Applying IEC 61850 to Real Life: Modernization Project for 30 Electrical Substations

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***Abstract*—This paper describes the modernization and energization of Guarujá 2, an electrical substation integrated with the IEC 61850 suite of protocols. This was the first of 30 substations in a modernization project for Elektro Eletricidade e Serviços S.A., a large electric distribution utility in Brazil.**

The scope of the Guarujá 2 project included:

- **New human-machine interfaces (HMIs)**
- **Modernization of all supervisory control and data acquisition (SCADA) systems**
- **Substation automation**
- **Replacement of old electromechanical protection relay panels**

The project included automating the control of 12 circuit breakers, 7 new motorized disconnect switches, and 2 parallel 30 MVA power transformers with load-tap-changer controls. The system provided seamless integration of both IEC 61850 MMS (Manufacturing Message Specification) and DNP3 LAN/WAN (local-area network/wide-area network) to exchange control data between relays, programmable automation controllers, load-tap-changer controls, and rugged computers.

In this system, the feeder, bay control, and transformer relays communicate using peer-to-peer IEC 61850 GOOSE (Generic Object Oriented Substation Event) messages for the protection and control schemes, including breaker failure and bus protection, interbay interlocking, event report triggers, and automatic transfer between two 138 kV lines. The adoption of IEC 61850 made it possible to build a decentralized automation system, distributed over several intelligent electronic devices (IEDs).

This paper describes the new implementations of the protection and automation functions using the IEC 61850 suite of protocols. Details include the architecture and the functionalities of the protection, control and monitoring system, and the laboratory tests performed to verify and validate its performance. The paper concludes with a discussion of the benefits that were extended to Elektro's customers due to the modernization project and the adoption of a fully automated substation system.

I. Background

Elektro Eletricidade e Serviços S.A. is a Brazilian electric power utility that serves parts of the states of São Paulo and Mato Grosso do Sul. Currently Elektro serves approximately 1,950,000 customers, meeting the needs of 5,700,000 people in 228 cities over an area of 120,000 km^2. Elektro owns 120 operating substations and 74,300 km of distribution lines.

A. Substation Modernization Program

Elektro believes investing in the modernization of its substations is a crucial factor for its development. Since the substation modernization program began in 2000, Elektro's technical team has searched for the best and most advanced technology available for improving the substation supervision and automation projects.

The project is divided into several stages; each stage includes the modernization of a defined number of substations. In 2006, the first stage was concluded.

The good results obtained with the first stage of the modernization program, when equipment like remote terminal units (RTUs) and programmable logic controllers (PLCs) were still in use, encouraged the company's technical team to search for more modern solutions for the second stage, foreseeing even better results.

The need to supervise and control the equipment that used old technologies, without interface to supervisory control and data acquisition (SCADA) systems, led to the following preliminary stages of the program:

- Replace the old 13.8 kV circuit breakers with new circuit breakers, including auxiliary contacts available for supervision.
- Install drive motors in the manual disconnect switches.
- Retrofit the power transformer control panels.
- Retrofit the ac and dc power supply systems.
- Remove the old control cables and those without reliable insulation.

The new project philosophy, as defined by the Elektro technical team, was expected to comply with the following requirements:

- New technologies, accepted worldwide, disseminated by the electrical energy sector.
- Reduction of copper cables used, despite the higher number of points to be supervised and automated.
- Reduction of auxiliary relays and other equipment in the control and protection panels.

- Ability to expand the substation automation and protection system without needing major changes in the current project.
- Reduction of maintenance interventions.
- Standardization and simplification of professional training in system automation, preparing technicians to operate a common system inside the company.
- Redundancy of the control and distribution system of information to the control center and local human-machine interface (HMI).
- Significant reduction in field installation by reducing the amount of accessory equipment.

B. Modernization of Substations With IEC 61850 Suite of Protocols

In 2006, Elektro started the second stage of the modernization project that includes 30 substations, developed the project specification, and chose DNP3 as the protocol to integrate the intelligent electronic devices (IEDs). At that time, the DNP3 protocol was used to facilitate IED integration in various substations and in Elektro's remote control center. Therefore, Elektro's technical team began the project with a mastery of the DNP3 protocol.

