Using a Real-Time Digital Simulator to Compare Performance of Conventional Relays With Relays Based on IEC 61850 Sampled Values

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Original edition released July 2021

Using a Real-Time Digital Simulator to Compare Performance of Conventional Relays With Relays Based on IEC 61850 Sampled Values

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Abstract—**This paper compares the performance of two protection systems by measuring the same analog quantities. One system takes measurements through direct wiring, and the other receives information over Ethernet using the IEC 61850 Sampled Values (SV) protocol. The tests use a real-time digital simulator (RTDS) responsible for generating the analog quantities of the faults and measuring the response time of both systems by closing their respective digital contacts, consequently opening the circuit breakers. This paper is a translation of the original work of the same title.**

I. Introduction

Substation digitalization has gained relevance in recent years, and several studies have addressed the topic. One of the major reasons for substation digitalization is the reduction of cables used in conventional installations [1].

The IEC 61850 generic object-oriented substation event (GOOSE) protocol—which replaces the conventional control signals exchanged between intelligent electronic devices (IEDs) through physical contacts—already has many applications around the world, and users have some experience with how it works [1]. To enable GOOSE messaging across multiple IEDs, high-performance and high-reliability Ethernet networks are designed to transmit protection, control, engineering access, and monitoring information. This kind of network is known as a station bus; however, it is not the focus of this work.

The next step in the complete digitalization of a substation is to replace the cabling between instrument transformers and any relays with an Ethernet network. The IEC 61850-9-2 standard is an option through the Sampled Values (SV) protocol. The IEC 61850-9-2 process bus has different technical requirements than the station bus, making these networks physically independent. One characteristic of the process bus is the high availability it requires. When power system protection is totally dependent on this infrastructure, it requires cybersecurity to prevent unwanted access, precise time distribution using the IEEE 1588 protocol, and recovery times within microseconds.

The main objective of this paper is to evaluate the performance of protection systems that receive SV through the IEC 61850-9-2 protocol compared to conventional relays, for which performance metrics are already known. For this, a real-time digital simulator (RTDS) is used to simulate a transmission line and generate faults, producing single Phase A faults on the line with variations in fault location, fault resistance, incidence angle, current transformer (CT) saturation, and process bus traffic volume.

II. Test Scenarios

The RTDS is used to generate analog signals which are then applied to two protection systems: one conventional and one simulating a substation with a process bus that uses SV messages. The two relays have identical protection algorithms. Thus, the variation in operating times is due to differences in analog signal acquisition.

The RTDS applies analog signals directly to the conventional relay and to an IEC 61850-9-2-compatible merging unit (MU), which is the IED responsible for digitizing the measurement information and transmitting it to the process bus. The MU must have equal or better hardware requirements than protective relays because it is installed in the substation yard; therefore, it must be robust enough to withstand environmental conditions such as high temperatures, humidity, and electromagnetic exposure. The MU must also have built-in high-speed, high-current interrupting contacts because auxiliary tripping relays may have temperature limitations incompatible with a substation yard and cause additional delays in fault-clearing time. As MUs and Ethernet switches become part of the protection system, they must meet at least the same requirements as the protective relays in terms of type testing, certification, and high availability. Reference [2] shows the high failure rate of MUs installed in China and suggests that an accelerated lifespan test be used to evaluate them.

The process bus is responsible for delivering information generated by an MU to the protective relays quickly and reliably. To ensure resilience against process bus failures, the network needs to be carefully scaled using rapid failure-recovery techniques, such as software-defined networking (SDN) or network duplication. To this end, switches and relays were interconnected through 100 Mbps ports, and 1 Gbps ports were used for interconnection between switches.

When both protective relays receive measurements generated by the RTDS, they execute the protection algorithm and send a tripping signal using the distance element in Zone 1. It should be noted that both relays use the same algorithm, and by extension, the operating times of the distance elements must be equal. The conventional relay closes a digital contact on its own hardware, while the relay connected to the process bus issues a GOOSE message via the process bus to signal the MU to close a digital contact. The digital contacts of both devices have a closing time of less than 10 µs, i.e., the contact time is negligible and will be disregarded throughout this analysis.

The RTDS receives tripping signals from both solutions and opens the circuit breakers, also simulated in this test. The circuit breakers completely interrupt the currents when zero-crossing occurs after mechanical opening of the poles [3]. This behavior allows different opening times, which depend on the protection time and other conditions, such as fault incidence angle and the X/R ratio of the system. Both simulated breakers have the same mechanical opening time of two cycles, but the primary goal of complete current interruption also depends on the arc-extinction time.

The process bus requires high-precision time synchronization so that analog measurements generated by different MUs are synchronized to the protective relays. For this test, the IRIG-B protocol is used, but another option is the IEEE 1588 Precision Time Protocol (PTP).

