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Microgrid Fault Stability and Protection Considerations

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SUMMARY

In planning for Distributed Energy Resources (DER) in a microgrid, careful consideration must be taken to ensure the DER and microgrid are resilient during both grid-connected and islanded operation. There are many factors considered in the design of a microgrid, including the size of an existing DER, or the size of a new DER, the preferred DER/microgrid control technology and the material and labors costs. This paper discusses protection topics that need to be considered when analyzing microgrid voltage stability during fault conditions. Areas examined are fault contributions and voltage ride-though concerns with synchronous generators and inverter based DERs. A case study simulated on a real time power system simulator is presented in this paper.

KEYWORDS

DER, RTDS, Inertia, Protection

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INTRODUCTION

Many electric customers are investing in microgrids and DERs while maintaining a utility connection to provide additional reliability and resiliency during grid disturbances, which could interrupt electrical service. The U.S. Department of Energy defines the microgrid as ‘‘a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island mode” [1]. The microgrid can have a diverse portfolio of distributed generation (DG). These include synchronous generators, induction generators and inverter-based generators. When the utility source experiences a disturbance, the microgrid can disconnect from the utility and operate in island mode. When operating in island mode, steady state operation and normal transient loading is managed by several types of technologies. The control can be in the form of a local controller, such as DG unit controllers or possibly a microgrid centralized controller responsible for managing multiple DG units and the connected loads. A DG controller or centralized controller response-time may be too slow to maintain voltage and frequency stability during a fault condition and therefore relies on the protection scheme to mitigate stability issues. The microgrid’s protection system must be designed to ensure that when a fault is cleared, the voltage and frequency can recover to an acceptable post-fault state. The protection philosophy of a microgrid is affected by its operating mode, as well as other factors such as the generation profile. Considerations for the protection system design must include the operating characteristics of both synchronous and inverter-based generators as well as the voltage and frequency dependencies of loads. The security, reliability, and sensitivity of the protection system must also be acceptable during both grid-connected and islanded operating scenarios. Many microgrids use protection that is standard time overcurrent-based, as would be used in a typical medium voltage application without DG sources. The overcurrent protection may not operate as intended or cause a mis-operation during islanded operation due to a lack of system inertia. By the time a relay operates to clear the fault, the microgrid DG voltage source may have collapsed to the point that the fault becomes unrecoverable. This paper explores various fault scenarios a microgrid may experience with synchronous and inverter-based generation as well as areas to consider when converting an existing distribution system into a microgrid.

FAULT CONSIDERATIONS DURING GRID-CONNECTED OPERATION

When a microgrid is operating grid-connected, the DERs within the microgrid and the grid both contribute to the voltage and frequency stability of the microgrid while serving the loads. Under steady state conditions, this includes large load variations. The amount of contribution, or active power provided by the microgrid will vary from the design of each microgrid or the microgrids’ mode of operation. For instance, some DERs may be used to provide peak shaving assistance to an area during time of excessive consumer demand, like on hot summer days. When running in grid-connected, the DERs operate as a current sources. They can be dispatched to supply a certain amount of active and reactive power to the local area thereby curtailing the grids’ power contribution into the microgrid.

When there is a fault or disturbance during grid-connected operation, in most cases, there are interconnection agreements in place that govern the response of the interconnecting DER up to the Point of Interconnection (POI). In the U.S. a standard cited by most utilities is IEEE Std. 1547 Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electrical Power System Interfaces. This standard outlines the requirements for the interconnection and interoperability between the utility and DERs [2]. Section 6 of the standard calls out the DER response requirement during abnormal conditions, such as the required ride-through requirements during a voltage disturbance without exceeding DER capabilities. See Figure 1 for Category 1 voltage-ride through requirements. Per IEEE 1547, any tripping of the DER, or other failure to provide the specified ride through capability, due to DER self-protection as a direct or indirect result of a voltage disturbance within the applicable ride-through regions, will consider the DER in non-compliance with the standard.

