News From the Editor – Updates and Enhancements to Process Bus IEC 61850-9-2 and Related Standards

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News from the editor – updates and enhancements to process bus IEC 61850-9-2 and related standards

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Abstract

This paper provides an update on the recent standard developments related to Sampled Value (SV) communications. These standards propose that the current transformer (CT) and voltage transformer (VT) outputs that are presently hardwired to various destinations (relays, meters, intelligent electronic devices [IEDs], and supervisory control and data acquisition [SCADA] systems) be digitized at the source and then communicated to other devices using an Ethernet-based local-area network (LAN). This approach is especially important for modern low-power instrument transformers (e.g., optical CTs and high-voltage divider-based VTs) that can provide highly accurate information about primary voltage and current waveforms but are often unable to drive the traditional analog interfaces (5 A/120 V). While very promising, the SV communications bring along a distinct set of issues regarding the interaction of various International Electrotechnical Commission (IEC) standards and the need to standardize device and network performance as well as protocols. This paper shares the authors' experiences from participation in Utility Communications Architecture (UCA) and International Council on Large Electric Systems (CIGRE) interoperability demonstrations.

1 Introduction

Over the past three decades, microprocessor-based protection and control systems have revolutionized the way we manage and operate the power system. Aided by modern network communications, they provide unprecedented insight into network operation, empowering transmission system operators to respond to ever-changing market forces and energy demands. Fiber-optic communications technology has become the main choice for intersubstation communications. The same technology is also recognized for its ability to safely bridge the high-voltage (HV) potential and for its immunity to electromagnetic disturbances present in the HV substation yard. Optical transformers promise to make primary system measurements safer and more precise, while enabling size reduction of the primary system plant.

The low-power instrument transformer (LPIT) and intelligent switchgear revolution has, however, been very slow. Substation yard wiring is still predominantly copper-based with well-established 1 A/5 A and 120 V secondary level standards. The need for low-cost technology and the sheer number of individually terminated copper conductors in traditional wiring approaches (shown in Fig. 1) have long fostered a dream of fully digital secondary systems based on fiber-optic communications technology. However, this dream cannot be realized without a strong set of interoperable international standards that are mature enough to compete with the tried-and-true analog interface standards.

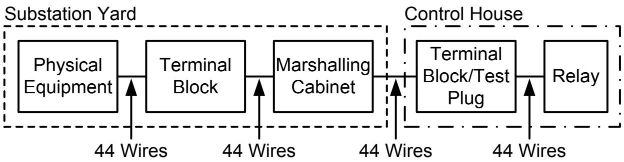

Fig. 1. Traditional wiring approach with relays in the control house.

While the industry waits for the availability of intelligent primary equipment, the merging unit (MU) concept has attracted interest. An MU has conventional copper connections to the primary equipment and acts as a field-mounted input/output (I/O) module (see Fig. 2) that digitizes analog measurements, binary statuses, alarms, and control signals. The MU publishes the I/Os as digital messages over fiber-optic communications links to provide significant wire reduction. The cyclic nature and predictable receipt of the messages permits the subscriber to immediately detect disruption to the message delivery and to continuously monitor the health of the data connection.

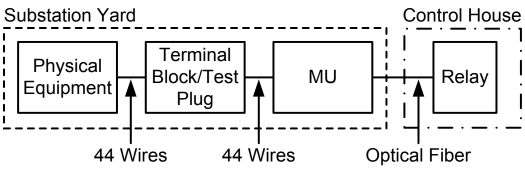

Fig. 2. Simplified diagram that shows cable reduction potential with Ethernet-based MU technology.

Sampled Value (SV) technology, described in the IEC 61850 series of standards, is the latest Ethernet network-based solution that promises to bring the digital secondary system dream to fruition. This paper (a shortened version of [1]) reports on the latest standardization efforts that are necessary to make digital secondary systems a reality.

2 Digital secondary systems

As explained in [2], Ethernet is gaining fast acceptance for packet-based message exchange to support data, voice, and video services.

