Balancing DER Ride-Through Requirements and System Protection: A Utility Perspective

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Abstract— **Duke Energy is in the process of evaluating the impacts of adopting IEEE Std. 1547-2018 on its electric system. This paper will be focused on ride-through requirements of IEEE Std. 1547-2018 and its impacts on distribution system protection for utility-scale Distributed Energy Resource (DERs) sites. Various aspects of choosing DER voltage and frequency protection settings, including coordination with Under-Frequency Load Shedding schemes and various zones of transmission and distribution protection, will be discussed in the paper. In addition, the performance of a sophisticated voltage-based scheme was evaluated through Hardware-in-the-Loop (HIL) testing to identify local transmission faults from the DER's utility protective device, in an effort to remove all sources from the faulted zone. The objective was to achieve ride-through for all out-of-zone faults, allowing the DERs to fully support the system to the maximum extent possible, while also providing adequate system protection.**

This paper details the control HIL validation process that included relays for multiple DER sites and modeling of the distribution and transmission systems. The testing provided sufficient data that was used to allow Duke Energy to make informed decisions on balancing the ride-through requirements with system protection.

1. Introduction

With the proliferation of Distributed Energy Resource (DERs), it is important to ensure that these generators will not adversely impact the reliability of the electric system during temporary and permanent grid disturbances. In particular, the ride-through settings of DERs should be well coordinated with system protection. The goal of this study was to holistically evaluate how any modifications to the utility's large DER protection settings in adopting IEEE 1547-2018 will impact distribution and transmission systems. To this end. the process involved gathering requirements from multiple business units in Distribution Department as well as technical inputs from Transmission system planners.

One challenge that was identified early during the study is that DERs can contribution to faults on the local transmission line that feeds a transmission tapped substation. When this occurs through a Delta-Wye grounded (Yg) power transformer the DERs can potentially cause excessive transient overvoltage (TOV) conditions after the fault is cleared on Transmission system, especially for a single line to ground fault scenario. The TOV condition may damage the surge arresters and other power equipment insultations, rated for phase-to-ground voltage. A voltage-based scheme was proposed and evaluated to identify the in-zone transmission faults (especially single line to ground fault) from the DER's utility protective device such that the DER sources can be removed as fast as possible from the distribution feeders.

2. System Topology

Historically transmission system design practices were for substations that had one-way power flow and there was no need for complicated protection schemes on many of these assets. Due to this, for decades many substations were constructed as taps along the main transmission line with a high-side disconnect and no metering and protection devices. These tapped substations introduce a unique dilemma for DERs and protection systems, especially where the substations does not have a high-side breaker on the transformer or no high-side voltage and frequency protection relays are installed. Also, communication-assisted protection or Direct Transfer Trips (DTT) schemes can be challenging and costly to retrofit into these substations. The existence of DERs on the distribution system in low load conditions can cause the power to flow into the transmission system. In such scenarios, a Transmission single line-to-ground fault on the delta-connected line can cause an excessive TOV condition on the transmission side of the substation transformer after the line breakers clear the fault due to the loss of effective grounding. The transmission line remote terminals are expected to trip for faults along the line, such as F4 shown in Figure 1. However, under this condition, the fault is not completely isolated and the DERs in the distribution network can still contribute to the fault and cause equipment damages and safety concerns on the transformer high side.

It is not a foregone conclusion that the DER will remove itself from the fault in a timely manner given the abnormal condition response requirements of IEEE 1547 [1]. For inverter-based DERs (IBR-DERs), we assume that the inverter will enter into momentarily cessation state and stop its current output or trip on other protective functions. The problem with this approach is that it goes against basic protection principles for fault isolation. A mechanical type of isolation during a fault, like a circuit breaker or disconnect switch is required for operational awareness and safety. Power electronic isolations (e.g., momentary cessation) are very foreign and unreliable from a system operations perspective since the inverter may start to gate the power electronics without the area electric power system (EPS) operator knowing it is capable of operating.

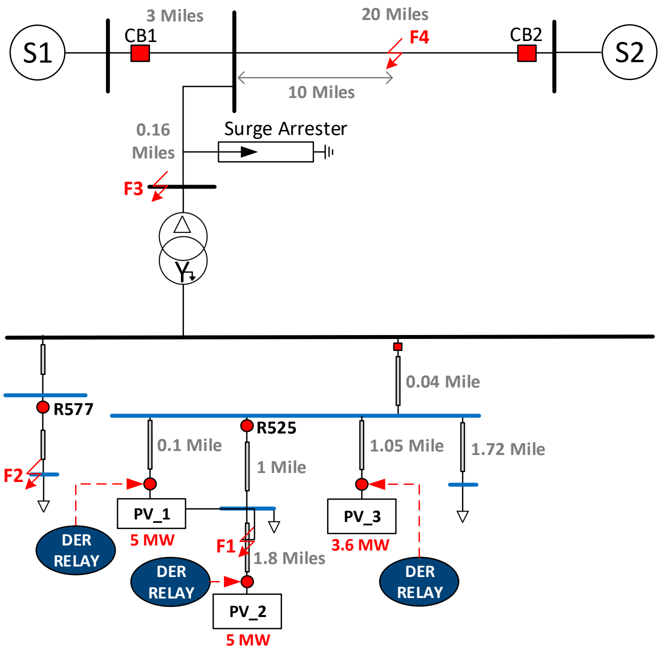

Figure 1: Substation System Topology

3. Transient Overvoltages

Most of the utility sub-transmission and distribution systems were designed without the consideration of DER connection on the distribution feeders. The addition of DERs in the distribution system caused a weak-infeed for the transmissions lines for which the fault cannot be completely cleared without proper communication among the protection relays at each line terminal. For the example system shown in Figure 1, there is no protective relay at the transmission tap or transformer high-side circuit breaker to isolate the fault. Therefore, whenever there is a fault on the line and the line breakers (i.e., CB1 and CB2) open to clear the line, the tap will remain connected. When there are DERs connected to the distribution system, the DER fault current contribution to the line fault will continue untill the DERs' protection relays/functions detect the abnormal event and trip. Due to the Delta connection of substation power transformer, the DER contribution can potentially induce high transient ground fault overvoltage (GFTOV) for unsymmetrical faults, which may damage the power equipment if not properly mitigated. The magnitude and duration of the transient overvoltage (TOV) depends on many factors including load to generation ratio of the transmission line segment, zero-sequence impedance paths left in the system, DER capabilities, DER trip time, etc.

