GE
Grid Solutions

Process Bus:

7 OF YOUR MOST PRESSING QUESTIONS ANSWERED

Best Practices Guide by:

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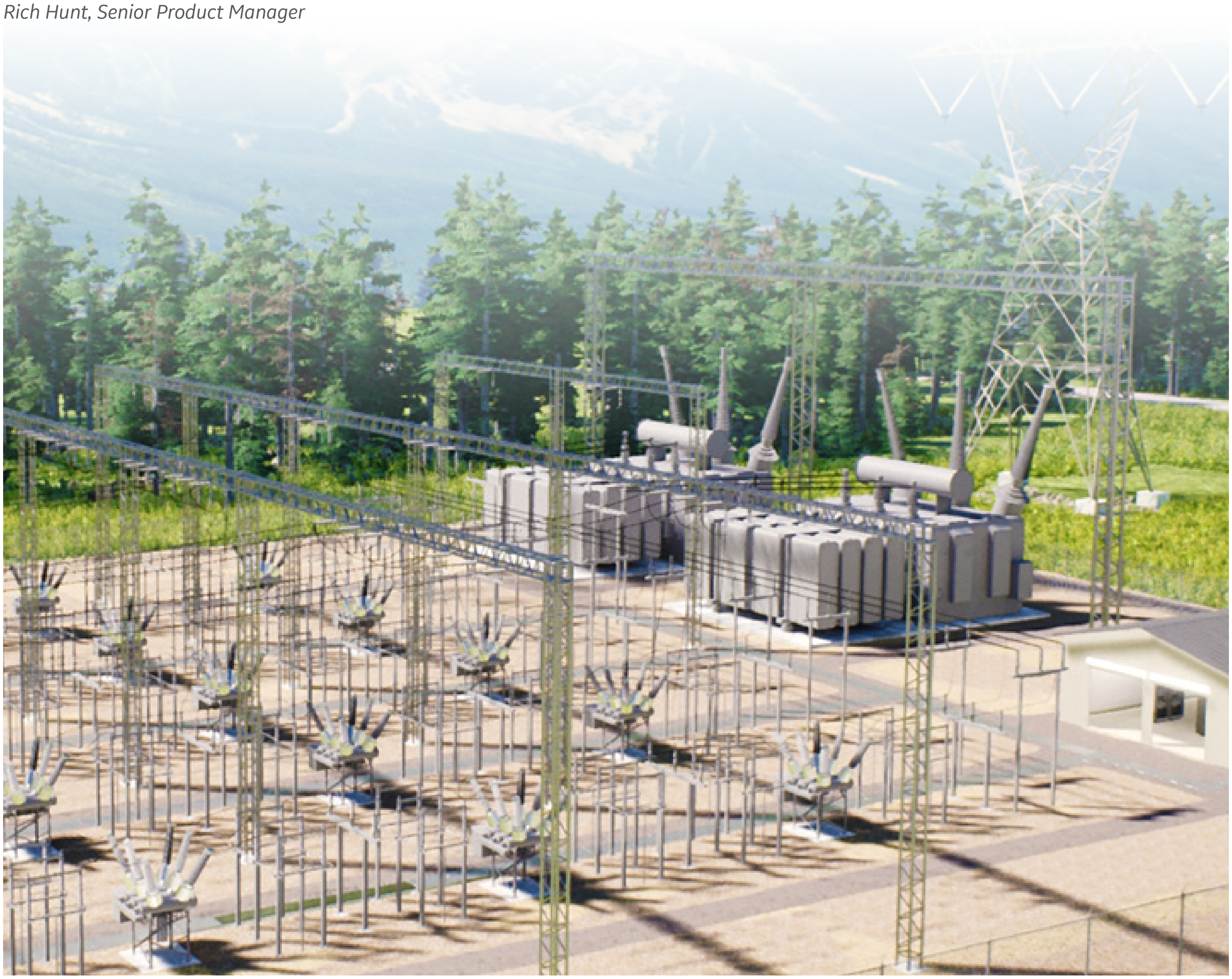

imagination at work

Summary

As critical nodes in the electrical grid, digital substations are essential to the future of the electric power industry in terms of the intelligent data they can provide. Transmission and distribution utilities recognize that adopting a modern substation model is necessary to respond to the challenges of today's energy environment, including renewables integration and the need to adjust supply and demand in real time, while at the same time improving power delivery reliability and quality in a cost-effective manner.

