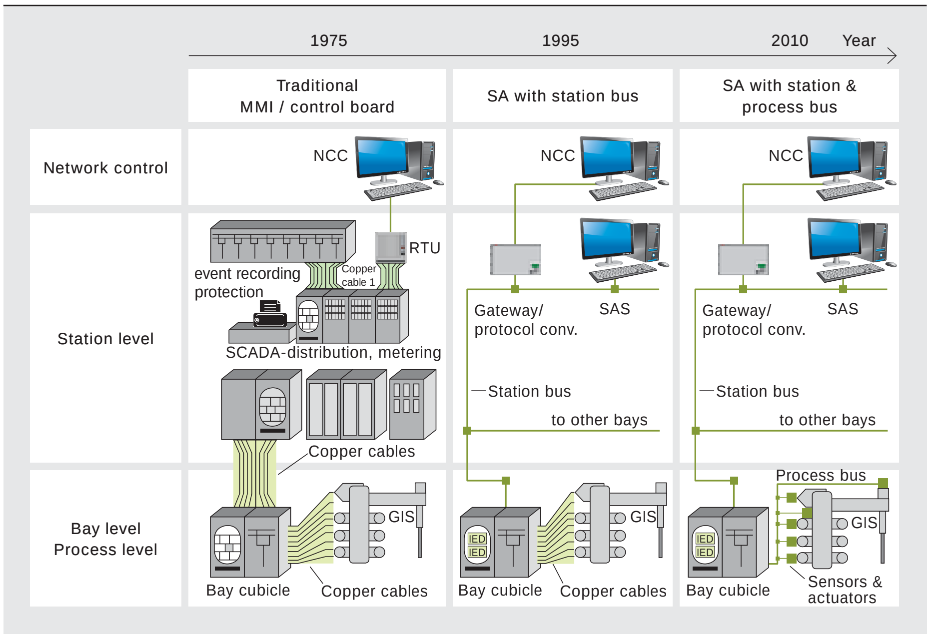
Next generation substations

Impact of the process bus

HANS-ERIK OLOVSSON, THOMAS WERNER, PETER RIETMANN – Substations are a crucial element for the transmission and distribution of electrical energy. Their primary role is to transfer and transform electrical energy (stepping-up or down the voltage). This is done with high voltage switching equipment and power transformers. In order to protect and control, instrument transformers supply the status of the primary system to secondary equipment. ABB has the expertise, experience and technology to design and build substations of any size.

1 Development of secondary systems for substations



Since the first substations were built more than 100 years ago, there has been tremendous development of both the primary equipment (switchgear, power transformers, etc.) and the secondary equipment (protection, control and metering, etc).

ABB has been engineering and constructing substations from their very beginning and has delivered more substations than any other supplier. The first substations deployed had air-insulated switchgear (AIS). The development focus for AIS was on circuit breaker (CB) technology that would increase reliability and reduce maintenance. In 1965 ABB delivered the world's first substation with gas-insulated switchgear (GIS). With GIS the footprint of substations can be reduced by about 60 percent, by housing all primary conductors within earthed SF_6 gas-insulated aluminum tubes. Over the years new generations of GIS have been developed, providing today's GIS with, among other things, a considerably smaller footprint (for more detail see "Compact and reliable" on pages 92-98 of *ABB Review* issue 1/2009).

Due to the reduced maintenance of CBs, new substation design principles emerged for AIS in the late 1990s. The disconnecting function was still required but more for maintenance of overhead lines and power transformers. This led to the development of two types of solutions with disconnect switches (DSs) integrated with the CB function. One was a hybrid (PASS™), which has a separate DS design in the same gas compartment as the CB. Another one was the disconnecting CB (DCB), which uses the same contact for both breaking and disconnecting functions. Due to the reduced maintenance of CBs and the protection by SF_6 gas of the DSs' primary contacts from external pollution, the availability and reliability of AIS substations using hybrid or DCB has increased. Furthermore the footprint of AIS substations using this technique can now be reduced to about 50 percent.