Figure 1 can help illustrate the root cause of the TOV in detail. For a permanent single-phase-to-ground fault at F4, the line protection relays (either line differential or distance protection at CB1 and CB2) will operate in around three cycles. This operation results in opening the CBs and clearing the fault in less than 6 cycles. However, due to the contribution of DERs or IBR-DERs from the distribution side toward the fault at F4 (note that the fault at F4 is not cleared or isolated from the high-voltage (HV) side of the transformer), the phase-to-ground voltages on the healthy phase may increase significantly. It may damage the surge arresters and other power equipment insultations, rated for phase-to-ground voltage, mainly because the HV side of the substation transformer will lose the system's effective grounding path after the transmission line circuit breakers opening/tripping. Figures 2&3 show the voltage waveform on the HV side when CB1 and CB2 open in response to a fault at F4 using PSCAD and RTDS simulation respectively. After the islanding of the distribution system from transmission, the HV side of the substation transformer may reach values greater than 2 pu of phase-to-ground voltage, depending on the voltage magnitudes on the distribution side. The reason for the higher than theoretical phase-ground voltage observed is because the load to generation ratio may allow the DERs to increase the voltage level to more than 1pu at the distribution system after system island. Compounding the issue voltage control equipment on the EPS to operate to maintain the voltage with the ANSI nominal service voltage range [4], this could cause the voltage to be boosted during islanded conditions. If the DERs or DER-IBRs in the distribution system trip before the transmission relays trip the line breakers (island formation), high TOV levels on the HV side of the transformer will be avoided.

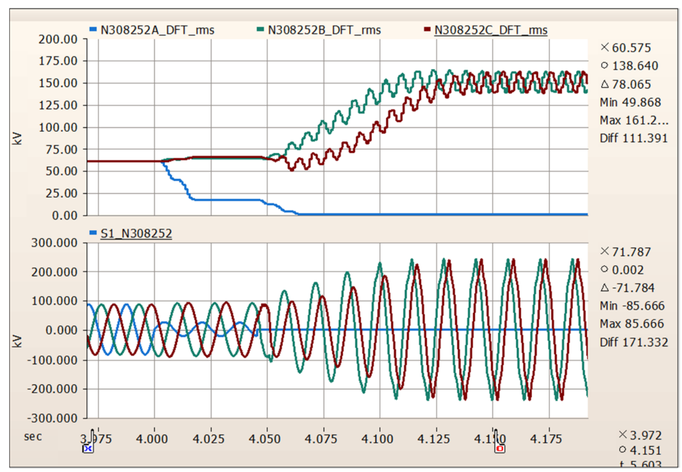

Figure 2 : Transient Overvoltage Caused by SLG Fault on the Transmission Line

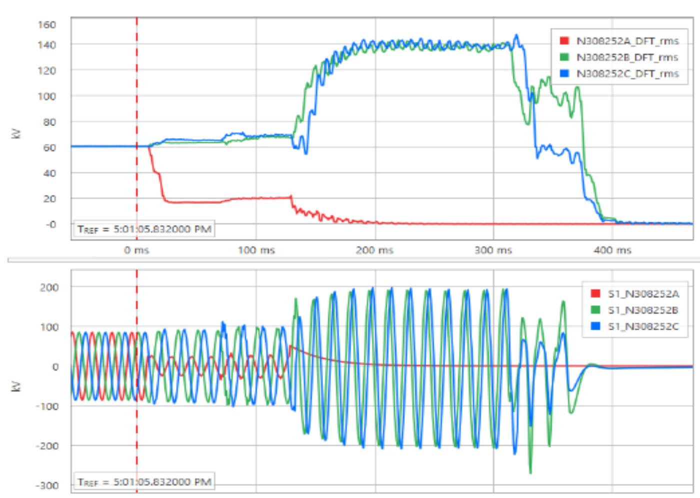

Figure 3 : Transient Overvoltage Caused by SLG Fault on the Transmission Line (RTDS Simulation)

Utilities have long been taking measures to mitigate this issue. Installing a potential transformer on the HV side of the transformer to implement overvoltage protection, such as 59G, can be used to trip the transformer's low-voltage CB or using the distance protection relay with a residual voltage compensation can resolve this issue [1]. However, these two methods require the high-side open-delta Potential Transformer (PT) to obtain the zero-sequence voltage. This may not be possible due to space or installation constraints. Several utilities also require DERs—particularly large-scale inverter-based DERsto be equipped with DTT. In order for the transfer trip scheme to help protect against transmission line GFTOV the transmission remote terminals must be included in the scheme. However, these solutions may be unavailable or costly to implement and maintain.

4. Voltage Protection Scheme

A. Passive Voltage Protection Scheme

Passive voltage protection schemes consist of basic phase over (59P) or under (27P) voltage elements. These schemes will react to voltage excursions experienced on the grid. For most DERs, these voltage deviations are generated from the interconnecting system. These excursions may emanate from various expected system dynamics and/or unexpected contingencies. System actions such as closing switches may create an expected voltage effect. Lightning strikes are unexpected contingencies that will result in a voltage reduction.

A major benefit of this scheme is that it can be easily implemented to detect faults in the distribution system. Based on the law of physics for a synchronous generation-based system, we know that at the location of a pure (no fault resistance) single-phase to ground fault there will be a drastic reduction in voltage along the faulted phase. This voltage reduction will reduce as we move away from the fault and closer to the synchronous generation along the transmission system.

For a DER these voltage propagations are a function of the interconnecting system. Voltage is a system characteristic that can have wide area impacts in terms of a protection scheme. Thus, when a voltage excursion occurs it typically propagates throughout the entire system. This is especially true for an inverter-based DER, operating with a unity power factor control system since it will not output any reactive current during the voltage abnormality. This predictable behavior allows us to utilize voltage elements with a high degree of reliability for fault detection.