When evaluating the design for grid-connected operation, the small-signal stability of the microgrid must be evaluated with the grid source compensating for slow governor or exciter responses from the DER. It important to obtain step response data from the DER equipment suppliers. The data will be used for modeling and verification. In many cases, microgrid projects are proposed and executed within existing infrastructures “brown field”. The project could be scoped to use existing switchgear and distribution transformers. The existing equipment within the microgrid needs to be carefully evaluated considering the microgrid DER. Considerations such as how will the equipment be electrically connected to the existing power system network and will the additional fault current over-duty existing equipment or cause any miscoordination. Subtransient and transient fault contributions are more substantial with synchronous generators however additional harmonics from inverter-based generation may cause issues with protective relays. In [3], the author highlights the concerns and challenges with networked microgrids and how the DGs can contribute large amounts of fault current that could exceed the design fault level of existing equipment.

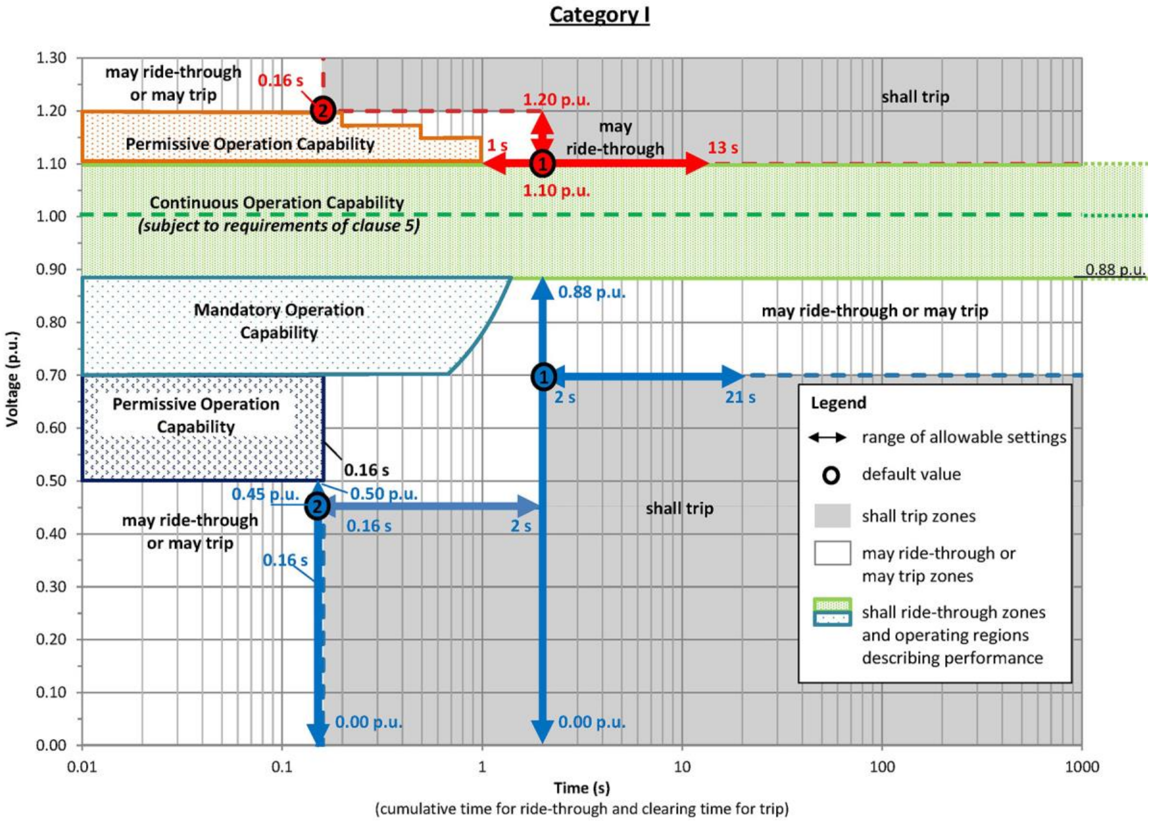

Figure 1 – IEEE1547 standard Category 1 DER Voltage Ride-through

FAULT CONSIDERATIONS DURING ISLAND MODE OPERATION

When a disturbance occurs near a microgrid and the microgrid disconnects from the grid and runs exclusively on the DERs, the microgrid has formed an intentional island [2]. The island can synchronize back to the grid and continue to operate in parallel only if the grid has returned to nominal system voltage and frequency. When an organization or group has purchased and installed a microgrid system, the expectation of reliability is the same whether operating in grid-connected mode or island mode. In many cases microgrid projects have justified the financial funding required to design and install because of the significance of the connected loads. The microgrid can offer additional resiliency the organization or group responsible for the loads demands. Depending on the fault or disturbance, the microgrid needs to remain stable and online. Fault analysis needs to be studied for both grid-connected island mode scenarios.

There are three main types of distributed generation; synchronous generators, induction generators and inverter-based generation. Because the response characteristics of each type vary, dynamic features of the DGs need to be carefully evaluated when developing a microgrid. Unlike a synchronous generator, the short circuit contribution from an inverter-based generator may be as low as 2 p.u. of the inverters rated load capability [4]. Because the fault current is controlled, the inverter fault current may differ from different manufacturers or even the same manufacturer's models. As discussed in [5], due to the controllability of an inverter's output current, the difference in performance under different types of faults may not be obvious. Because of their complex behavior, when studying fault response, it is likely to be inaccurate to model them as either a constant voltage source behind a Thevenin equivalent impedance or a basic constant current source. It's also important to note that in most 3-wire inverter design