Performance of IEC 61850 Sampled Values Relays for a Real-World Fault

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Performance of IEC 61850 Sampled Values Relays for a Real-World Fault

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***Abstract*—On September 25, 2021, the Commonwealth Edison Company's (ComEd) system experienced a catastrophic 138 kV pothead failure near a transition from an overhead line to an underground cable at a 138 kV substation. This section of the line uses an IEC 61850-compliant Sampled Values (SV) bus differential relay (87B23-79DTL) that receives digitized current and voltage values from two merging units (MUs). The 87B23-79DTL relay detected the fault in under 10 milliseconds from the fault initiation and correctly blocked two breaker reclosing relays from any reclosing attempts. An adjacent SV bus differential relay (87B23-2), which is configured to protect the bus section to which this line is attached, properly restrained for this close-in fault.**

In this paper, we provide an overview of the ComEd protection scheme implemented at the 138 kV substation, which is a mix of conventional relays that use traditional potential transformer and current transformer inputs and SV relays that use MUs from multiple manufacturers. We compare event records gathered from conventional distance relays (21) that also operated for this line fault, as well as a conventional bus differential relay (87B23-1) that properly restrained. From this analysis, we show that the SV relays provide similar performance as their conventional relay counterparts.

Additionally, we discuss a unique fault signature that was found through further analysis of the high-resolution event record as well as methods to check the performance of the MUs by comparing the data gathered from the SV relay and the conventional relay.

I. Introduction

The Commonwealth Edison Company (ComEd) provides electric service to more than four million customers across northern Illinois, the majority of the state's population. ComEd is a subsidiary of Exelon Corporation and has a history of implementing IEC 61850-based systems in stages to test the viability of the new technology and adapt it to the workplace. The evolution of these systems, including technology and topology choices, new technology in the workplace, metrics, and lessons learned, is discussed in detail in [1]. The paper in [1] discusses ComEd's third-generation IEC 61850 system, which was in the design phase at the time of publication. However, this paper specifically discusses the third-generation implementation and analysis of an event that occurred at Substation A.

II. Overview of IEC 61850 Sampled Values (SV)

IEC 61850 promotes the digitization of power system quantities and signals traditionally carried by copper conductors. IEC 61850 Generic Object-Oriented Substation Event (GOOSE) messaging is often the first IEC 61850 protocol that utilities implement to digitize signals used for protection and control purposes. This initial step provides a valuable opportunity to gain experience with the new technology prior to the implementation of complete digital secondary systems. GOOSE messages can be used to exchange both digital and analog quantities but are not used to exchange raw current and voltage samples used in protective algorithms by protective relay subscribers. IEC 61850 9-2, commonly referred to as SV, is the service that is used to exchange the raw power system samples from the station yard to the control house over Ethernet communication cables or network(s). SV operates on the same publish and subscribe model that GOOSE messages implement. Successful implementations and lessons learned are a useful starting point, but there are additional considerations for SV systems.

The digitization of these signals requires that functions traditionally done in a single intelligent electronic device (IED) be separated into multiple IEDs. In the simplest terms, these IEDs are:

- A merging unit (MU), which is normally located close to the primary equipment and performs the analog-to-digital conversion and publishes the digitized quantities in the SV message.
- A local-area network, which is used to permit the transfer of the SV message between IEDs. The topology and technology used must ensure that the samples are delivered consistently and without delay.
- Protective relays, which subscribe to the SV message and perform traditional protective algorithms. The subscriber relay must be able to securely adapt to a loss of SV messages through interpolation and the freezing of protection logic to ensure security of the system.
- A Precision Time Protocol (PTP) clock, which provides time synchronization to all devices. PTP is the time distribution of choice for IEC 61580-based systems as it can use the network to distribute time and aligns with the goal of reducing the wiring that would be required for conventional systems such as IRIG.

All these components are required and must work together for a successful SV implementation. IEC 61850-9-2 on its own does not provide the details required for a multimanufacturer implementation. To promote the interoperability of SV, the Utility Communications Architecture (UCA) International Users Group released an implementation guideline to assist with deployment of the technology. Reference [2] describes a subset of IEC 61850-9-2, including common sampling rates and message payload, that is commonly referred to as IEC 61850-9-2 LE. Further work by committees and manufacturers is underway to define and manufacture digital interfaces based on IEC 61850-9-2. However, the implementation at Substation A, which is discussed in this paper, is based on IEC 61850-9-2 LE.