The major disadvantage of this scheme is the lack of security for fault detection. These elements are inadequate for determining if a fault is within the primary zone of protection or outside the zone of protection. This is especially true in a distribution system where zones of protection vary widely and may be extremely small in length. This is mainly due to the high levels of diversity with line switches and various other protection systems that are installed along the distribution feeder. The result is that this element may be susceptible to misoperations for faults within the distribution or transmission system.

IEEE 1547 is a widely used interconnection standard that advocates for the implementation of passive voltage-based protection for fault detection on the distribution or transmission system. In the past, the standard preferred for DERs to be removed from the interconnecting system very quickly during abnormalities. For this type of scheme, the philosophy led to DERs tripping for faults far beyond the zone of protection; deep into the transmission system. However, as DER penetration increased the industry began to recognize this practice may not be idea for future system stability. In 2018 the industry codified this in the IEEE 1547 standard revision that introduced a paradigm shift to our industry. The standard now requires this protection scheme to provide ride-through performance.

There is always a balancing act for dependability and security when protection schemes are developed or designed. Depending on the situation, you may bias the scheme in one of these areas but not too much to ensure that the protection is reliable. Historically, this is achieved by simplifying the expectations of the scheme and not requiring it to do too much from a performance perspective. Most protection schemes are supervised by some variable (e.g. harmonics, directionality, etc.) that inherently increases the security and performance of the scheme. Passively voltage-based schemes do not have this luxury to improve their performance. This severely limits their expected performance capability. Asking a voltage-based scheme to provide secure fault detection and isolation, as well as ride-through may be a bridge too far.

The 1547 standard does not require that the DER itself provide ride-through performance. A severe flaw in the expected performance of the resource. Essentially, the resource can take itself off-line and provide no support to the system for functions not defined in the standard. As in industry, we have seen this movie before in the form of PRC-024[3]. Transmission connected inverters are constantly tripping for system level faults when they should have ridden through and provided the system with support. Gaps in PRC-024, such as Phase Lock Loop (PLL), momentary cessation, and negative sequence injection, have been widely discussed throughout the industry and may lead to a revision.

There also appears to be some confusion within the industry regarding the understanding of ride-through and system support from a stability perspective. The underlying foundation of system support is that when a voltage or frequency excursion occurs on the system, each generation resource is expected to increase its real or reactive current output to maintain system stability. If the expectation is for the DERs to stop gating their power electronics circuits (momentary cessate) during system abnormalities, then start gating within a few cycles after the system has recovered then these resources will not provide system stability support during the forcing function that creates stress on the system. We would be relying on the transmission system connected synchronous generation to maintain stability and reestablish equilibrium on the system. This equilibrium is the voltage recovery the inverter based DERs are relying on to actually perform an action. This means that these resources may essentially not do anything until the transmission system has corrected the stability issue.

B. Voltage Based Signature Schemes

Duke Energy has investigated the implementation of sophisticated voltage schemes that use a combination of voltage elements to detect fault signature. These fault signatures are represented by the voltage magnitudes a DER relay may see during certain types of faults. These voltage signatures are driven by the transmission system connected generation. Hence, they require the DER to be connected to the transmission connected generation, through the transmission system, for the scheme to reliably identify the fault. If the transmission breakers operate to isolate the fault and the DERs continue to inject current into the islanded system, the voltage scheme does not detect the signature due to the Delta winding in the substation transformer. Figure 4 shows logic for detecting the Transmission single line to ground faults (T-FAULT) at the DER location. A two-phase undervoltage element and a third-phase OV element capture the voltage as reflected through the Delta-Wye grounded substation transformer, which arms the scheme that triggers the pickup timer. However, to help mitigate mis-operations the following elements should be evaluated to help secure the scheme:

- Zero-sequence Over Voltage element (59N) which would only assert for Distribution ground faults
- Negative-sequence element (59Q) would assert for imbalance in the system, which could indicate a fault
- Distribution Line to Line Fault Logic

Once these conditions are met, the T-FAULT logic will pick up (T-FAULT_PU) and operate after pickup timer expires to trip the DER for a line to ground fault on the transmission side.

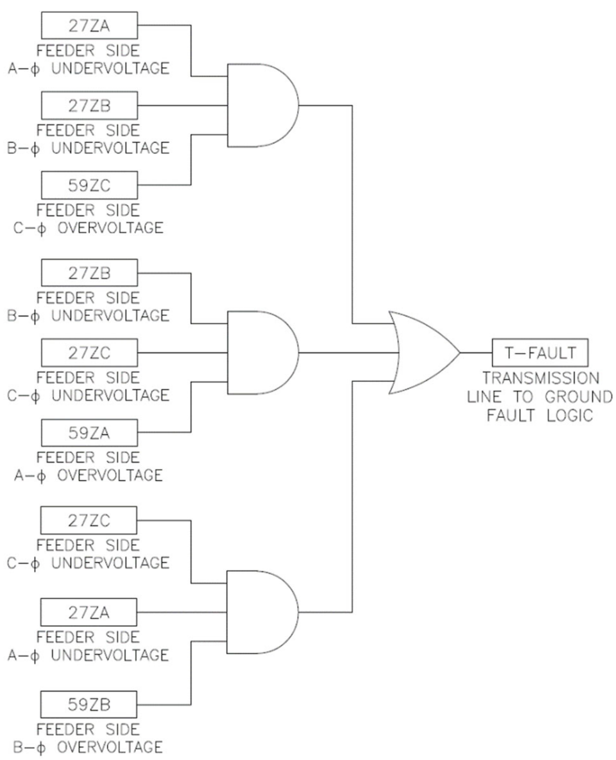

Figure 4 : Transmission Single Line to Ground Fault Logic

In order to implement a scheme like this the T-FAULT logic would need to operate for faults that are in the transmission zone that is connected to the substation tap. This could be accomplished by tuning the scheme to operate for voltage magnitudes that could be expected in this zone. However, this becomes increasing more difficult when there is asymmetry in the transmission lines that are connected to the substation tap, refer to Figure 1. In this scenario you must compromise between adequately protecting the transmission line or risk overreaching into an adjacent transmission, as shown in Figure 5.

