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CIGRE US National Committee
2019 Grid of the Future Symposium

Application of IEEE Standard 1547-2018 Considering Impact of DERs on FIDVR

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SUMMARY

In February 2018, the IEEE standard 1547-2018 was approved and published. The standard establishes criteria and requirements for interconnection of Distributed Energy Resources (DERs) with Electric Power System (EPS). As penetration of DERs continues to grow, this revision of the standard developed interconnection requirements for DERs with a focus on reliability of the bulk power system or grid. The standard offers multiple ways to configure DER controls to avoid being a detriment to the grid. It is up to the Area EPS operators (or interconnecting utilities) to identify system characteristics and require DERs to implement various grid compatibility controls. This paper presents a case study made to evaluate various control options available in the IEEE standard 1547-2018 with focus on their impact on Fault Induced Delayed Voltage Recovery (FIDVR). These wide-area system studies are typically a responsibility of Transmission Planners, whereas, developing interconnection requirements for DERs belongs to Distribution Providers. As such, there needs to be a coordination between Transmission & Distribution organizations in developing interconnection requirements for DERs. The results of this case study are used to develop recommendations for consideration by Distribution organization as interconnection requirements for DERs are being developed.

KEYWORDS

Distributed Energy Resources, FIDVR, IEEE 1547-2018

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1.0 Introduction

The penetration of Photovoltaic (PV) inverter-based resources (IBRs) in the state of Georgia, USA, is increasing at a fast pace. Most of the existing and new installations are large utility scale transmission connected resources. These resources connect directly to the 115kV and 230kV transmission network. These large utility scale PV inverter-based resources are not considered Distributed Energy Resources (DERs). A resource which is directly connected to the Distribution Network is considered a DER. This could be further classified into Utility Scale DER (U-DER) and Retail Scale DER (R-DER). U-DERs are typically a three-phase interconnection mostly ranging from 0.5 to 10 MW in capacity with some exceptions. Currently, the penetration of U-DERs onto Georgia's electric grid is approximately 200-250 MWs. In the near future, it is estimated that the penetration of U-DERs could grow to as much as 500 MWs or more. R-DERs typically are represented by residential and commercial rooftop solar installations. Currently, the penetration of R-DERs in Georgia is minimal.

Till now, the penetration of DERs was minimal, i.e., their behaviour during grid disturbances was not significant enough to negatively impact system reliability. The legacy IEEE standard 1547 required DERs to trip offline for major grid disturbances. As penetration of DERs continues to grow, it is important to understand the impact of their behaviour during various grid events. Additionally, for systems with large penetration of DERs, their performance must be optimized in order to not degrade grid reliability during large system disturbances. The latest IEEE standard 1547-2018 offers multiple ways to configure DER controls for specific operation during various disturbances. The interconnecting utility, generally referred as the Area EPS operator in the standard, could require DERs to be configured in grid support mode to avoid degrading system reliability.

With the publication of the latest IEEE standard 1547-2018 [1], the Distribution Department of various operating companies in the Southern Company umbrella are revising interconnection requirements for U-DERs. In general, personnel associated with distribution system do not study various types of grid disturbances, which is usually a responsibility of the Transmission Planner and/or the Planning Coordinator in the area. As DER penetration increases proper consideration of DERs operation becomes necessary to maintain stability of the system, a proper coordination between Transmission and Distribution is necessary while developing interconnection requirements for U-DERs. This paper presents such a coordination effort at Southern Company. The metro-Atlanta and surrounding area in North Georgia is a FIDVR (Fault Induced Delayed Voltage Recovery) prone zone. This paper presents a study focused on FIDVR with a high penetration case of DERs. The study results are used to develop recommendations for consideration by the Distribution Department as interconnection requirements for U-DERs are being developed. If U-DERs are configured based on these recommendations, then they are expected to provide dynamic reactive support to the system during FIDVR type events. The paper also includes initial concerns of the Distribution Department to these recommendations. The discussion between Transmission and Distribution organizations is ongoing at the time of writing of this paper. The paper also sheds some light on R-DERs and their impact on FIDVR events.