The sample rate for 60 Hz systems defined in IEC 61850-9-2 LE is 4.8 kHz. The sample interval is 1 second / 4.8 kHz = 208 microseconds. The MU publishes this message with a fixed payload of 4 currents (IA, IB, IC, IN) with the resolution of mA followed by 4 voltages (VA, VB, VC, VN) with a resolution of cV. In addition to the headers that are used in GOOSE, IEC 61850-9-2 LE messages contain two specific fields that are used by subscribers to both align and monitor the SV subscription. The MUs must be time-aligned to ensure coherence of samples from multiple MUs. A time stamp is created by using a sample counter known as the field smpCnt. The smpCnt increments with each published sample from 0 to 4,799 every second, where sample number 0 is expected to occur precisely at the top of the second and each subsequent message would be separated by precisely 208 microseconds. The time difference between when the smpCnt is encoded in the message and when the message is published by the MU is considered the MU processing delay. Subscribers use the smpCnt to ensure the continuity and order of samples received in each SV message. Subscribers that are synchronized to the same high-accuracy time source can use the smpCnt to determine the SV message delay, including both MU processing and network delays. The sample synchronization status of the message is represented in the field smpSynch, which is an integer value from 0 to 254. During normal operation when the message is published by an MU synchronized to a global area clock signal, it contains a value of 2. Other values are used to indicate specific states of synchronization. 0 is used to indicate not synchronized, 1 indicates synchronization to a local area clock, and 5-254 indicate a specific PTP clock when using PTP power profile. Subscribers need to evaluate the smpSynch value of all incoming streams to enable or disable protection elements accordingly.

Methods for selectively enabling and disabling protection elements based on received smpCnt and smpSynch values are considered a local issue and may differ in each subscribing relay. Subscribing relays need to have a predetermined delay, during which they wait for SV messages to arrive before alarming and entering a contingency mode. This additional time, referred to as the network delay, includes the MU processing delay and all delays introduced by network equipment. This delay is seen as a reduction in the overall protection system operating time when compared to a conventional relay with the same characteristics. The subscribing relays at Substation A buffer the SV samples to a length controlled by the channel delay setting. The channel delay setting is set by using the measured maximum network delay of the subscribed streams combined with the number of lost SV messages the relay is required to ride through by interpolating data. Substation A has a measured network delay of 0.63 milliseconds. Through testing, it was determined that subscriber relays in service need to buffer three samples to ride through transient clock synchronization events. A channel delay setting of 1.5 milliseconds was selected using calculations from [3] and is generally the reduced operating time compared to a conventional relay. The channel delay setting needs to be considered when analyzing events from different systems.

III. ComEd Implementation of SV

IEC 61850 systems often use the terms station bus and process bus to describe the type of communications that occur on each network. Station bus protocols include all those used by conventional systems to monitor and control the power system. The station bus often includes GOOSE and PTP in addition to protocols for supervisory control and data acquisition (SCADA) and engineering access. Process bus IEC 61850 protocols typically refer to SV, GOOSE and PTP. Users can choose to implement a separate or combined station bus and process bus network. They can also choose to implement various topologies and network technologies to meet the application requirements for station bus and process bus networks.

As mentioned earlier, Substation A is the third generation of ComEd IEC 61850 implementations. Previous experiences in deploying the earlier implementations provided some key guiding principles for adding SV into the current design. Previous designs focused only on station bus protocols that implemented SCADA, engineering access, GOOSE, and PTP protocols using Parallel Redundancy Protocol (PRP) networks. Based on experience and to facilitate repeatable designs, the introduction of SV resulted in ComEd defining the term process bus to refer to a separate network that is reserved for SV messages exchanged between MUs and subscribing relays. This decision provided isolation from the existing proven station bus designs and allows reusing existing station bus designs on systems that use SV.

This station employs a mix of both conventional and SV relays and two independent protection systems that are separate physical networks. System 1 relays are the conventional type and implement only station bus networks that follow the previous designs. The station bus networks are PRP software-defined networks to provide redundant PTP and GOOSE messages. System 2 relays are a mix of SV and conventional relays. The System 2 relays use the same station bus PRP network as System 1. The System 2 process bus network is a software-defined network employing a failover topology.

IV. Implementation and Lessons Learned

Highly accurate network time synchronization is essential for successful SV systems. ComEd had implemented a PTP-based system previously using its PRP networks with an independent PTP master clock on each network. In this arrangement, each IED is actively seeing and training from a different clock on each physical network interface and uses the best master clock algorithm (BMCA) to determine the clock and interface to be used. In the SV system, monitoring of SV subscription and synchronization status, including the blocking of any SV protections when issues were detected, revealed that transient issues with synchronization that had been previously undetected or insignificant to conventional relays could be seen by SV subscribing relays.

Using PRP networks for PTP time synchronization added additional complexity for troubleshooting transient issues with synchronization. Independent PTP master clocks, transparent clocks (network switches), SV subscribers, and MUs all implementing the BMCA independently makes it difficult to determine where a momentary issue may exist. It became evident that timekeeping Relay Word bits and reports to show the present time synchronization status were now as important as power system quantities. Event reporting digital and analog data and triggers were added to IED oscillography reports to assist with the analysis. Network traffic capturing devices were also required to analyze the PTP traffic seen by IEDs during transient synchronization events. With PRP networks, the IEDs see two simultaneous PTP streams, resulting in the need to capture traffic on both ports simultaneously when an event occurred to analyze the complete picture of what the IED was seeing. Information collected from these events was used to enhance IED performance when using PTP on PRP networks.