When considering a practical application in substations, opting for PTP has considerable advantages over IRIG-B because the time synchronization is provided by the process bus network itself, optimizing the physical environment. However, care must be taken so that high traffic or incorrect queue prioritization and processing settings do not hinder PTP packet delivery and, as a result, the accuracy of the time synchronization [4]. Fig. 1 shows a diagram of the equipment involved in the tests detailed here.

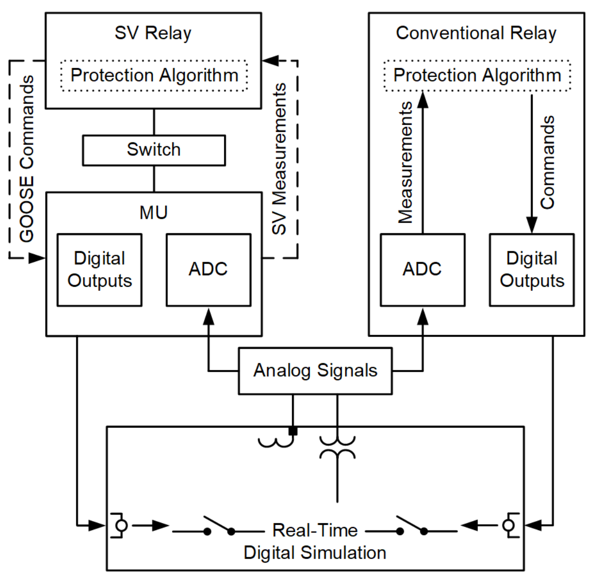

Fig. 1. Test diagram: SV solution on the left, conventional solution on the right.

In Fig. 1, the SV-based solution is on the left and the conventional solution is on the right. Both solutions have three common components: a protection algorithm, an analog-to-digital converter (ADC), and digital outputs. No significant differences are expected for the same components applied in the two solutions. Both solutions receive the same single set of analog signals that is generated by the RTDS, and both solutions also transmit the tripping signal to the RTDS, which calculates the timing of the respective breaker openings relative to the start of the event.

In a conventional relay, the information exchange between the ADC and the protection algorithm, and from the protection algorithm to the digital outputs, is performed internally by the equipment itself. In the SV-based solution, this information exchange is accomplished via Ethernet network. This exchange is represented by dashed lines, as shown in Fig. 1.

The MU is responsible for ADC conversion and for formatting the SV packet. This SV packet travels over the network and is delivered to the relay, which opens the SV packet, interprets it, and executes its algorithms. When deciding on a trip signal, it creates a GOOSE message and sends it back to the network. This packet travels the same path again and is delivered to the MU, which interprets it, processes it, and closes the contact. These delays do not exist in the conventional solution because all processes are carried out within a single piece of hardware. Where the same conditions exist in each system, it is expected that the process-bus-based solution will have a higher total trip time than the conventional solution.

Currently, most IEC 61850 applications within transmission systems in Brazil do not use GOOSE messages for breaker trips, based on the authors' experience. This paradigm would have to be changed in SV-based systems.

The IEC 61869 standard specifies that the MU must have a maximum processing time of 2 ms for protection applications [5], and the IEC 61850-5 standard specifies that trip-related applications must ensure message transmission times of less than 3 ms [6]. Fig. 2 shows a diagram representing the time constraints mentioned in both standards.

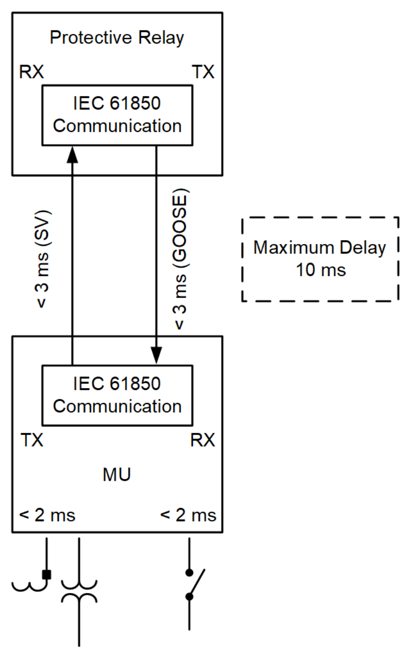

Fig. 2. Requirements for speed of communication between IEDs.

The MU scans the analog data of current transformers (CTs) and potential transformers (PTs) and formats the SV packet within 2 ms. Delivery of this packet to the protective relay should occur within 3 ms, including any delays imposed by network traffic. This communication is represented by the left-side, upward-pointing arrow in Fig. 2. From the samples available in the subscriber relay, it sends a trip signal via

GOOSE message to the MU, which must be delivered within 3 ms. This communication is represented by the right-side, downward-pointing arrow in Fig. 2. After receiving the signal to trip, the MU now has 2 ms to close its digital contact; this time specifically is not defined by the standards, but it is a specification of the hardware used. The digital contacts used in the test have a negligible mechanical closing time of up to 10 µs. Therefore, considering all delays allowed by the standards, it is expected that the process bus-based protection could take 10 ms longer than conventional protection, at most.