The latest step in substation development comes with the introduction of the standard IEC 61850-9-2 for the process bus interface. For primary equipment, this means conventional instrument transformers (CIT) that use copper, iron and insulation material providing analogue values (1 A, 110 V) can be exchanged for fiber-optic sensors that send a process bus digital signal via fiber optic cables to metering, protection and control equipment. As the use of sensors increases gradually over time the requirement for a secondary system to support both CIT and non-conventional instrument transformers (NCIT) during this transition period will become apparent. This requirement is obvious when extending substations, since the new bays will contain NCITs and existing bays will contain CITs.

The greatest physical impact of process bus will be on AIS with live tank CBs or DCBs, where the measuring transformers can be integrated in the CB or DCB, allowing the substation's footprint to be reduced substantially. For hybrid and GIS solutions, the footprint reduction will be less significant as the insulation distance between primary and secondary equipment is already reduced by the use of SF_6 gas. However, the process bus will enable the use of non conventional voltage transformers (VTs) making equipment much lighter (a traditional VT is quite heavy). Further, the manufacturing time can be reduced since all adaptations can be done with software and the hardware can be standardized.

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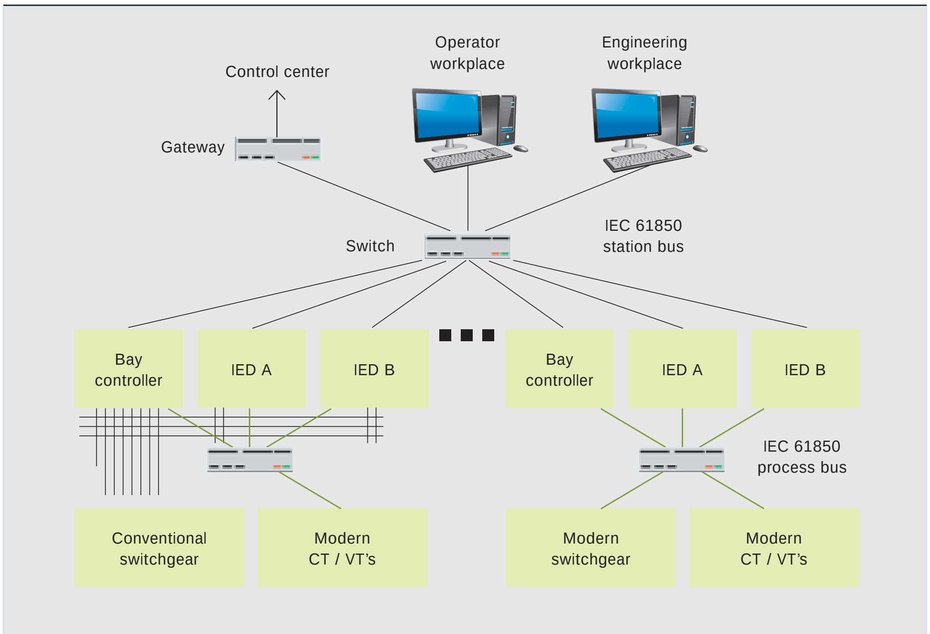
2 Topology of substation secondary systems



The introduction of the process bus will also mean changes regarding interfaces for CBs and DSs. All signals, digital and analogue, to and from the control room can now be run via process bus in a few optical fibers instead of tons of copper cables. The CBs and DSs will include I/O electronics for signal transfer from optical to electrical and vice versa.

Secondary side developments

The digital (r)evolution has provided technical solutions for substations. Digital technology was first implemented in substations in the 1970s, providing communication channels from the substations to control centers ➔ 1.

During the early 1990s, with the increased capacity and speed of computing and communications technology, digital protection and control devices, the so called IEDs (intelligent electronic devices) were installed in substations. Digital communication between the IEDs was introduced using station bus with protocols that differed between manufacturers ➔ 1.

With the introduction of the IEC 61850 standard, substations are moving into a new era regarding communications. All manufacturers can adapt their products to the same communication model and protocol, making it possible for different manufacturers IEDs to “talk with each other” and thus interoperate on the same station bus, replacing all previous proprietary protocols.

IEC 61850 also includes a new standard for the communication between the high-voltage apparatus and IEDs, the so called process bus using the 9-2 profile and communications architecture. The process bus has high requirements on bandwidth since it will be used to transfer continuous sampled values from the primary process.