with no neutral forming circuit, the inverter only injects positive sequence symmetrical current [5]. When working with an inverter-based generator or a synchronous generator, it is imperative to understand how the DG will response to faults for all control modes and mix of DGs. Common control modes for DG units are P/Q control, V/F control and Droop control. Because most inverters have built in current limiters to protect the internal power electronics, the control mode could have a significant effect on the fault current. [5] discusses the control loop strategies for P/Q, P/F and Droop control modes and how fault current can vary between the different control modes. It is critical to understand and obtain the control information from the DG equipment suppliers to ensure any simulation model used during design evaluation accurately reflects what will be installed.

Typical conventional medium voltage and low voltage protection systems use inverse time breakers for system short circuit faults. When the microgrid is operating in island mode, the inertia or available fault current will be substantially less in comparison to grid-connected operation. If a fault occurs during island mode and the associated breaker near the fault does not operate as expected, the microgrid could collapse due to exceeding critical clearing time, mis-operating a breaker, or tripping a DG unit. When designing or analyzing a power system, it is common for engineers to perform load flow and short circuit studies using commercial software. These software packages produce accurate results when analyzing power systems operating in parallel to a grid or stiff source. To analyze islanded microgrid systems under different operating modes and fault conditions, real-time modeling should be considered for system and protection design. If modelled correctly, simulators that perform electromagnetic transient simulations of power systems can provide the results that are expected for the final installed product. Many of these simulators can also be setup in a hardware-in-the-loop (HIL) configuration by adding hardware such as relays and controllers. The case models in this paper were developed using RTDS® RSCAD® software and simulated on a NOVACOR RTDS® real-time simulator.

CASE STUDIES

This paper performed four case studies to examine a microgrids' distribution voltage profile during fault events in both grid-connected and island modes. The cases included synchronous and inverter-based DERs. The microgrid case study had a 13.2 kV distribution system with a single connection to a 34.5 kV grid via a 50 MVA transformer. See Fig. 2. The DER portfolio consisted of (2) 7.5 MW 4.16 kV synchronous generators and one (1) 4.16 kV inverter-based generator with a constant DC source emulating a 5 MW battery energy storage system (BESS). The distribution loads included three (3) 13.2 kV feeders with lumped loads; two (2) 4.4 MVA loads and one (1) 1.2 MVA load. To analyse the microgrids' voltage stability two faults were triggered at select locations in separate cases within the microgrid; one 3-phase line to ground fault on a lumped load branch circuit, and one single line to ground fault on the 13.2 kV distribution. The 51-function modelled in the distribution breakers used an IEC Standard time/current curve. Note all plots in this simulation were L-G measurements.

