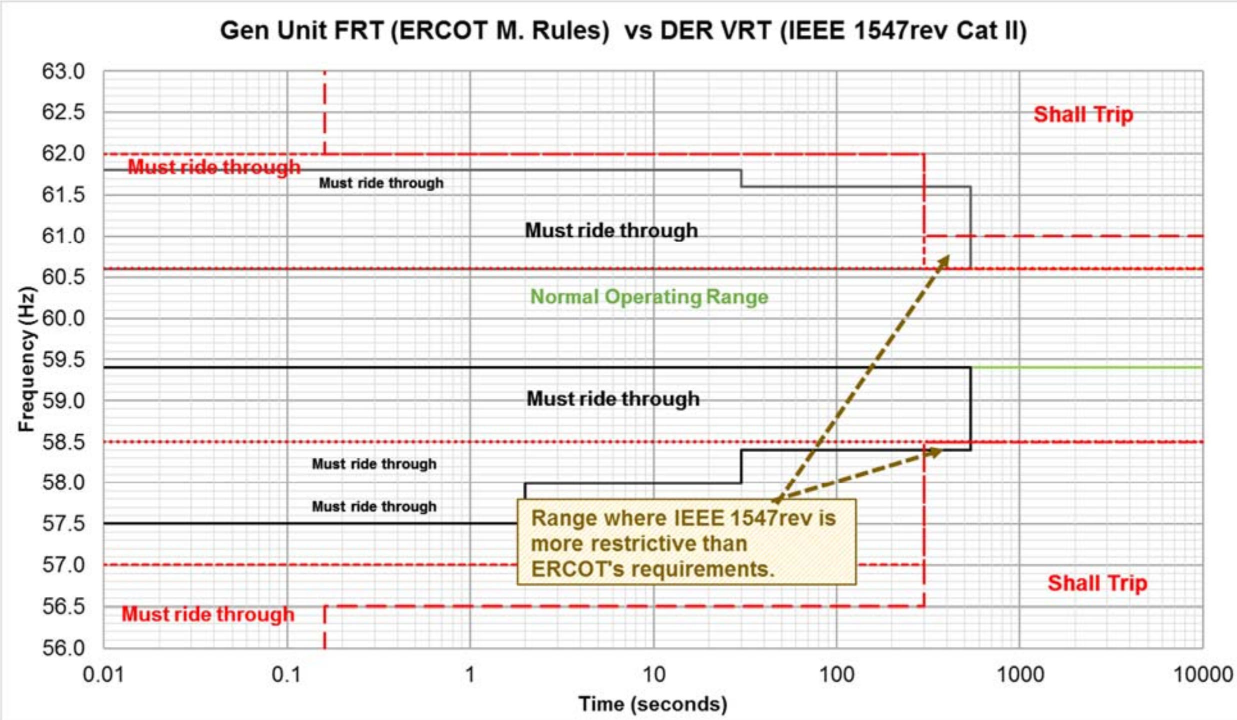




The following chart overlays the frequency requirements specified in PUC Rules (dashed red lines) with the frequency requirements for all Generation Resources in ERCOT's Operating Guide (solid green and black lines).



As this chart shows, there are a few ranges where the requirements in the PUC Rules are more restrictive than ERCOT's requirements which could cause DERs to trip when ERCOT needs these to operate. As of the writing of this paper, the proposed IEEE1547-2017 standard includes ride-through provisions that more closely match ERCOT's requirements compared to current requirements.


Gen Unit FRT (ERCOT M. Rules) vs DER VRT (IEEE 1547rev Cat II)
Frequency (Hz)
Time (seconds)
63.0
62.5
62.0
61.5
61.0
60.5
60.0
59.5
59.0
58.5
58.0
57.5
57.0
56.5
56.0
0.01
0.1
1
10
100
1000
10000
Shall Trip
Must ride through
Must ride through
Must ride through
Normal Operating Range
Must ride through
Must ride through
Must ride through
Range where IEEE 1547rev is more restrictive than ERCOT's requirements.
Shall Trip
Must ride through