The key step in substation digitization is the implementation of a process bus, a digital communication highway between the primary equipment and protective relays in the control house, made possible with the IEC 61850 standard. The worldwide acceptance of IEC 61850 and the financial and operational benefits offered by process bus are not at issue. Instead, the challenge for many continues to be a lack of practical experience and expertise to work with process bus. This paper will explore common questions and best practices when considering process bus, helping to break down the barriers to implementation and set utilities on a path to success.

1. How do we get started?

A logical first question when introducing any new process or technology into an organization is around change management. In the context of the digital substation, it's important to consider how process bus impacts both staff and design practices. Utilities need to establish how they develop, roll out and teach digital substation design internally, and define what it means for their existing substations.

Adopting the use of digital communications as described in the IEC 61850 standard can affect protection and control design (and possibly the performance of protective relays), and will likely result in changes to test procedures and tools. Therefore, the first step in any implementation should be to develop a plan for rolling out IEC 61850 knowledge throughout the organization.

In our experience, we have seen two best practices for adopting IEC 61850. The first is to set up an IEC 61850 lab (one large enough to mimic a substation), then assign a core team to the lab. The team needs to learn the IEC 61850 standard, networking, and tools; and then work through the design for their particular system. This lab acts as a test bed, a replica of existing substations, and an excellent training site for staff going forward. Working with many utilities, we have seen that it is not always possible to commit the resources (either personnel or financial) to such a lab. However, GE has partnered with companies to create this type of environment.

The second-best practice is to use an actual project for learning and design. A utility should pick a future project that is three to five years out from being installed, such as a substation expansion. This project also becomes an IEC 61850 learning exercise, and the design team on the project become your in-house experts. Because the project is resourced as with any active project, it becomes a living lab. This is what Tennessee Valley Authority (TVA) did with their Bradley substation project.[1] The project, first located at a TVA engineering facility, was used as the development lab. Engineers worked from this location for more than two years, designing, validating and testing the new system before transporting the building to the Bradley substation for installation and final commissioning.

It's worth noting that a process bus project does not have to be new construction; it is possible to update existing substations to use process bus. It is also cost effective to do so. For example, if you're planning to refurbish the protection and control system in a substation, it is more efficient to use process bus than the existing traditional architecture. In other words, install the I/O devices and fiber optic cables in the switchyard, and new panels with process bus-capable relays in the control house. Although not quite as clearly advantageous as installing process bus in a new substation, it is still faster to design, has a smaller footprint, and uses fewer skilled resources to install and test when compared to refurbishing with conventional relays.

GE has supplied equipment for more than 100 process bus projects in transmission, distribution and industrial applications in service in 27 countries, ranging from a single distribution feeder to the complete refurbishment of a transmission switching substation. For example, an Azerbaijan utility implemented an IEC 61850 pilot project, upgrading several substations. Following the initial pilot, three more substations were commissioned. The average application per substation was six bays of line protection with bay control, two bays for transformer protection with separate backup, and feeder protection (16 bays, but this last without process bus). The benefits were significant, including saving more than 50% in labor. Labor savings were realized through substation design standardization, and a reduction in time required for the installation of wires, commissioning and testing, as well as intelligent electronic device setup. In addition, a 70% cost savings was achieved due to a reduction in time and cost for cable trays and trenches, and fewer civil/construction costs required for the control room when compared to a conventional substation. Refer to Table 1 for a labor analysis between process bus and a conventional substation based on this project.[2]

TASK	Conventional SAS implementation labor (Days)	Process bus implementation labor (Days)	Labor savings* (Days)
Engineering – Detailed and complete design	90	50	40
Panels – Production and wiring	90	30	60
Installation and cabling	60	30	30
Testing and commissioning	90	30	60
Relay configuration	30	45	-15
TOTAL	360	185	175

Table 1: IEC 61850 reduction in labor hours for main tasks for a substation retrofit project

** Customer-supplied data*

2. How should process bus be installed in the field?

Once your organization is set up for IEC 61850, there are many things to consider around the practical installation of process bus in a substation. Commonly asked questions include: Where do you put I/O devices such as merging units, remote I/O modules, process interface units, or digital instrument transformers? Has anyone replaced copper wiring with digital communications over fiber optics? Are any companies sending trip signals through communications, or are they still hardwiring the trip signals with copper wiring?