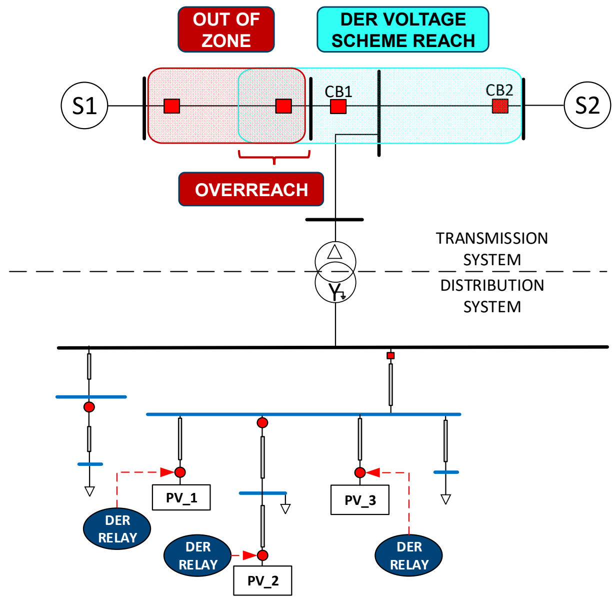

Figure 5 : Voltage Scheme Reach Issue

In this example the scheme cannot protect the line between CB1 and CB2 without overreach beyond CB1. While this may seem trivial on the surface if the distance between the substation tap and the further transmission breaker (terminal) is many tens of miles greater than the closer breaker this is a problem that may overreach into several zones of protection. Yet again this challenge of overreach would not be a problem but the T-FAULT scheme needs to detect the fault and trip the utility's protective device before the transmission breaker opens thus preventing this scheme from riding through an event out of zone. Although IEEE 1547 does not apply to the utility's protection and therefore ride through is not required for this example, refer to Figure 6. It is not good practice to implement a protection scheme that will miscoordinate without understanding the risk and which may degrade BPS reliability[5].

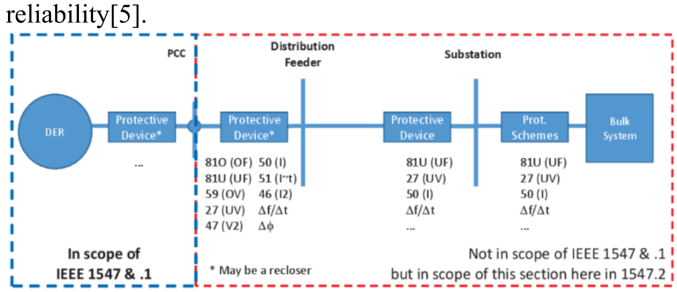

Figure 6 : Examples for distribution utility equipment that is not in scope of IEEE STD 1547-2018 but may impact BPS reliability (Source: IEEE1547.2/D6.5, Fig33) [6]

Another consideration when evaluating this approach is that the fault signatures are based on theoretical and textbook voltage relationships. The real-life power system is riddled with entropy and faults are not as “clean” as the theoretical examples may depict. In addition, the voltage magnitudes can also vary based on pre-fault conditions or dynamically during the event the transmission connected synchronous generation will react to system level faults by injecting more reactive current in an effort to boost system voltage. This dynamic action may impact the dependability of these type of schemes since it is difficult to predict system dynamics for every type of fault and fault location.

5. Frequency Protection Scheme

Frequency protection schemes have historically been used for abnormal system configurations such as full load rejection or unintentional islanding. For transmission connected generation resources, islanding operation is not as big of a concern. This is because we design the transmission system and generation with the expectation that they may be in temporary islands, and we want these resources to support the load within the island. Distribution connected resources are not expected to operate in an island condition. This is because as an industry we want transmission connected resources to maintain voltage and frequency stability; as well as provide adequate fault current. Hence, if we lose the transmission system, then we want to trip the DERs until the system can recover and re-establish equilibrium.

Typically, during distribution island operation. DER megawatt output does not match the load within the island. This leads to either a decay in system frequency (more load than generation) or an increase in system frequency (more generation than load).

In the past, IEEE 1547 preferred for DERs to be removed from the system expeditiously during frequency excursions. With the latest revision to IEEE 1547, DERs are required to stay connected and provide frequency ride through performance during frequency excursions. In theory, this should help system stability. However, this assertion requires some nuance. Traditionally, frequency support occurs in the form of primary frequency response and regional ACE. Synchronous generators that have headroom within their prime mover system are expected to increase their governor valve position and provide more mechanical input energy into the generator as a means of primary frequency response.

DERs within Duke Energy are required to operate with a unity power factor control system. This means that the resource is always outputting fault real current (megawatt) output. Essentially, as the interconnecting system voltage or frequency swings, the DER will continue to provide the same output and wait for the transmission system to correct the stability issue. When a system frequency excursion occurs, the DERs will more than likely not have any headroom for additional current output. What this means is that at best the DER will support the frequency decay of the system. Hence, the frequency nadir is expected to be higher than if the DERs tripped offline. This should help with underfrequency load shedding (UFLS) schemes by allowing the transmission system more time to re-establish frequency equilibrium. However, this will not support frequency stability in the traditional manner we are accustomed to for a generation resource. It is important that system operators and transmission planners understand this nuance when it comes to DER frequency ride-through.

Widening the frequency band time delay requirements should, in theory, help the system during frequency excursions. However, this hinders our ability to detect and prevent unintentional islands. For DERs, the protection philosophy was more biased to system protection. Now the pendulum has swung, and the bias is much more towards what is perceived as system support.

There are active anti-islands schemes that may be embedded within inverter-based DER system. The problem is that these schemes are complicated and it is difficult for the utility to trust if they will work correctly since they are embedded within the inverter control system.

For synchronous based DER, there is a very well understood overspeed function that may be implemented in the prime mover system. This function does not have to adhere to the 1547 ride-through requirements and can be used to improve anti-islanding detection for cases when the generation exceeds the load within an island.