2.0 Fault Induced Delayed Voltage Recovery (FIDVR)

The FIDVR is a phenomenon where the system voltage remains at significantly reduced levels for several seconds after a transmission, sub-transmission or distribution fault is cleared [2]. Small induction motors tend to slow down or stall and consume more reactive power during a fault due to low voltage. Even though the fault is cleared quickly, in the order of a few cycles, the increased reactive demand results in prolonged voltage depression on the transmission network. Factors resulting in slow voltage recovery includes duration, type and location of a fault, availability (or lack) of dynamic reactive support on the system and presence of induction motor load on the system. The metro-Atlanta and surrounding area in North Georgia is a FIDVR prone zone. The primary source of dynamic reactive power support in this part of the system is the transmission connected synchronous generation located in North Georgia. A significant penetration level of DERs could have the effect of displacing these currently available sources of dynamic reactive power in this part of the system. The large percentage of summer weather demand/load in this area is due to small residential/commercial air-conditioners. On July 30th in 1999, this area experienced a multi-fault event during which the transmission system experienced delayed voltage recovery which lasted approximately 15 seconds [3]. Based on the analyses of this event, 50% of total real power load during summer peak is assumed as small induction motor load. The load in power flow cases used for various system studies is presented at transmission buses, i.e., distribution system (transformer and feeders) are not explicitly modelled in power flow cases. To account for impedance offered by the distribution system, the load is represented behind a fictitious impedance equal to 0.01 + j0.10 per unit at load MW base in FIDVR studies. The small induction motor load uses the "CLOD" model. The distribution system impedance is modelled as a branch impedance in the "CLOD" model.

Southern Company Transmission's voltage recovery criteria for FIDVR events is noted below:

- For a normally cleared fault, all transmission buses should recover to above 80% nominal voltage within 2 seconds of the initial fault.
- For a three-phase fault followed by breaker failure, all transmission buses should recover to above 80% nominal voltage within 4 seconds of the initial fault.

3.0 Modelling of DERs

Usually, the Transmission Planning power flow model does not include details of the distribution network. The load served by the distribution network is typically modelled on high side bus in the Transmission Planning power flow model. If the penetration of DERs is minimal, one could account for it by netting the DER with the load itself or by modelling the DER directly on the high side bus. As the penetration of DERs increase, it is necessary to understand their behaviour and impact to various grid disturbances, which requires accounting for distribution network impedance for DER modelling in Transmission Planning power flow models. As noted earlier, DERs are usually categorized as U-DERs and R-DERs. In this study, future U-DERs are modelled with 5 MW capacity. However, the U-DER capacity could range anywhere from 0.5 MW to 10MW with some exceptions. An example of U-DER modelling is shown in Figure 1. The load is moved from the high side bus to the low side bus. The nominal voltage rating of the low side bus is assumed to be 20kV. A load serving distribution transformer is added with a 6.5% impedance on the Load MW base. The load is represented with 3.5% impedance on the Load MW base, resulting in total of 10% impedance from the high side bus. This matches with the distribution network impedance noted in section 2 used with the "CLOD" model, where load is connected to the high side bus. The generator step-up transformer (20kV/480V) is modelled with an impedance of 10% on 5 MVA base. The U-DER itself then is connected to the 480V bus. This set up assumes that the U-DER is connected close to the load serving substation. It could be located further down the feeder, in which case, a 20kV feeder with some impedance could be modelled to reflect it correctly. But given that the step-up transformer impedance is large enough, the feeder impedance could be ignored. Although not accurate, the model in Figure 1 is preferred compared to modelling U-DERs on the high side bus itself. It is important to note that DERs are usually small in size and scattered around the system, modelling of each in the Transmission Planning power flow model with great accuracy is very impractical. As such, when it comes to U-DER modelling, some approximation is necessary and appropriate.

