Solving Synchronization Challenges Using Distributed Signal Acquisition With Fiber-Optic Links

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***Abstract*—The challenges of designing synchronizing systems for utility and industrial power systems have become more complex. New and existing generation are separated from transmission points of interconnection by ownership and distance, requiring isolation between facilities. Distributed energy resources located throughout the power system are becoming more common and are usually used to form microgrids with diverse synchronizing points. Often, voltage transformer (VT) and control signals across synchronizing breakers are not available. Further, automatic synchronizing systems are being favored over manual systems to reduce operator workloads and improve performance, response times, and flexibility.**

Traditional synchronizing technology limits the possible solutions to these challenges. Designers are frequently faced with the choice of adding expensive VTs at various synchronizing points, relying on operators to go to remote locations to synchronize manually, or designing complex systems for analog-digital-analog conversion using amplifiers to recreate a remote signal for the synchronizing circuits. The complexity of these systems makes them less reliable.

An advanced automatic synchronizer (A25A) that uses digital secondary system (DSS) technology enables cost reduction and improved reliability, performance, and personnel safety. Using the A25A, we can design systems not considered possible using traditional technology. A DSS replaces hardwired analog and binary signals with merging units that are located wherever needed and interface to the A25A via point-to-point fiber-optic links. In this paper, we discuss the challenges of conventional synchronizing systems and show the advantages of using the A25A with new DSS technology as a practical solution.

I. INTRODUCTION

Synchronizing systems are used in diverse applications throughout the power system. The first application that comes to mind is connecting an incoming generator to a running grid. This is the origin of *incoming* and *running*, the common terms used to describe synchronizing systems. The controlled system (i.e., the system that can be adjusted for matching frequency, voltage, and angle) is the incoming system; the larger power system that the incoming system is being connected to is the running system. However, synchronizing systems are also used in many other applications such as transmission substations, industrial distribution systems, and microgrids.

For example, you may find a synchronizing panel in a transmission substation. A synchronizing panel includes a synchroscope, at a minimum, and usually incoming and running voltmeters and synchronism lights [1]. Operators can turn on the synchronizing panel to ensure that the two systems on either side of the open breaker to be closed are synchronized. In such applications, there are no controls for adjusting the frequency and voltage on the synchronizing panel.

Synchronizing systems are usually found in industrial power distribution systems where onsite cogeneration systems are used. Cogeneration systems often provide combined heat, process steam, and electric power to support the industrial production process. In such systems, the trend has been to upgrade the plant control systems to create a reliable islanding system that allows the industrial plant to separate, survive, and re-synchronize [2]. This allows the plant to operate islanded from the grid when normal grid power is not available. These systems often have very robust distribution systems with multiple ways to feed critical loads and many separation points. Each separation point requires a synchronizing system. Centralized, plant-wide synchronizing systems are commonly used in these applications.

The latest trend creating requirements for novel synchronizing systems is leveraging the decentralized nature of renewable energy sources to create local microgrids to improve service reliability for neighborhoods, college campuses, industrial parks, and commercial districts. These systems are not new. However, the term *microgrid* has become common to describe these localized grids that can disconnect from the traditional grid to operate autonomously. The U.S. Department of Energy defines a microgrid as:

> A group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid (and can) ***connect*** [emphasis added] and disconnect from the grid to enable it to operate in both grid-connected or island-mode. [3]

As the definition states, one important requirement for a microgrid control system is the ability to synchronize (i.e., reconnect) the microgrid back to the main grid.

The challenges of designing synchronizing systems for these diverse applications are more complex than the traditional generator synchronizing application. However, it is now common for new and existing generation to be separated from transmission points of interconnection by ownership and distances, requiring isolation between facilities. Often, the voltage transformer (VT) and control signals may not be available to implement synchronizing systems using conventional technology. Further, automatic synchronizing systems are being favored over manual systems to reduce operator workloads and improve performance, response times, and flexibility. Therefore, designing conventional generator synchronizing systems has become more challenging.

Conventional synchronizing systems can include both manual and automatic synchronizing functions. For manual systems, a synchronizing panel is necessary to provide the information required for an operator to complete the process. For this function, there is no substitute for a synchroscope. Traditional synchroscopes require that incoming and running voltage signals be available for direct connection to the device. Traditional automatic synchronizers share this limitation as well.

Soft synchroscopes are only suitable for allowing operators to monitor an automatic synchronizing system. The variability of latencies involved in a computer-generated soft synchroscope does not allow an operator to time the close command to anticipate closure at exactly zero degrees phase coincidence [1]. It has been proposed that synchrophasor technology may be suitable for such applications; however, this technology has never been commercialized [4].

In the past, if synchronization with remote signals was required, one approach was to build a system that: (a) digitized the remote VT signal; (b) transmitted it over a low-latency communication link; (c) converted the digital signal back to analog; (d) amplified the signal; (e) used the reconstituted voltage signal to drive traditional synchronizing equipment. Such systems were complex and had many components, and therefore had relatively low reliability and performance. However, they eliminated issues with long VT signal runs where induced noise and possible ground potential rise made hardwired connections impractical.

An advanced automatic synchronizer (A25A) can overcome many of the limitations of traditional synchronizing equipment. The A25A has been available for many years [1]. But with the advent of full function digital secondary system (DSS) technologies, even better systems for addressing the challenges of complex synchronizing systems are possible. DSS technology has been in development for many years. Originally, this technology was used to replace binary input/output (I/O) signaling with messages transmitted over serial, and later Ethernet, communication links. In substation applications, these serial or Ethernet communication links could use fiber-optic cables to replace large numbers of copper control cables between the protection and control panels in the substation control enclosure and the high-voltage yard equipment [5]. DSS technology has evolved so that copper instrument transformer signal cables can also be replaced with fiber-optic communication links for analog sensing signals.

This paper reviews challenging synchronizing applications and demonstrates how A25A technology can solve many difficult problems and provide improved simplicity, reliability, and performance. We discuss three classes of solutions:

- Systems where hardwired sensing and control signaling is acceptable.
- Systems where an A25A can be located near the synchronizing breaker and synchronizing signal sources, and control signaling can be performed via communication links.
- Systems where both sensing and control signals must be connected to the A25A via communication links.

The paper also briefly discusses the two types of DSS systems available: Ethernet networked DSS systems based on international standards, and DSS systems that use simple point-to-point communication links based on proprietary devices and protocols. The second type of DSS solution is emphasized for its greater simplicity in solving problems where networked DSS is not the backbone of the system design architecture.

II. SYNCHRONIZING SYSTEM IN A TRADITIONAL SUBSTATION DESIGN

Synchronization is an intricate process. It requires the correct operation of a variety of mechanisms and systems, i.e., mechanical, electrical, and human. Synchronization must be performed carefully to prevent damage to the generator and to ensure there are no impacts to the power system as a whole. The requirement for a proper synchronization is that the voltage amplitude, frequency, and phase angle of the incoming generator and running power system or bus should closely match.

Faulty synchronization can cause significant surges, disturbances, and oscillations to the power system [1]. The impact is more severe if the system is weak compared to the size of the generator. Faulty synchronization can also result in the generator tripping and being unable to pick up load.

