Design and Implementation of an IEC 61850 GOOSE Based Protection Scheme for an Islanded Power System

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***Abstract*—The design concepts for the 1 MW microgrid power system installed at Ameren Illinois's Technology Applications Center are presented. Specifically, the design and implementation of an IEC 61850 GOOSE messaging based protection scheme for the microgrid system is discussed. The reasoning for utilizing the scheme are presented, as well as the general functions.**

***Index Terms*—Microgrid, Islanding, Renewable Energy Sources, Energy Storage, Power System Protection**

I. Introduction

When protecting microgrid systems, communications between protective relays are often utilized. This paper presents the design and implementation of a GOOSE based protection scheme at an operational 1 MW microgrid with renewable generation, battery energy storage, and traditional natural gas generation serving Ameren Illinois customer loads as well as the Ameren Technology Applications Center (TAC). This paper aims to convey the general implementation strategy of the system, and to describe the methods employed in successful operation of the system.

This paper will provide an overview of the microgrid system, establish the need for a communication-based protection scheme, the objectives of the scheme, the infrastructure required, and the performance measured from the implemented system.

II. System Overview

A. System Configuration

The microgrid system consists primarily of the following assets, shown in Figure 1:

- 125 kW PV Solar Array
- 100 kW Wind Turbine
- 250 kW/500 kWh Battery Energy Storage
- (2) 500 kW Natural Gas Generators
- Ameren Illinois utility connection at 12 kV

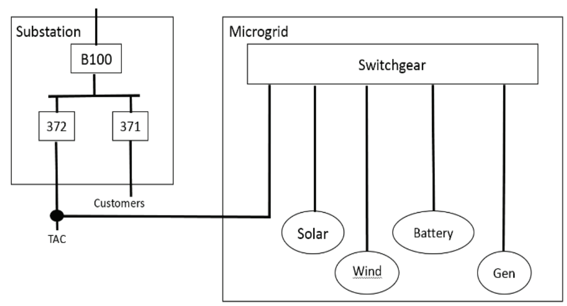

Figure 1: Ameren TAC Substation and Microgrid

In addition, the system has two load groupings, given in Table I:

Load Name	Feeder No.	Avg. Demand
TAC Load	372	50 kW
Customer Load	371	600 kW

TABLE I. AMEREN MICROGRID LOADS

B. System Description

Ameren's 12 kV substation feeds both the TAC load and a 600kW average of customer load via their TAC substation. These feeders are protected by recloser devices named for their feeder numbers (see Figure 1). Installed upstream of these reclosers is another recloser (B100), which acts as a single point of interconnection device for islanding both loads, while recloser 372 can be utilized to island only feeder 372. Each recloser (B100, 371, and 372) are all equipped with microprocessor relays.

The generation is interconnected to the distribution system through underground distribution switchgear. Each connection to the underground distribution switchgear has a fault interrupter and an associated microprocessor relay.

The microgrid is designed to operate in a variety of modes, including the ability to operate as an island disconnected from the utility source.

When islanding the full system, which includes the TAC load plus the customer load, roughly 650 kW of generation is required, on average, and a maximum of 1,000 kW. Given the maximum nameplate ratings of the generation equipment listed above, we can see that it is common for the natural gas generators to be generating power to supply these loads.

However, it is possible to also open recloser 372 and island just the TAC load of approximately 50kW using wind and solar PV generation with a potential capacity of 225kW.

To do this, we utilize the grid-forming capability of the battery energy storage system inverter, as well as real-time curtailment of the PV and wind production coupled with fast-charging and fast-discharging schemes of the inverter. This results in a stable power system of extended duration, even with renewable penetration rates more than 100% of the connected load.

The system is designed to synchronize the generation to the utility source to allow for seamless transition into and out of the islanded modes of operation.

III. GOOSE Based Protection Scheme

A. Need for Communication-Based Protection Scheme

The two primary drivers necessitating the use of a communication-based protection scheme in the Ameren microgrid were system stability and selective coordination.