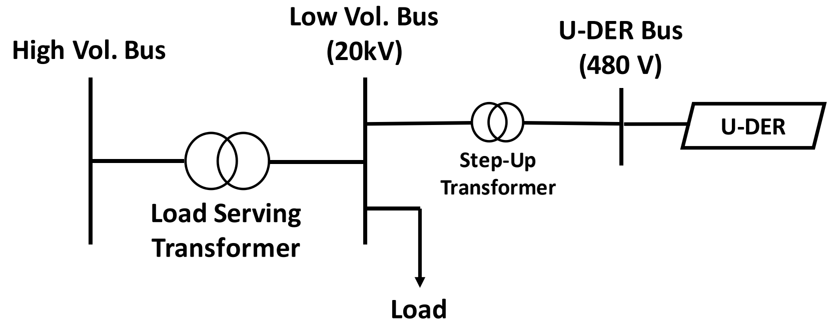

Figure 1: Modelling of U-DERs

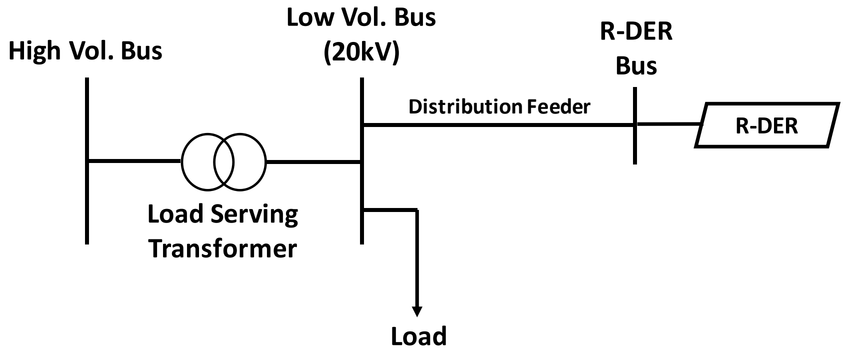

Figure 2: Modelling of R-DERs

Figure 2 shows an example of R-DER modelling. These types of resources are typically located at commercial and residential customer sites. Just like with modelling of the U-DER, the load serving distribution transformer is modelled with 6.5% impedance on the Load MW base, and the load is moved from high side bus to the low side bus. The load is represented with 3.5% impedance on the Load MW base, resulting in total of 10% impedance from the high side bus. The distribution feeder is added with 3.5% impedance on the Load MW base, resulting in a total impedance of 10% from the high side bus. The R-DER is then added to the end of the distribution feeder. Contrary to U-DERs, R-DERs are modelled at the end of an equivalent distribution feeder.

4.0 Study Assumptions

The purpose of this study is to understand impacts of increased penetration of DERs to North Georgia FIDVR. With this intent, approximately 1500 MW of U-DERs are added to the Transmission Planning power flow model, scattered around the system except for in the metro-Atlanta area. The metro-Atlanta area is very congested, and there is a lack of real-estate for utility scale DERs. For the purpose of this study, forecasted U-DERs are added to buses where system load was neither too small nor too large, assuming this implies there is availability of real-estate for utility scale DERs. Approximately 600 MW of U-DERs are modelled in North Georgia (north of line connecting cities of Columbus, Macon and Augusta) outside of the metro-Atlanta area. Per experience with past studies, synchronous generators connected to 115kV and 230kV system in North Georgia provide the most dynamic reactive support needed to mitigate FIDVR type events. As such, the objective of this study is to understand the impact of 600 MW of U-DERs located in North Georgia on FIDVR events. The remaining 900 MW of U-DERs are modelled in South Georgia (south of line connecting cities of Columbus, Macon and Augusta). Even when configured to provide dynamic voltage support, they are not expected to aid with FIDVR events in North Georgia due to their distance from the metro-Atlanta area.

For obvious reasons, the metro-Atlanta area is the prime location for residential and commercial rooftop solar installations or R-DERs. Currently, the penetration level of residential and commercial rooftop solar is still relatively low. For this study, approximately 750 MW of R-DERs in the metro-Atlanta area are modelled in the Transmission Planning power flow model.

Based on experience with the system, dynamic simulations are run for a normally-cleared three-phase fault on a 500kV transmission line, which is considered as a worst normally-cleared contingency in North Georgia from FIDVR perspective. The second order generic models (REGC_A and REEC_A) for wind and photovoltaic generation are used to represent DERs in dynamic simulations. At the time of this study, the PSSe version in use did not support the DER_A model, which is likely preferred over the use of second order generic models.

The objective of the study is to focus on configuring DER controls based on IEEE standard 1547-2018, such that their impact to voltage recovery during a FIDVR event is not worse than the current system performance. As such, various penetration of DERs is not considered.