The communication time of SV messages is measured by the protective relays that subscribe to them, based on the time stamp of received messages whose sample count (SmpCnt) is 0, as these are generated at the top of the second in the MU. It is important to use channel time as a compensation setting in a relay that subscribes to these messages so that it applies an intentional protection delay, which then gives it time to compare all streams of the same SmpCnt [7].

Reference [8] is a study on operating times obtained in tests performed with relays and MUs from various manufacturers.

III. Test System

The test simulates the protection of a 138 kV line with parameters shown in Table I. The algorithm responsible for detection is the distance protection, and the first zone is set to 80 percent of line impedance.

Table I
System Parameters

Parameter	Value
Rated frequency	60 Hz
Rated voltage	138 kV
Line length	50 km
Positive sequence impedance	25.41 ∠ 68.25º Ω
Zero-sequence impedance	95.19 ∠ 74.80º Ω
Pre-fault current	200 A
Source-to-impedance ratio	0.5
Zone 1 reach	20.33 Ω
CT	C800
PT ratio	2000/115
CT ratio	100/5
Breaker mechanical open time	2 cycles

IV. Tests Performed

A. Variation in Fault Location

The goal of the first test is to determine the trip time difference between the two systems, accounting for faults at different locations on each line. The results illustrated in Fig. 3a show the average response time in ten trials at each location, in addition to the maximum and minimum values of the ten trials. All faults in this test are performed with an incidence angle equal to 0 degrees, without fault impedance. Fig. 3b shows the average difference in operating times between the two solutions for various fault locations.

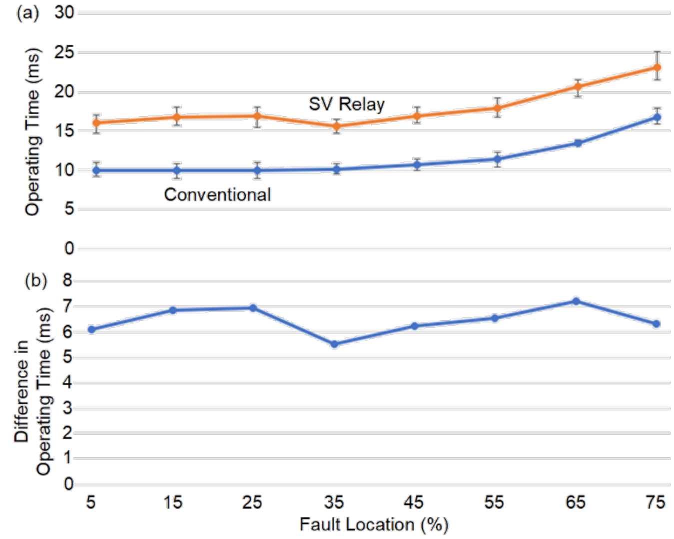

Fig. 3. (a) Operating times of the two solutions evaluated for several fault locations. (b) Average difference in operating times for different fault locations between solutions.

As expected, the performance of the process bus protection system is slower than that of the conventional system. Another significant observation is that the performance time of the SV-based solution is less deterministic; it has a greater discrepancy between maximum and minimum values than the conventional system.

B. Variation in Incidence Angle: Single-Pole Tripping

Based on the results of the previous test, several faults are analyzed on 65 percent of the line, with incidence angles varying from 0 to 359 degrees. In addition to assessing the difference in protection system operating times, the analysis includes the precise moment when breakers opened and cleared a short circuit. In this trial, a single-pole breaker with only the faulted phase opening is considered.

Fig. 4a shows the digital contact operating times for both solutions, and Fig. 4b shows the time difference between the two solutions.

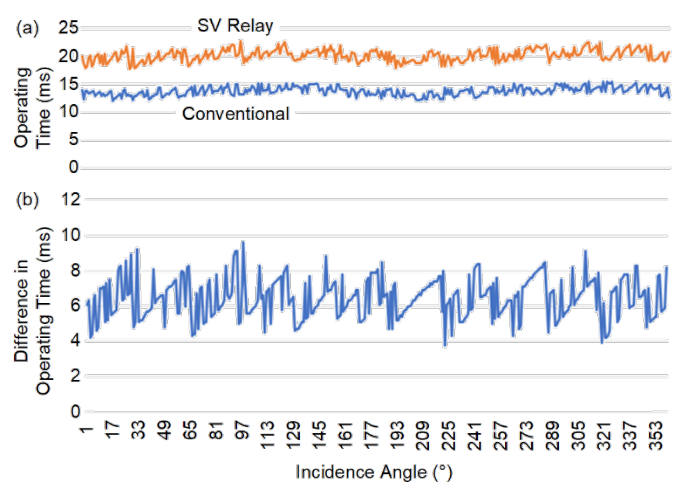

Fig. 4. (a) Comparison of operating times for various points of incidence. (b) Operating time difference between solutions in relation to the point of incidence: single-pole tripping.