Microgrid systems often have low inertia, particularly when operating islanded. Low inertia power systems change in frequency more rapidly when the balance between system active power generation and demand is upset. This mismatch between generation and demand can be caused by faults, generation tripping, load swings, or black-starting the microgrid from a de-energized condition. This speed of frequency change is illustrated in the equation shown below [2].

$$2H\omega \cdot \frac{d\omega}{dt} = P_m - P_e$$

Where:

H is the inertia, in seconds

ω is the generator speed in per-unit of the rated speed

P_m is the mechanical output power, in per-unit

P_e is the electrical output active power, in per-unit

For example, in a microgrid with an inertia of $H = 1\,s$, rejecting rated load (e.g. during a close-in fault) and operating at rated speed, the rate of change of speed would initially be 50% of rated speed per second. In a 60 Hz system, this would corresponds with an initial rate of change of 0.5 Hz per cycle.

The faster rate of change of frequency in low inertia microgrid systems challenges system recovery. When the frequency deviates substantially from nominal, more system loads and generation are likely to be impacted. One example of this impact is generation tripping offline, potentially causing cascading generation loss and leading to system collapse. Furthermore, larger deviations from nominal frequency challenge stable system recovery, particularly when the resources installed are diverse (e.g. different energy sources and manufacturers). Consequentially, prompt response by protection and control systems to arrest the frequency changes is particularly critical in low inertia islanded microgrid systems, including the Ameren microgrid.

In addition to system stability, selective coordination of the protection system was another driver for usage of a communication-based protection scheme. Conventionally, distribution system protection consists primarily of overcurrent protection, which is coordinated using time-current characteristics (TCCs). This method of coordination results in devices electrically closer to the fault responding faster than series devices electrically farther from the fault across all current levels. This time-grading method of coordination results in devices electrically closest to DERs responding more slowly to many system faults. An example of coordination using TCCs is shown below. As discussed previously, low inertia microgrid systems require a fast response to events, rendering time-grading to achieve coordination while islanded an undesirable option.

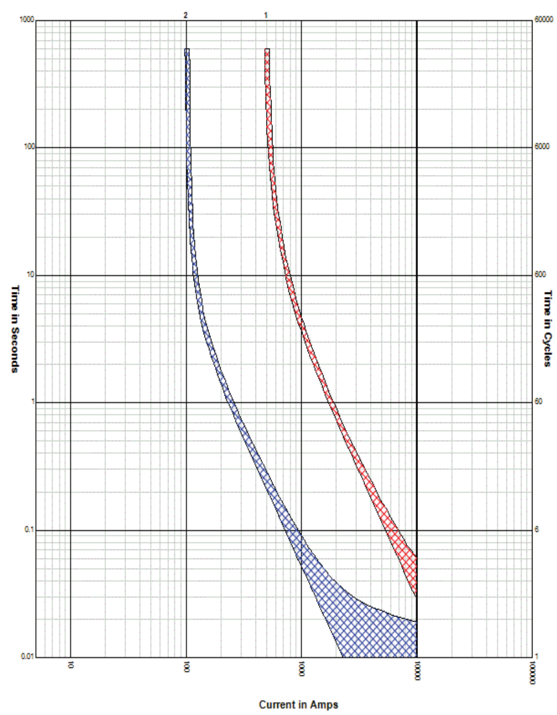

Figure 2: Example TCC Plot

The example TCC plot, shown in Figure 2, shows two overcurrent protective devices coordinated via time-grading. The downstream device (on the left, in blue) and an upstream device (on the right, in red). This plot illustrates that at any current, the upstream device responds slower than the downstream device.

Time-current coordination in microgrids is also challenging when there are multiple resources supplying fault current. During an event, the current measured by different devices in the system may vary, as the current supplied to the fault is coming from a combination of several resources. Furthermore, directional protection is necessary to achieve selectivity with multiple resources, as the protective device associated with the generation needs to respond first to faults between the protection and the generator but delay response for faults of comparable current magnitudes in the opposite direction. Utilizing a communication-based protection scheme can help to mitigate these challenges in a microgrid system.

