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INDUSTRY TOPICS

PROTECTION AND CONTROL SYSTEM USE OF NON-CONVENTIONAL INSTRUMENT TRANSFORMERS AND PROCESS BUS

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Digital substations are gaining traction, with real-world commercial installations now accepted among utilities. Main enablers for this technology are the non-conventional instrument transformers and standalone merging units using IEC 61850 process bus communication. IEC 61850 can improve the overall reliability and resiliency of the 21st century substation using digital communication. High-voltage measurement and control has recently improved to offer easily installed sensors with direct digital outputs offering excellent accuracy, stability, and faster frequency response. By going directly to digital, these state-of-the-art sensors preserve signal integrity and ease of connections through fiber communications. Unlike previous optical sensors that had some reliability concerns, the introduction of a new fiber optic current sensor (FOCS) design combines the inherent isolation of the optical current sensor with redundant systems to power, accurately process, and output signals capable of directly supporting substation automation. These modern optical sensors embedded in free-standing form using modern polymer insulators free of oil or SF6 gas — or integrated into other power equipment such as live or dead tank breakers and gas insulated substations — can simplify the merging unit architecture and deliver the full promise of IEC 61850 to utilities and their customers.

The introduction of stand-alone merging units provides an equivalent approach to digitizing the secondary signals available in the switchyard. This approach also simplifies communication between the equipment in the switchyard and the relays in the control panel. In adherence to the IEC 61850 standard, the merging units easily virtualize any CT or PT signal available today from a conventional sensor. By implementing these merging units in the process bus, the complete potential of adhering to the IEC 61850 standard can be achieved.

This article discusses basic application variants, results, and field experiences involving the non-conventional instrument transformer (NCIT), combined with the flexibility and modularity of the stand-alone merging units for process bus IO systems. In addition, the paper covers field installations of the GIS sensor technology and the availability of IEC 61850-9-2 implementation.

An overview will be provided to show the digital substation's key benefits highlighting safety, reliability, functional consolidation, and cost drivers leading to customer savings. Utilities are facing an increased demand on substation information and the digital substation opens the door for real-time data exchange. The digital substation solution's key technologies (relays, advanced substation automation, and modern instrument transformers) position IEC 61850/Ethernet as technology enablers and not obstacles.

DIGITAL SUBSTATION AND INDUSTRY CHALLENGES

Digital substations have evolved over the past two decades. The introduction of the microprocessor into substation automation, protection, and control has revolutionized the utility industry for the good and the bad. The push from a "dumb grid" to a "smart grid" has enabled the digital world to expand well beyond the traditional scope of protection, control, and supervisory control and data acquisition (SCADA). The ideal vision of knowing all aspects of every substation networked into an intelligent grid opens the opportunity to have information at our fingertips.

One challenge continues to be the stranglehold from regulatory standards for reliability and security when, in fact, a smarter and highly intelligent automation system can make the grid much more reliable and dependable. The other challenge results as utility personnel struggle to find adequate time to research and explore new technologies that could change the landscape of the power system protection and control network. The upcoming generation of system and protection engineers has lived in the digital world their entire lives. As the aging infrastructure continues to feebly perform, the system has very little know-how on whether it is working or not, or the ability to make proactive decisions to limit outages or damage, restore consumers faster, and provide the post-mortem information to make necessary improvements.

The last challenge is our aging and retiring workforce. The amount of knowledge leaving our industry each year is mind-blowing. Another challenge with the younger generation is a lack of company loyalty. Today's younger employees have no concept of a lifetime at a single employer; this means that companies with increasing pressure on performance have lost the ability to retain their younger employees in dire times. With the younger workforce's attachment to their digital devices, it is important to note that our society's digital world has only been possible through the tight integration of information, resources on a common platform (open standards), and Moore's Law continuing to prove that if it is not possible today, ever-advancing technology will make it practical tomorrow.