The following DG and fault configurations were modelled.

- Parallel operation, all 3 DGs with a low impedance 3-phase to ground fault triggered.
- Islanded, all 3 DGs with a low impedance 3-phase to ground fault triggered.
- Islanded with 1 DG with a low impedance 3-phase to ground fault triggered.
- Islanded with 1 DG with a low impedance 1-phase to ground fault triggered.

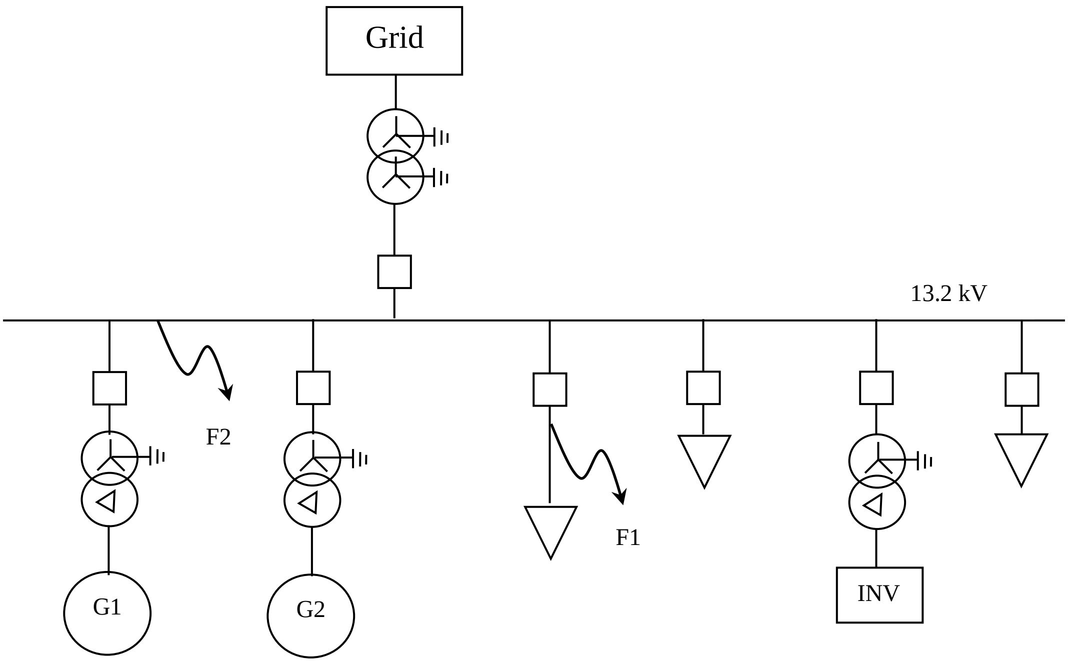

Fig. 2: Microgrid Case Study 1-line Diagram

In the first case, the microgrid was simulated in grid-connected mode with all three (3) DERs synchronized and all distribution loads connected. The two synchronous generators were set up with RSCAD® internal gas turbines and associated speed control with internal droop. The inverter was modelled with a 6-pulse IGBT power-bridge system configured to run as a current source. At t=0.5 sec, a 3-phase low impedance line to ground fault (F1) was triggered on one of the 13.2kV distribution loads. See Fig. 2. During the fault, the 13.2 kV voltage dropped to 0.94 p.u. (see Fig. 3). The timed over current distribution breaker operated at approximately t=1.1 sec and the 13.2kV distribution recovered back to nominal voltage (see Fig. 4).

During the fault, the 13.2kV distribution voltage was stable and considered within acceptable limits for continued microgrid operation.