It is evident that the difference in operating time ranges from approximately 4 to 9.5 ms. Each of the breakers modeled here has a two-cycle mechanical opening time. That is, after two cycles from the trip signal reception, the circuit breaker opens, but current continues to flow until it crosses zero and is completely interrupted. Fig. 5 shows the differences in breaker opening times.

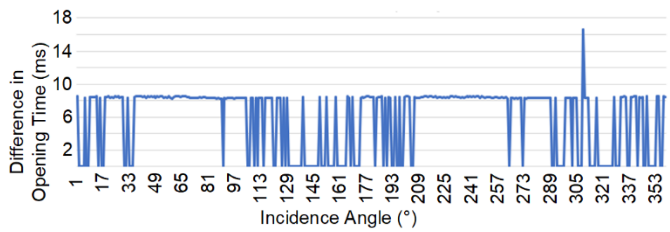

Fig. 5. Differences in breaker opening times: single-pole tripping.

An analysis of Fig. 5 shows that, regardless of the time differences in the protective relays, there are only three possibilities for breaker opening times in this test scenario.

1) Time Difference of 0 ms

For better understanding, Fig. 6 shows the oscillography of the test performed for a 140-degree incidence angle.

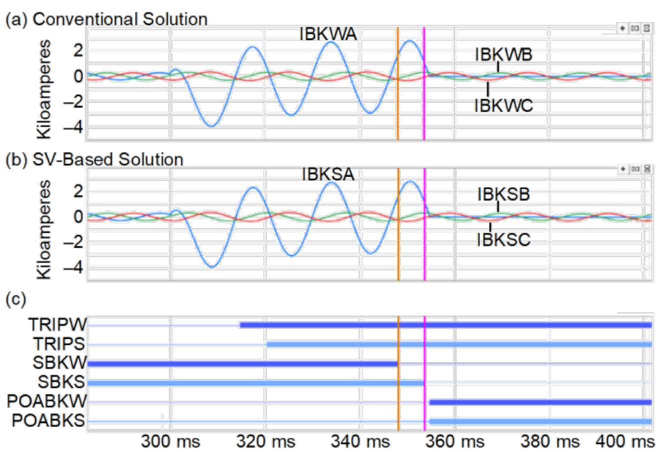

Fig. 6. Test with incidence angle equal to 140 degrees.

Fig. 6a shows currents measured by the conventional relay (IBKWA, IBKWB, and IBKWC), while Fig. 6b shows quantities measured by the SV relay (IBKSA, IBKSB, IBKSC). Fig. 6c reflects the digitals collected by the RTDS. It is evident that the conventional relay tripping signal (TRIPW) is received before the SV relay signal (TRIPS). The breaker linked to the conventional system finishes opening its poles (SBKW goes to zero at the orange cursor) before the breaker linked to the SV relay (SBKS goes to zero at the magenta cursor), but both breakers are running current at these moments and wait for the next zero-crossing of Phase A to open. In this case, both breakers open at the same time (i.e., without lag).

2) Half-Cycle Time Difference

This is the most likely case, where the conventional solution breaker interrupts the current half-cycle before the SV-based solution. Fig. 7 shows the oscillography of the test with an incidence angle of 240 degrees.

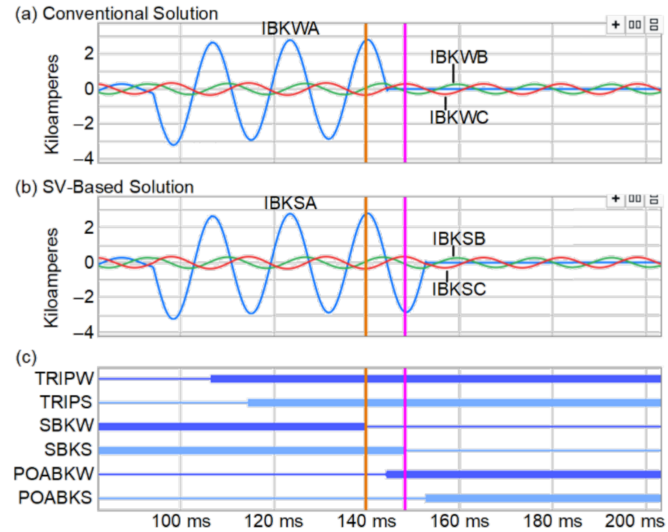

Fig. 7. Test with incidence angle equal to 240 degrees.

Fig. 7 shows the currents of both breakers, as well as the digital signals collected by the RTDS, in the same order as in Fig. 6. TRIPW is received before TRIPS, which allows the conventional solution breaker poles (SBKW) to open before the SV relay's poles (SBKS). Both breakers wait for the next zero-crossing to interrupt the current. In this case, the zero-crossing that effectively interrupts the current is a half-cycle out of phase.