6. Protection Scheme evaluation

For large DER interconnections Duke Energy requires a utility owned protective device at the Point of Common Coupling (PCC). This protective device is often a recloser and relay package, that is implemented to perform multiple use cases such as metering, protecting the EPS, and control. In order to objectively understand the impact of implementing ride through for these types of installations the existing protective settings used by the company were updated to align with the guidance from IEEE 1547-2018 to create a reference benchmark settings file. The performance of the DER Ride-Through (DER-RT) settings file was compared to the performance of the T-FAULT voltage signature scheme to evaluate any potential benefit to implement this accelerated scheme.

The typical DER protection that is implemented at the PCC made up of multiple pieces of logic that include passive elements, system sequence components, and DER system fault detection.

i. The passive elements that are implemented which are based on IEEE 1547-2018, Section 6, are inputs to logical Timer 1 pickup:
   - 27-1 Undervoltage Level 1
   - 27-2 Undervoltage Level 2
   - 27-3 Undervoltage Level 3
   - 59-1 Overvoltage Level 1
   - 59-2 Overvoltage Level 2
   - 81U-1 Underfrequency Level 1
   - 81U-2 Underfrequency Level 2
   - 81O-1 Overfrequency Level 1
   - 81O-1 Overfrequency Level 2

ii. The sequence component elements that are implemented are to detect sequence components often associated with faults on the EPS, which are inputs to logical Timer 2 pickup:
- 59N Zero Sequence Overvoltage
- 59Q Negative Sequence Overvoltage

iii. The directional overcurrent elements that are implemented to detect faults within the DER site drive logical Timer 3 pickup.

7. TESTBED SETUP

A laboratory setup that employs Control Hardware in Loop (CHIL) simulation to test the protection setting's performance was constructed. In CHIL simulations, the protection relays under test are interfaced with the RTDS through analog and digital input/output cards to perform closed-loop testing. In such testing environments, the relays under test typically receive the secondary voltage and current signals from the RTDS simulator through the GTAO (analog output) cards. Tripping signals can be realized by using digital input interface cards, namely GTDI cards. To monitor relay protection elements in real-time, the generative transfer network card (GTNETx2) allows the RTDS to interact with the relay through ethernet protocols like generic object-oriented substation event (GOOSE). The relay digital signals are imported to the RTDS through GOOSE for this setup to enable enhanced data collection. This interface should resemble a much closer environment to field conditions. Figure 7 shows the integrated testbed for performing closed-loop HIL testing.

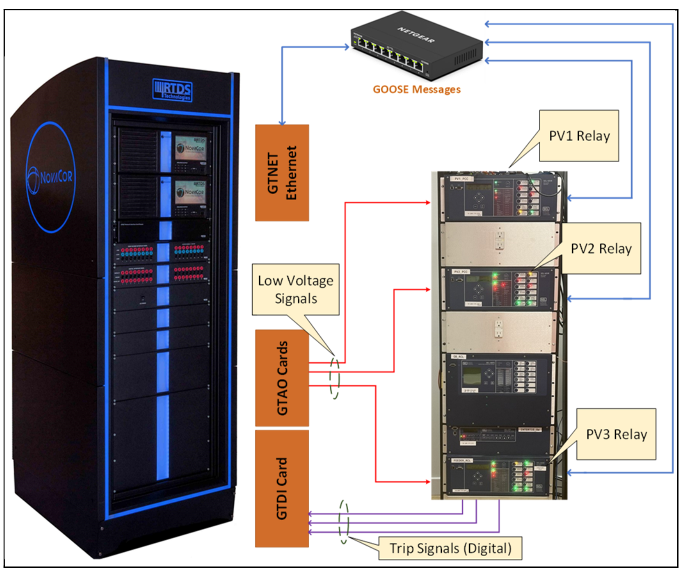

Figure 7: CHIL Laboratory Test Setup

8. TEST RESULTS

This section discusses the observations from analyzing the test results for two different voltage protection schemes, namely DER-RT passive element protection and T-FAULT voltage signature-based protection discussed in Section 4. A few test cases are explained in detail to assist with understanding the overall protection system performance.

Suppose a BCG fault happens on the Distribution Feeder at Location F1 (see Figure 1). For this fault case, it is expected that only PV2 and recloser 525 will trip. In response to the fault, the voltage signature protection scheme trips the PV2 relay on the Timer 2 logic (zero-sequence OV element) in approximately 5.4 cycles. This trip is an expected response. However, the other two PV relays also trip on T-FAULT logic, designed to detect LG faults on the transmission system. Figure 8 shows the COMTRADE event plot for PV3, indicating the undesired operation of T-FAULT logic. It should be noted that Recloser 525 trips on an OC element in this case (in 6.6 cycles).

The DER-RT passive voltage scheme trips on the 27-3 element to isolate the fault (27-3 is the level-three under-voltage element). However, PV1 and PV3 ride through the fault as expected. Like the previous scenario, Recloser 525 trips on the OC element (in 6.3 cycles).