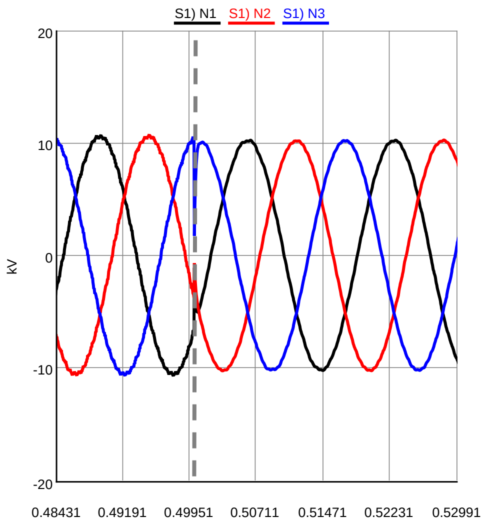

Fig. 3 – 13.2 kV t=0.5 sec fault

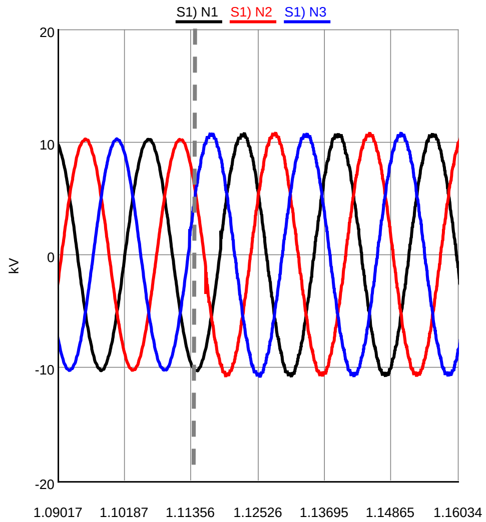

Fig. 4 – 13.2 kV t=1.11 sec 51 operation

In the second case, the microgrid was simulated in island mode with all three (3) DERs running in parallel and all distribution loads connected. As in the earlier case, the two synchronous generators are set up with RSCAD® internal gas turbines and associated speed control with internal droop. The inverter was modelled with a 6-pulse IGBT power-bridge system configured to run as a current source. At t=0.5 sec, a 3-phase low impedance line to ground fault (F1) was triggered on one of the 13.2 kV distribution loads. See Fig. 2. During the triggered fault, the voltage dropped to 0.81 p.u. (see Fig. 5). The inverter output current only increased to 1.09 p.u. during the fault. The distribution breaker operated at approximately t=1.18 sec and the 13.2 kV distribution recovered to nominal voltage (see Fig. 6).

During the fault, the 13.2 kV distribution voltage was considered to be within acceptable limits for continued microgrid operation. Generator breakers were not enabled during this case. If enabled and configured per equipment specification, they could have mis-operated prior to the distribution breaker clearing the fault. With the assumption that the DGs did not trip offline, the microgrid should have been able to ride through the fault. Detailed modelling of the exact DG units would be needed to confirm the assumption. If the original interconnection was required to meet IEEE 1547 category 1 ride through requirements, the 13.2 kV distribution was in the range of mandatory operating capacity (see fig. 1), even though the interconnection agreement may not be enforced while in island mode.