A synchronizing system monitors the power system condition, controls the governor and exciter/automatic voltage regulator (AVR) of the incoming generator, and issues a close command to the synchronizing breaker to bring the generator online. The synchronizing system is used to synchronize a single generator, an inverter, or multiple gensets. The breaker should be closed when the angle difference between the incoming and running voltages is minimal. Per IEEE C37.102-2006, the requirements of synchronization are that the breaker closing angle should be between ±10 degrees, the voltage difference should be less than 5%, and the frequency difference should be less than 0.067 Hz [6].

A. Conventional Synchronizing Systems

In a conventional manual synchronizing system, proper synchronization is largely dependent on the operator. The operator must perform two jobs. First, the operator is responsible to match the frequency and voltage of the incoming generator with the running bus by controlling the governor and the AVR set points. Second, the operator must close the breaker when the phase angle difference between incoming and running voltages is as close to zero as possible.

A conventional synchronizing system consists of a synchronization panel with meters and indications like voltmeters, a synchroscope, and lamps to provide the operators information for manual synchronization. The synchroscope is connected between the incoming and running voltages as shown in Fig. 1. The VTs are hardwired to the synchroscope and the voltmeters. The operator uses the synchroscope as a visual indication to determine the correct instant to close the breaker. If there are multiple synchronizing points in the system, the operator uses a synchronizing switch or controls programmed into the plant distributed control system (DCS) to physically switch the VT circuits and control signals based on the generator and breaker selected for close. Once the correct incoming and running voltages are selected, the operator controls the frequency and voltage magnitude to bring them within the acceptable range. When the frequency and voltage magnitude are within range, the operator uses the dial on the synchroscope (shown in Fig. 1) to close at a near zero angle difference.

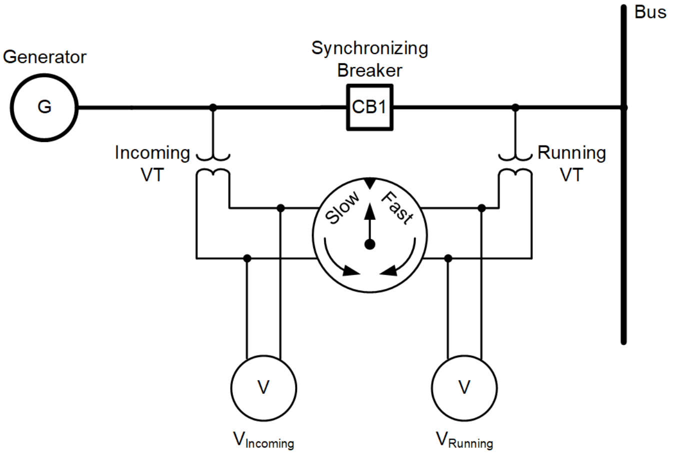


Fig. 1. Electromechanical synchroscope

As stated previously, a manual synchronizing system requires the VT inputs and the control signals to be hardwired; therefore, design of such circuits requires complex wiring. The problem with wiring complexity is multifarious; complex wiring could result in hidden wiring failures. It is difficult to expand such systems because of the pre-existing complex wiring, and it is also difficult to test such systems. Additionally, human error can cause faulty synchronization in manual systems with heavy reliance on operators.

An advancement on the manual synchronizing system is the automatic synchronizing system. An automatic synchronizing system can compensate for the breaker close mechanism delay to ensure the breaker closes at the correct instance to secure a near zero angle difference. It measures the slip and calculates the advanced angle at which to energize the close coil. The slip-compensated advanced angle is calculated using (1):

$$\text{ADVANG}^0 = \left(\frac{(\text{SLIP})\,\text{cyc}}{\text{sec}}\right)\left(\frac{\text{sec}}{60\ \text{cyc}}\right) \left(\frac{360^0}{\text{cyc}}\right)\left((\text{TCLS})\,\text{cyc}\right) \tag{1}$$

where:

ADVANG is the advanced close angle.

TCLS is the circuit breaker close mechanism delay.

The main advantage of an automatic system is that it can ensure a consistent close with a near zero angle difference every time, unlike a manual system that relies on an operator. Like the manual system, the automatic synchronizer can send control or error pulses to bring the voltage and frequency of the generator within the synchronism acceptance criteria. Once the frequency and voltage are matched, it closes the breaker at the slip-compensated advanced angle calculated using (1).

The synchroscope is generally also a part of the automatic synchronizing system, but the synchronizing system does not rely on the operator and synchroscope to close the breaker at the correct instant. The dependency on an operator to synchronize systems based on visual information is thereby reduced. The automatic synchronizer still requires operator interference to manually switch the voltage signals if more than one synchronizing breaker exists. If multiple synchronizing breakers are controlled through one automatic synchronizer, the associated VT circuit wiring becomes very complex. Although the automatic synchronizer is an improvement to the manual system, it still requires signal switching and complex wiring to route the voltage and control signals from the synchronizer to the VT, breaker, and generator control system (GCS).

B. A25A Systems

A25A systems have all the capabilities of a typical synchronizer, and offer enhanced flexibility in terms of system configurations and improved reliability when compared to their conventional counterparts. Reference [1] covers the components, features, and benefits of an A25A system in detail. The major points of A25A systems are highlighted in this section.

An A25A system has six independent single-phase voltage inputs, which remove the need to switch the VT signals manually. With multiple isolated VT inputs, A25A systems can be programmed to account for multiple synchronization points and system configurations. The operator can select the synchronizing breaker from the A25A user interface. The A25A can be programmed to automatically use the measurements from the correct VT source from the six voltage inputs, depending on the circuit breaker selected for synchronization.

A25A systems interface with a GCS to send control pulses to the governor and the AVR, bringing the generator speed and voltage into the synchronism acceptance limits. This can be achieved in multiple ways. The A25A device has a human-machine interface (HMI) with an LCD display and various LED indicators that the operator can use to telemeter the data to a control center for manual adjustments. Alternatively, the A25A can be configured to issue correction pulses to a dedicated remote I/O (RIO) module to control generator speed and voltage. The RIO module is in the GCS and is connected to the A25A device via fiber-optic communication links. The correction pulses can also be transmitted via the IEC 61850 GOOSE protocol.

Ideally, the A25A is located close to the VTs and the breaker. In such a scenario, close signals can be hardwired to the breaker. But if a single A25A device is used to control multiple breakers, the distance between the breaker and the A25A might be an issue. In such a case, a dedicated RIO module for the breaker can be used to issue the close command if the A25A is located far from the synchronizing breaker.

Fig. 2 shows the analog, digital, and I/O signals of an A25A system in a traditional substation.