During the proposal development stage, Elektro decided to request an alternative option for automating the substation based on the IEC 61850 Communication Networks and Systems in Substations standard, analyzing the advantages that the new standard could provide. The decision to use the IEC 61850 alternative had advantages that outweighed the additional costs due to investment in training the team, the possible changes in philosophy, and the expense of changing the project.

The motivation for choosing a new substation project philosophy using the IEC 61850 suite of protocols was based on the following criteria:

- Use of high-speed Ethernet-based communications systems.
- Interoperability of equipment from different manufacturers.
- Substantial reduction in the amount of cables used, making the commissioning easier and reducing the probability of failures.
- High system reliability and availability with the use of simpler projects and more efficient architecture.
- Obsolescence no longer a short-term problem.
- Easy expansion of the system.

Elektro was convinced that the ease of field installation, the faster identification of failures, the implementation of automated functions, and the new, faster, and more selective protection schemes would provide a return on investment in a shorter period than initially estimated.

The decision of which system should be implemented in the substations was not based solely on the lowest price but also on the best technical solution; therefore, certain evaluation parameters were established, including:

- Mean time between failures (MTBF).
- Warranty.
- Compliance with technical standards.
- Operating ambient temperature range.
- Technical support.

The stages of the project discussed in this paper cover the modernization of 30 substations over the period of four years (2007–2010). In this period, more than 500 IEDs will be installed, tested, and integrated using the protocols described in the IEC 61850 standard.

II. Substation Guarujá 2 – First Substation to Be Modernized

The project began with the modernization of the 138 kV Guarujá 2 Substation (138/13.8 kV, 2x25/33.3 MVA), which serves a region with a highly concentrated load along the coast of the state of São Paulo, an important center for tourism. The substation single-line diagram is shown in Fig. 1. The other substations involved in the project have similar physical characteristics to those of Guarujá 2 Substation.