3) Time Difference of One Cycle

In some cases, it is possible that the difference in operating times between the two relays results in a one-cycle delay in breaker opening. Fig. 8 shows the oscillography of the test performed with an incidence point of 309 degrees in the same order as the previous figures.

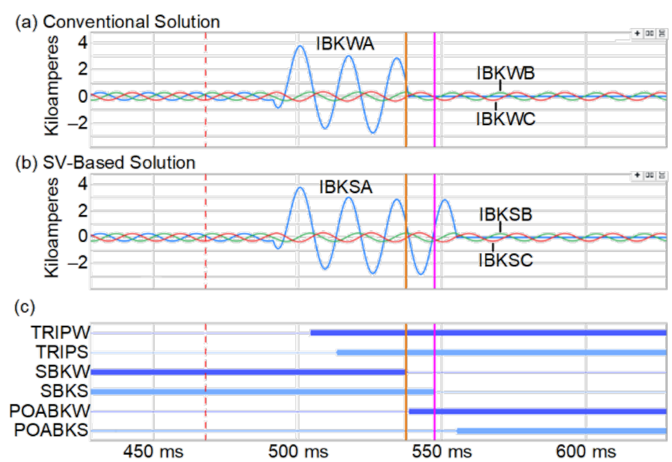

Fig. 8. Test with incidence angle equal to 309 degrees.

In this test, TRIPW is measured 9.1 ms before TRIPS. This allowed the breaker poles of SBKW to open 9.1 ms before the respective poles in SBKS. Immediately after the conventional breaker's poles are open, a zero-crossing is found, providing a quick interruption of the arc. The SV-based solution breaker finishes its pole opening after 9.1 ms, which makes the next zero-crossing take one cycle longer than the conventional solution opening.

C. Variation in Point of Incidence: Three-Pole Tripping

As shown previously, similar behavior can be observed when a three-pole breaker is present, with one small difference. Fig. 9a shows the trip times obtained in both solutions for faults on 65 percent of the line with varying incidence angles. Fig. 9b shows the difference in operating times between the solutions.

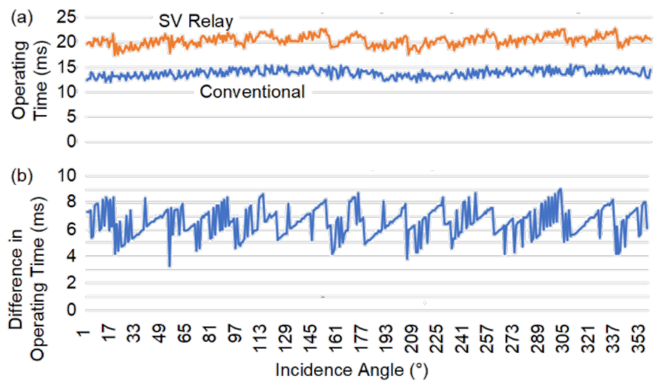

Fig. 9. (a) Comparison of operating times for various points of incidence. (b) Time difference between the two solutions in relation to the point of incidence: three-pole tripping.

Fig. 10 shows the difference in opening times of the breakers, which are now three-pole.

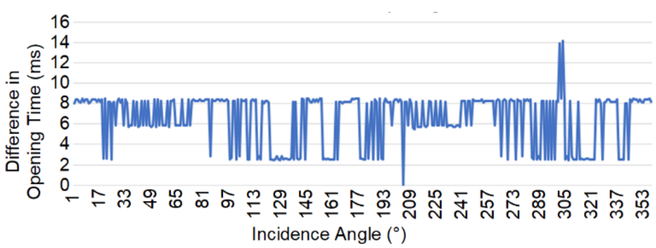

Fig. 10. Differences in breaker opening times: three-pole.

The observed behavior is similar to that shown in Fig. 5, but there is no guarantee that the difference between breaker openings is a half-cycle multiple because the last phase to be interrupted will not necessarily be the faulted phase in a three-pole breaker.

Fig. 11 shows the oscillography of the 304-degree incidence point test, which results in a fault interruption difference of 14.2 ms.

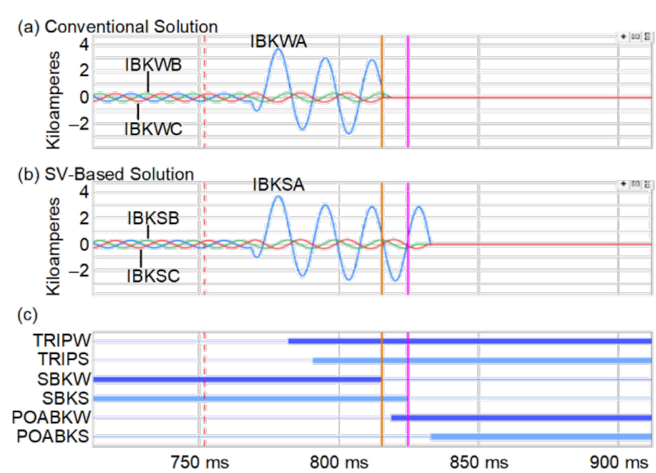

Fig. 11. Test with incidence angle equal to 304 degrees.