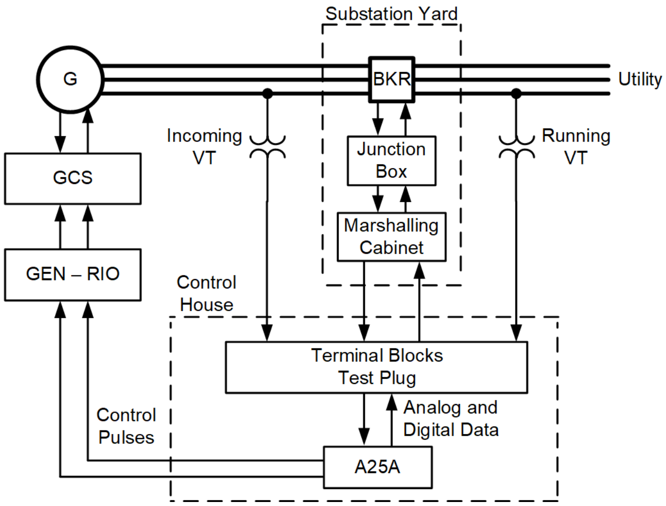


Fig. 2. A25A system in a traditional substation

The A25A can also be programmed to allow for various indications, alarms, and event recording. Alarms can be configured throughout the stages of the synchronization process—from the selection of a breaker to issuance of a successful close command or a failed breaker close. These alarms are integrated into the plant DCS so that all pertinent information is available in the control room. To retain the operator controls for supervisory checks, the A25A systems can be programmed to allow for multi-level operator supervision, if desired. The operator controls the overall process, including permissive prior to a dead bus close or parallel close, while the A25A system secures operator command by performing parallel checks. Fig. 3 shows a typical front-panel layout of an A25A device.

III. Complex Synchronizing Systems and Challenges

The challenges of designing synchronizing systems for utility and industrial systems have become more complex primarily because of the diversity in the application of synchronizing systems. The benefits offered by existing conventional synchronization devices are rather limited. This section discusses applications that have complex synchronizing system requirements.

A. Generation and Transmission Interconnections

Generation and transmission interconnections are required to pool power plants and load centers to minimize the total power generation capacity and cost. Generation and transmission services are provided by separate, independent entities. With the separation of these service providers, the interconnection points (also referred to as points of common coupling [PCCs]) may be separated by distance, ownership, or both. This requires isolation between the two facilities. Often, the analog and control signals across the breakers may not be

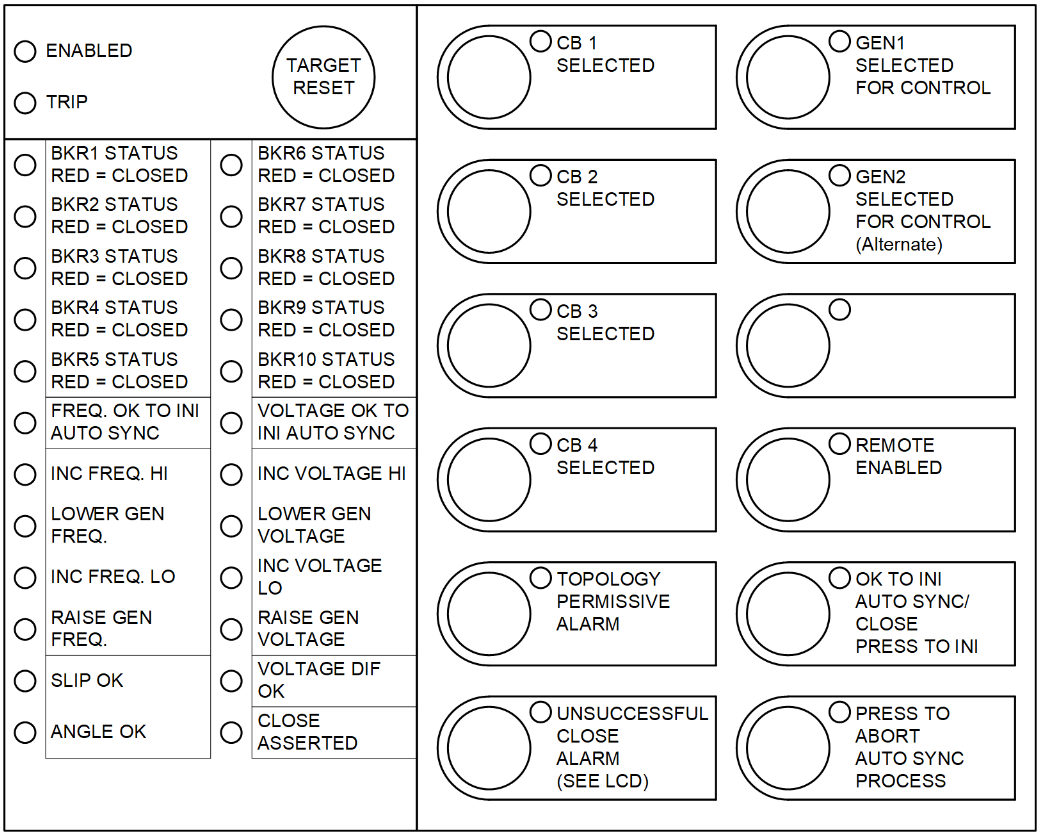


Fig. 3. A25A device front-panel indications and controls

available for use. In such scenarios, designing a synchronizing system that can cater to those needs is challenging. A solution is that the generating station can install a local synchronizing breaker and associated VTs to synchronize the generation with the transmission network; however, this solution may not be cost effective. Alternatively, long cable runs are required to be installed from the VTs in the transmission substation to the A25A device in the generating station. Longer cable runs are expensive and can result in ground potential rise and induced voltages along with complexity in wiring. The following section discusses a newer, more robust solution to this problem.

B. Distributed Energy Resources and Microgrids

A microgrid generally operates while connected to the grid and can be separated from the main grid automatically in case of a crisis or separated manually to function as an island. These islands have multiple synchronizing points (i.e., PCCs) that can be used to resynchronize back to the main grid or to synchronize two islands to each other. In any case, the synchronizing system must account for all possible island and grid configurations to provide a flexible and reliable solution. These decentralized grids improve service continuity under abnormal system conditions. When a microgrid is islanded, it needs to be synchronized with the utility grid at the PCC before reconnection. Microgrid resynchronization is different from traditional grid resynchronization because of unpredictable loads and the presence of distributed generation with renewable and non-renewable sources of power. When a distributed energy resource (DER) is operating with a load while the DER is synchronizing, the dynamics of the load can affect synchronizing speed and accuracy. It is common to have a synchronizing system at every PCC in microgrid applications, but if a centralized synchronizing system is used then measuring voltage at different points in the microgrid and bringing the VT signals to the A25A device can be a difficult task.

C. Industrial Systems

It is common for larger industrial facilities to have cogeneration systems. Similar to microgrids, these systems can be disconnected from the grid, operated as an independent island, and re-connected to the grid. Depending on the type of industry and the load it is serving, critical load islanding may be necessary. In critical load islanding, critical loads are islanded under abnormal system conditions to ensure service continuity to these loads. The distribution network is designed such that there are multiple ways to serve these critical loads. Multiple routes result in multiple synchronizing points with each point requiring a synchronizing system. These synchronizing points could be located next to each other or hundreds of yards apart, depending on the facility design. With multiple synchronizing breakers, long and complex cable runs are installed to the synchronizer for VT and close signals. Careful planning is required to design one or multiple A25A systems to account for all possible topology permissive, and VT switching in the case of smart A25A, for every synchronizing point. Complex network configurations of these systems and the demand for highly reliable synchronizing systems have resulted in a shift toward the use of a centralized synchronizing system.

D. Synchronization Challenges With Complex Systems

Designing a synchronization system for such challenging applications is difficult. To design a robust synchronization system, it is necessary to understand the potential challenges of the application and design a system that addresses those issues. The system should have no single points of failure or common-mode failure problems to be completely reliable. The instrument transformer circuits must have proper isolation and grounding. The dc control circuits must also have proper isolation. Synchronizers for these complex systems could be designed with multiple control interfaces located separately or a single plant-wide centralized control interface.