On the secondary equipment side the most obvious physical change will be from copper cables to fiber optic cables. The massive reduction of secondary cabling will mean reduced cost for cables and associated equipment such as cable trenches and installation material. Man hours for installation and testing on-site will be reduced and more thorough testing can be made at the factory before delivery to site, leading to a secondary system of higher overall quality. Also the architecture of the secondary systems will change compared with today’s substations. The bay house principle, in which the relay and control equipment are decentralized in the switchyard, will disappear since there will be no copper connections between the switchgear apparatus and metering, protection and control devices, as the process devices can now be mounted directly onto the primary apparatus. The central control room of the substation will become the natural location for relay and control equipment connected by fiber optics to marshalling cubicles close to the primary equipment. Interface equipment, such as merging units will be located in the marshalling cubicle.

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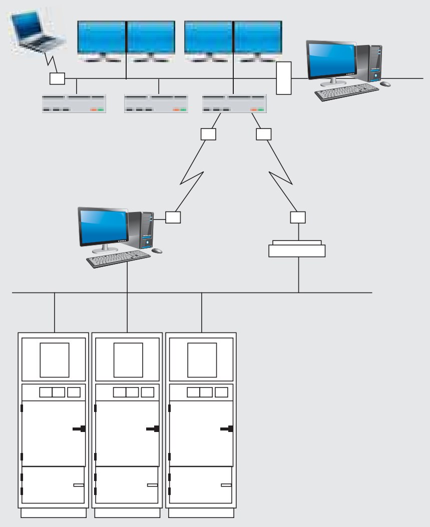
Process Bus – connecting the last mile

The widely accepted standard IEC 61850 defines the complete communications architecture for station and process bus to ensure a high level of device interoperability. The standard’s data models and communication services are the key to interoperability between multi-vendor substation protection, control devices (IEDs), and station computers (gateways) via Ethernet. A substation’s secondary system with station and bay level devices communicating over the so-called station bus has been widely adopted by utilities and vendors ➔ 2.

The cyclic exchange of sampled values, ie, between NCIT and IED devices for protection functions and other purposes is also defined in the standard (part 9-2). The interconnection between sensors, actuators, protection and control devices, is referred to as "process bus" (lower part ➔ 3). This means that not only analog data, but also status information from primary switchgear to IEDs, as well as command signals from IEDs to the primary switchgear can be exchanged. This interconnection between sensors, actuators, protection and control devices, is referred to as the “process bus” (lower part ➔ 2). A vendor-agreed subset under the umbrella of the utility communication architecture (UCA) foundation has been in place since 2004. This subset specifies the exchange of sampled values and is called IEC 61850-9-2LE (light edition). Today, pilot projects utilizing the process

3 Control system architecture and its life times



Both new installations as well as the increasing number of secondary retrofit or extension installations will see both sensor and conventional instrument transformer technologies side-by-side.

bus for sampled values are in operation already and the execution of the first commercial project for Powerlink Queensland's Loganlea 275 kV substation is well underway.

Modern substations, both new installations as well as the increasing number of secondary retrofit or extensions installations will see both sensor and conventional instrument transformer technologies side-by-side. The same applies for handling signaling commands and position indications to and from primary switchgear.

Realizing the process bus

With the process bus, new devices such as merging units (MU) for the optical sensors, as well interface units for conventional instrument transformers, are needed. In addition switchgear controllers for circuit breakers and disconnectors ("Breaker IEDs") will be introduced. Those devices can be seen as conversion "endpoints" to and from the primary process to the secondary equipment.

A merging unit, as the name implies, merges various input signals into one digital output signal, eg, three phase sensors can have one common electronic unit, which transform the optical signals from the sensors into digital sampled values and make them available on the process bus.

A switchgear controller contains electronics for handling binary input and output signals (signal and power contacts). The device will communicate status information and commands through the process bus.

The location of the electronics depends on a number of criteria. Primary apparatus with electronics integrated in the drive cubicles is one possibility. On the other hand, it must be possible to handle cases where the primary equipment does not yet contain communication interfaces. Here, system integrators need to mount the process electronics as near as possible to the primary equipment, eg, to locate them within the marshalling kiosks.