D. Variation in Fault Resistance

All previous faults were simulated without fault resistance. In this section, results are shown for faults with varying fault resistance in primary Ω. Fig. 12a shows the operating times of both protection systems. The results correspond to the average of ten trials under the same conditions, and the graph also shows the maximum and minimum values obtained. Fig. 12b shows the mean operating time difference in relation to the fault resistance variation.

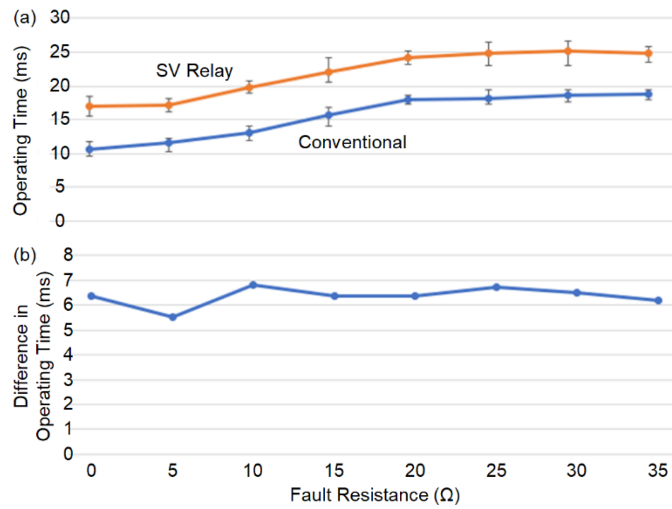

Fig. 12. (a) Operating times as a function of fault resistance. (b) Difference in operating time as a function of fault resistance.

It is evident that an increase in fault resistance causes a delay in the distance relay operation, which is expected because it reduces the fault currents and the voltage sag. The increases in operating times are similar for both solutions so that the time difference between them remains approximately constant, in the range of 5.5 to 7 ms. This demonstrates that the increase in fault resistance does not generate significant variation from earlier results.

E. CT Saturation

All previous tests were performed with secondary impedance equal to 8 Ω and power factor equal to 0.5 inductive, which are values equal to the standard burden of the CT in use. In the CT saturation test, faults are simulated on 30 percent of the line with an incidence angle of 0 degrees and variation in secondary burden. Fig. 13a shows the operating times obtained from both solutions with an increase in the secondary impedance of the CTs, causing their saturation. Each result is the average of ten similar trials, and the graph also shows the maximum and minimum value of each test. Fig. 13b shows the average difference in operating time in relation to the secondary impedance of the CT.

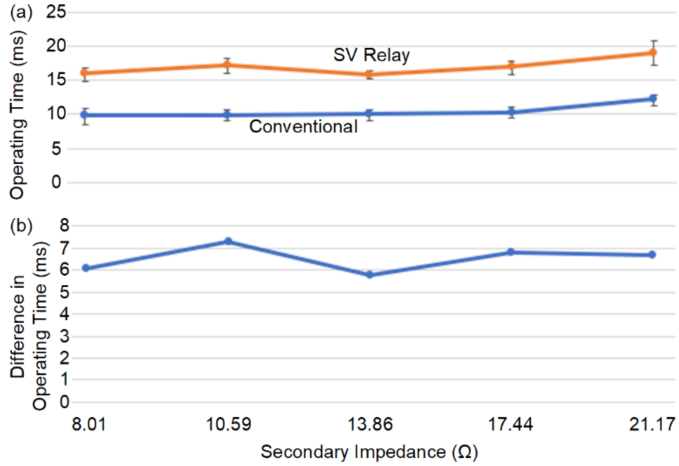

Fig. 13. (a) Operating time in relation to CT secondary impedance.
(b) Difference in operating time in relation to CT secondary impedance.

It is evident that there are no significant differences in the operating times of either solution when there is an increase in the secondary CT impedance; both relays have subcycle elements and can respond before the CT saturation, as observed in this test.

Fig. 14 shows a conventional relay oscillography with a CT whose secondary impedance is 17.44 Ω, which represents more than twice its standard impedance. In this oscillography, Fig. 14a shows the CT primary currents, and Fig. 14b shows the CT secondary currents. The digital variables are illustrated in Fig. 14c, showing that the TRIPW signal is emitted within 10 ms, even with CT saturation.