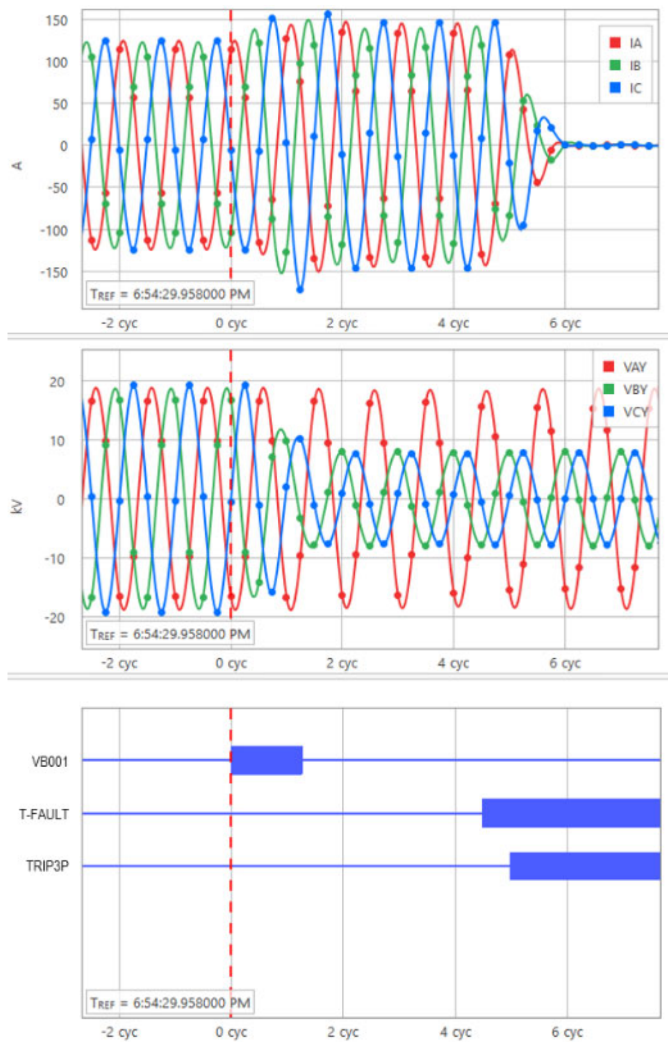

Figure 8: COMTRADE Event File for a Fault at F1 (PV3, voltage signature based protection)

A Phase-A-to-Ground (AG) fault occurs on Distribution Feeder at Location F2 (Figure 1). For F2, the PV sites are expected to ride through the fault and stay connected. However, to clear/isolate the fault, the upstream Recloser 577 operates in about six cycles (2.91 cycles trip time plus three cycles breaker time). To illustrate the importance of coordinating the protection at the DER site with the EPS protection, Timer 2 is set to operate in 4.5 cycles for all three PV units. In this scenario, the relatively quick operating Timer 2 creates a racing condition with recloser 577 (which is upstream of the fault). The result is that Timer 2 trips all three PV units. Figure 9 shows the COMTRADE event plot for the PV1 relay, indicating Timer 2 picks up (TIMER 2_PU) and then asserts tripping the recloser in approximately four cycles.

Whereas the DER-RT passive voltage scheme Timer 2 (zero- and negative-sequence OV element) is set to operate in 10 cycles. Subsequently, the PCC reclosers will ride through the fault until the fault is isolated by Recloser 577.

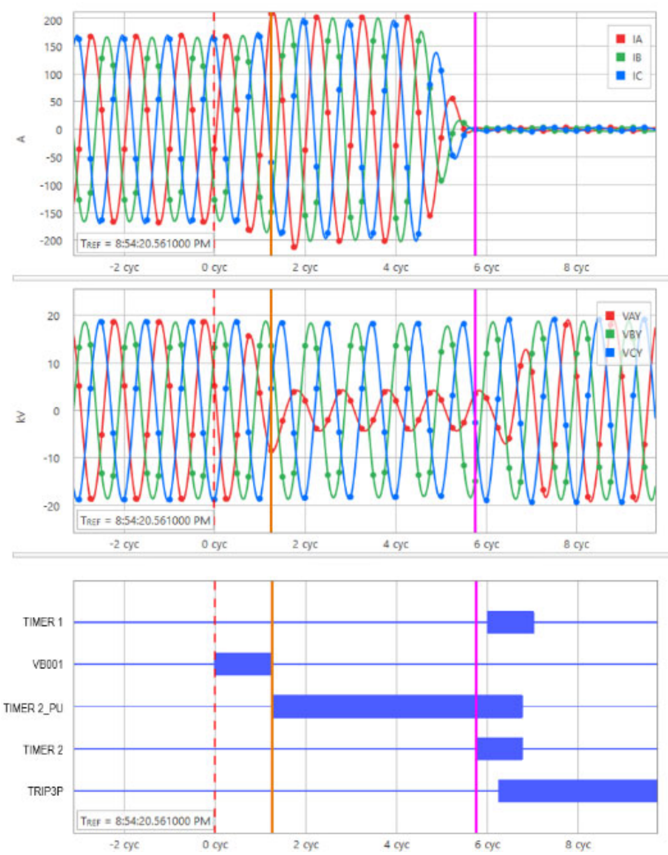

Figure 9: PV1 DER Relay COMTRADE Event File for a Fault at F2 (PV1, voltage signature based protection scheme)

Suppose an AG fault happens at the HV (100 kV) substation (Location F3 in Figure 1). For this fault scenario, the PV units are expected to trip before the transmission protection (ideal case) to prevent TOV and potential damage to surge arrestors. Voltage signature based scheme relies on the T-FAULT logic discussed in Section 4.B for PCC recloser to trip the DER before the system islands (i.e., before the operation of the transmission protection). In response to the fault, the T-FAULT scheme (zero-sequence OV element) at the PCC recloser detects the AG fault at location F3 and in approximately **five** cycles. The transmission protection relays (CB1 and CB2 in Figure 1) take around 13 cycles to clear the fault (including operating time). Figure 10 shows the COMTRADE event plot for the PV1 relay, indicating the T-FAULT trip element.

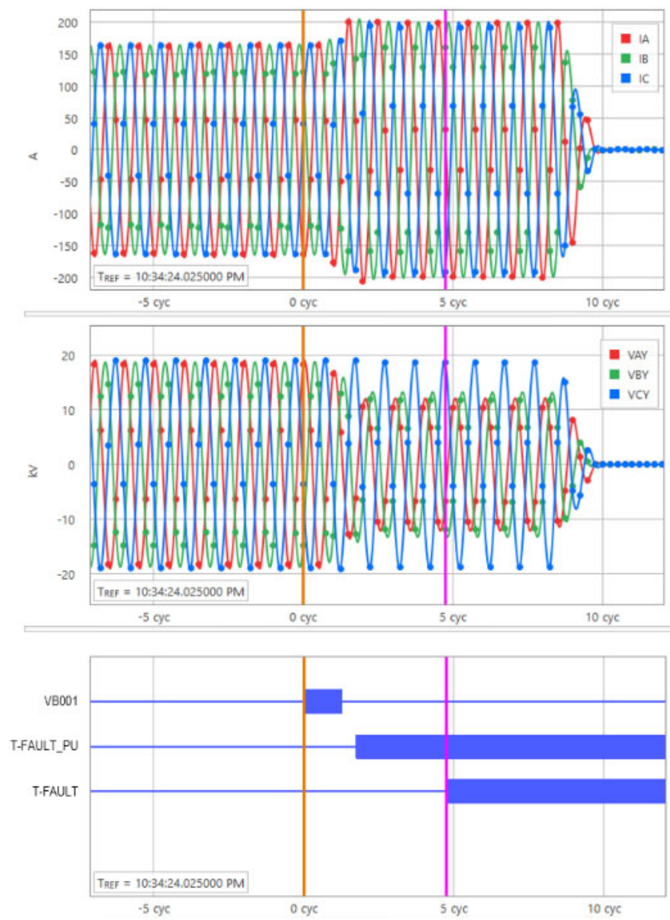

Figure 10: PV1 DER Relay COMTRADE Event File for a fault F3 (PV1, voltage signature based protection scheme)