Implementers and maintainers of PRP systems must be aware of and check for failures that are hidden by PRP networks. An example of this was observed during a planned firmware update to a PTP master clock on one of the PRP networks. It was not until the clock was removed from service for the update that a failure was annunciated on the partner PRP network. This resulted in a loss of synchronization to SV subscribers and MUs that resulted in the blocking of protections on the SV system. This situation is not unique to PTP and could happen to other mission-critical GOOSE or SV messages. Care must be taken during planned maintenance activities. Further innovations to monitoring logical nodes are required for PRP systems to annunciate failures on each network independently.

The SV subscribers used in this system have an SV channel delay setting range from 1 to 3 milliseconds that is set in the field. During commissioning, the network delay was measured as 0.63 milliseconds. The initial channel delay setting chosen was 1 millisecond to compensate for the network delays and have the SV relays operate as close to the same speed as the conventional relays for in-zone faults. The reduction in the channel delay time comes at a cost in that it also reduces the number of samples that the subscriber interpolates before blocking the protection. It was found that during a transient time synchronization event on an MU, subscribers with the 1-millisecond channel delay setting had a protection blocking event. Analysis of these events resulted in a field change of the channel delay setting to 1.5 milliseconds to allow the subscriber relay to interpolate for the loss of three samples. After completing this change, the transient loss of synchronization in MUs no longer resulted in a protection blocking event in a subscriber.

V. Event Report Analysis

Now that we have provided an overview of IEC 61850 SV, ComEd implementation, and lessons learned from the Substation A installation, we now look at an event that occurred at Substation A.

On September 25, 2021, an A-phase-to-ground fault at Substation A occurred near a transition from a 138 kV underground cable to an overhead line. A picture of the damage is shown in Fig. 1. An oil-filled pothead that serves as the junction point from the overhead line to the underground line exploded. This explosion threw debris and oil around the surrounding area. Fortunately, no one was nearby when this explosion occurred.

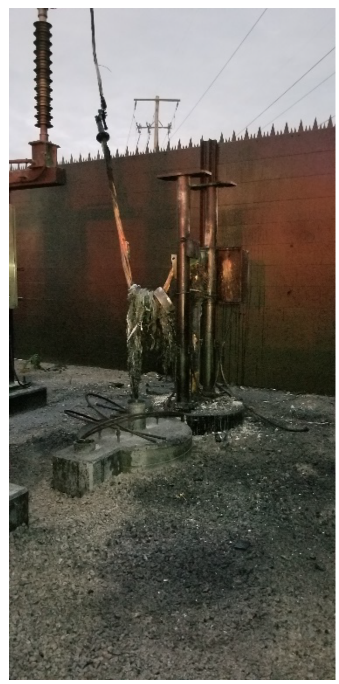

Fig. 1. Damaged overhead-to-underground transition.

Fig. 2 shows a simplified relaying one-line diagram with the location of the fault marked. The Substation A to Substation B line is a radial line (there is no fault current contribution from Substation B). There are five separate relays that respond to this fault and are described with their relay type, function, and the current transformers (CTs) they acquire analog data from in Table I. All relays in Table I are made by Manufacturer A.

TABLE I
SUBSTATION A BUS PROTECTION, LINE PROTECTION, AND BREAKER CONTROL RELAYS

Relay Name	**Relay Type**	**Function**	**Analog Data Acquisition**
87B23-79DTL	SV	Underground line section fault locator—sends GOOSE messages for reclosing lockout to 50BF-1 and 50BF-2 on Breakers 18 and 22	CT 3 via MU Manufacturer B CT 5 (Optical) via MU Manufacturer C
87B23-1	Conventional	System 1 bus protection for Substation A Bus 23	CT 1 CT 6 CT 9
87B23-2	SV	System 2 bus protection for Substation A Bus 23	CT 2 via MU Manufacturer A CT 7 via MU Manufacturer A CT 8 via MU Manufacturer A
21-1	Conventional	System 1 line protection for Substation A–Substation B transmission line	CT 4
21-2	Conventional	System 2 line protection for Substation A–Substation B transmission line	CT 3
50BF-1, 50BF-2	MU and conventional	Breaker failure and control relays for Breakers 18 and 22—receive GOOSE messages for trip (21-1 and 21-2) and lockout (87B23-79DTL)	CT 7 CT 8