Complex system arrangements described in this section require multiple VT circuits to be brought into the synchronizing system. This becomes a bigger issue in conventional synchronizing systems because of manual VT signal switching. In manual systems, this results in complex schematic designs and wiring. Troubleshooting such systems is difficult as intricate cabling can result in hidden wiring failures and reduce the overall reliability. A similar problem arises in automatic synchronizing systems because of complex wiring. Moreover, detailed planning, careful programming, and thorough testing is required to verify that the A25A device can successfully synchronize in all scenarios.

Lastly, the close signals need to be sent to multiple breakers situated in different locations. Control circuits needed for this application, including status inputs, can be complex and long. Dead bus permissive, synchronizing close indicators, and anti-paralleling interlocks are often required to improve the safety and continuity of service. These interlocks could be hardwired, or they could be programmed in the synchronizing systems.

IV. DIGITAL SECONDARY SYSTEMS

One area of power system protection and control that has remained virtually unchanged is the use of copper cabling to bring instrument transformer data and control signals from the substation yard to the microprocessor relay in the control house. An alternative approach is to replace copper with fiber-optic communication links. This solution is called a digital secondary system (DSS) or a digital substation solution.

Fig. 4 shows a simplified diagram of a traditional substation and how the signals are routed over copper. Fig. 5 shows a simplified diagram of a digital substation where a device(s) separate from the relay performs the analog-to-digital conversion of instrument transformer signals and has contact I/Os to interact with the primary equipment, such as circuit breakers. The device that performs this function is called a merging unit (MU). The MU is installed in the substation yard.

The information is digitized by the MU and transmitted over fiber-optic digital communication links to the intelligent electronic devices (IEDs) in the control house. Fig. 6 and Fig. 7 show two different architectures for streaming digital data between the MU and the IED based on what is inside the cloud in Fig. 5.

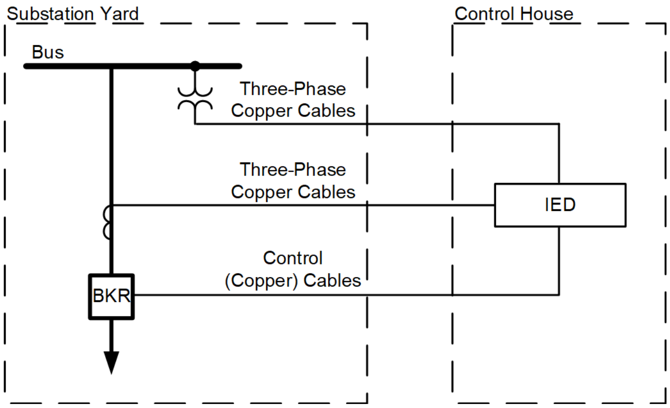


Fig. 4. Connections for a traditional substation

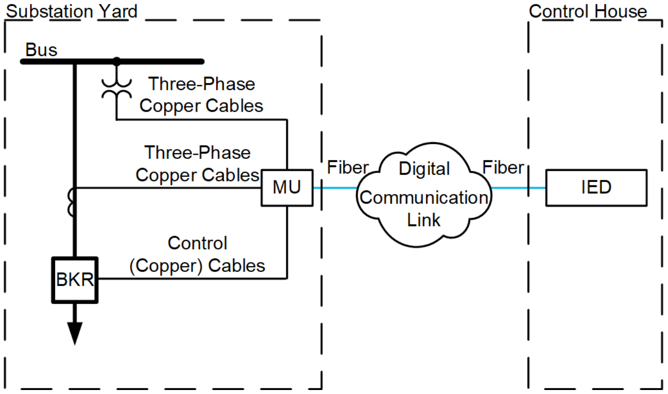


Fig. 5. Connections for a digital substation

A DSS solution can be employed in two different architectures. The first approach is to implement a process bus using a switched (i.e., Ethernet-based) network architecture. The other is a point-to-point architecture. Both use fiber-optic communication links. The following sections provide details on the two approaches.

A. Switched Network Architecture Approach

Switched network architecture is based on the Sampled Value (SV) Process Bus concept in the IEC-61850-9-2 standard [7] [8]. In this architecture, the instrument transformer data are digitized at the source and communicated to the IEDs in the substation control room over a switched network. Fig. 6 shows a simplified version of the switched network architecture solution. The instrument transformer data are digitized in the MU and brought to a switch in the control house, which distributes the information to the IEDs in the network. The Ethernet packets in the switched network architecture are multicast, meaning the data from the MU are sent to all devices in the network, even those that did not subscribe to the data. For this reason, network management tools need to be employed to ensure that network traffic arrives only at the desired location and that excess network traffic does not impact protection and control. The data from the MUs must be synchronized and time aligned because of the switched nature of the Ethernet network. Time alignment is usually performed by a satellite-synchronized clock in the network that synchronizes all MU and IED clocks via IEEE 1588 Precision Time Protocol.

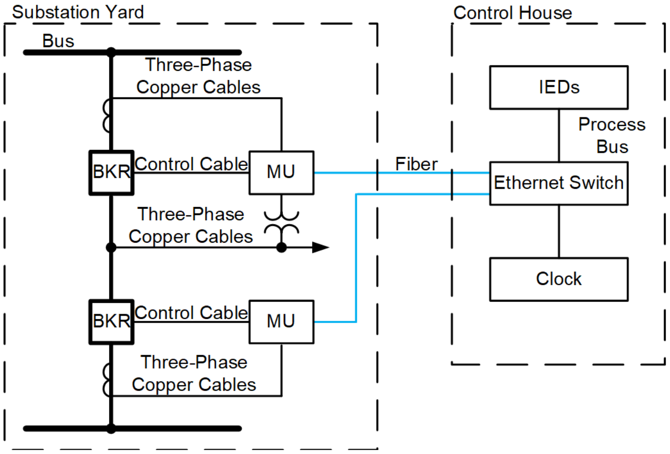


Fig. 6. Switched network DSS solution

B. Point-To-Point Architecture Approach

A point-to-point architecture greatly simplifies a digital substation. In a point-to-point architecture, the MU is connected to the IEDs by a point-to-point fiber-optic link. Fig. 7 shows a simplified version. The data from the MU are not multicast and routed via managed Ethernet switches. Instead, they are sent over a direct fiber link using the manufacturer's proprietary protocol. Therefore, switches and satellite-synchronized clocks are not required in this configuration [9]. The reduced number of devices and the fact that the point-to-point architecture does not require network engineering offer great simplicity over a switched network solution.