In the power industry, IEC 61850 packet-based protocols are associated with Ethernet by design. These protocols include manufacturing message specification (MMS) for supervisory control and data acquisition (SCADA) as well as engineering access and real-time protocols that support communications-assisted protection and automation. IEC 61850 real-time protocols include Generic Object-Oriented Substation Event (GOOSE), more generally called generic substation event (GSE), and SV services [2].

IEC 61850 systems that use GOOSE and SV services to transfer information to and from primary equipment are known by many names, including process bus and digital substation. Neither of these two terms is an exact match. Process bus implies that a physically separate network is required for real-time data transfer, which is not correct. Digital substation is even more misleading because most of the secondary equipment has used digital microprocessor technology for decades. Given these limitations and the need for clear terminology, the authors propose to use the term "digital secondary systems" instead.

As [2] discusses in more detail, application requirements for the real-time protocol services (GOOSE and SV) include replacing wires traditionally used for information exchange between components. The horizontal data paths, labeled "wires" in Fig. 1, represent pairs of copper wires conducting real-time state, binary, and analog measurements. In this case, each data path includes a data source on the left and a data client on the right [3]. A typical bay requires 44 conductors. Fig. 2 illustrates an MU that performs the analog-to-digital (A/D) function for the information formerly conveyed by copper conductors at the control house. Instead, the MU publishes the information in a digital message over a single fiber-optic cable. Common protocols that are used to digitize and transmit bidirectional information between equipment in the substation yard and the relay in the control house include IEC 61158 EtherCAT, IEC 61850-9-2 Sampled Values, and IEC 61850 GOOSE [2] [3].

Although very comprehensive, IEC 61850 was created to standardize power system management and associated information exchange and intentionally does not define power system apparatus requirements or behavior. Therefore, there needs to be further standardization by other technical committees. This problem also creates uncertainty about the best way to apply IEC 61850 technology and leads to newer digital secondary system standards, including the IEC 61869 series that is maintained by IEC Technical Committee (TC) 38 (Instrument Transformers).

While conceptually very simple, the design in Fig. 2 does not illustrate Ethernet network topologies or additional capabilities that can be provided via multiple concurrent paths for digital messages. The fiber-optic link in Fig. 2 between the MU and the relay is illustrated as a dedicated, private, point-to-point interface. For a complete substation with multiple data clients performing protection and automation, this point-to-point method requires multiple cables, each one connected between the MU and a data consumer. This is especially true for station-wide protection services, such as for bus differential protection, bus voltage sharing, and breaker failure protection. A more general, interoperable, standards-based approach with a switched Ethernet network is shown in Fig. 3.

As mentioned in [2], an Ethernet switch makes it possible to share MU data with multiple clients, such as relays. It also allows multiple relays to issue trip commands, implement breaker failure protection, enable operator or SCADA control, and perform other functions necessary in day-to-day operation.

Whenever possible, a single optical fiber is used to carry many measurements. Fig. 3 shows a general, SV-based digital secondary system concept that has the typical dual-bus, breaker-and-a-half topology with conventional instrument transformers and breakers served by three standalone MUs (SAMUs). An SAMU is a time-synchronized data acquisition device that can convert the secondary measurements provided by instrument transformers into a continuous stream of samples, which are subsequently streamed over the fiber-optic-based communications network. In this digital secondary system concept, the data acquisition system is installed as close as possible to the primary system HV apparatus. Substation yard copper wiring is replaced with fewer fiber-optic communications cables.

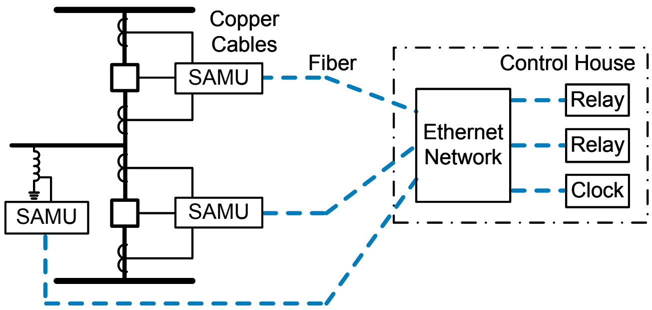

Fig. 3. Digital secondary system concept applied to an air-insulated HV substation.