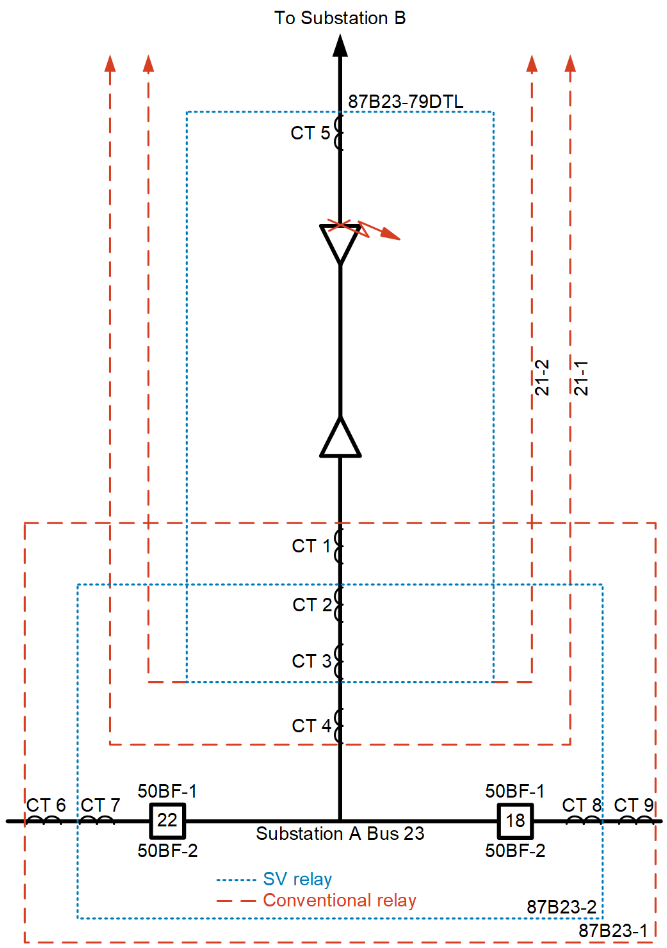

Fig. 2. Simplified protection one-line diagram.

For this fault, Relays 21-1, 21-2, and 87B23-79DTL operated and Relays 87B23-2 and 87B23-1 restrained. This is the expected and correct operation for all relays. In the next subsections (A through C), we analyze the events provided by the relays in more detail.

In the following analysis, an unfiltered event report refers to an event containing unfiltered analog data sampled at a fixed sample rate. A filtered event report refers to an event containing the fundamental frequency phasor data and is sampled at a variable rate defined by the frequency of the system (i.e., 12 samples per cycle, where time duration of a cycle can be variable). Both event types contain digital data.

A. 87B23-79DTL Event

The unfiltered event report data, sampled at 2 kHz from the 87B23-79DTL relay, are shown in the top two graphs in Fig. 3. The Substation A contribution (I01, I02, I03 from CT 3) to the fault is significant with peak current values higher than 30 kA. In contrast, the Substation B terminal produces no fault current contribution (I04, I05, I06 from CT 5), but some load is connected to the line. The 87B23-79DTL relay is a low-impedance bus differential relay that vectorially adds the filtered current contribution from the two three-phase current sources to produce an operate current (IOP1, IOP2, and IOP3). The relay also adds the magnitude of the two three-phase current sources together to create a restraint current (IRT1, IRT2, IRT3) using filtered current. For this A-phase-to-ground fault, there was very little current flowing in the unfaulted phases, and we plotted only the A-phase operate magnitude and restraint magnitude (IOP1 and IRT1) on the third graph. IOP1 and IRT1 are equal.

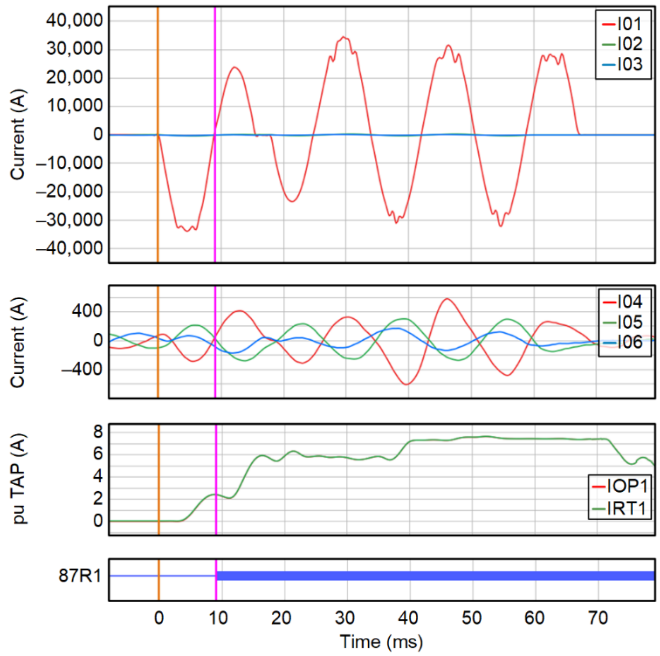

Fig. 3. 87B23-79DTL event.