Interoperability and architecture on the process bus

Field experience with sensors has been gathered for more than ten years now, mostly in conjunction with protection and control equipment from the same vendor. For the process bus, utilities are executing an increasing number of pilot installations in order to gain experience. Widespread commercial adoption has not yet taken place.

Interoperability

Both the communication architectures (9-2, 9-2LE) and the steady-state behavior of sensors are defined (IEC 60044). The transient signal response of merging units has not yet been standardized. The latter defines the extent (in terms of angle and amplitude) to which a merging unit output signal is allowed to differ from its corresponding input signal. This is essential since protection algorithms and the corresponding data acquisition hardware and filtering has so far been "interconnected" within one device, the IED. Now those parts are split up into different physical devices that can be supplied from different vendors, and therefore a transient signal response standard is essential for correct functioning. A newly formed working group with Cigré (B5.24) is addressing signal interoperability and results are expected during 2011.

Process bus communication architectures

Several different process bus architectures exist. In fact, depending on factors such as distance (location of MUs and IEDs), communication capabilities (single port, multiple ports), available network bandwidth, availability considerations or communication topologies, such as point-to-point, star or ring configurations the process bus architecture can vary considerably. Both utilities and vendors are working on guidelines for reference topologies for such architectures.

Refurbishment and extension of existing SA systems

The typical life cycle of the primary and secondary equipment of a substation is illustrated in ➔ 3. During the life time of the primary equipment the entire secondary equipment or parts of the secondary equipment are replaced between one to four times.

The most interesting and future prrof migration scenarios will be the ones in which IEC 61850-based equipment is introduced in steps to already installed systems. There are two main driving factors for this: Retrofit and extension of substations or of system functionality. With the long life of primary equipment compared to secondary equipment, there will be a continuous need for secondary equipment replacement, while retaining the existing primary equipment.

By introducing the process bus it will be possible to make a very efficient retrofit of protection and control systems with minimum outage. While keeping the substation in service using the old equipment, the new IEC 61850-9-2-based equipment can be installed and tested using new fiber optic cables laid in parallel to existing copper cables. A short outage is necessary to connect the new protection and control equipment to the existing primary equipment. When the substation is taken into service again the old protection and control equipment together with all copper cabling can be removed or can remain.

Refurbishment drivers

There are different reasons for refurbishing a substation or parts thereof. These can depend on the starting point (eg, whether starting from a conventional remote terminal unit, RTU, solution or from a proprietary numerical control system). All of the below drivers may be applicable or only a selection of them.

Increase system availability

Exchanging 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

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 the test personnel close to primary equipment or without the risk of inadvertently opening current transformer (CT) circuits.

Increased functionality

Fully distributed system architecture coupled with un-restricted communication and process capability enables the system to add new functions easily with zero or minimal outage time, giving the user additional benefit with respect to safe and secure system operation.

Interoperability

By deploying the IEC 61850 compliant solution[1], interoperability with regard to communications with other manufacturer's equipment can be achieved. The benefit to customers is that IEDs from different suppliers can be mixed on the same bus without concern for communication incompatibilities.

Prospects

The introduction of the IEC 61850-9-2 process bus standard in substations will give the following main advantages:

The footprint of primary switchgear can be reduced since fiber optic sensors (NCIT) can replace conventional measuring transformers. This will be most pronounced for air-insulated substations, especially when using live tank CBs.

Traditional VTs are quite a heavy part of GIS and by using new sensor technology for voltage measurement the equipment can be made much lighter. Further, the manufacturing time can be reduced since all adaptations of NCIT can be done with software and their hardware can be standardized leading to an overall shorter delivery time.

On the secondary side the massive reduction of secondary 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. Testing at site will be very much reduced and more thorough testing can be made at the factory. This will lead to higher quality overall and a reduced time at site.

Changing to optical sensors (NCIT) will increase personnel safety since there will be no risk of injuries due to the inadvertent opening of current transformer secondary electrical circuits.

For retrofit, the possibility of installing the new 9-2 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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Footnote
1 There are a number of solutions slightly different in architecture etc. that will be compliant with IEC 61850.