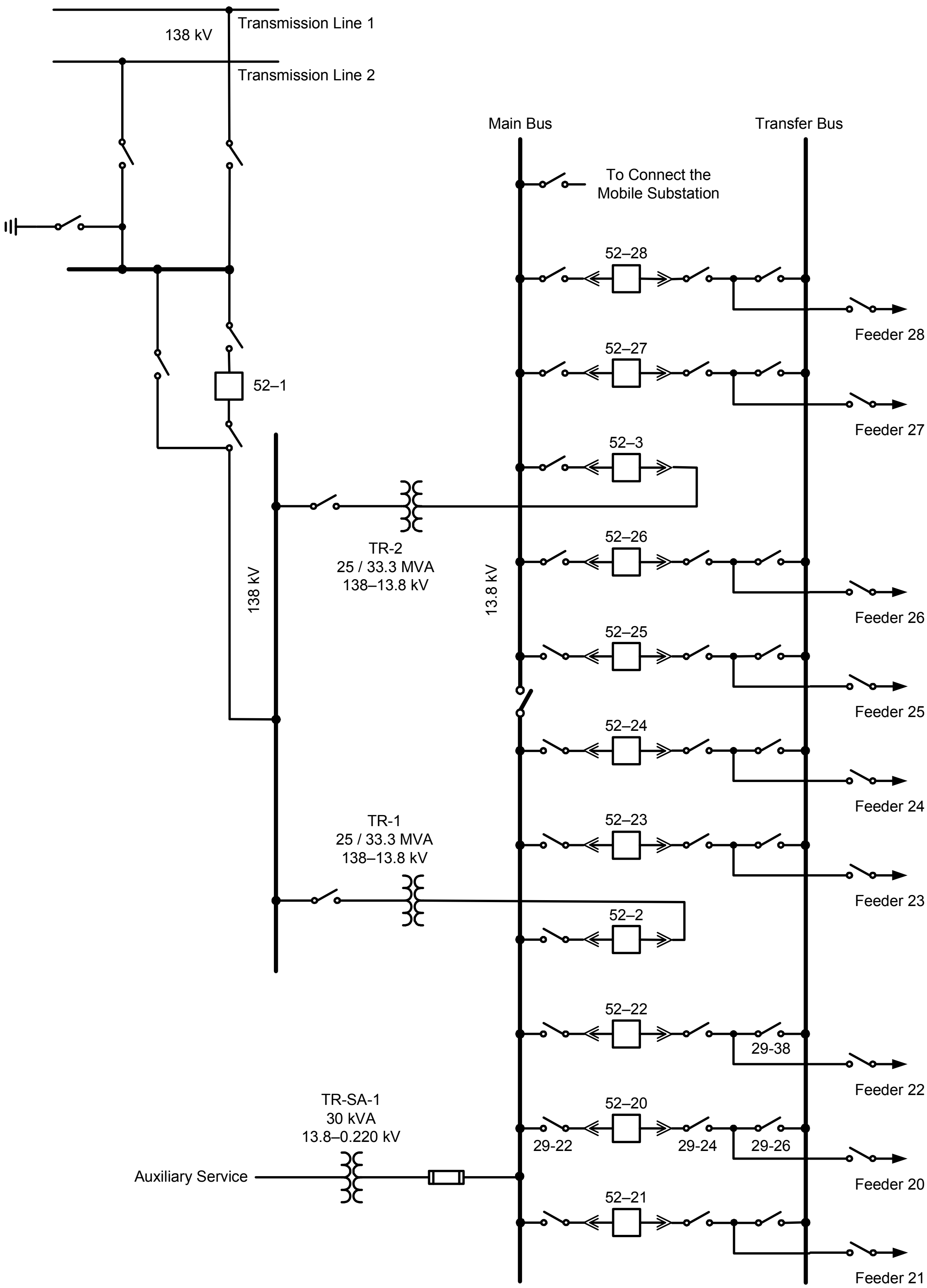

Fig. 1. Guarujá 2 Substation Single-Line Diagram

Fig. 2 shows the distribution of IEDs in the substation bays. All the protection/control IEDs use the IEC 61850 GOOSE (Generic Object Oriented Substation Event) messages and other IEC 61850 messages to convey operational data, which we refer to collectively as MMS (Manufacturing Message Specification) messages. The IED used for voltage regulation includes only the IEC 61850 MMS messages. The functions implemented in each IED are discussed later in the paper.

The IEDs perform all the functions for protection, control, metering, interlocking, automation, event recording, oscillography, circuit breaker wear monitoring, etc. No additional equipment or devices like test blocks, auxiliary relays, lockout relays, or meters were installed. The protection IEDs have high-current interrupting capacity contacts that can operate directly in the circuit breaker trip and close coils, eliminating the need for auxiliary relays.

III. Project Requirements

To ensure the reliable performance of the supply system for customers and the safety of the equipment installed, Elektro defined the substation operational characteristics based on the following stages:

- Calculation of the minimum and maximum short-circuit values.
- Establishment of the operation voltage ranges.
- Protection coordination and selectivity.
- Establishment of the automation system architecture.
- Establishment of the communications means.
- Requirements for physical adaptation of equipment.
- Establishment of the supervision and control points for the automation system.
- Establishment of the substation logic and automation schemes.

Based on the operational conditions, Elektro established the substation logic and automation schemes, as well as the need for exchanging information between different IEDs using the IEC 61850 GOOSE protocol. The philosophy adopted in developing the logic schemes is based on the following premises:

- The bay logic schemes should be preferentially developed at the IED level, in a decentralized manner, and with the least possible physical interconnections between the equipment. The use of GOOSE messages should be prioritized.
- The processing time of the logic schemes should be short enough to ensure correct operation of protection functions such as the logic selectivity between IEDs. To achieve this, the processing time of all the user logic schemes associated, directly or indirectly, with the protection functions must have the same processing time as the IED protection functions.
- The logic schemes at the substation level, with information exchange among IEDs, must be implemented using IEC 61850 GOOSE messages. This method should reduce the physical IED I/Os, increase the communications speed, and reduce the cables required inside the panels and trenches.