The digital substation is no different. Open standards are now in place and have matured to the point of different manufacturers (some more than others) interoperating on a common platform. Technology for the complete digitization of the power system information, as well the speed and performance of the information exchange, allow real-time performance with better accuracy and open up possibilities for the digital substation. Who will be embracing this new technology? You do not have to look far, as our younger generation has the capability and is fearless to new technology advances. They are the key to pushing this new technology to advance protection, control, and automation into the modern era.

THE STANDARD — IEC 61850

Without standards, we revert back to the 1990s when proprietary solutions resulted in one manufacturer's system unable to communicate to another's. Back then, products were installed with network interface modules (NIMs) in an attempt to make minimal information available to the network control centers. Today, the industry can appreciate the vision of John Burger from American Electric Power, who started the movement in the U.S. market to migrate the industry to a common standard. The history of the EPRI LAN Initiative to UCA to IEC 61850 is an entirely different article, but what has transitioned in the last 20 years has changed the landscape for modern and future control systems.

Wide-scale adoption of digital messaging for intra-substation communication is only possible if it is based on a common standard. Otherwise, we will revert back to the 1990s when information was piecemeal and fragmented, with mutually incompatible signaling creating an assortment of messaging within silos or islands of automation. IEC 61850, *Communication Networks and Systems for Power Utility Automation*, is not just a protocol, but rather a comprehensive standard defining a communication architecture and philosophies that specify how the functionality of substation devices should be described, how they should communicate with each other, what they should communicate, and how fast that communication should be. All of this is essential in achieving multi-vendor interoperability and realizing the benefits of a truly digital substation.

IEC 61850 defines two main communication hierarchies inside the substation for information exchange between devices and from device to the sensing interface in the primary equipment (Figure 1). For inter-device communication, the IEC 61850-8-1 part of the standard, also known as the station-level bus, can be generalized as the necessary requirements for inter-bay and communications to the outside world. From the initial release of the IEC 61850 standard in 2004, the station bus brought the main benefit of the standard and was widely implemented by most vendors with a vested interest to support the changing world environment. The station-level bus provided a means for the common architecture targeting interoperability across vendors as well as significant reduction in copper wires through the introduction of unsolicited peer-to-peer device communication. Also known as Generic Object Oriented Substation Event (GOOSE) messaging, it is based on hardened Ethernet technology usable in the harsh substation environment.

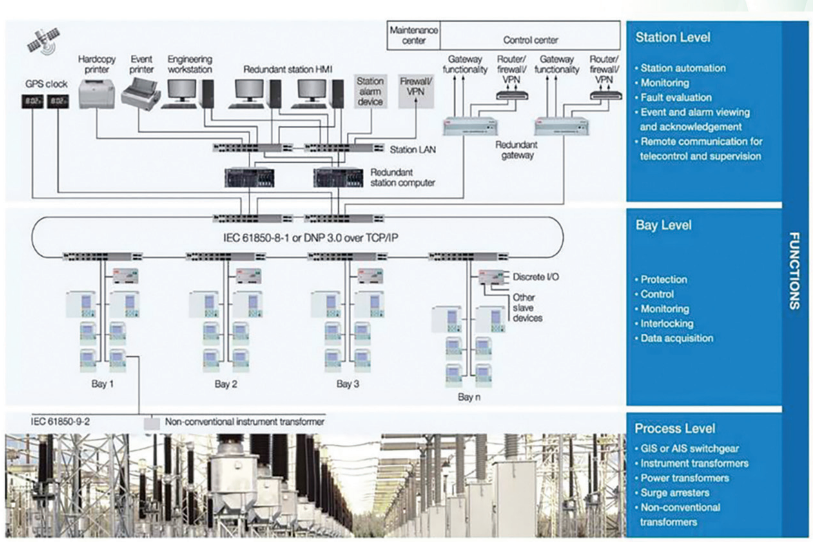

Figure 1: *Digital Substation Functional Levels*

The second communication hierarchy introduced in the 2004 standard was the process bus as defined in IEC 61850-9-1 (point-to-point unidirectional) and IEC 61850-9-2 (multipoint bidirectional) for communication between the protection and control-bay-level devices and modern instrument transformers installed at the primary apparatus in the switch yard (Figure 2).