The DER-RT logic will provide protection using a passive voltage-based scheme, slower than the T-FAULT scheme. Using the passive element voltage signature scheme, TIMER 2 (negative- and zero-sequence OV elements) trips the PCC reclosers in approximately 12 cycles. Figure 11 shows the COMTRADE event plot for the PV1 relay, indicating the TIMER 2 trip element.

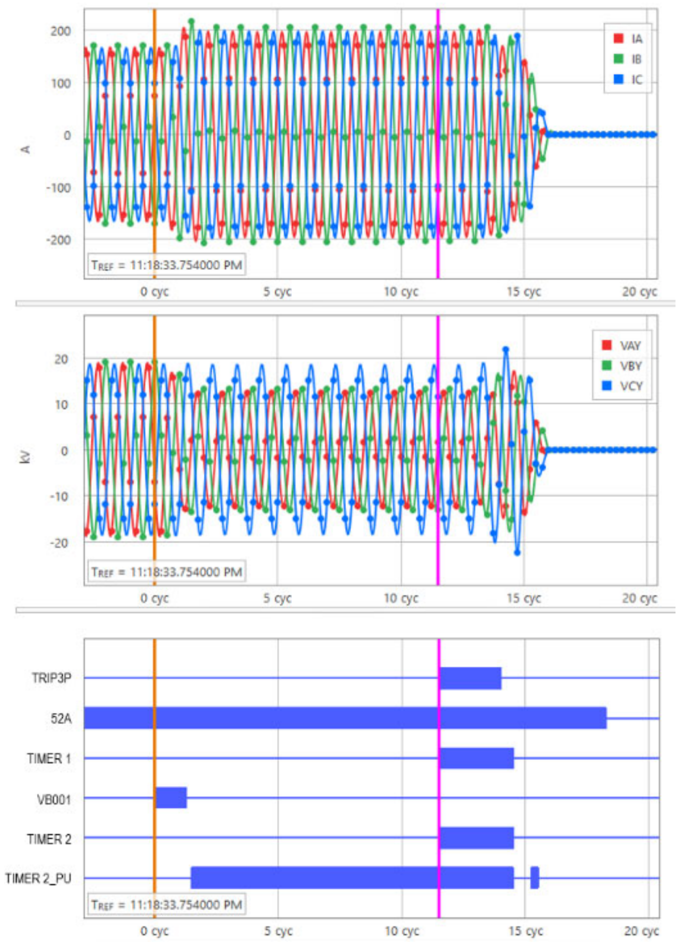

Figure 11: COMTRADE Event File for a fault F3 (PV1, DER-RT protection scheme)

Suppose an AG fault happens at the transmission line at Location F4 (see Figure 1). This is an in-zone fault (like the F3 fault scenario) for which the PV units are expected to trip on the T-FAULT logic. Whereas for DER_RT logic should provide protection depending on the fault location and type.

After the fault, the T-FAULT logic in the PCC reclosers fail to detect the transmission fault and trip before the system islanding. The transmission protection relays (CB1 and CB2) take around 13 cycles to clear the fault (including CB operating times). As a result, an overvoltage builds, causing the Timer 1 logic (Level 2 OV element) to assert. Figure 12 shows the COMTRADE event plot for the PV1 relay, indicating the TIMER 1 trip element. It is worth noting that the T-FAULT element does not assert for this fault, causing longer operation of the protection scheme (approximately 23 cycles).

The DER-RT passive elements in the PCC reclosers take longer to trip. Timer 2 (Level 2 OV element) element trips in about 23 cycles. Figure 13 shows the COMTRADE event plot for the PV1 relay, demonstrating the Level 2 OV element pick-up (59-2_PU).

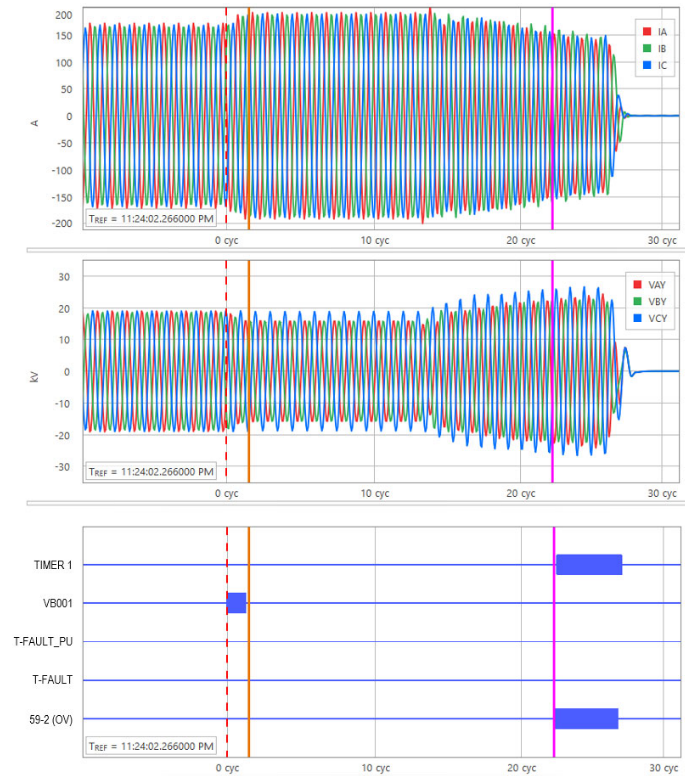

Figure 12: COMTRADE Event File for a fault F4 (PV1, voltage signature based protection scheme)