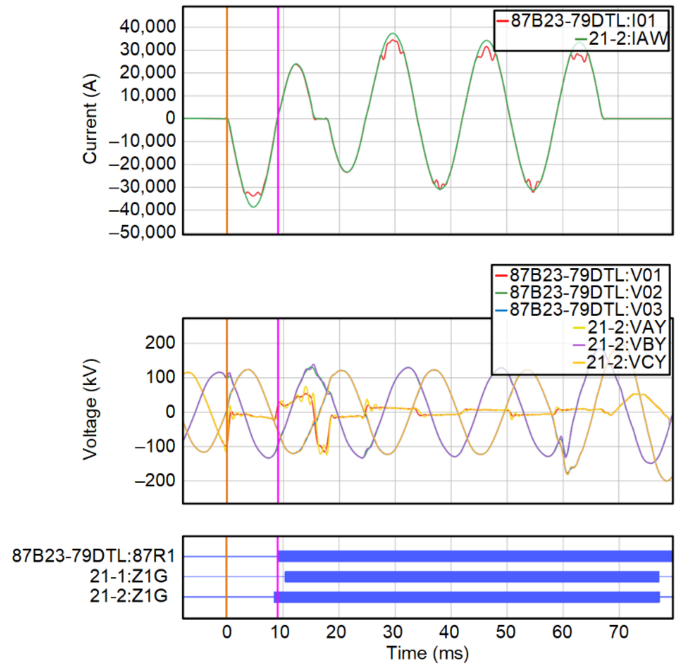

Fig. 4. 21-1, 21-2, and 87B23-79DTL data.

The IOP1 and IRT1 signals are scaled by the CT ratio settings and additional TAP scaling settings available in the relay. The CT ratio is 600:1 and the TAP scaling for all terminals is 5. All primary current values are divided by 3,000 (600 • 5). This puts the IRT1 and IOP1 signals in per unit (pu) of the TAP setting.

The ratio of operate current over restraint current (measured in percentage) is 100 percent, because IOP1 equals IRT1. For an operation to occur, the relay was set such that the ratio of operate current over restraint current had to exceed 60 percent. This requirement was met, and the relay was able to operate within 9 milliseconds of fault inception (87R1 assertion). Upon operation, the 87B23-79DTL relay sent a GOOSE message to 50BF-1 and 50BF-2, which are the breaker control relays at Breakers 22 and 18 to prevent reclosing on the underground section.

B. 21-1 and 21-2 Event

While the 87B23-79DTL relay prevented reclosing, the 21-1 and 21-2 relays issued a breaker trip for the fault and sent GOOSE messages to 50BF-1 and 50BF-2 to operate Breakers 22 and 18. The 21-2 unfiltered analog data and digital data were added to the 87B23-79DTL event to compare the analog data acquisition of a conventional relay (21-2) to the SV relay (87B23-79DTL) as shown in Fig. 4. The digital data from 21-1 was also added. The event report analysis software that was used automatically time-aligns the events based on the trigger time of the event report. Fig. 4 illustrates several key points.

The SV relay automatically compensates for the 1.5-millisecond channel delay for analog quantities when generating the unfiltered event report. This can be thought of as shifting the analog signals 1.5 milliseconds to the left along the x-axis. This allows for direct comparison between the analog signals from conventional relays and from SV relays when doing event analysis.

The digital bits shown are from the filtered event report sampled at the protection and control processing rate of each relay. These event reports contain the precise moment a digital Relay Word bit asserted. Using digital data from the unfiltered event report, which are not sampled at the protection and control processing rate of the relay, can produce a small timing error in Relay Word bits' assertion time. The maximum error when looking at unfiltered event report Relay Word bit assertion time is the time between samples (in this case, 0.5 milliseconds).

The analog data for 21-1 are not shown, but they are identical to the data for 21-2.

The fault arc temporarily extinguishes about 15 milliseconds into the fault. At this point, the current goes to zero and the voltage temporarily recovers for a 2-millisecond duration. The fault arc then reinitiates, once again collapsing the voltage and producing a large amount of fault current. All three relays operate prior to the fault arc temporarily extinguishing. The temporary arc extinguishment could be a result of the pothead explosion creating enough air displacement to temporarily extinguish the arc. Or perhaps a piece of nonconductive material, such as porcelain from the bushing, temporarily interrupted the connection from the energized equipment to ground during the explosion. Regardless of the exact method of arc interruption, we suspect that the explosion of the pothead occurred just after the relays had determined there was a fault and operated.

The 21-2 relay operated in 8.3 milliseconds, the 87B23-79DTL relay operated in 9 milliseconds, and the 21-1 relay operated in 10.3 milliseconds. Relays 21-1 and 21-2 have identical settings. There is a 2-millisecond difference in the conventional relays' operate time. These relays have a protection and control processing rate of 8 samples per cycle, which equates to a 2-millisecond processing interval (PI). It is reasonable to see a difference of 1 PI for operation times.

The A-phase current from 87B23-79DTL, which comes from an MU monitoring CT 3, does not exactly match the current from the conventional 21-2, which gets current directly from CT 3. The disagreement occurs near the peak values of current. It is suspected that the MU at CT 3 did not precisely report the CT 3 current above 50 A secondary. The voltage signals seen in each relay align very closely.

To further investigate the effects of the errant MU-produced current from CT 3, we looked at the filtered analog data from each relay. The filtered analog data for the A-phase current of Relays 87B23-79DTL and 21-2, which monitor the same current on CT 3, are shown in Fig. 5.