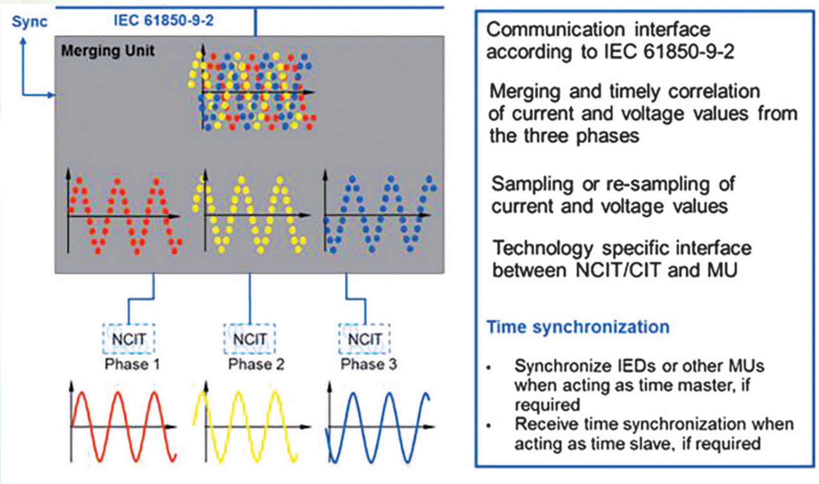

Figure 2: *Communication Interface According to IEC 61850-9-2*

In Edition 2 of IEC 61850, released in the past few years, IEC 61850-9-1 has been removed because its usefulness and application were limited. For process bus communications, IEC 61850-9-2's main attributes are the streaming sampled measure values (SMV) where modern sensors digitalize the power system current and/or voltage measurements into a package of synchronized measurement values communicated to the protection and control devices. The standard does not define the type of sensor or the means for the digital transformation, but rather, defines a merging unit that collects the sensor information and prescribes a standard way to package and communicate the output.

The exchange of sampled values between these modern sensors or non-conventional instrument transformers (NCIT) and intelligent electronic devices (IEDs) for protection functions and other purposes allows for the real-time digital information exchange. The interconnection between the sensors and actuators, which are physically connected to the power system process, is why the term process bus is used as the interface to the protection and control systems. This enables the standard-compliant digitalization of the last mile in substation automation, and brings with it a wide range of benefits in the digital substation.

NON-CONVENTIONAL INSTRUMENT TRANSFORMER TYPES FOR GAS-INSULATED SUBSTATIONS

The NCIT and process-bus technology has experience from a series of six outdoor gas-insulated substations (GIS) with process bus and NCIT technology installed and commissioned in 1999. As the IEC 61850-9 part of the standard was not released until 2004, these early installations were based on proprietary communication architectures. That notwithstanding, the sensor and digitalization technology experience was invaluable and is still used today with modern merging units supporting IEC 61850-9-2. The use of fiber-optic networks not only eliminates vast parts of the copper cabling, it also increases operational safety by isolating the primary from the secondary process.

The NCIT sensor families cited earlier are based on redundant sets of Rogowski coils for current measurement and two independent capacitive dividers for voltage measurement (Figure 3). The Rogowski coil is a device used to measure alternating current. It comprises a toroidal winding where the current-carrying conductor passes through the center of the toroid. The current output of the sensor is a voltage, which is proportional to the derivative of the current. The Rogowski coil has superb performance and improves linearity over a wide dynamic range, from metering to protection, and addresses the main issues of traditional CTs from the inductive open circuit as well saturation performance during fault conditions. The modern sensor also contains no oil, so this equipment is environmentally friendly and extremely safe.

Figure 3: *Gas-Insulated-Substation NCIT Use*

Designed with fully redundant design of the sensors (including the associated electronics), this allows two completely independent and parallel protection systems, boosting the availability of the entire secondary protection system. As sensor electronics can be replaced independently and without shutting down the entire protection system, maintenance and repair activities require less time. Further, because there are no live parts to handle, maintenance activities are much safer. The GIS Sensor also saves significant space as it mounts on the gas insulated bus or on the hybrid breaker bushing (shown in photo below) — compared to requiring free-standing or integrated current and potential transformers, which are much larger in size — as well as additional space required in the substation switchyard layout.