For process bus to really improve project costs and project delivery schedules, I/O devices need to be installed as close to primary equipment as possible. Ideally, they should be included as part of the primary equipment, with the conceptual goal of becoming a smart primary substation asset. In most cases, the I/O devices are electronic devices that need environmental protection from dust, water, and extreme heat and cold, and therefore require mounting in an equipment cabinet or marshalling kiosk (see Figures 1-3 for examples). An exception would be devices such as the GE's Multilin™ HardFiber Brick Process Interface Unit, which has a cast aluminum shell, is IP66 rated, and may be mounted outdoors.[3]

Figure 1: Example of a marshalling cabinet (kiosk) for process interface units

Figure 2: Example of a process interface unit mounted directly inside the equipment cabinet

Figure 3: Outdoor mounting of the process interface unit in the switchyard

Utilities adopting process bus today are sending trip signals through communications. This is the whole point of process bus - to stop using custom-designed copper wiring schemes. Tripping through communications has been proven to work reliably for decades. A process bus design must help ensure that circuit breaker trip signals pass through the communications network, and operate the circuit breaker. Process bus installations have been successfully tripping circuit breakers for fault conditions for nearly 10 years, such as in the Azerbaijan and Tennessee Valley Authority projects, so the concept is well proven.[4] When using communications to trip, the general performance requirements remain unchanged because it is still necessary for the protection and control system to reliably clear faults. In practice, this requires redundancy for trip signals sent through communications.

Process bus supports common techniques for reliable protection, including redundant schemes, overlapping zones, and backup zones. Redundant protection will send trip signals to redundant I/O devices using different communications paths, as shown in Figure 4A. Trip signals can be sent to multiple I/O devices simultaneously, and through different communications paths, as shown in Figure 4B. In these figures, process interface units (PIUs) are merging units combined with contact I/O for status and control of primary equipment, like GE's Multilin HardFiber Brick or GE's Reason MU320 Process Interface Units. Remote I/O (RIOs) are contact I/O for status and control of primary equipment, like GE's DS Agile Switchgear Control Unit (SCU).

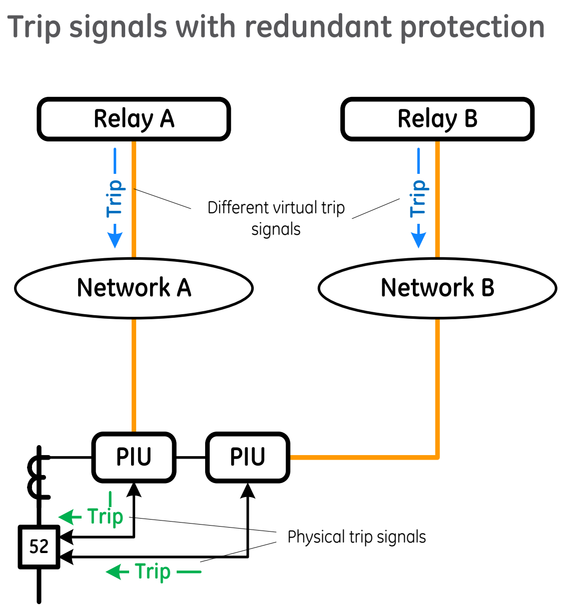

Figure 4A: Redundant protection will send trip signals to redundant I/O devices using different communications paths

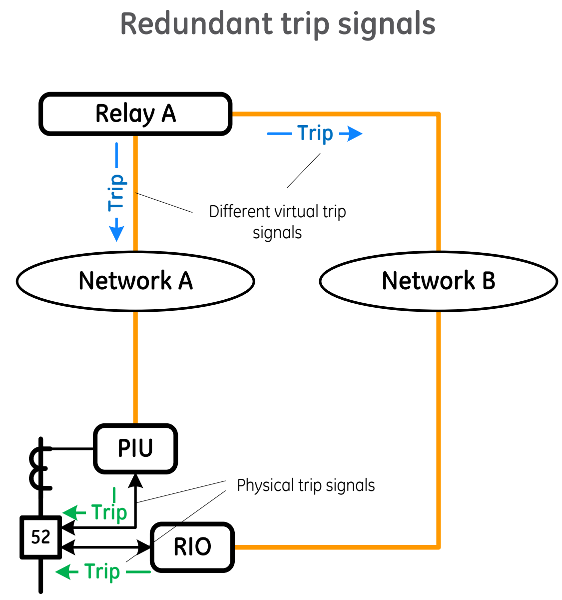

Figure 4B: Trip signals can be sent to multiple I/O devices simultaneously, and through different communications paths