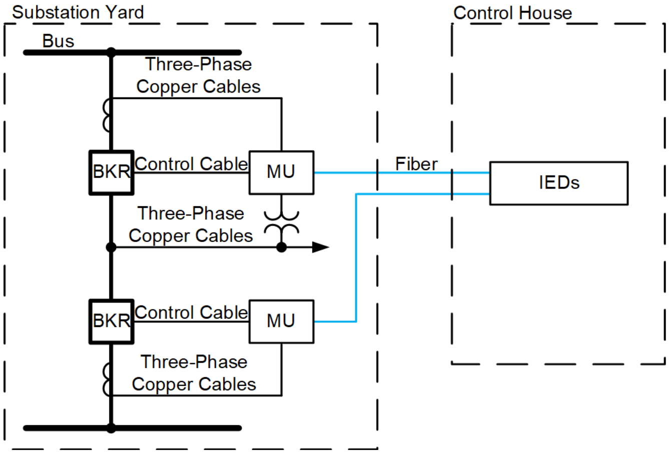


Fig. 7. Point-to-point DSS solution

C. Autosynchronization With DSS

Switched network and point-to-point architectures can be applied to DSS-based synchronizing systems. Each has its own advantages. The question of which technology to choose for the synchronizing system design depends on a variety of factors. If the synchronizer is part of an overall protection system that uses networked DSS technology, using the switched network architecture provides many benefits. All relays in the protection system and the A25A can be tied to a single network. The data from the MUs can also be shared with multiple devices in this setup. Another advantage of the switched network solution is that IEDs from different vendors can be used because all devices use the same protocols as defined in IEC-61850-9-2. Ethernet traffic can be controlled in the switched network solution with virtual local-area networks (VLANs).

If an autosynchronizer is being added to an existing substation, point-to-point architecture provides many benefits, but the simplicity that it brings in the design, commissioning, maintenance, and operation makes it a striking choice for an autosynchronizer application [9]. The point-to-point solution is inherently simpler to install in an existing generating station because it does not require any complex network engineering. Therefore, switches and a robust time-synchronization system are not required, and the fiber-optic links can be directly applied between the synchronizer and the MU. Because the links are point-to-point, the system uses channel-based time synchronization, so the system is not dependent on GPS clocks or other sources of high-accuracy time. The direct links provide the flexibility of future expansion of synchronizing breakers. With a networked architecture, the network requirements, bandwidth, and traffic management all need to be re-evaluated for expansion. For a point-to-point architecture, simply connect the MU to the synchronizer and recommission it with the new topology.

The point-to-point solution is designed such that it is simple to deploy and maintain. The next section describes the design, features, and benefits of the A25A system when applied with a point-to-point DSS solution.

V. IMPROVED A25A WITH DSS SOLUTION

The benefits of the point-to-point DSS are immense. Because the DSS protects and controls the primary equipment using digital devices in the secondary system that transmit data via fiber-optic cables, the point-to-point DSS not only simplifies the synchronizing system, but also offers improvements to the overall design when compared to its traditional counterpart. An A25A system with a DSS performs all the functions of a typical A25A system, overcomes the challenges posed by complex system designs, and offers additional benefits not considered possible previously.

A. System Design

To understand the design and connections for an A25A with a point-to-point DSS solution, consider a simple system shown in Fig. 8. An A25A system is used to synchronize generator G across circuit breaker CB1. The A25A system monitors the voltage on both sides of CB1, transmits pulses to the GCS, and issues a close to CB1 at the right instant. The minimum inputs needed to perform the synchronization are the single-phase voltage signals. The MU for a point-to-point architecture is purpose-built. In a DSS setup, an MU will be installed in the yard by CB1. The single-phase voltage signals from the VTs and breaker status from CB1 are hardwired to the breaker MU. To bring the signals to the A25A system located in the control house, fiber-optic cable is run from the MU(s) in the yard to the A25A system in the control house. The MU can send these data to additional IEDs, if desired, by adding more fiber-optic links. Instead of running multiple long and heavy copper cables, thin and sturdy fiber-optic cables are easy to install and occupy less space.

Once the VT inputs are made available to the A25A, the system compares the two voltages against the user-defined synchronism acceptance criteria. If G requires adjustment to match the running bus, raise or lower control pulses are transmitted to the governor and AVR controls in the control house. The pulses are transmitted through a dedicated MU over fiber-optic communication links. The generator MU is hardwired to the governor and AVR system to control the generator frequency and voltage, respectively. When all synchronizing conditions are met, the generator is ready to be connected to the grid. The A25A computes the slip-compensated advanced close angle to issue the close signal to CB1. The close signal is transmitted to the BKR1 MU via fiber-optic cable. The issuance of a close signal can be monitored via the front panel of the A25A system.

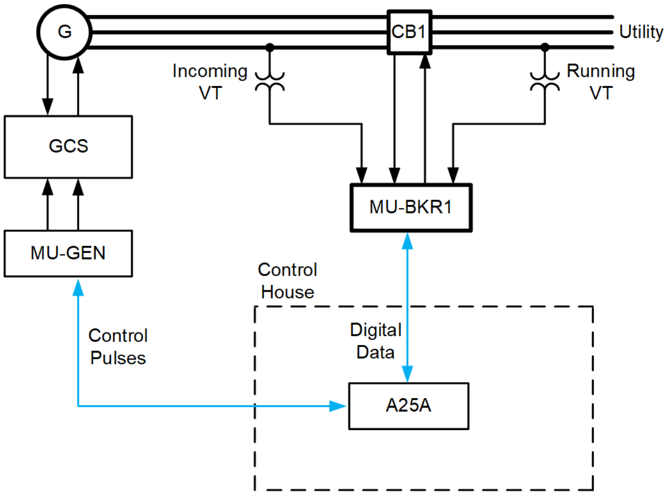


Fig. 8. A25A system with a point-to-point DSS solution

B. Features

This section covers the features and benefits of the point-to-point DSS solution when used with the A25A system.

1) Merging Unit Design

The MU for a point-to-point architecture is purpose-built with enhanced capabilities for better performance of the DSS. The MU hardware has an LED interface that includes indications for each port and overall hardware health.

The MU has four small form-factor pluggable fiber ports, which can share data from a single MU to as many as four IEDs. The MU can also be connected to other relays in the control house along with the A25A. The MU is available with either eight CT inputs or four CT and four VT inputs. Connections for digitizing additional signals for use by other relays is not shown. The CT terminal blocks on the MU are self-shorting for safety. The MU also features 16 contact inputs and 7 contact outputs. The inputs are universally rated with a programmable pickup level. The outputs include three Form A hybrid, high-speed, high-current interrupting contacts, two conventional Form A contacts, and two standard Form C contacts. Additionally, the A25A has I/Os for direct connection to the DCS I/O modules or any other function. The A25A can accept fiber-optic links to as many as eight MUs.

The MU design is simplified to the point that it does not require a microcontroller or user settings. This simplified design is an important attribute of the point-to-point DSS. The devices mounted in the field have no need for complex configuration. A failed unit can be replaced easily. Mapping of current and voltage signals is performed in the A25A settings.

2) Design Benefits

As discussed previously, generation and transmission interconnection points can be separated by long distances. The distances are so long in some cases that using copper wiring is not practical. In a DSS solution with many analog and control signals moved from copper cables to a single fiber-optic cable run for digital data transmission, the design is simplified already. Implementing this in a complex system with multiple synchronizing points where multiple voltage signals need to be brought in to the A25A device, a single MU can transmit voltage signals from four single-phase VTs. Given that the A25A device can functionally accommodate as many as six single-phase voltage inputs, two MUs can be used to bring in six voltage inputs to the A25A using only two direct fiber cables. This can significantly reduce the quantity of copper cables in the substation yard. It also reduces the system installation time, material and space expenses, and installation labor expenses required for cable routing, commissioning, documentation, and the need for qualified technicians. These qualities make the overall design flexible, scalable, and economical.