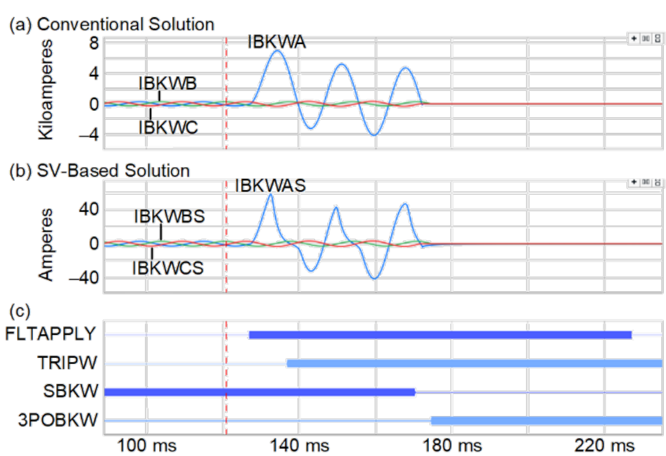

Fig. 14. Fast operation of conventional relay even with CT saturation.

F. Variation in Network Traffic: VLAN Disabled

A substation is expected to have more than one MU and more than one subscriber protective relay, which increases traffic on the process bus. To simulate the heaviest network traffic conditions, several tests are performed with faults on 45 percent of the line, the incidence angle at 0 degrees without fault resistance, and with variation in the number of published SV streams in the network.

An IEC 61850-9-2LE SV stream is an information packet containing four voltages and four currents that are approximately 150 bytes long, with a 10-byte SV Identifier and an approximately 20-byte Ethernet header. Because these messages are published 4,800 times per second on a 60 Hz system, it is estimated that approximately 5.76 Mbps of bandwidth is consumed per stream [9]. Fig. 15 shows the performance times of both solutions accounting for an increase in network traffic. Each test is performed ten times, and the graph shows the tests' average values, as well as the minimum and maximum values. In this case, the virtual local-area networks (VLANs) of the switches are intentionally disabled.

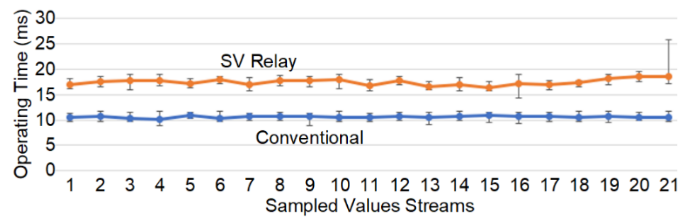

Fig. 15. Operating times compared to the number of streams on the network.

Fig. 15 shows that when the number of streams is greater than 18, the average operating time of the SV-based solution increases. For an extreme case of 21 streams, the maximum difference in operating times reaches 15 ms. However, the most important events are not represented in the graph; starting from 18 streams, SV-based protection begins to fail.

With 18 streams on the network, traffic approaches 100 Mbps and congests the communication channel, leading to additional queue delays and packet loss. The SV relays used in this test have interpolation functionality, which can keep protection enabled for up to three packets lost. There is a specific report available on the protective relay for process bus analysis that provides critical diagnostic data. Fig. 16 is an example report showing that the relay is losing packets and successfully interpolating the waveform without disabling protection.

```
Ctrl Ref : XXX_401_1CFG/LLN0$MS$MSVCB01
APP ID : 4000

Last Update: 04/16/2019 18 : 56 : 32
Accumulated downtime duration (since       : 0000 : 01 : 24
last reset)                                : 463
Maximum downtime duration                  : 00.24

 #   Date         Time            Failure
 1   04/16/2019   18 : 56 : 32    INTERPOLATED
 2   04/16/2019   18 : 56 : 32    INTERPOLATED
 3   04/16/2019   18 : 56 : 31    INTERPOLATED
 4   04/16/2019   18 : 56 : 30    INTERPOLATED
 5   04/16/2019   18 : 56 : 29    INTERPOLATED
 6   04/16/2019   18 : 56 : 29    INTERPOLATED
 7   04/16/2019   18 : 56 : 26    INTERPOLATED
```

Fig. 16. Diagnostic report showing interpolation of samples.

In cases where the network is near its limit, starting at 18 streams, packet loss is likely to be high enough to disable protection, as happens in some test cases where the protection does not operate. This is strong evidence that using a VLAN can improve system performance.

G. Variation in Network Traffic: VLAN Enabled

VLANs can be used in SV packets for traffic segregation. The previous test is intentionally performed without using this technique to congest the relay Ethernet port that subscribes to SV packets. This same test is repeated where the SV relay only receives relevant information on its Ethernet interface by enabling and configuring VLANs on the switches. Fig. 17 shows the average operating times in relation to the number of streams present on the network. The maximum and minimum values of the test sample are also represented.

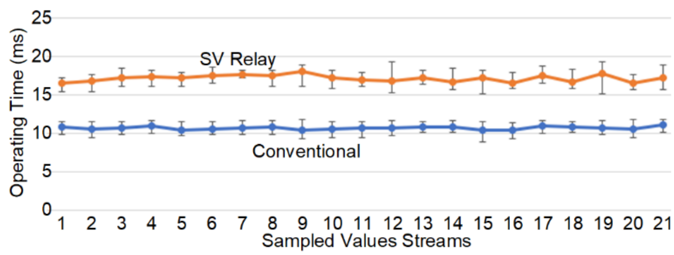

Fig. 17. Operating times compared to the number of streams on the network.