Protective relays and control equipment are still located in the substation control house with the network equipment, allowing instrument transformer data to be streamed to multiple consumers or clients at multiple destinations.

Although the general system concept always applies, there are many ways that the basic technology can be tailored to meet particular design goals. For example, conventional instrument transformers can be replaced by their modern optical equivalents. Optical CT implementations can use individual fiber-optic pairs for each phase with measurement electronics located inside the substation control house. Alternately, measurement electronics can be located in the HV yard while delivering digital data to the fiber-optic network using the standardized SV output. An instrument transformer with a digital output can be integrated into HV equipment, enabling a greatly reduced footprint, intelligent breakers, disconnect switches, grounding switches, and so on.

Equally interesting changes are possible in the substation control house. Parts of the Ethernet network can be distributed throughout the substation yard, or multiple relay functions can be consolidated in a purpose-built computer. Network topologies are not fixed either, ranging from simple point-to-point links to highly configurable software-defined networking (SDN) topologies. While the digital messages and associated data exchange services are well-defined in the standards, the preferred equipment configurations and best practices used to design the substation have not been agreed upon. Early adopter utility experiences and manufacturer competition are playing a major role in bringing some order to this emerging market.

A digital secondary system concept discussion is incomplete without considering the SV application in the medium-voltage (MV) space. Fig. 4 shows the compact arrangement and short distances typically found in metal-enclosed MV switchgear applications. Protective relays are in the immediate vicinity of the breakers to take advantage of excellent equipotential bonding that is common to all device cabinets.

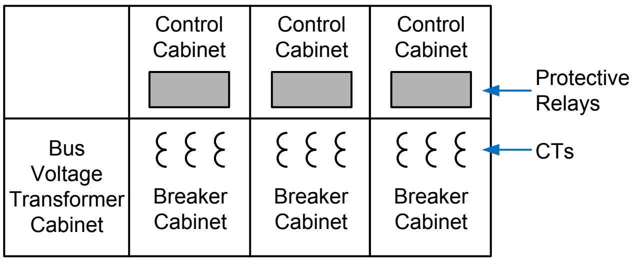

Fig. 4. Typical metal-enclosed MV switchgear.

MV applications provide very limited opportunity for copper reduction and can be made reasonably safe with insulated bus technology and arc-resistant switchgear construction. Intelligence is distributed with the protective relays assigned to each breaker, creating an intelligent switchgear interface. Instrument transformers are so close to protective relays that the conventional SAMU approach makes very little sense. Regardless of the lack of value derived from wire reduction, the distributed intelligence inherent in metal-enclosed MV applications can still benefit from SV-based technology, as shown in Fig. 5.

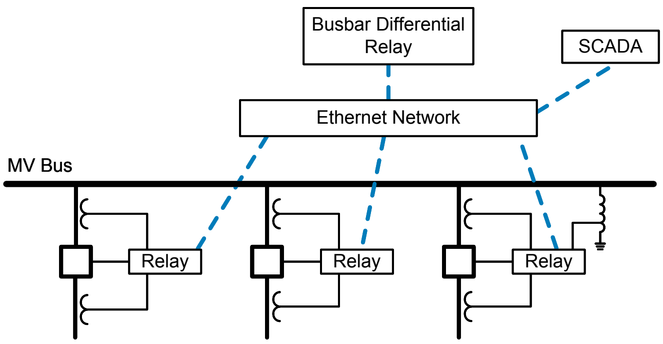

Fig. 5. Digital secondary system concept applied to metal-enclosed MV switchgear.