The GOOSE-based protection scheme implemented at the Ameren microgrid uses communications to achieve selective coordination and the speed required for stable recovery.

B. Protection Communications Objectives and Design

The communication-enabled protection scheme was designed to fulfill the requirements of selective coordination and speed for stability. These objectives were attained using GOOSE messaging to communicate the direction of fault current, transfer trip signals, and system configuration.

To selectively and promptly isolate faults in the system both while islanded and grid-tied, the direction of fault current is communicated between relays in the system. When the relays identify that a faulted condition is present by monitoring system currents, voltages, and frequencies, the direction of the fault current is communicated between protective devices and their immediate neighbors. Direction is only communicated during fault conditions to minimize unnecessary communication network traffic. Relays monitor the direction of the current measured by neighboring relays to determine whether they should operate or delay their response.

This communication-based protection scheme works by measuring and communicating the directions of fault currents flowing into and out of a protection zone. If fault current is detected flowing into a protection zone and is not also detected leaving the zone, the relays will determine the zone is faulted and trip. If fault current is detected flowing into a protection zone and also flowing out of the protection zone, the relays will determine the zone is not faulted, and delay operation to allow other protection to clear the fault.

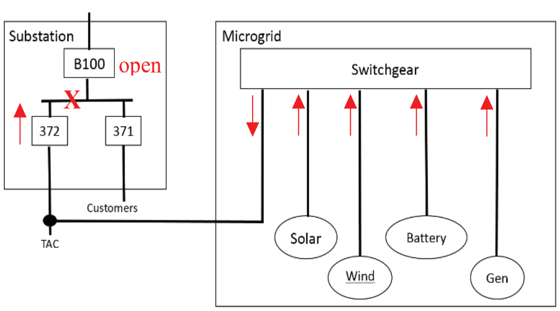

Figure 3: Example Fault Scenario

Above, Figure 3 illustrates an example fault scenario. In this scenario, all breakers except B100 are closed, a fault is indicated by an X at the substation bus, and directions of current measured are indicated by arrows. In this scenario, the relay at Breaker 372 communicating its measurement of current towards the substation would result in a delayed response of the switchgear outgoing breaker relay, measuring current flowing out of the switchgear. The outgoing switchgear breaker relay, communicating that fault current is flowing out of the switchgear, will result in delayed operation of the breakers associated with the wind, solar, energy storage system, and generator, which are each measuring current into the switchgear. The relay at Breaker 371 does not measure fault current flowing out of the substation bus, and thus Breaker 372 determines that the substation bus is faulted and operates to clear the fault.

Transfer trip signals are also communicated over GOOSE messaging. Considering the same example, fault scenario, tripping Breaker 372 clears the fault current. However, breakers B100 and 371 need to be tripped and locked out to avoid closing another source into the faulted bus. In this scenario, since Breaker 372 tripped when the relay detected fault current flowing into the substation bus, the relay is programmed to also send a transfer trip signal to the other breakers bounding the protection zone the fault is in (i.e. B100 and 371).

Yet another piece of information that is communicated over GOOSE messaging is the open/closed status of each breaker in the system. From the breaker status information, each relay can determine the configuration of the system. Most importantly, breaker status information can be used to determine if the system is currently operating in an islanded or grid-tied configuration. System configuration is significant to the relays, because the vastly different fault current across the configurations of the system necessitate adjustments in the protection settings. The relays use the system configuration information to ensure that they are appropriately set to protect the system in its present configuration.

In summary, the implemented GOOSE-based protection scheme is designed to achieve protection speed and selectivity by communicating and utilizing directional current measurements, transfer trip signals, and breaker status information.