Enabling and correctly configuring VLANs results in efficiently filtered network traffic, which means the total traffic volume on the network does not influence the individual relay under analysis. Operating times vary slightly in all tests, regardless of traffic, and in no test did protection fail to operate.

V. MUs With Protection Elements

A mixed solution can be created that delivers the benefits of the IEC 61850 SV protocol, such as interoperable information sharing and reduced copper cabling in the substation, while retaining performance in operating times. To make this possible, the protection algorithms must be brought to the MU. MUs that function as full protective relays for bay protection can publish SV values from the measurements taken. Fig. 18 shows an example of this type of solution.

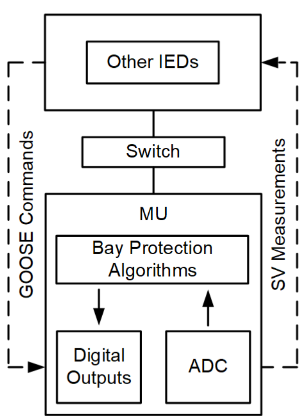

Fig. 18. MU with protection elements.

Fig. 18 represents an MU that is a line protective relay. In this IED, 21, 67, 79, and all other elements of a conventional and complete line relay are available. It also has event sequencing, oscillography, and bay control features. All of these elements are independent of the Ethernet network, which means they are insusceptible to communication delays and cyberattacks on the process bus, and they are also independent of substation timing devices. Furthermore, this MU is installed in the substation yard, resulting in reduced electrical wiring. In addition to providing process-bus-independent bay protection, this same IED publishes SV messages on the network, as shown in Fig. 18 (the IED is illustrated as a switch for simplicity). It assigns these measurements to other IEDs that need them, such as a bus protective relay or a digital disturbance recorder.

VI. Conclusion

Several conclusions can be drawn from these analyzed scenarios. One of them is the high speed of the protection used, which has subcycle elements and allows operation in times of less than one cycle in various tests. While one solution relies on information transfer via the Ethernet network, SV-based systems encounter other delays which increase the total fault-clearing time in all scenarios.

Because the SV-based solution is slower than the conventional solution, it is possible to study the impacts of these delays on the electrical system. It is important to note that the trip signal emitted by the relay is not the information that matters to the protection system, but nonetheless it is the opening of the breakers that will physically clear the fault.

For tests with single-pole tripping enabled and variation in incidence angle, the time lag between solutions is 6.5 ms on average. Some tests have results as low as 3.8 ms or as high as 9.6 ms. By varying the incidence angle, peculiar behavior is observed in the effective opening of the breakers, such as zero-time, half-cycle, or one-cycle differences. For electrical studies that must consider maximum fault-clearing time, such as stability studies, the protection operating time of SV-based solutions should be recognized as one cycle longer than the conventional system time results—in the worst case—as long as the delay between trips is no more than 9.6 ms (which is the maximum difference found in the tests). Clearing time may exceed one cycle when this difference increases.

In 1976, the American utility Bonneville Power Administration conducted a study on one of its lines and found that the increase of one cycle in protection operating time corresponds to a 250 MW reduction in transmitted power with the same stability levels [10]. It is important to recognize that the use of SV-based protection impacts the stability of the electrical system, and this effect can be significant.

This additional protection system delay can have even greater effects on transformer protection. Reference [11] shows a required operating time of 1.5 cycles for differential transformer relays. In other words, the use of an SV-based system could add a delay on the same order of magnitude as the protection algorithm itself, allowing internal faults to cause severe damage to transformers.

The SV-based solution has an advantage when it comes to CT saturation. It is likely that an SV-based protection system has a lower level of saturation as compared to a conventional system because the MU is in the substation yard, while the relay is usually located in the control house. Considering this physical arrangement, the cabling of the SV solution is less than the conventional solution. For a conventional solution, installing the protective relays in the substation yard is a more-reliable alternative that also reduces cabling costs [12].

Over the past few decades, practically all protective relay manufacturers have sought to reduce protection times, either by implementing half-cycle filters [13] or by no longer using phasors [14], and this has had many benefits for the electrical system and society at large [15]. Adopting IEC 61850 SV-based solutions, however, has had different results. As such, it is the authors' opinion that this technology should continue in development to avoid these protection delays.

VII. References

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VIII. Biographies

Andrei Coelho received a degree in Electrical Engineering with an emphasis in Electrical Power Systems from Universidade Federal de Itajubá (UNIFEI) in 2014 and a specialization in Electrical Systems Automation from Instituto Nacional de Telecomunicações (INATEL) in 2019. He has been working in Schweitzer Engineering Laboratories, Inc. (SEL) application engineering and technical support since 2014, focusing on transmission and distribution applications as well as various industrial branches in the areas of protection, control, and automation. He contributes to articles and technical presentations at industry seminars and is a course instructor at SEL University.

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20210713 • TP6972-01