PIU: Process interface unit
RIO: Remote I/O

Be cognizant of speed when tripping through communications. For standard output contacts, industry-wide the tripping time for instantaneous elements is approximately 3 ms slower than conventional relays. With high-speed high-break output contacts, tripping time is 1 to 1.5 ms slower than conventional relays. In general, a time delay of this length does not have a material impact on the performance of the system, given that breaker operating time is typically two cycles or more.

3. Does process bus really save time in engineering?

It's worth expanding upon the previously discussed labor savings example from the Azerbaijan pilot project. Does adopting process bus really save engineering time, or does it simply trade executing wiring schematics in a conventional substation for a similar amount of time developing the network design and configuration with IEC 61850?

While there are some changes to the engineering tasks and processes, we have consistently seen a net savings in engineering time with process bus. Our experience over multiple projects has shown that an average savings of 20% on engineering time should be expected, after the learnings gained from the first few projects. The significant reduction in time used to design and document the copper wiring for a protection and control system more than offsets the additional time required to design the communications network. (Figure 5)

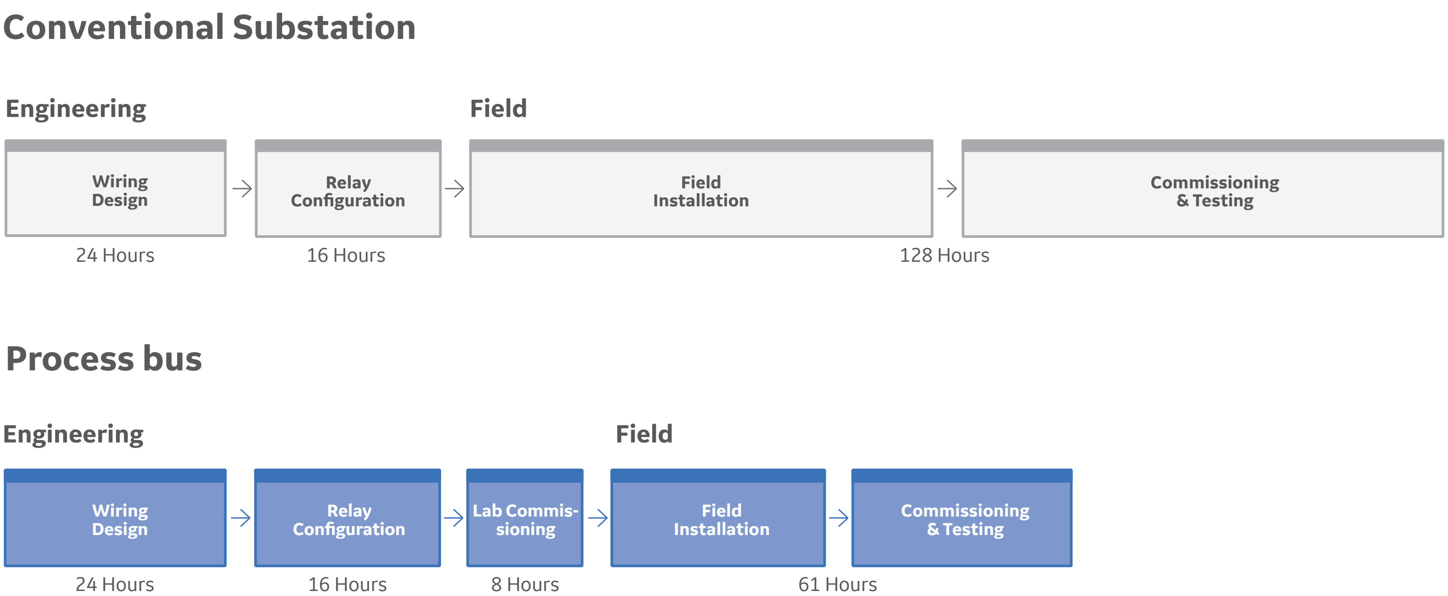

Figure 5: In a conventional substation, deploying a relay can take up to 168 person-hours of work for wiring design, configuration, installation, commissioning and testing. With process bus, setting up the same relay can take just 109 hours. Utilities can realize a 50% reduction in in-field time, with substations commissioned in days versus weeks.