5.0 Application of IEEE Standard 1547-2018 for U-DERs

The objective of this study is to evaluate the impact of DERs on FIDVR events. As such, only the performance requirements for abnormal voltage response, as outlined in the IEEE standard 1547-2018, are considered. The study evaluated the impact of voltage disturbance ride-through, mandatory voltage tripping, and dynamic voltage support requirements.

<u>Voltage Disturbance Ride-Through Categories</u>

The IEEE standard 1547-2018 offers three different abnormal operating performance Categories, I, II and III. Per this standard, DERs are required to meet performance requirements of either of these Categories, and the interconnecting utility or the Area EPS operator is responsible for specifying which one of these Categories DERs must meet. The requirements of the voltage ride-through Category I provides minimal support to the transmission system during grid disturbances. The Category II performance requirements most closely align with the existing NERC reliability standard PRC-024-2. The Category III requirements are based on the California rule 21 and provides with the highest grid disturbance ride-through capabilities.

This study is focused on evaluating Categories I and II only, as the need for category III does not seem necessary at this time based on current experience. Refer to Figures H.7 and H.8 in the IEEE standard 1547-2018 for Category I and II ride-through performance requirements respectively. Both Categories offer the Continuous Operation region, Mandatory Operation region and Permissive Operation region. For both Categories, the region with voltage ≥ 88% and ≤ 110% is defined as the Continuous Operation region with no bounds on the time scale. The DER is required to stay connected and continue to exchange current with the Area EPS in this region. However, this study focuses on the Mandatory Operation region as the objective is to understand impact of DERs during FIDVR events. For Category I, the region with voltage ≥ 70% and < 88% falls in the Mandatory Operation region, but on a time scale the region is limited by a linear slope of 0.25 per unit voltage/second starting at 0.7 second for 70% voltage, i.e. a line from 0.7 second at 70% voltage to 1.42 second at 88% voltage. In the Mandatory Operation region, DERs are required to continue to exchange active and reactive current with the Area EPS. The Category I Mandatory Operation region does not fully encompass Southern Company Transmission's voltage recovery criteria noted in section 2. The Southern Company Transmission network is planned to recover voltage above 80% in either 2 seconds or 4 seconds depending on the type of contingency. If DERs are equipped with Category I ride-through capability, they would cease exchanging current with the grid before the voltage has recovered to above 80% during a FIDVR event. This DER characteristic could negatively impact the voltage recovery trajectory of the grid.

The category II Mandatory Operation region is both deeper on a voltage scale and wider on a time scale compared to Category I's Mandatory Operation region. The voltage down to 65% is covered in the Mandatory Operation region. On a time scale, the region is limited by a linear slope of 0.115 per unit voltage/second starting at 3.0 second for 65% voltage, i.e. a line from 3.0 second at 65% voltage to 5.0 second at 88% voltage. This Mandatory Operation region coordinates well with Southern Company Transmission's voltage recovery criteria. If DERs are equipped with the Category II ride-through capability, then it would continue to exchange active and reactive current with the grid during a FIDVR event.

In summary, the Category II ride-through capability offers grid support for a longer time compared to Category I ride-through capability, especially considering FIDVR events.

<u>Mandatory Voltage Tripping Requirements</u>

The IEEE standard 1547-2018 requires DERs to enter "cease to energize" mode when voltage is below or above specified undervoltage and overvoltage thresholds respectively. The standard defines two thresholds, including default setting and allowable range, for both undervoltage and overvoltage condition for each abnormal performance operating Categories. As the objective is to understand impact to FIDVR events, the focus here is on undervoltage trip settings. The undervoltage trip settings are referred as UV1 and UV2. The default UV1 setting for Category II ride-through capability is 0.70 per unit voltage with a clearing time of 10 seconds. The range of allowable setting for voltage is 0.0 to 0.88 per unit with a clearing time ranging from 2.0 to 21.0 seconds. To coordinate with the Southern Company Transmission's voltage recovery criteria, it is important that UV1 pickup is set to 0.8 per unit or less with a clearing time of 4.0 seconds or longer. The default UV2 setting is 0.45 per unit voltage with a clearing time of 0.16 seconds (10 cycles). Most breaker failure contingencies on the transmission network clear in approximately 12-15 cycles. The breaker failure clearing time could be longer when it is not critical to system stability. To ensure that DERs stay connected to the system during breaker failure contingencies, it is important that UV2 clearing time is delayed to 0.32 seconds (20 cycles) or longer.