It is worthwhile to note that expanding the system to add a synchronizing breaker in a traditional substation is a cumbersome task—from the design of copper installs in the yard, to testing, finding, and correcting wiring errors and testing the A25A system in a live circuit. Further, fully automated systems, like a smart A25A system that does not rely on operators, generally require redundancy. The data sharing capability of the MU is a huge benefit in both cases. In case of system expansion, a new MU with a single fiber cable run will need to be planned; or, an existing MU and its fiber channel can be used for data transmission. For redundancy in the system, the same voltage inputs on the MU can be shared with as many as four IEDs, multiple A25A devices, and/or other protective relays (e.g., synchronism check relays) in the control room. Such a setup reduces maintenance and capital costs. The A25A device can monitor the health of the fiber link to the MU. If the communication link is compromised, an alarm is generated in the A25A system and the synchronization process can be stalled until healthy signals return.

3) Configuration

The point-to-point architecture supported by the MUs greatly simplifies A25A implementation. With zero network engineering, mapping the analog and digital quantities in the internal A25A logic is simple and intuitive, reducing system configuration complexity. Moreover, configuring the A25A systems to account for a new breaker in the system is achieved by simply mapping the new analog input from the MU into the automatic synchronizer logic.

Smart A25A devices are designed to reduce the amount of copper needed for an installation and to minimize the number of MUs. In turn, this offers high-speed protection and faster data transmission time. The absence of switches or other network devices in the point-to-point architecture leads to low latency and low jitter, and there is no need to time synchronize all devices.

4) Security

Cybersecurity becomes a concern in DSS solutions because of the increased number of devices, location of these devices, and the fact that instrument transformer data are sent over a communications medium with some level of exposure. Point-to-point architecture is inherently secure because of the lack of entry points into the data [10]. A point-to-point solution uses proprietary protocol that is not compatible with standard switched networks; if connected to a switch, the Ethernet packet will simply be discarded.

The MUs have no settings and no programmability, limiting the exposure outside of the established controlled security perimeters. MUs do not have a microcontroller in their hardware design, which greatly simplifies cybersecurity compliance and exposure requirements.

Most cybersecurity exposure does not come from a lack of features or equipment, but rather from human error. In a point-to-point solution, all data are communicated via direct fiber-optic links. Therefore, the requirements to design a network, manage traffic, and configure VLANs are completely removed. The point-to-point solution does not require clocks and switches, which require their own management and security assessment, and therefore greatly simplifies overall design and maintenance [9].

5) Commissioning and Troubleshooting

In a DSS solution, the high-energy control cables are located away from the control room. This decreases, or even eliminates, several potential electrical safety hazards like open-circuited CTs or short-circuited VTs. Fiber cables do not conduct electric currents, making fiber data connections resistant to electromagnetic interference, lightning, or fire. Fewer cables mean a reduced number of routing paths and connections. This reduces wiring errors and wrong connections, thus reducing time spent rewiring. These benefits lower the chances of a faulty synchronization, thereby offering a more reliable system.

Further, commissioning and testing of A25A systems with fiber is convenient and simple. With a conventional system, one would need to isolate the VT circuit by opening it, verifying the isolation with a live-dead-live check, then carrying the test set to the yard to inject voltages from the terminals in the VT junction box. If VTs are spread across the yard or separated by long distances, isolation and testing are extremely difficult. Alternatively, with fiber-optic cables and MUs, testing can be performed by placing a test MU by the A25A system to inject voltages. The solution could also be preconfigured and commissioned in a test environment (e.g., lab or office), then use the status LED indicators for healthy signal indication and debug wiring errors during onsite installation. Additionally, each port has an individual LED indicator to speed up troubleshooting if the communication channel is disrupted. This greatly reduces commissioning time.

VI. UTILITY GENERATING STATION EXAMPLE

An A25A can solve many challenges in the utility bulk electric system as well as generator synchronizing systems. For example, in many hydroelectric generating stations the generator control room is near the base of the dam, close to the generating units. Often, the high-voltage synchronizing breakers are in the switching station a significant distance away, above the river valley that was dammed to create the impoundment reservoir. Sometimes a similar situation occurs when a generation owner locates their generating plant not far from the utility transmission substation. With conventional synchronizing technology, a local synchronizing breaker and VTs must be installed at the power plant as shown in Fig. 9 and Fig. 10. In these applications, the limitations of conventional synchronizing systems may require installation of expensive primary equipment that might not be needed otherwise.

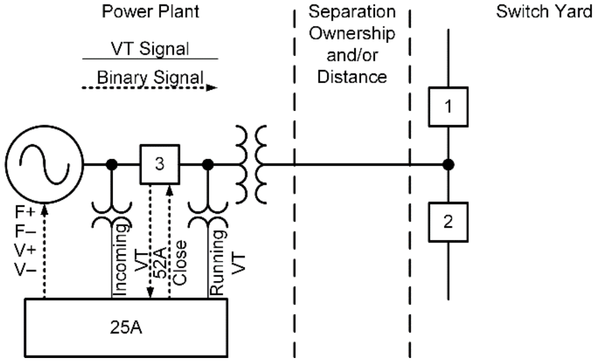


Fig. 9. Generator with a low-side synchronizing breaker

A. *A25A With Binary I/O DSS*

Compare the synchronizing system shown in Fig. 10 with the one shown in Fig. 11. The A25A with a remote binary I/O module eliminates the requirement for a local synchronizing breaker (CB3 in Fig. 9) and running signal VT. This type of A25A has been available for many years [1].

In one application, the A25A was used to significantly improve operations at a large hydroelectric power plant. Because of their high capacity, the generators did not have low-side synchronizing breakers. There was not room for installation of high-side 500 kV synchronizing breakers at the power plant. The 500 kV switch yard where the synchronizing breakers were located was a 20- to 30-minute drive from the power plant, or longer during inclement weather.

Prior to modernizing the synchronizing system, to synchronize a generator it was necessary for an operator to go to the switch yard and enable the manual synchronizing panel. The switch yard operator then called power plant operators over a telephone link and instructed them to manually adjust the voltage and frequency of the incoming generator until the switch yard operator could close the breaker to synchronize the generator to the grid.

With the modernization to a system similar to Fig. 11, operations could remotely enable the A25A from the power plant or the SCADA operations center. The A25A would adjust the generator and synchronize the unit quickly and accurately. In that application, redundant A25A devices were installed to ensure these generators could always be quickly brought online to support the bulk electric system.