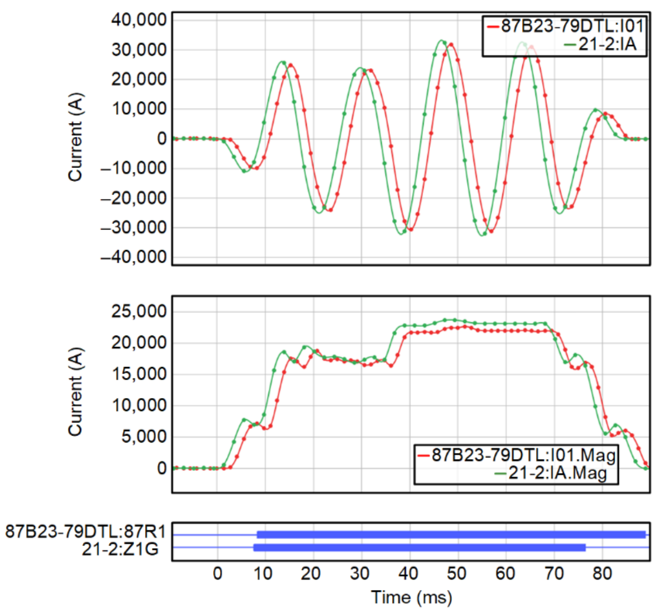

Fig. 5. 21-2 and 87B23-79DTL filtered A-phase current.

In Fig. 5, it is clear that the filtered analog signals from the 87B23-79DTL relay do not have the 1.5-millisecond channel delay removed. This is because the analog sample rate used by the conventional relay (i.e., 8 kHz) may be different than the SV relay (4.8 kHz). This means different anti-aliasing filters are used during the downsample process when converting the SV to a filtered value at the PI of the relay. These filter delays vary from relay to relay and cannot be easily accounted for. The current I01 from the 87B23-79DTL relay lags behind the 21-2 relay current, IA. Because of the channel delay, the angular error between the two relays' A-phase current phasor is 32.5 degrees, as shown in (1). However, the overall angular error can differ from (1) due to differences in filtering as previously noted or differences in the tracked frequency between the two relays. Great care must be taken if using filtered analog data from an SV relay and a conventional relay in event report analysis.

$$0.0015 \text{ s} \cdot 60 \text{ Hz} \cdot 360° = 32.5° \tag{1}$$

The error in the sampled A-phase current signal produces a lower overall current magnitude reported in the 87B23-79DTL relay. The 21-2 relay reports an A-phase current magnitude of 23 kA, while the 87B23-79DTL reports an overall current magnitude of 22 kA. This equates to a magnitude error of about 4.35 percent. This error is smaller than the 10 percent error we can expect with a well-sized CT during fault conditions [4].

C. *87B23-1 and 87B23-2 Event*

The 87B23-1 and 87B23-2 relays correctly restrained for this fault. The event report for both relays is shown in Fig. 6. The unfiltered analog data retrieved from 87B23-1 is nearly identical to 87B23-2, so we show only the current data from 87B23-1 (top graph). In the second and third graphs, we show the unfiltered time-domain-based operate and restraint currents for each relay. The Relay Word bit 87B23-1:CON1 is the external fault detector (EFD) from 87B23-1 and the Relay Word bit 87B23-2:CON1 is from 87B23-2. Both relays correctly identify this as an external fault.

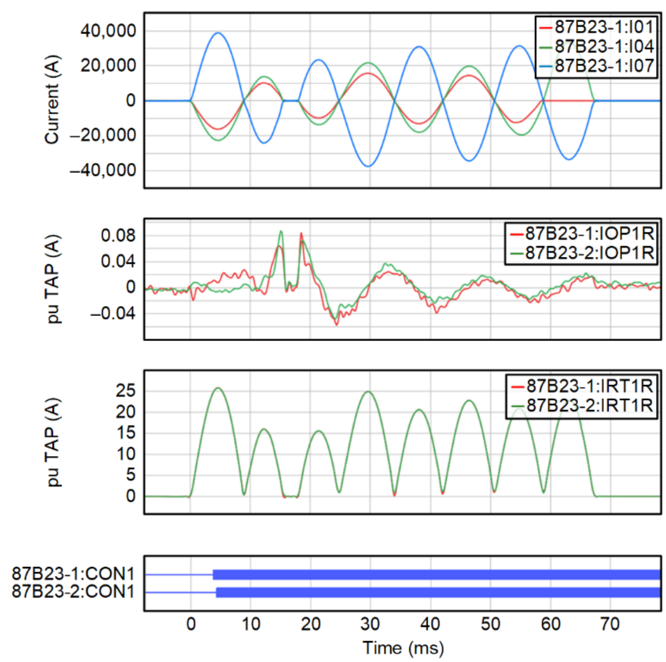

Fig. 6. 87B23-1 and 87B23-2 event data.

The current 87B23-1:I07, shown in Fig. 6, which is from CT 1, is the same as the current seen by the 21-1 (CT 4) and 21-2 (CT 3) relays except that the polarity is opposite. This is expected due to the connected CT polarity of the relays.