Contrary to the open-air, HV substation concept, which often uses SAMUs and concentrates intelligence inside the substation control house, MV applications foster distributed intelligence with direct data exchange and cooperation among peers [4]. Data exchange is used in cases when protection and control functions cannot be executed locally, such as to support busbar differential protection, implement transformer differential, share bus voltage across the relay lineup, or establish differential protection across an MV cable that is used to connect independent switchgear sections. SV data sharing is especially beneficial in cases when the conventional CTs and VTs are replaced with low-energy sensors (e.g., Rogowski coils and resistive voltage dividers), which take very little space but cannot be hardwired to multiple relays the way conventional voltage transformers (VTs) can. SV-capable relays with peer-to-peer data exchange capability and built-in low-energy sensor support are of special interest for space-critical applications and complex MV systems found in offshore applications and high-density data centers.

3 Instrument transformer standards

The act of separating the data acquisition system from the applications it serves creates a new set of challenges and standardization opportunities. It requires close cooperation between multiple technical committees. In the case of SV systems, interested committees include IEC TC 57 (Power Systems Management and Associated Information Exchange), which creates and maintains the data models and communications mechanisms defined in the IEC 61850 series, and IEC TC 38, which is tasked with defining signal processing and apparatus-level requirements defined in the IEC 61869 standard series. On the consumer (relay and meter) side, IEC TC 95 (Measuring Relays and Protection Equipment) is interested in making sure that the data MUs produce are appropriate for protection, that the devices themselves meet the stringent requirements described in the IEC 60255 series, and that they are accurate enough to calculate the synchrophasors described in IEC/IEEE 60255-118-1. IEC Subcommittee (SC) 77A (EMC — Low Frequency Phenomena) is interested in the power quality applications of SV. Finally, the IEC TC Subcommittee 17A (Switching Devices) is interested in SAMU coordination with IEC 62271-3.

These standards establish new lines of responsibility and a new contract between the sources (LPIT and SAMU) and the consumers. The following subsections provide an overview of the key instrument transformer standards being developed by IEC TC 38 and present some of their more interesting features.

3.1 IEC 61869-6 additional general requirements for low-power instrument transformers

IEC 61869-6 defines the general requirements applicable to LPITs. Because LPITs may use electronics and digital signal processing techniques, this standard defines the expected frequency response and anti-aliasing filter requirements that are common to many devices, including SAMUs and instrument transformers with built-in digital outputs. The frequency response mask concept is shown in Fig. 6.

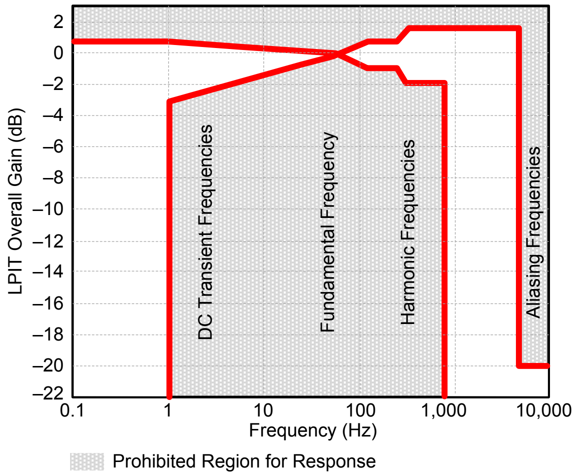

Fig. 6. Frequency response mask concept.

Based on this concept, the frequency response (gain) of the LPIT with digital outputs or an SAMU must fall in the unshaded areas. A similar requirement is provided for the phase fully defining the expected device performance. Fig. 6 shows that a device compliant with IEC 61869-6 can be ac- or dc-coupled, but when ac coupling is involved, the device is required to preserve signals with frequencies higher than 1 Hz. This requirement establishes a new contract between the instrument transformer and the device using the SV data. For example, in the past, protective relays could assume that all instrument transformers were of the same type, matching each other, and could therefore simply be added to form a differential zone. With the 1 Hz frequency mask requirement in place and no standardized behavior below 1 Hz, relay manufacturers are now responsible for ensuring that their protection schemes operate correctly for an arbitrary LPIT or SAMU combination. For example, the SAMU or MU can be dc-coupled or behave as a first-order 1 Hz, 0.1 Hz, or 0.2 Hz high-pass filter. In short, the SAMU or MU must stay within the frequency mask limits, but those limits are fairly relaxed. A frequency mask requirement creates new work for both the LPIT and relay manufacturers, but it also establishes clear lines of responsibility by defining the best- and worst-case waveforms that a subscribing device may receive. Specialized devices such as phasor measurement units (PMUs) may require better phase accuracy but can now use common terminology defined in IEC 61869-6 to express phasor measurement values.