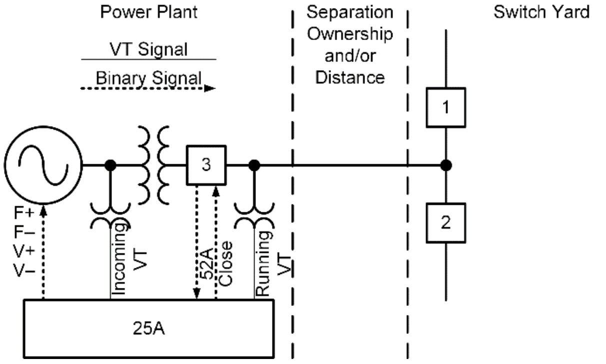


Fig. 10. Unit-connected generator with a high-side synchronizing breaker

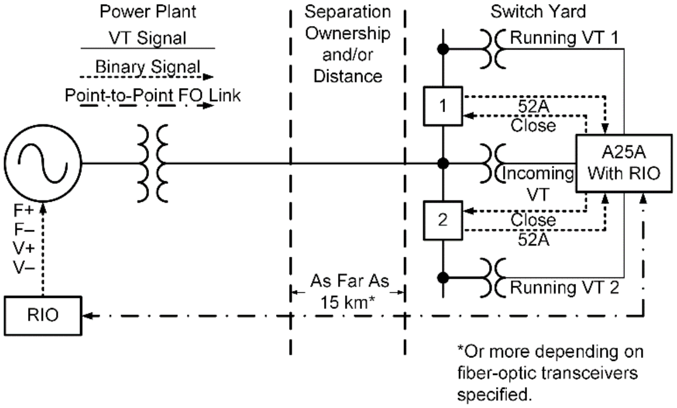


Fig. 11. Unit connected generator with an A25A and RIO

B. *A25A With Full DSS Merging Unit*

In many applications, it is desirable for the A25A to be located in the control room with the power plant operators. The A25A has a rich information display that provides operators with useful information when monitoring the synchronizing process. The new, full DSS-capable A25A makes this possible.

The A25A is mounted in the synchronizing panel in the power plant control room. An MU is mounted near the generator VT, governor, and AVR to digitize the incoming VT signal and adjust the generator during synchronizing. A second MU is mounted at the breaker control panel in the switch yard to digitize the running VT signals and close the breakers.

Notice in Fig. 12 that an incoming VT is no longer needed in the switch yard for the synchronizing system. The A25A can compensate for the voltage difference between the low-side generator VT and the high-side bus VTs. Of course, it is always recommended that a synchrocheck relay be installed for two-level supervision of the close circuit [1]. An incoming VT would still be required for the synchrocheck relays on CB1 and CB2. A variation on Fig. 12, shown in Fig. 13, requires only the

MU in the switch yard connected to an incoming VT in addition to the two running VTs. In this case, the generator frequency and voltage correction pulse outputs are connected directly to the A25A and the second MU is eliminated.

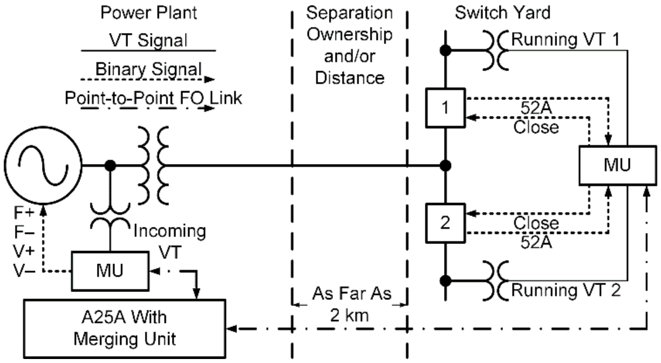
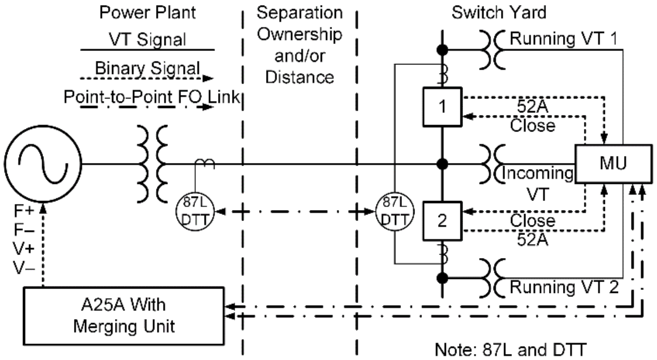


Fig. 12. Unit-connected generator with an A25A and MU

Fig. 13 shows a project using an A25A with full DSS capability. In this application, the power plant is owned by a generation company and the switch yard is owned by a transmission utility. In this application, the power plant owner wanted to own and maintain the major components of the generator synchronizing system. For this reason, the configuration shown in Fig. 11 was unacceptable. Further, the two entities wanted complete separation between protection and control systems in each of their facilities. The utility agreed to install the MU because it is a simple, low-maintenance device.



Note: 87L and DTT systems are redundant. Only one system is shown for simplicity.

Fig. 13. Separating facilities with different ownership

In this system, the only interconnection between the two facilities is two sets of fiber-optic cables with diverse routing paths. The high-voltage leads between the high side of the generator step-up (GSU) transformer, owned by the generating company, and the synchronizing breakers, owned by the utility, are protected by redundant line current differential relays; there is one system on each diverse fiber-optic cable. Fig. 13 only shows one system for simplicity. The generator and GSU zone relays trip the utility breakers over the DTT link embedded in the 87L channels. While the automatic synchronizing system is not fully redundant, the A25A and the MU have redundant communication links using fiber pairs in each of the diversely routed fiber-optic cables.

VII. INDUSTRIAL APPLICATION EXAMPLE

It is becoming increasingly common for industries to have their own generation. In such a scenario, synchronizing the local generation to the grid and forming critical generator and load islands under certain conditions is desired. Such a system generally requires a robust autosynchronizer that can receive voltage inputs from different locations on the plant. This section provides an example of an industrial facility with cogeneration that employed an A25A system with a point-to-point DSS.

The system consists of as many as three generators and multiple synchronizing breakers connecting the facility to the utility. Before installing the A25A with a DSS, some of the synchronizing circuits were brought to a single synchronizing panel located by the generator control room. The panel featured multiple VT connections, auxiliary relays, switches, and long lengths of copper cables for voltage measurements and control signals. The panel included auxiliary relays to switch the voltages and control signals for synchronizing different breakers. When the utility is islanded from the grid, the operator uses the synchronism check panel in conjunction with manually adjustable generator voltage and frequency controls to connect back to the utility.

The system required an upgrade from the outdated manual synchronizing system to a more robust and reliable technology. The new system also accounts for additional synchronizing breakers between the plant and the utility. In addition to replacing the existing functionality, the facility also wanted to simplify the implementation and commissioning of the new system. Based on the synchronizer requirements and the fact that the generators and synchronizing breakers are spread across the facility, an ideal solution was an A25A with a point-to-point DSS. The smart autosynchronizer with MUs was proposed to gather the incoming VTs and breaker signals, control the generator governor and AVR system to match voltage and frequency, and close the selected breaker as the slipping systems come into phase. This system minimizes operator interaction and replaces the existing synchronism check panel.

The electrical system of the facility consists of two distant locations: the utility substation and the power plant. The three generators (GA, GB, and GC) in the power plant are tied to three utility transformers in the substation. Three A25A systems (A25A X, A25A Y, and A25A Z) are used to synchronize each of the three generators across fifteen breakers located throughout the electrical system. Fig. 14 shows a simplified one-line drawing of the upgraded system. The figure only shows two incoming utility lines (UT 1 and UT 2), two generators (GA and GB), and two A25A systems (A25A X and A25A Y) for the sake of simplicity. The design of the A25A system of the third generator is very similar to A25A X and A25A Y.