In fact, good upfront engineering practices should establish a process bus communications network design that is scalable for all substations in a utility's network. This allows the utility to reuse the design. Simply leave out communications devices and their respective configuration when using the established design for a smaller project. This upfront, reusable, scalable design is also a best practice for the rest of the protection and control scheme. Because design in this case is simply managing data, it requires only one upfront design for the protection and control system; this design can then be reused by turning off any data or devices that aren't needed in the next substation.

4. How does process bus impact protection & control reliability?

Probably one of the most critical questions around process bus is whether it affects the reliability of the protection and control system. With respect to the operating state of process bus, there are two ways to look at the topic of reliability. The first consideration is basic availability – will the system work? The second consideration is how often does it need to be fixed, or – as it is more commonly described – what is the mean time between failure (MTBF)?

The first answer is that a process bus system will work; a redundant process bus system will be as available as a redundant conventional protection and control system. The second answer is the overall protection and control system MTBF will be lower, but this lower system MTBF is offset by process bus devices being much easier to replace because no or limited field wiring is involved. This lower mean time to repair (MTTR) for process bus is significant. Compare modern protection relays, where multiple functions – along with the necessary field wiring – converge into a single device. Replacing a line protection relay requires an engineering and installation project, and the resulting MTTR can be three days. With a properly designed system and process bus devices, the MTTR should be very short - in the range of an hour for I/O devices, four hours for other IEDs. There is no need to lift and replace copper wires to swap out a failed device. Instead, the operator only needs to disconnect the network cables, remove the device, install a replacement, then re-connect the network cables (see Figures 6A and 6B).

Figure 6A: When installing a process interface unit, operators only need to unscrew the connectorized cables, reducing MTTR time and effort

Figure 6B: Installation and/or replacement of a process bus enabled protection and control device is simplified, as only communication wires are connected to the device

In short, process bus aims to meet both considerations in regard to reliability. By using redundant systems of similar MTBF, a process bus system offers the same type of reliability as a conventional architecture. And by separating the hardware and application from complex copper wiring schemes, components become easy to replace, with many devices replaceable in a matter of an hour or two. So, while the MTBF may decrease, this differential is offset by the ease of repair and replacement of devices on a process bus system.

Finally, in helping utilities adopt process bus, it is clear that process bus can facilitate the implementation of highly complex and advanced protection and control schemes. For example, we have seen a utility implement multiple zone protection devices, an architecture that hasn't seen widespread adoption due to the complexity of installing copper wiring. Process bus eliminates concerns around wiring, and allows further convergence of functions. One utility that has adopted process bus uses a multi-zone feeder relay (GE's Multilin™ F35 Feeder Protection System) to protect four feeders independently, and uses a bus differential relay (GE's Multilin™ B30 or the Multilin™ B95^{Plus} Bus Protection Systems) to provide bus protection and redundant overcurrent protection for the feeders.[7,9]

5. How does process bus impact the testing of relays?

Testing is an important consideration when adopting process bus. How is the protection system isolated for testing? How does process bus impact the testing of relays? How do we help ensure CT/VT (analog measurements) are correct when these measurements arrive virtually? Does process bus really change testing, or does it just change test procedures and test equipment?

Process bus doesn't change the basic requirements for testing. There is still acceptance testing, commissioning testing, maintenance testing, and troubleshooting; however, the adoption of process bus does, or should, change the procedures for testing protection and control systems. The high-level answer is that process bus may also change the tools necessary for testing. But adopting process bus leads to a more fully monitored protection and control system, which greatly reduces testing effort.[8]

A process bus system consists of three overlapping subsystems: I/O devices, communications network, and protective relays (Figure 7). The modular nature of process bus permits these subsystems to be tested independently of each other. If all three subsystems are working correctly, the system is working correctly.[9]