3.2 IEC 61869-9 digital interface for instrument transformers

IEC 61869-9 defines the instrument transformer digital interface requirements. The standard is based on IEC 61850-9-2 and is, in effect, an interoperable profile (subset) of IEC 61850-9. IEC 61869-9 replaces the unofficial Utility Communications Architecture (UCA) guideline known as IEC 61850-9-2LE, which was used for early SV implementations. With the release of IEC 61869-9, the contents of the original UCA guideline are finally within the care of IEC and are further enhanced by lessons learned in numerous pilot installations. The IEC TC 38 working group, which is in charge of the new standard, took the opportunity to use the guideline as the lowest common denominator that must be supported by all devices, while giving developers freedom to add support for configurable data sets, embedded logical nodes with signal processing capability, and a new consolidated sample rate set. Backward compatibility with UCA guidelines also ensures that early adopters of SV, LPIT, and SAMU technology are not left stranded.

IEC 61850-9 defines improved time-synchronization capabilities based on the IEEE 1588 and IEC 61588 Ethernet-based synchronization standards and also defines new sampling rates that are necessary to support dc measurements aimed at closed-loop control applications. Input filtering and filter delay issues are addressed by giving the responsibility for group delay compensation to the LPIT or SAMU. This approach allows new devices with digital outputs to be specified using the same phase and magnitude error terminology and accuracy classes used to specify conventional instrument transformers. The standard also defines the maximum latency (internal processing) delay allowed for various applications, as shown in Table 1.

Application	Maximum Processing Delay
High-bandwidth dc control	25 µs
Time-critical, low-bandwidth dc control	100 µs
Protection and measuring	2 ms
Quality metering	10 ms

Table 1: Maximum internal processing delay times allowed by IEC 61869-9-2.

3.3 IEC 61869-13 standalone merging unit

IEC 61869-13 defines apparatus aspects for the SAMU. An SAMU is envisioned as a self-contained data acquisition device capable of converting the conventional instrument transformer output to instantaneous digital samples and publishing those samples to substation devices using an SV service defined in IEC 61869-6 and IEC 61869-9. IEC 61869-13 is still in development as of early 2017.

IEC 61869-13 defines the required type tests, insulation, electromagnetic compatibility (EMC), and safety requirements for SAMU devices. Recognizing the fact that new devices are typically mounted in the immediate vicinity of the HV breakers, IEC TC 38 based their recommendations for the standard on the wealth of information available from substation yard-based relay installations. They concluded that new SAMU devices are exposed to very similar conditions and must meet or exceed the general capabilities defined in the IEC 60255 series of standards. SAMU EMC requirements defined in IEC 61869-13 match IEC 60255-26 with safety requirements based on IEC 60255-27. Special consideration is also given to gas-insulated systems (GISs), which may be exposed to higher stress.

One topic of particular interest to the protection community is SAMU behavior under dynamic (fully offset) fault conditions. To manage this issue, IEC 61869-13 encourages SAMU manufacturers to use a nonsaturating front end. When using saturable components (e.g., auxiliary CTs commonly found in protective relay front ends), an SAMU must pass a fully offset close-open-close-open (C-O-C-O) sequence prescribed in the standard and declare the highest X/R ratio that meets the IEC 61869-13 requirements. The same approach is used for linear ac-coupled inputs. Typical test waveforms are illustrated in Fig. 7 and Fig. 8.

Fig. 7 illustrates the effects of a linear, first-order, 1 Hz, high-pass filter, which is the highest cutoff frequency allowed by the frequency response mask defined in IEC 61869-6. The high-pass filter modifies the slowly decaying exponential component without significantly affecting the 50 Hz signal. Modification is best illustrated by calculating the composite error (i.e., instantaneous difference between the two signals expressed in percentage points) shown in Fig. 8.