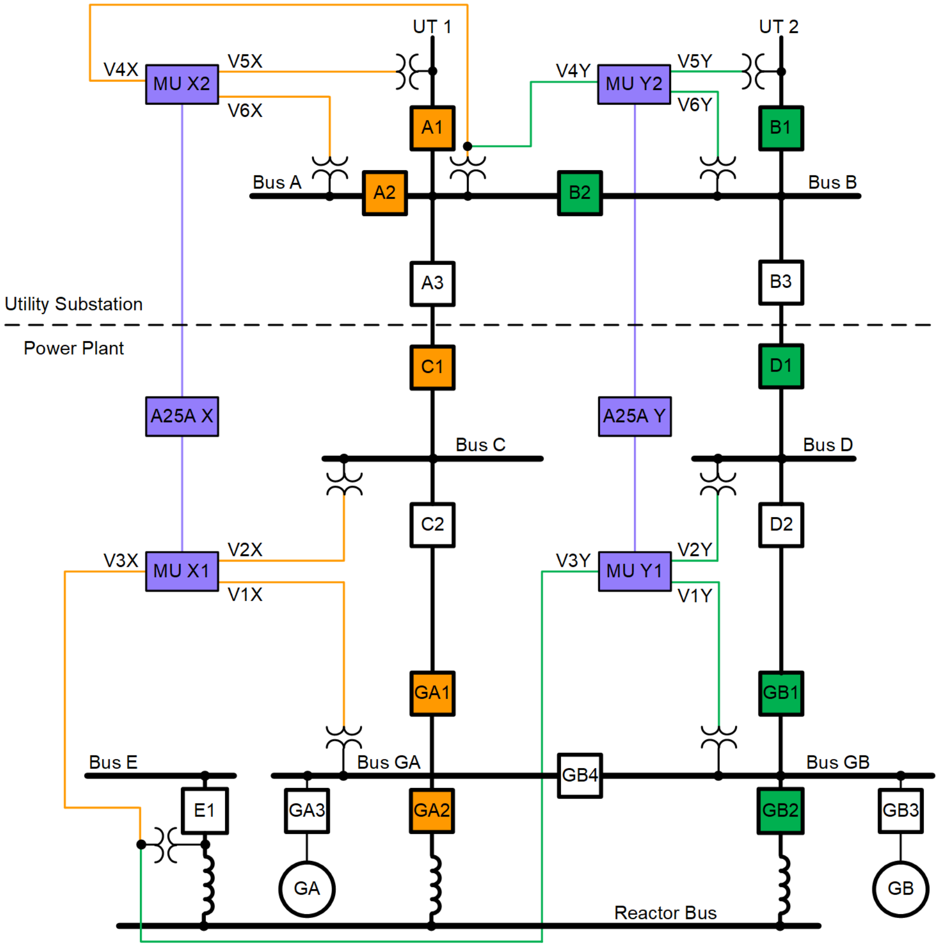


Fig. 14. Simplified one-line drawing of an A25A with a DSS

A25A X and A25A Y are used to control five breakers each. The A25A X breakers are shown in orange: utility breaker A1, utility bus-tie breaker A2, utility power plant tie breaker C1, generator bus breaker GA1, and reactor bus breaker GA2. Similarly, the A25A Y system breakers are shown in green. Six voltage inputs are required for each A25A system to control and synchronize across these five breakers. The distance between the utility substation and power plant, and the addition of new breakers, made long copper cable runs for voltage and control signals an uneconomical and complex solution. For simplicity and safety, MUs were deployed with the A25A device to physically isolate both I/O terminations and VT terminations from the A25A device. Two MUs were used for each A25A device. MU X1, placed in the power plant, is connected to VTs V1X, V2X, and V3X. MU X2, placed in the utility substation, is connected to VTs V4X, V5X, and V6X. Similarly, MU Y1, placed in the power plant, is connected to VTs V1Y, V2Y, and V3Y. MU Y2, placed in the utility substation, is connected to VTs V4Y, V5Y, and V6Y. By using DSS technology, MUs were located close to termination points, which minimized copper cable runs and guaranteed a reliable solution. The small copper runs between the primary device and VTs are represented by orange lines for A25A X and green lines for A25A Y. The MUs bring these voltages to A25A X and A25A Y as digital data by using point-to-point fiber-optic links represented by purple lines.

The front panel of the A25A had all five controllable breakers programmed for selection. The operator can select any of the five circuit breakers for synchronization via the A25A device front panel. The A25A device then automatically selects the incoming and running voltages based on predefined topologies to close the selected breaker. Table I shows the voltages needed to synchronize across different breakers controlled by A25A X. There are different conditions and supervisions that need to be met before the breakers can be closed. These additional conditions were programmed as multiple topology permissive in the A25A X. The status bits between the A25A device and breaker control device used IEC 61850 GOOSE communication protocol, which eliminated the need for a dedicated breaker RIO or an MU. Further, the synchronism check capabilities of the breaker control IEDs provided the desired supervisory check. The A25A Y is programmed similarly to create different topologies to synchronize across the five breakers.

Generator MUs were used to send control pulses from the A25A to the GCS system to bring the generator within synchronism acceptance criteria. The manual synchronizing panel was retained to back up the A25A solution. Installation of the three new A25A systems with point-to-point DSS technology made the synchronizing system more robust, less complex, and less reliant on operators.

TABLE I
INCOMING AND RUNNING VOLTAGES FOR A25A X

Circuit Breaker	Incoming Voltage	Running Voltage
A1	V4X	V5X
A2	V4X	V6X
C1	V2X	V4X
GA1	V1X	V2X
GA2	V1X	V3X

VIII. CONCLUSION

As the electrical grid becomes more convoluted with multiple generator owners and islanded microgrids, the need for control systems that are easy to implement and deploy is increasing. A25A systems are powerfully equipped to overcome most challenges posed by conventional system designs. The challenges include, but are not limited to, automatic switching of voltage signals, reduced operator dependency for a proper synchronization, and a close at zero degrees. However, in cases with multiple points of interconnect separated by distance and limited availability of VTs and breakers, the solution offered by conventional systems becomes limited. Integrating complex VT and breaker circuits from various physically separated locations needs a simple yet complete solution. The evolution from conventional copper-based substations to fiber-optic-based digital substations offers advantages to these challenges.

The DSS solution combined with the smart A25A system simplifies the design by eliminating copper cable runs and, therefore, lessens the probability of hidden wiring failures. This allows for numerous benefits. While the design substantially reduces substation costs including planning, material, and labor expenses, it also improves reliability and performance with the dedicated MU units. Replacing copper removes dangerous high voltage from the control room, making working conditions safer. The MU units can be located at any synchronizing point. Fiber cables are run between the MUs and the A25A system. In turn, the A25A is pre-configured with the incoming MU data, which simplifies the user-friendly mapping at the A25A device end. While the A25A includes robust features to ensure proper and safe synchronization, the MUs assist in continuous monitoring of the system all the way from the voltage and breaker signals in the yard to the generator control room. These digital data can also be shared between redundant A25A systems or with other supervisory IEDs in the control room, thus providing an extremely flexible solution. The self-testing capabilities of the A25A systems with DSS assists fast commissioning times. Testing and troubleshooting are straightforward with simplified system architecture.

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X. BIOGRAPHIES

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