NCITs installed on Hybrid Breaker Bushing

Since the first installation in 1999, more than 300 non-conventional instrument transformers and their electronics have been installed in Powerlink Australia's substations. Notably, in more than 10 years of service, none of the primary converters has failed. Based on experience values, the mean time between failures (MTBF) of the sensor electronics is over 300 years. This demonstrates the extreme reliability and high availability of the sensors, even in the very demanding environmental conditions of the Australian climate.

STAND-ALONE MERGING UNIT (SAM) FOR CONVENTIONAL SENSORS

While NCITs are ideal solutions for new installations, it is also important to provide retrofit solutions for brownfield upgrades. A stand-alone merging unit (SAM) bridges traditional and digital technology. The SAM digitizes potential transformer and current transformer analog signals into digital communications (Figure 4).

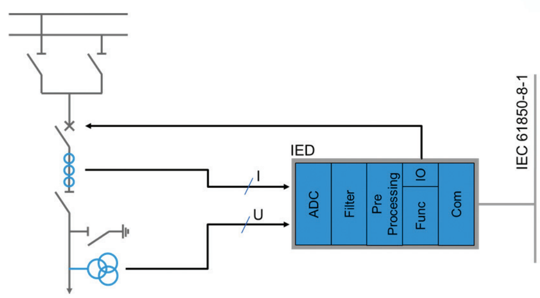

Figure 4: *Stand-Alone Merging Unit for Conventional IT Connection to Process Bus*

A SAM system combines voltage and current measurements, which are available on the SAM system bus, into an IEC 61850-9-2 compliant stream. This combined IEC 61850-9-2 stream is available on all IEC 61850 access points on SAM modules. The stream merging on the IEC 61850 access points is enabled by default and can be set via configuration parameters. Stream merging requires certain quality criteria of the streams available on the SAM system bus to be met. If those criteria are not met, then the stream merging is disabled. For maximum flexibility, the SAM is modular. Key components of the SAM include CT interface, VT interface, and a time-sync module.

SAM modules may be mounted using a DIN-rail and are typically placed in a station panel or marshalling kiosks near the primary equipment.

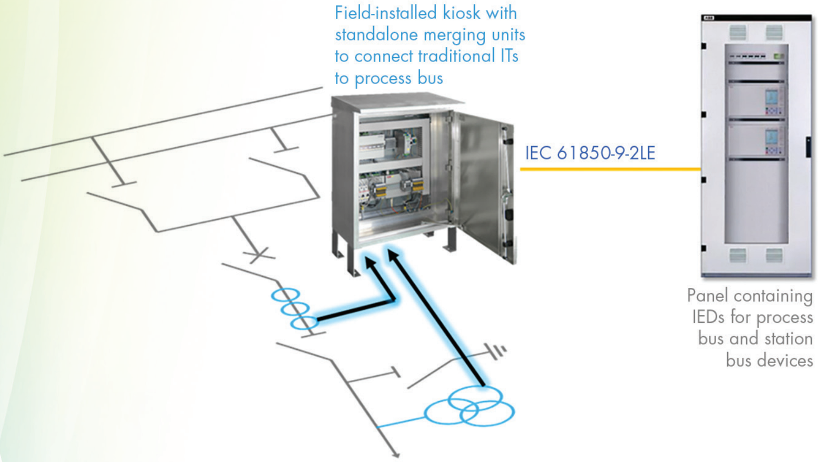

Figure 5: *Retrofitting Conventional Substation for Digital Functionality*

A marshalling kiosk with redundant SAMs is shown in Figure 5.

By adhering to the same IEC 61850 standard, these merging units can seamlessly integrate with any other non-conventional instrument transformer that is compatible with the same standard. This natural blend opens up the application possibilities of these devices.