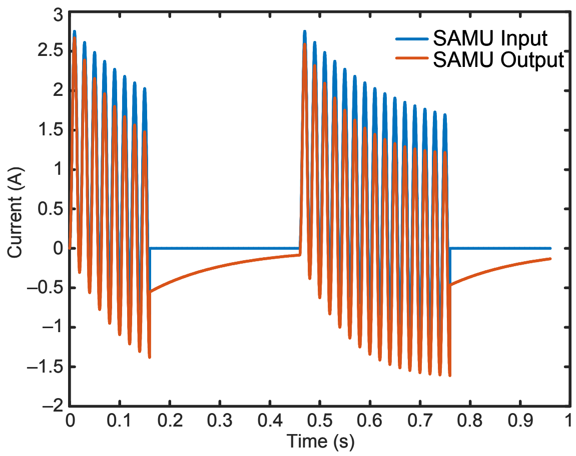

Fig. 7. Fully offset C-O-C-O sequence waveform before and after passing through a SAMU 1 Hz, high-pass filter.

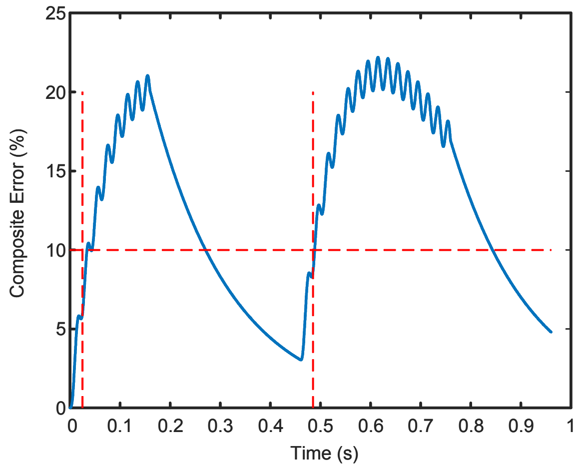

Fig. 8. Composite error calculated for the SAMU output waveform in Fig. 7.

Note that composite error grows very quickly, reaching 10 percent around 26 ms after the fault initiation. At the same time, the root-mean-square (rms) and phasor values of the fault current remain unaffected by the high-pass filtering function, as shown in Fig. 9.

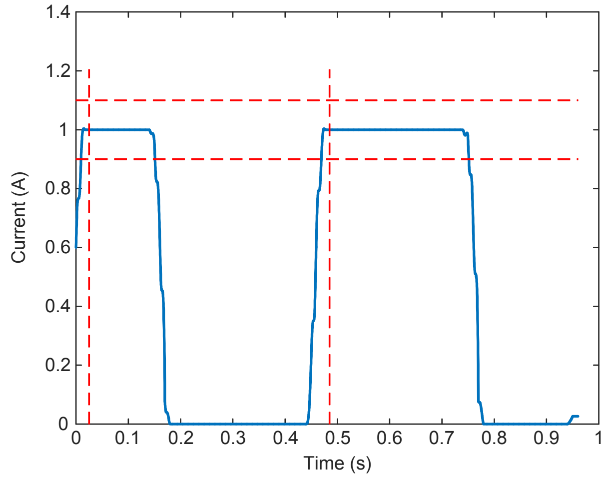

Fig. 9. Cycle-based rms value calculated for the SAMU output waveform in Fig. 7.