The time-domain-based IOP (IOP1R) and IRT (IRT1R) values in Fig. 6 are nearly identical between the two relays. The time-domain operate current, which is the addition of all the unfiltered current signals, is near zero throughout the entire event since all current is flowing through the zone of protection, not into the zone of protection. The time-domain restraint current, which is the addition of the absolute value of all the unfiltered current signals, increases rapidly at fault inception.

The 87B23-1:CON1 Relay Word bit asserts in 3.73 milliseconds from fault inception and the 87B23-2:CON1 Relay Word bit asserts in 4.33 milliseconds from fault inception, as shown in Fig. 6. This means the SV relay was only 0.6 milliseconds slower than the conventional relay at detecting an external fault.

A simplified logic diagram for the EFD is shown in Fig. 7.

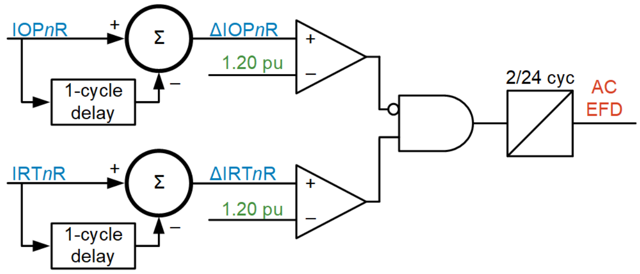

Fig. 7. EFD in 87B23-1, 87B23-2, and 87B23-79DTL relays.

The EFD is used to add security to the differential protection by quickly determining if the fault is within the zone of protection before the effects of CT saturation diminish relay security [5]. For an external fault, we expect the restraint current to increase but the operate current to remain at zero. If the change in restraint current over the course of 1 cycle (ΔIRT1R) is high, and the change in operate current over the course of 1 cycle (ΔIOP1R) is low, the relay declares the fault external after 2/24 cycles (1.389 milliseconds). It is important to note that the ΔIOP1R and ΔIRT1R signals are generated from unfiltered time-domain signals, not the filtered phase-domain values. Because of this, accurate reproduction of the current signals is very important at fault initiation for the relay to operate properly.

Fig. 8 shows the ΔIRT1R signals for 87B23-1 and 87B23-2 compared to the 1.2 pu threshold. We did not plot ΔIOP1R as it was apparent from Fig. 7 that it would not exceed the 1.2 pu threshold. The automatic 1.5-millisecond analog channel delay compensation provided by the relay in the unfiltered event is manually removed from 87B23-2 by shifting the signal 1.5 milliseconds to the right along the x-axis. The black cursors show the moment at which the 87B23-1 relay ΔIRT1R signal is above 1.2 pu and the moment when the logic in Fig. 7 times out (3.5 milliseconds). The green cursors show the moment at which the 87B23-2 relay ΔIRT1R signal is above 1.2 pu and the moment when the logic in Fig. 7 times out (2.6 milliseconds).

The two relays do not have their PIs in sync, so there are some discrepancies between this time differential (0.9 milliseconds), and the true operation time differential (0.6 milliseconds). This figure illustrates that it is possible for the time differential between the operate time of a conventional and SV relay to be shorter (or longer) than the channel delay setting. This is due to slight variations in the PI that each relay provides the Relay Word bit output.

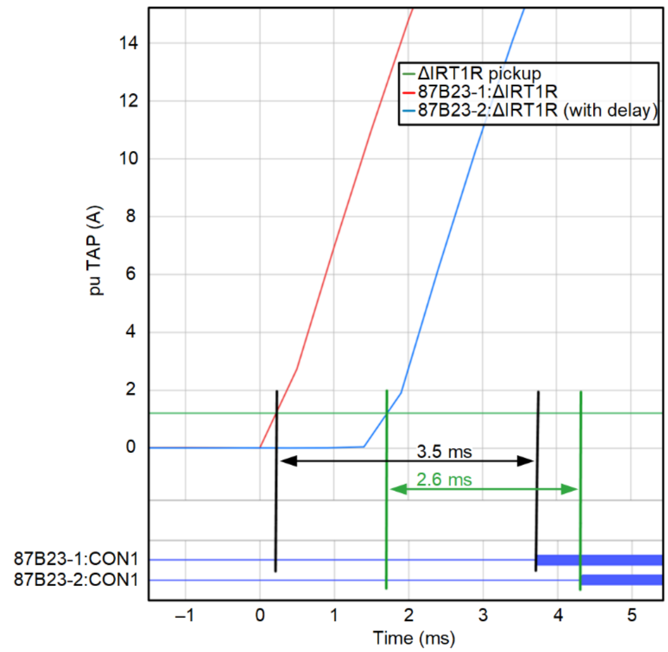

Fig. 8. 87B23-1 and 87B23-2 CON bits.

D. *GOOSE Message Performance*

In the discussion in Section V.C, we are simply looking at the relay operation time. For signals that must be transmitted using a GOOSE message to issue a trip to a breaker (like the trip signals from the 21-1 and 21-2 relays to the 50BF-1 and 50BF-2 relays), additional time delays must be considered to determine the amount of time it takes a breaker relay to issue a trip to the breaker.