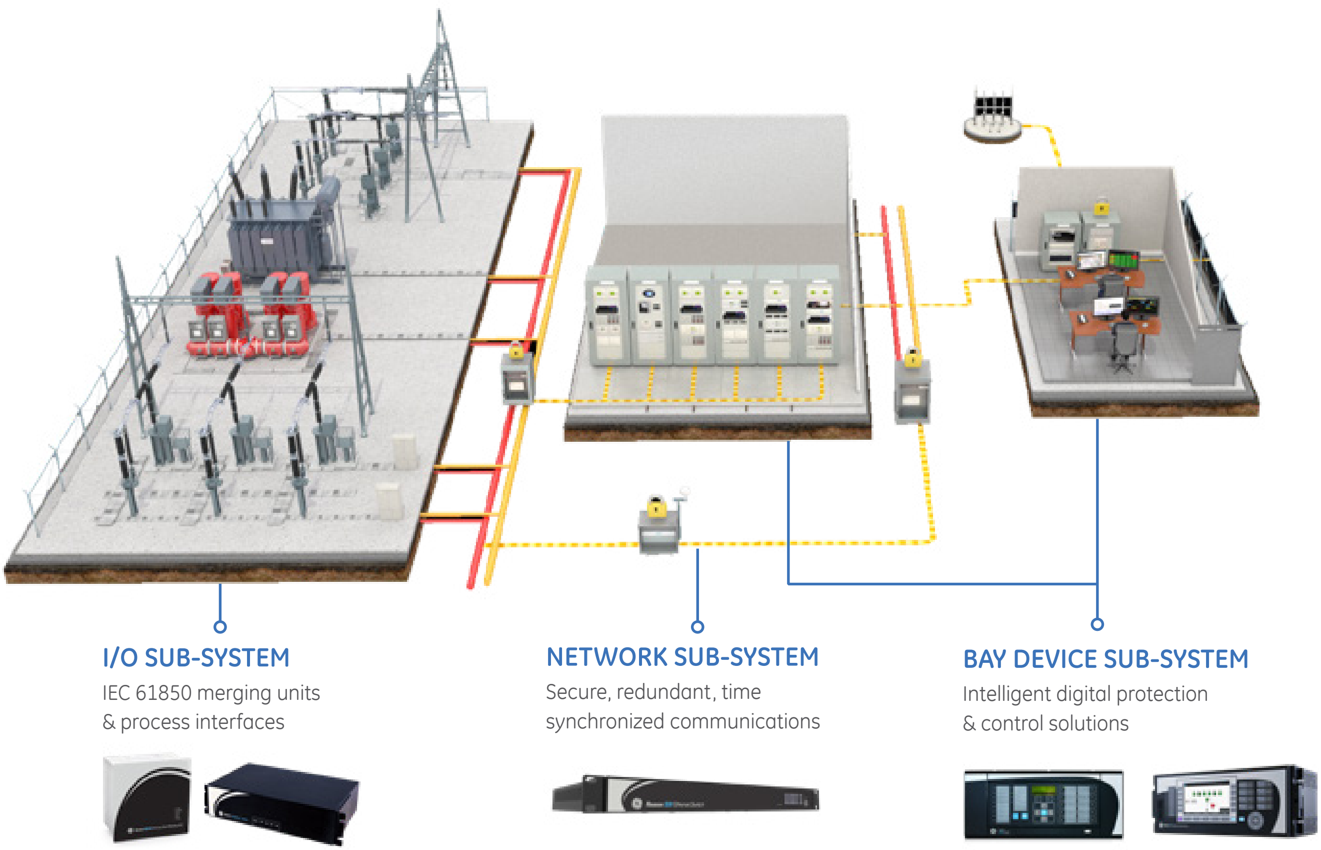

Figure 7: Process bus subsystems

For commissioning, these subsystems can be tested independently during factory acceptance tests before the materials are shipped to site. However, there is still checkout commissioning required; it is still necessary to verify that the correct I/O device is talking to the correct relays. CT ratios and polarities must still be checked on site, but this can be performed with only I/O devices installed. This method of testing speeds up commissioning (by as much as two-thirds in the project in Azerbaijan) while reducing project risk.

The biggest change is in maintenance testing. For this, it is necessary to capture digital signals produced by devices under test, and create digital test signals. One method is to use substitute devices to create and capture data, using standard test devices to create analog signals. The better way is to design your system for test, and use the testing capabilities described in Edition 2 of the IEC 61850 standard. It is possible to put devices in test modes where they only subscribe to and publish test data. It is also possible to put devices into simulation mode, where they only subscribe to simulation data for test purposes. Simulation data can be created by virtual test sets to quickly test devices. So, under IEC 61850, it is possible to isolate devices for test and use simulated data to test specific devices.