Dynamic Voltage Support

The IEEE standard 1547-2018 does not require DERs to have a dynamic voltage support capability. It simply recognizes that the DER may have capability to provide dynamic voltage support and if so, it could be enabled upon a mutual agreement with the Area EPS. It is up to the interconnecting utility to require DERs to have dynamic voltage support capability. U-DERs with the dynamic voltage support capability are expected to impact the voltage recovery during FIDVR events in a manner comparable to existing system performance. Figure 3 shows a voltage recovery plot with and without the dynamic voltage support from U-DERs. Note that U-DERs are modelled with Category II ride-through performance capability. The dynamic voltage support is emulated by modelling U-DERs operating in a Q-priority mode, i.e., reduce active current and increase reactive current when the voltage falls out of the Continuous Operation region and the inverter is operating at its rated current limit. For the opposite case (U-DERs with no dynamic voltage support capability), U-DERs are modelled to operate in a P-priority mode, i.e., continue to inject active current with a constant power factor, regardless of voltage magnitude. In both cases, if the voltage is less than 65%, the U-DER enters momentary cessation mode, i.e., U-DERs are providing dynamic voltage support only when the voltage is in the Mandatory Operation region.

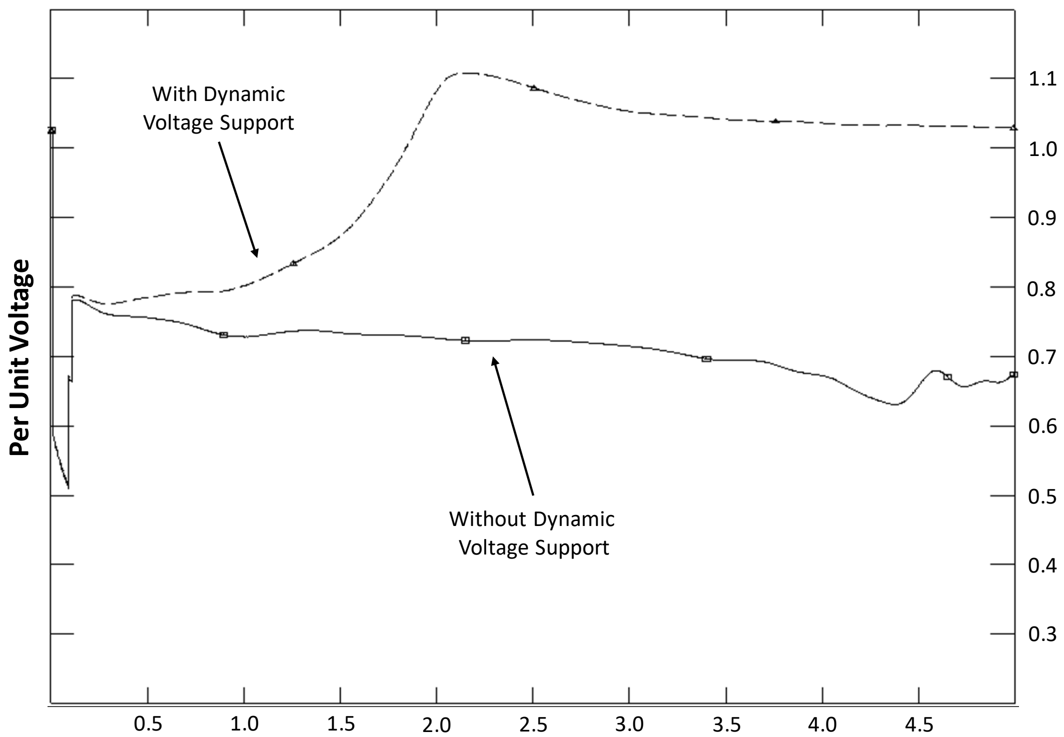

Figure 3: Voltage Recovery with and without dynamic voltage support

It is evident that there is a significant improvement in the voltage recovery when U-DERs are modelled to provide dynamic voltage support as compared to not providing this support. It is also important to note that this improvement can only be attributed to the 600MW of U-DERs modelled in North Georgia. It is estimated that the improvement provided by U-DER's dynamic voltage support capability to voltage recovery is comparable to one achieved by adding an approximately 400 MVar capacity Static Var Compensation (SVC) system. However, it is important to note that the IEEE standard 1547-2018 does not define the performance of DER dynamic voltage support capability. Various manufacturers may implement this capability differently from that envisioned in this study. Hence, the actual support for voltage recovery is expected to vary.