Fig. 9 shows the assertion of Z1G in the 21-2 relay and the three-pole trip signal (3PT) that is issued at 50BF-2 for Breaker 18 (50BF-2(18):3PT) and Breaker 22 (50BF-2(22):3PT). In each breaker relay, a three-pole trip is initiated via Virtual Bit 58 (VB058). There is a 7-millisecond time delay between the relay declaring a fault and the breaker relay issuing a trip.

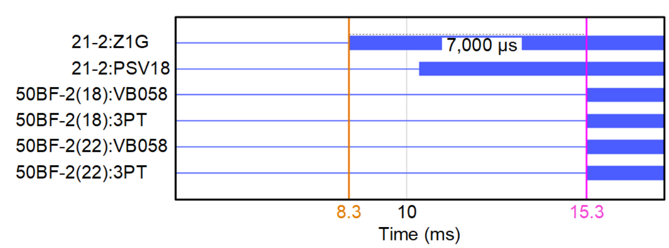

Fig. 9. Delay from relay operation to breaker trip signal.

We note that 2 milliseconds (1 PI for the 21-2 relay) can be saved from the overall trip time if intermediate logic (PSV18) was not used to send the GOOSE message to the 50BF-2 relay. ComEd uses relay logic for GOOSE message bit transmission to maintain a uniform naming convention for all Manufacturer A relays on their system.

The remaining 5-millisecond delay is from publishing the GOOSE message on the network, transmitting the GOOSE message over the network, and processing the GOOSE message at a subscribing relay. Since this event, advances have been made in GOOSE message processing for relay virtual bits that can further reduce operate time [3].

The relay system operate time, excluding relay contact time, is under 1 cycle (15.3 milliseconds) for this fault.

VI. Conclusion

This paper presents evidence of the performance of a real-world example of a multimanufacturer IEC 61850 SV solution operating correctly for a real-world fault. A low-impedance bus differential SV relay (87B23-79DTL) correctly identified the fault in the zone of protection and blocked reclosing via a GOOSE message to two breaker control relays. Two low-impedance bus differential relays, one a conventional relay (87B23-1) and one an SV relay (87B23-2), correctly restrained for this fault, which was out of their zone of protection.

Key lessons learned from this installation and analyzing the event data are:

Timekeeping Relay Word bits and reports to show the present time synchronization status are key in identifying system performance.

Setting a conservative channel time delay increases system dependability during clock resynchronization events.

The SV relays used in this application automatically remove the network channel delay from the analog signals in the unfiltered events. This allows for efficient and correct comparison between conventional and SV relays, even for users unfamiliar with IEC 61850.

The SV relays used in this application do not remove the network channel delay from the analog signals in the filtered event reports.

The binary digital data (Relay Word bit status) are unaltered in any event report. However, to determine the most precise operation time of the relay, download data are sampled at the protection and control processing rate of the relay.

Due to slight variations in relay processing, it is possible that an SV relay and a conventional relay can operate at nearly the same time. This is because the channel delay and PI duration of the relays can be similar.

VII. References

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VIII. Biographies

John Bettler has a BSEE from Iowa State University of Science and Technology and an MSEE from Illinois Institute of Technology (IIT). John has worked at Commonwealth Edison Company (ComEd), a power company in the Chicago area, for 29 years. He has experience as a field engineer and protection engineer. Currently, he is the principal engineer for ComEd's relay division. His team's purview includes 4 kV and 12 kV feeders up to 765 kV transmission lines and all transmission and distribution equipment in between (e.g., transformers, buses, cap, and inductors). John's team also reviews interconnections, independent power producers, and distribution generation projects. John is also adjunct faculty at IIT and University of Wisconsin-Madison teaching power and protection classes. He is a PE in Illinois.

Ryan McDaniel earned his BS in computer engineering from Ohio Northern University in 2002. In 1999, he was hired by American Electric Power (AEP) as a relay technician and a protection and control engineer. In 2005, he joined Schweitzer Engineering Laboratories, Inc. (SEL) and is currently a principal engineer. His responsibilities include providing application support and technical training for protective relay users. Ryan is a registered professional engineer in the state of Illinois and a member of IEEE.

David Bowen, a Certified Technician (CTech), graduated from the Electrical Engineering Technologist program at Georgian College in Barrie, Ontario, Canada. He is currently an application technologist for automation products in the sales and customer service division at Schweitzer Engineering Laboratories, Inc. (SEL). David has held this position with SEL since 2008. In this role, he provides training and assistance to customers applying SEL power system protection, automation, and communication products. Before coming to SEL, he spent 17 years working in protection, control, and automation departments at utilities in the greater Toronto area. During this time, he performed system integration for protective relays in applications ranging from 230 kV utility substations and low-voltage distribution to electromechanical relays and modern digital relays. David specializes in power system automation, legacy system integration protocols, and modern IEC 61850-based systems.

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