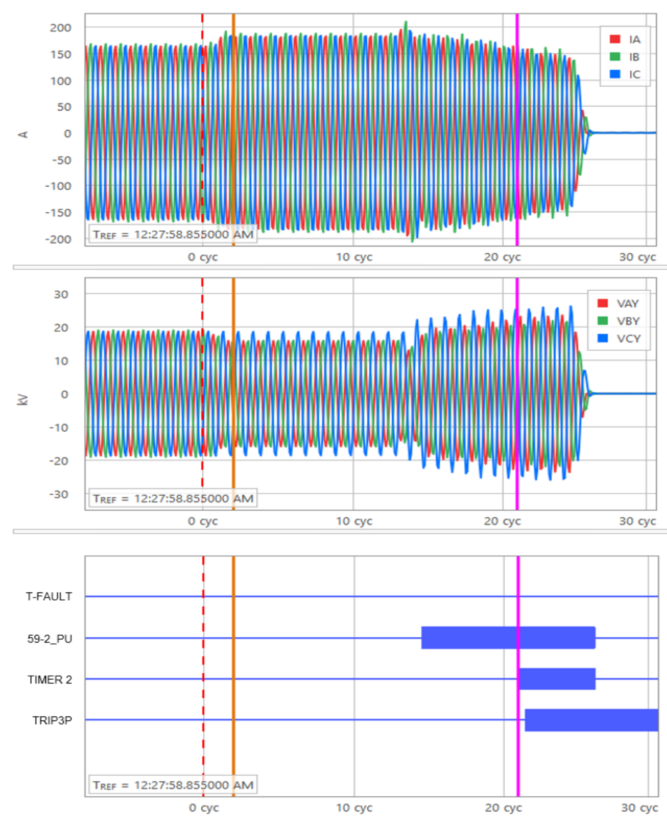

Figure 13 : COMTRADE Event File for a fault F4 (PV1, DER-RT protection scheme)

9. Conclusion

The initial work of gathering input and requirements from multiple business unit in the company was paramount in defining the basis for adopting IEEE 1547-2018 and DER ride through performance requirements. Some of that work is documented in this paper however it requires a comprehensive review of not only the DER system's passive elements but a review of the entire system. Without this review the potential impact of Transmission system equipment damage would have not been identified. The IEEE 1547-2018 standard discusses \abnormal conditions when reflected to the Area EPS, however it is relatively silent on the risks introduced to the entire system from implementing ride through. The work on IEEE 1547.2/D6.5 has made significant strides in providing guidance for DER interconnections however there is still room for improvement. Additionally, without the testing discussed in this paper legacy protection logic (Timer 2) impacts to ride through would not have been identified and addressed.

The work in this paper is being considered as implementation plans are being finalized. The T-Fault logic while initially promising in its current iteration does not provide results showing reliable operation in our testing to proceed. The required speed of the scheme poses over-reach and under-reach risks and requires tuning depending on system characteristics to reduce those risks. The work we have done has shown we can detect most faults of concern on the transmission line connecting to the substation with our DER-RT logic however the speed of the scheme may stress components in our system.

As we continue our journey in the ever evolving electric power system we will work on ways to accelerate our fault detection schemes where it does not impede ride through. As we move to implementation we also acknowledge the work is not "done" and this will become an area for continuous improvement and study, in light of this we are working to develop the tools and resources to allow our teams to be successful in the future.

This paper illustrates how we are addressing one aspect of DER systems that include a utility protective device, there may become a time where the composite impact of smaller DERs poses similar operational risks. The industry will need to continue to evolve our expectations for "ride-through performance" and continue to develop requirements such as minimum fault current output from a DER that would help provide a more uniform performance and in turn allow for the development of additional protection schemes. Leveraging some of the work done for Transmission connected generators through IEEE 2800 may also provide benefits for larger DER interconnections.

10. References

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11. Biographies

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Jason Eruneo received his B.S. in electrical engineering from University of South Florida in 2008, master's degree in engineering from University of Florida in 2017, and an M.B.A. from University of Florida in 2018. He is a registered professional engineer within the state of Florida. He has worked in the power industry for nearly 15 years in protection and control design and system protection engineering. He has contributed to the development of NERC PRC standards development and is a member of the NERC System Protection and Control (SPCS) Working Group. He is a main committee member of the IEEE PES Power System Relaying and Control (PSRC) Committee and vice chair of the Rotating Machinery Protection Subcommittee of the PSRC.

Yujie Yin is an executive advisor within Advanced Technology Integration team, Quanta Technology. He is a senior member of IEEE, CIGRE B5 WG member and a licensed Professional Engineer in the Province of Ontario. He received his Ph.D. from the Mississippi State University in 2020, his Bachelor of Computer Science and Master of Electrical Engineering from Western University, Canada, in 2004 and 2006, respectively. He also holds a Bachelor of Electrical Engineering degree from Hefei University of Technology, China.

Mo'ath Farraj is a senior consultant within Advanced Technology Integration team, Quanta Technology. He completed his MSc degree from the University of Manitoba in 2021. He was appointed a research assistant position during his MSc at the University of Manitoba. His research interests included real-time simulation, hardware-in-the-loop (HIL) testing, and distributed energy resource (DER) integration. He has worked in the power industry for nearly 3 years in EMT modelling for protection and control design and HIL Testing.

Amin Zamani is Executive Advisor and Sr. Director of Advanced Technology Integration at Quanta Technology. He has over fifteen years of industry and utility experience globally. He specializes in power system protection and control, deployment of emerging technologies, integration of Distributed Energy Resources (DER), and advanced real-time testing. In recent years, he has been leading several utility and industrial projects focusing on deployment of microgrids, distribution automation applications, wildfire mitigation solutions, and advanced protection solutions. Amin is a Senior Member of IEEE, an active IEEE PSRC member, and a professional engineer in the province of Ontario.