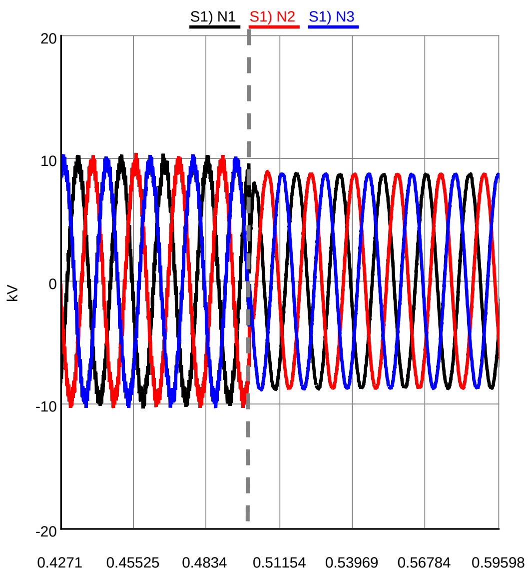

Fig. 5 – 13.2 kV t=0.5 sec fault

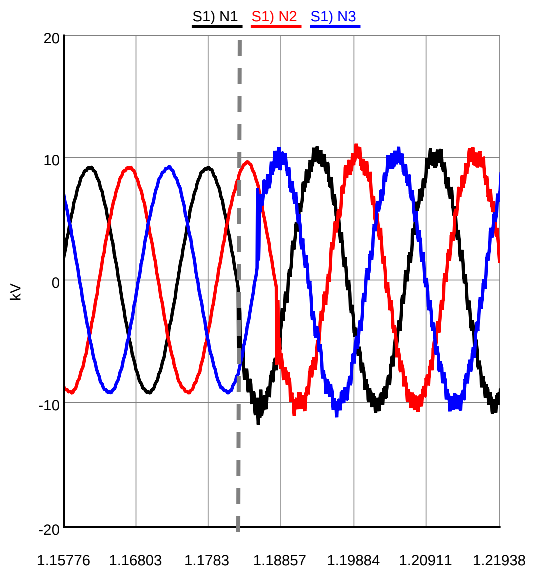

Fig. 6: 13.2 kV t=1.18 sec 51 operation

In the third case, the microgrid was simulated in island mode with one (1) DER running and connected with two (2) distribution lumped loads. As in the earlier cases, the synchronous generator was set up with a RSCAD® internal gas turbine and associated speed control with internal droop. Given the operating mode, droop control was not be required. At t=0.5 sec, a 3-phase low impedance line to ground fault (F1) was triggered on one of the 13.2 kV distribution loads. See Fig. 2. During the fault, the 13.2 kV voltage dropped to 0.56 p.u. (see Fig. 7). The timed over current distribution breaker did not operate. After the triggered fault (F1) was removed at t=1.3 sec, the 13.2kV distribution recovered to nominal voltage.

During the fault, the 13.2kV distribution voltage is not stable and did not appear to be within acceptable limits. The generator breaker was not enabled during this case and may have tripped due to over current or under voltage protection. If all the DER specific protection functions were enabled, it's reasonable to arrive at the conclusion the microgrid would not ride through the fault.