6. What are key considerations for device interoperability with process bus?

To start, let's address a commonly asked question around interoperability: what I/O devices and IEDs need to be interoperable in process bus? The answer is if you select I/O devices and relays that use the same datasets, they should be interoperable. One goal of the IEC 61850 standard is interoperability between devices, based on publish-subscribe communications and common data formats. Therefore, "interoperability" means the subscribing device can accept the specific IEC 61850-compliant datasets available from a publisher. However, the standard allows great latitude in the makeup of actual datasets.

The two message types commonly used in process bus are GOOSE and sampled value (SV) messages. Datasets used in GOOSE messaging typically contain only Boolean values, are straightforward to define, with the result that devices are widely interoperable. Interoperability for SV messages is more problematic due to decisions involving the number of measurements, number of samples, and sampling rate for each message. As a result, there are multiple SV datasets in use. The most common are the datasets defined in the 9-2LE ("Light Edition") Implementation Guidelines;[10] and in the IEC 61869-9 Standard,[11] which is very similar to 9-2LE. If interoperability is desired, you must specify the SV datasets to use between I/O devices and relays. For example, process bus systems using point-to-point communications (where the I/O devices are directly connected to relays) are generally more restrictive because the data sets are fixed specifically for this communication, and therefore only relays and I/O devices designed to work with this specific data set will be interoperable. Some vendors have published their data sets to facilitate multi-vendor interoperability.

7. What are the design considerations of a process bus architecture?

The communications architecture for process bus is a critical component of implementation, and understanding the basic considerations of introducing high-speed ethernet communications for process bus can help alleviate any hesitation induced by the perceived complexity surrounding this task. For example, how many networks should be established? Can one ethernet network be used for both process bus and station bus? How many I/O devices can be connected to one network?

To answer the first question, "station bus" and "process bus" should be considered concepts, not defined applications or requirements. It is very possible to put sampled value data, protection signaling, and SCADA traffic on one network under IEC 61850. GE is involved in a project where a utility has adopted this as a standard design, and just completed their first substation.[12] However, there are practical realities of bandwidth requirements on the network, traffic shaping, network ownership, and cyber security that influence the decision to put all traffic on one common network.

The network itself is the limiting factor when considering the number of devices on a network, maximum distance between devices, and number of devices that can share data. The number of devices is a function of the available bandwidth of the network, as well as the bandwidth required by data. Good network design will try to keep latency due to traffic within defined limits. Note that a merging unit (MU) or process interface unit (PIU) publishing sampled values with the most commonly used dataset (the 9-2LE dataset) requires 4.7 Mb (at 50 Hz) or 5.6 Mb (at 60 Hz) of bandwidth continuously. This will limit the number of MUs/PIUs to 10 to 12 on a 100 Mb network. The distance between devices is a function of the fiber optic transceivers and fiber cable used for communications. GE is involved in a successful installation where PIUs and relays are 1.5 km apart. In fact, the common industrial application for process bus uses this distance to improve transformer differential protection. Process bus replaces the long, large diameter CT secondary leads between the high voltage and low voltage switchgear rooms required for transformer protection with PIUs and fiber optic cables, greatly reducing the likelihood of CT saturation, and speeding and simplifying installation.

For networked process bus, there is no limit to how many devices an I/O device can share data with. All data is published to the network, and any device on the network can subscribe to this data. For point-to-point process bus, this is a function of the I/O device and the relay. With GE's HardFiber system, one Brick can connect to four different devices, and one Universal Relay can connect to eight different Bricks.