A modular approach to integrating IEDs in the process bus provides the additional flexibility of routing the sensor signals to the protection IED in the most optimized way. It opens up various new engineering solutions to implement existing protection philosophies. An excellent example is the implementation of decentralized bus bar protection.

BENEFITS OF DIGITAL PROCESS BUS REPLACING COPPER

Every copper wire in a substation is a potential risk, whether it is from a CT or PT circuit or a 125V dc control wire. The highly inductive current transformer secondary circuit poses the largest safety concern. The hazard results when an energized current transformer wire is unknowingly disconnected. From inductive circuit theory, current flowing through an inductive circuit cannot be instantaneously changed from 5 amps to zero.

A quick thanks to Wikipedia: $v(t) = L\frac{di}{dt}$

The mathematics formula implicitly states that a voltage is induced across an inductor, equal to the product of the inductor's inductance and current's rate of change through the inductor. As the inductance does not change during the open circuit, the rate of change in current from 5 to 0 amps instantaneously has the derivative (di/dt) resultant go to infinity. Thus, the formula's product voltage is dominated by the derivative blowing up to infinity and produces a very large voltage across the open circuited wires. Related to the substation application, an open CT secondary is equivalent to the inductive current going to zero; depending on the secondary load, arcing will occur as these dangerously high voltages build, putting field personnel at risk of serious injury or even fatality and equipment and the substation at risk from electrical fire. Minimizing copper leads to greatly improved safety.

The digital substation process bus for breaker status and control where copper control wires are replaced with digitized binary information can alone justify the switch to digital. Going digital can cut the quantity of copper wires in a substation by more than 80 percent, which is a substantial cost saving and, more importantly, a significant safety enhancement.

BENEFITS OF THE DIGITAL SUBSTATION

A fully digital substation is smaller, more reliable, has a reduced life-cycle cost, and is simpler to maintain and extend than an analog one. It offers increased safety and is more efficient than its analog equivalent. Not every substation needs to be catapulted into a wholesale digital world — it depends on the substation size and type, and whether it is a new station or a retrofit of the secondary system. Different approaches and solutions are required. Flexible solutions allow utilities to set their own pace on their way toward the digital substation:

- Increased system availability by replacing of electromechanical, static, or old-fashioned digital secondary equipment with modern numerical devices bundled to a real-time communication network and connected to a higher-level system such as a substation automation system or SCADA, allows continuous monitoring of all connected secondary equipment.

- Increased system and personnel safety, using remote control combined with authority and rule-based access and remote testing allows increased system safety and security. Personnel safety is increased since more tests can be done without putting test personnel close to primary equipment and without the risk of inadvertently opening CT circuits.
- Increased functionality with a fully distributed architecture, coupled with unrestricted communication and process capability, enables the system to add new functions easily with zero or minimal outage time, giving the user additional benefits in safety and security.
- Interoperability through deployment of IEC 61850 compliant solutions and interoperability regarding communications with other manufacturers' equipment can be achieved. The benefit is that IEDs from different suppliers can be mixed on the same bus without concern for communication incompatibilities.

CONCLUSION

The introduction of the IEC 61850-9-2 process bus standard in substations has provided a platform that all manufacturers can develop to achieve the overall goal of interoperability. John Burger's visionary ideas are being realized with the technology available today. In addition to interoperability benefits, the footprint of primary switchgear reduction using sensors (NCIT) instead of conventional measuring transformers allows a much safer work environment. On the secondary system, a massive reduction of cabling — by going from a lot of copper cables to a few fiber-optic communication cables — will mean reduced costs for cables and associated equipment such as cable trenches and installation material.

Also, improvement in fiber-optic current sensors and integration of the standalone merging units provides utilities and engineering firms with a great tool box for the future deployment of this maturing technology. For retrofit applications, the possibility of installing the new process bus system in parallel with the existing system will allow the substation to remain in service during the main part of the work. This will be a big advantage, reducing outages to a minimum during the retrofit process.

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IEEE 1588 Precision Clock Synchronization Protocol for Networked Measurement and Control Systems

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