The most conventional protection functions, such as time-overcurrent or distance protection, use rms or phasor measurements and are unaffected by the slowly decaying exponential wave component. Therefore, it is unfair to impose low-cutoff frequency requirements on all MUs and SAMUs. At the same time, high-performance, sample-based differential protection elements require good matching of the dc component from all instrument transformers in order to operate. Such high-performance functions complete their work within the first cycle (often in 3 to 8 ms), meaning a trip is already initiated by the time the high-pass filter can affect the input waveform. IEC 61869-13 recognizes the sample-based differential applications by requiring that the composite error observed during the first 25 ms of the fault remains within the 10 percent margin and applies the rms-based criteria once the 25 ms have expired. The proposed approach captures the needs of high-performance differential protection and simultaneously ensures that the SAMU output works well with rms- and phasor-based protection schemes. This approach also shows that the 1 Hz high-pass filter corner frequency defined in IEC 61869-6 is a good compromise between the two applications. Because the new dynamic response requirements are based on real-life protection schemes and have a precisely defined test, they are equally applicable to designs that use conventional input magnetics that could partially saturate. In effect, saturation is allowed as long as the errors do not exceed the 10 percent limits, as illustrated with dashed lines in Fig. 9.

In response to the needs of the power measurements community, IEC 61869-13 includes an informative annex that shows how the well-known accuracy classes, which are defined separately for the instrument transformer and the SAMU, can be combined to estimate the accuracy of the resulting digital output.

4 Future work

With the ink barely dry on IEC 61869-6, IEC 61869-9, and IEC 61869-13 at the committee draft for vote (CDV) stage, it is hard to imagine the need for additional changes. However, SV technology and associated applications are developing very quickly. New applications are constantly brought forward with the need for SV signals to serve all substation applications, resulting in new work areas that should be considered for the next revision cycle, including the following:

- Full-length UTC time-stamp support
- Automated transducer data exchange
- Cybersecurity

4.1 Full-length UTC time-stamp support

The latest revision of the synchrophasor standard IEC/IEEE 60255-118-1 includes an annex that describes the use of SV measurements as inputs to the PMU. A PMU used in this way becomes a signal-processing application that can be implemented anywhere SV streams are available. One IEC 61869-9 weakness identified in the annex is the lack of a full time stamp, which is normally replaced with a simple counter that rolls over every second. To operate with such time stamps, PMUs are forced to obtain time independently and reconstruct the full date and time information required at the PMU output. An alternative approach is to abandon the use of legacy, 1 pulse per second, signal-based time distribution and configure the LPIT and SAMU devices to output the full time stamp. The full time stamp is already supported by IEC 61850-9-2, meaning it is an option that could be added in the next revision of IEC 61869-9.

4.2 Automated transducer data exchange

The MU concept is exceptionally powerful for innovating new opportunities for system-wide applications via LPITs. To gain the full benefits made possible by LPIT technology, it is often necessary to use individual device correction (calibration) factors, which are currently printed on device nameplates. Correction factors have many decimal places that must be manually entered into the end device. The entry process is time-consuming and error-prone, so it is seldom used. IEC TC 38 foresaw this challenge when developing the IEC 61869-6 LPIT connector interface definition, so they specified that a pair of pins should be left for an embedded memory device that can store the LPIT nameplate data and individual correction factors for each device. This interface is known as a transducer electronic data sheet (TEDS), and IEC TC 38 has opened a new work item proposal to fully define the interface. At the time of the publication of this paper, IEC TC 38 expects that the TEDS interface will be based on the core principles described in IEEE 1451.4 with the new instrument transformer-specific templates defined by IEC TC 38.

4.3 Cybersecurity

Cybersecurity remains one of the weak spots for SV-based digital secondary systems. While the cryptographic protection of SV data is not a major concern, source authentication, data-tampering detection, and network infrastructure protection are very important for wide-range technology acceptance. Currently, standardized SV systems offer no inherent protection. Direct point-to-point links are presently the simplest topology-based cybersecurity solution. Deep packet inspection and whitelisting methods supported by SDN are the most advanced methods to ensure the deterministic signal delivery.

5 Conclusion

The digital secondary system concept, based on SV technology, continues to be of major interest to practicing power engineers. To reach a mature and fully interoperable system, many technical details need to be documented and standardized. International efforts in this domain span over a decade and continue at a vigorous pace. This paper provides an overview of recent standards that add to the wealth of knowledge describing this technology, explains various options and the relationship among different standards, and identifies some of the future work required in this space.

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