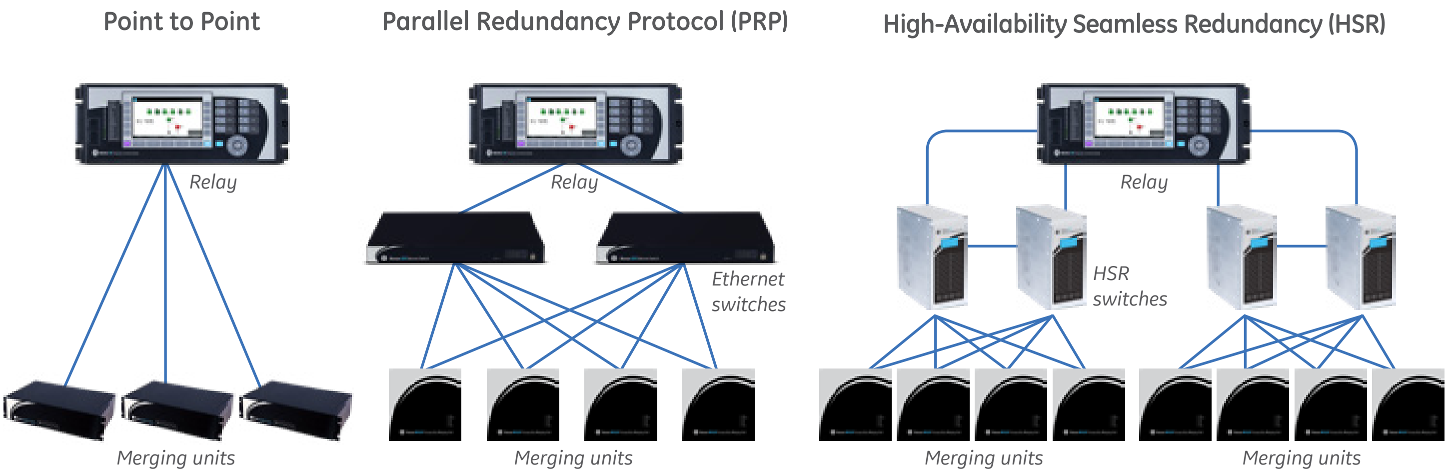

Figure 8: Examples of typical process bus architectures based on different communication philosophies

Another point is the use of manufacturing messaging specification (MMS). The use of MMS on process bus, especially for control services, must be carefully thought through. There are two main considerations regarding the use of MMS. The first is simply practical. MMS uses the “two party association” model of communications: an always on, point-to-point connection through the network. I/O devices may need to connect to many MMS clients, and must be able to handle redundant control commands. Bay control units and relays may need to establish connections to many I/O devices. The logic and communications mapping can be challenging for complex substation arrangements.

The second consideration is cyber security. MMS requires the use of IP addresses to establish communications between devices. MMS is therefore a routable protocol, increasing cyber security requirements. For example, the IEC 62351[13] standard requires the use of both authentication and encryption through secure key exchange for MMS. In North America, the use of IP addresses for process bus greatly increases the documentation required by the NERC CIP standards. A solution to limit the cyber security implications of process bus is to use the non-routable multicast GOOSE messaging to replicate the control functionality of MMS.

The use of sampled values may have an impact on oscillography. SV data is natively time stamped, so oscillography data can be easily captured and compared. However, the sampling rate is a consideration. The typical sampling rate used for SV data for protection is 80 samples per cycle. For most applications where protective relays and fault recorders perform oscillography capture, this sampling rate is high enough. For applications where a high sampling rate is required, SV data is available from some I/O devices at 256 samples per cycle.

Revenue meters can subscribe to sampled value data, just as relays do, and still have the potential to meet accuracy requirements. However, there are regulatory barriers since regulations for revenue metering focus on traceability of the data. With traditional revenue meters, specific independent instrument transformers dedicated to metering may be required, including cables installed in a locked cable trench, with the meter in a sealed cabinet. Process bus works with sampled value data published to a network shared with other devices. In the context of metering, this requires a documentation and approval process to show that process bus data and metering is traceable enough to satisfy regulators. Data from the protective relays using process bus can be used for panel metering applications.

Conclusion

Whether looking to retrofit an existing substation or build a new one, the benefits of implementing process bus using IEC 61850 are the same – total cost of ownership savings, a simplified architecture utilizing a manufacturer-agnostic universal methodology, and the ability to enhance situational awareness and reliability in the system. Protection and control capital cost benefits are a total project savings of 10%, including a 50% reduction in required labor. Since the introduction of IEC 61850, **GE has supplied equipment for more than 100 process bus projects in transmission, distribution and industrial applications in service in 27 countries** that serve as proof points to these advantages. To many, the main barrier is getting started, and with anything, this takes careful planning. This guide was created to assist in the planning process by providing answers to some commonly asked questions. Development of a process bus protection, control and monitoring system should be approached from the utility enterprise perspective that recognizes and addresses needs, while cost reduction and speed of deployment remain reliable and secure.

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