IV. Infrastructure Required

To facilitate GOOSE messaging, microprocessor relays with this capability were chosen. These relays differ from standard microprocessor relays, as they include a communications co-processor dedicated to the handling of high-bandwidth, high-importance GOOSE traffic. This co-processor enables GOOSE messages to be parsed with low latency (less than ½ cycle), and is necessary to ensure a reliable protection scheme.

As GOOSE traffic is typically high-bandwidth, it was critical that the communications medium was robust enough to facilitate this aspect. As a result, a fiber optic Ethernet network was implemented, as fiber optic cable is immune to electromagnetic interference (noise) and thus has high bandwidth.

As discussed earlier, the GOOSE messages were deemed of critical importance, as they send transfer trips, trip blocking, and trip permissive signals. Thus, the protection system is no longer solely a single, independent relay making a decision or solely a time coordination-based protection system. The protection system is now community based, utilizing a combination of signals derived internal to the relay and signals from adjacent protective devices. In order to increase infrastructure robustness, the Ethernet network utilized rapid spanning tree protocol (RSTP) in order to provide a redundant path of communications in the case a single networking route was compromised.

It is important to note that an additional MAC address is used in each microprocessor-based relay for the GOOSE messaging. This allows isolation of traffic and increases transmission speeds.

Within the fiber optic Ethernet network a dedicated Virtual Local Area Network (VLAN) was set up for GOOSE messages. This separated the other network traffic, which consisted of HTTP, SCADA & peer-to-peer traffic. The GOOSE messaging can be set up with different VLAN priorities if required, but in this specific application there was no separation of priorities between the protection messages.

V. Protection Communications Performance

To verify the round-trip time of the GOOSE messages was within the published value of ¼ cycle, a simple test was devised where one microprocessor relay would transmit its respective recloser's status to other microprocessor relays. Both relays were GPS time synched, so that it was possible to read the actual times that the messages were sent and received. Through event analysis between the two relays, it was seen that the time between the change of states of the recloser until the receiving microprocessor relay(s) received the GOOSE message was within tolerance.

To test the communication-based portion of the protection scheme, GPS time-synchronized secondary injection testing was used. This allowed multiple relays to see a simulated fault event simultaneously and respond accordingly. The expected outcome included a blocking signal to be transmitted from one relay to another using GOOSE messaging, in accordance with the relays' determination of the fault current direction, as well as a transfer trip signal to be sent by the relay that cleared the fault to all other electrically adjacent device to ensure isolation of the faulted zone. By implementing a short delay between the relay tripping due to the detection of fault current and the potential receipt of a blocking signal, we ensured a prompt and selective response to fault events.

In the example shown in Figure 3, the outcome resulted in Breaker 372 detecting current in the "reverse" direction, and the transmission of a blocking signal to the switchgear head-end device. This blocking signal in turn prohibited the switchgear's head-end device from tripping due to its own "reverse" over current element. Since Breaker 372 did not receive a blocking signal from any other device, it tripped on directional overcurrent and cleared the fault. Furthermore, since the switchgear head-end device saw the event clear before its backup inverse-time overcurrent element timed-out, it did not trip. Additionally, Breaker 372 sent a transfer trip signal to Breakers B100 and 371, which in turn tripped Breaker 371 instantaneously in order to isolate the simulated fault, although no fault current was detected by those relays.

Conclusion

At the Ameren microgrid, the system is capable of operating islanded with 100% renewable energy supply, and seamlessly connecting and disconnecting from the utility system. The system is supplied by a grid-forming battery energy storage system, wind turbine, and solar photovoltaic panels, each interfaced to the power system via inverters. The inertia-less islanded power system has been demonstrated to achieve stable operation, as described in this paper. The islanded system was tested and successfully demonstrated 24-hour operation with 100% renewable energy supply.

In order to achieve power system balance between high fault current grid-connected mode and islanded mode a number of design elements contributed. GOOSE messaging played a vital role in performing adaptive relaying and community-based protection within the microprocessor-based relay protection system. By transmitting blocking, permissive, and transfer trip messages amongst the relays the system was able to autonomously, securely and reliably protect the grid-connected or islanded system.

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