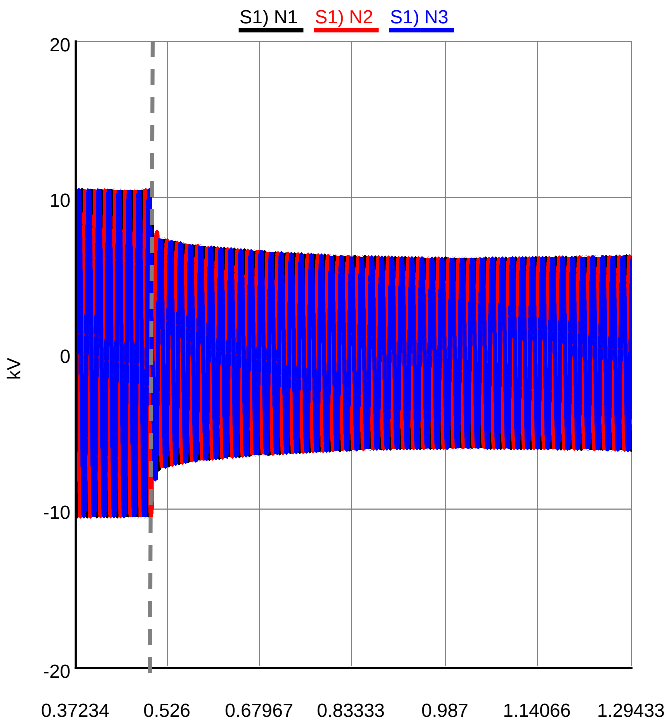

Fig. 7: 13.2kV t=0.5 sec fault

In the final case, the microgrid in operating in island mode with one (1) DER running and connected to one (1) distributed lumped load. Many microgrid designs are using existing distributed generators and equipment. In some recent design bids, the microgrid owner or developer has specified the use of specific original equipment. The configuration in this simulation includes one of the 7.5 generator connected to the 13.2 distribution via a 10MVA wye-wye grounded transformer. This is a likely scenario in which a 7.5MW standby generator had originally connected to transferring switchgear that isolated the DG from a wye-wye grounded distribution transformer to provide standby power to selected loads. The existing standby generator is configured to backfeed the 13.2 kV distribution, providing standby power to additional loads. The transferring switchgear has been removed and the DG has been reconfigured to connect with the existing 10MVA transformer. At t=0.5 sec, a 1-phase low impedance line to ground fault (F2) is triggered on the main 13.2kV distribution line. See Fig. 2. During the fault, two of the phase to ground voltage increased by the sqrt-3. (see Fig 8). None of the breakers operated and the generator bus does not measure a line-ground overvoltage condition. (see Fig 9). There is no zero-sequence path for the fault. While this fatal flaw would have been caught in most designs, the results highlights the need to evaluate all existing equipment when designing a microgrid in a brown field system.

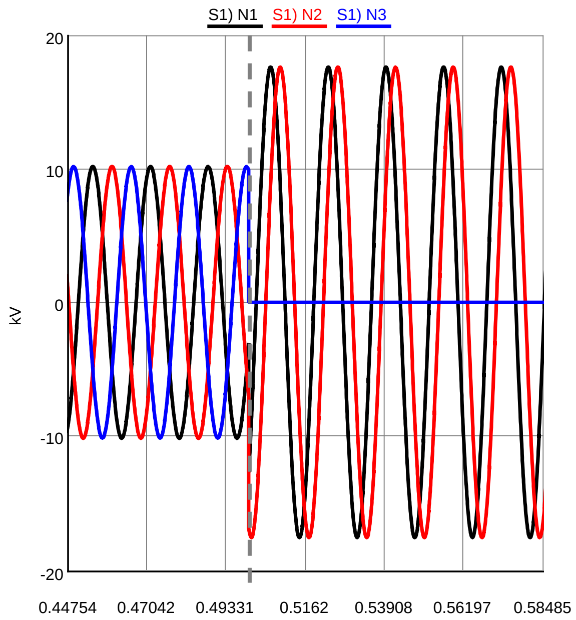

Fig. 8: 13.2kV Distribution

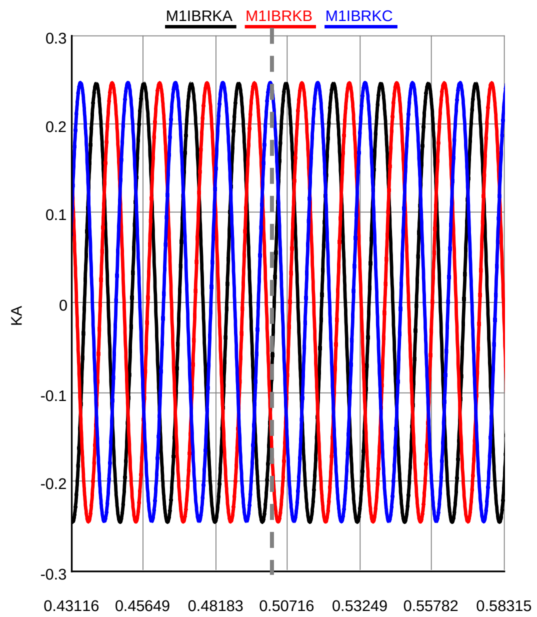

Fig. 9: 4.16kV DG bus

CONCLUSION

Designing a resilient microgrid requires carefully planning and simulating the protection design. One of the major technical challenges when designing a microgrid, that will operate in grid-connected and island modes, is the protection design. Due to fault current dynamics in both modes the microgrid must be modelled with accurate equipment data in a simulation environment that will yield precise results. This can be accomplished by working with DER vendors to build DER models that reflect the correct fault responses and executing the model simulations on a real-time digital simulator.

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