Current Injection in the Permissive Operation region

The Permissive Operation region of the Category II ride-through capability for undervoltage condition covers the following:

- Voltage ≥ 45% and < 65% with minimum ride-through time of 0.32 second
- Voltage ≥ 30% and < 45% with minimum ride-through time of 0.32 second

Per the IEEE 1547-2018 standard, when the voltage is within the Permissive Operation region, the DER shall not trip or shall maintain synchronism with the Area EPS. However, the standard allows that the DER may continue to exchange current with the Area EPS or may cease to energize. In the cease to energize state, the DER is not allowed to deliver active power, and is required to limit exchange of reactive power with the Area EPS. The limit on the reactive power exchange is low enough where it could be ignored while studying grid disturbances. It is up to the interconnecting utility to decide if DERs should continue to exchange current or cease to energize when the voltage is in the Permissive Operation region. In addition, the IEEE standard 1547-2018 allows DER to provide dynamic voltage support in the Permissive Operation region with a mutual agreement with the Area EPS operator. Figure 4 shows the comparison of the voltage recovery with and without current exchange between U-DERs and the Area EPS when the voltage is in the Permissive Operation region. It is assumed that U-DERs are configured to provide dynamic voltage support in this region. It is estimated that the improvement in voltage recovery shown in Figure 4 is comparable to one achieved by adding an approximately 200 MVar capacity SVC system.

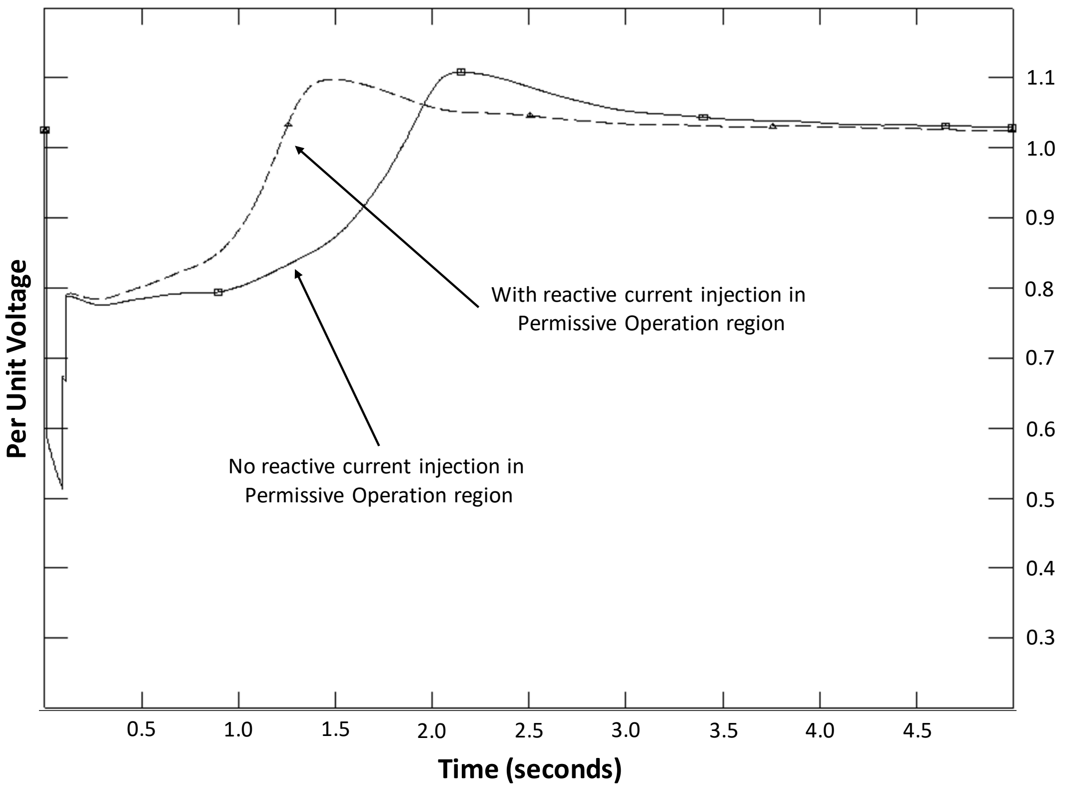

Figure 4: Voltage Recovery with and without current exchange in Permissive Operation region

Coordination Between Transmission & Distribution

Distribution Providers are responsible for developing interconnection requirements for U-DERs. Based on above analysis, Transmission Planning (TP) provided a set of recommendations for consideration by Distribution to be included in interconnection requirements for U-DERs. The conversation between two departments is ongoing currently. Following summarizes these recommendations and Distribution's initial response/concerns.

1. Abnormal Voltage Ride-Through Performance
   TP's Recommendation: Require U-DERs to provide category II voltage ride-through performance requirements for abnormal voltage condition.
   Distribution's Opinion – No concerns and likely to include in interconnection requirements.

2. Mandatory Voltage Tripping Requirements
   TP's Recommendation: Set UV1 to 0.8 per unit or less with a clearing time of 4 seconds or longer. Set UV2 clearing time to 0.32 seconds or longer.
   Distribution's Opinion – No concerns with UV1 voltage pickup and UV2 clearing time settings recommendation, however, not comfortable with a 4.0 second clearing time for UV1 due to concerns with possibility of a long duration fault on the distribution network. Preferred UV1 clearing time is 2.0 seconds.

3. Dynamic Voltage Support
   TP's Recommendation: Require U-DERs to be capable of providing dynamic voltage support and enable this capability.
   Distribution's Opinion – No concerns with enabling the dynamic voltage support capability if the U-DER is already capable of providing it. However, there is a concern about the lack of a process to test and validate enforcement of this requirement.

4. Current Injection during Permissive Operation Region
   TP's Recommendation: Require U-DERs to continue to exchange current, preferably reactive, with the Area EPS when the voltage is in the permissive operation region.
   Distribution's Opinion – No concerns if U-DER is already equipped to do so.

6.0 Application of IEEE Standard 1547-2018 for R-DERs

The R-DERs represent small scale residential and commercial rooftop solar installations. As noted earlier, approximately 750MWof rooftop solar is modelled in metro-Atlanta and surrounding area for this study. Simulations were first run assuming that these resources are engineered based on legacy IEEE 1547 standard, and then again assuming Category I ride-through performance requirements of the 2018 version of this standard. When configured per the legacy IEEE 1547 standard, as much as 50% of R-DERs trip during a normally-cleared three-phase fault. However, with the application of the Category I ride-through performance requirements per the 2018 revision, none of the R-DERs trip for a normally-cleared three-phase fault. Due the fact that these resources represent small scale residential and commercial rooftop installations, there may be a very little control over how they are configured. For conservatism, these resources are modelled to operate in P-priority and constant power factor mode with default mandatory trip settings for abnormal voltage based on Category I abnormal operating performance requirements. If configured in this manner, R-DERs are not expected to support voltage recovery during a FIDVR event. For now, the penetration of R-DERs remains very low, and is not expected to rise significantly in a near future.

7.0 Summary

This paper presents a case study to evaluate the impact of DERs to FIDVR type events. The study results show that DERs could provide a meaningful grid support during FIDVR events if configured properly. The study results are used to develop recommendations for Distribution's consideration while interconnection requirements for DERs are being developed to align with revised IEEE standard 1547-2018. These recommendations become increasingly important to maintaining the current level of grid reliability as higher penetration levels of DER are added to the system. As noted in the paper, Distribution personnel are concerned with some of these recommendations and discussions are still ongoing. It is possible that there are many different distribution providers of varying size over a large geographical area. If so, it is important that all distribution providers agree to these recommendations and consistently apply to all DERs within their jurisdiction.

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