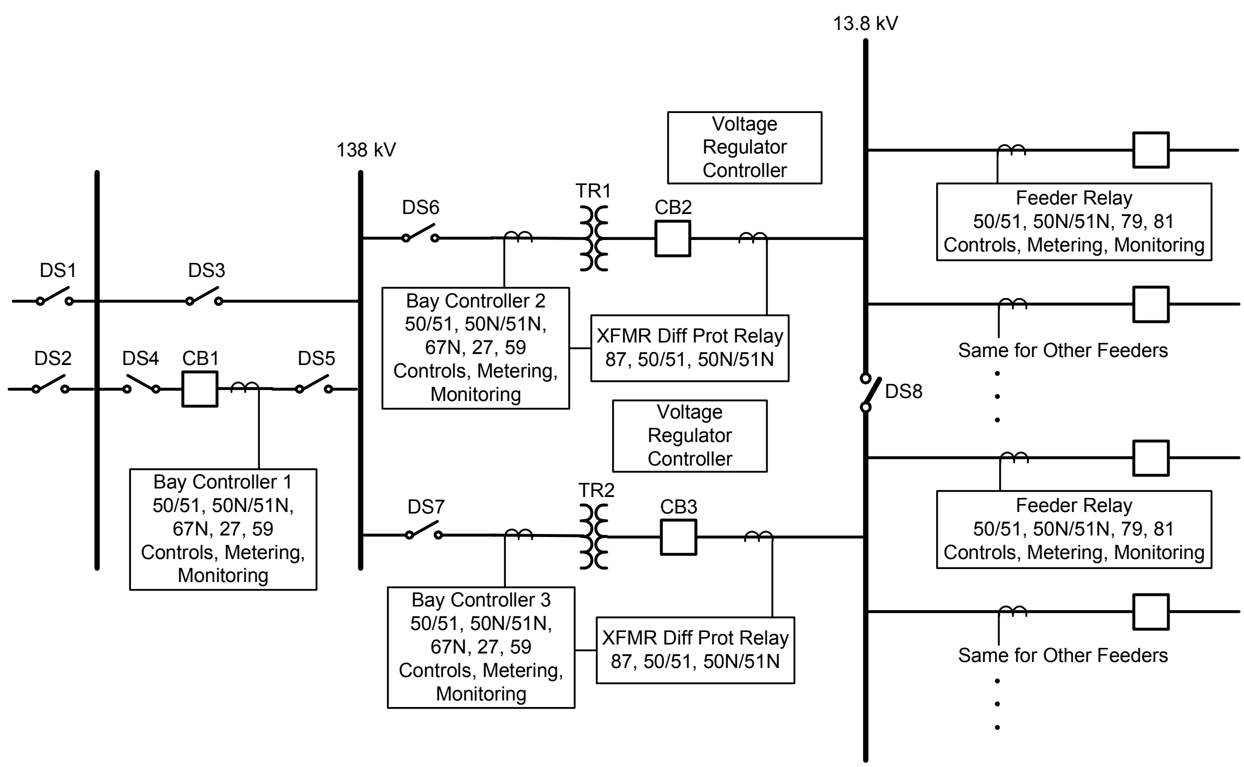

Fig. 2. Distribution of the IEDs in the Bays

- Whenever possible, there should be logic scheme redundancy, that is, the logic should be implemented in two IEDs. The choice of which IED will run the logic should be made through a user command or automatically based on monitoring the status of the IEDs that are executing the logic, i.e., if it is disabled, another IED will automatically run the automation logic.
- A single failure of the Ethernet communications network should not compromise the execution of logic schemes.

IV. Network Architecture

Elektro required a modular and distributed architecture of the protection, supervision, control, and automation system. The communications network architecture is shown in Fig. 3. To meet some of these requirements, the technical team planned the internal communications network of the substation to include redundant communications channels between the transmission line and power transformer bay controllers and the feeder relays. This was possible because the IEDs have redundant physical interfaces, which can automatically transfer communications to a backup interface in the event of a primary network failure (fail-over mode). If a communications cable or an Ethernet switch fails, communications now can be transferred to another Ethernet interface without compromising the entire system, ensuring the continuity of the logic schemes and the interlock functions.

IEDs with redundant Ethernet interfaces were connected to the switches using the double star configuration, while the IEDs with no redundant Ethernet interface (transformer differential relay and voltage regulator controller) were connected to only one of the switches.

The IEC 61850 suite of protocols was used only inside the substations. Although the IEC Technical Committee Working Group 57 plans to extend the use of IEC 61850 outside substations [1], it is presently not required beyond the substation. Because Elektro already employs a supervision system based on the DNP3 LAN/WAN (local-area network/wide-area network) protocol, they decided to use this protocol for communications with the control center and the HMI. To use this protocol, a gateway was needed to concentrate and collect data from the IEDs via IEC 61850, converting these data to DNP3 LAN/WAN and sending them to the local HMI and the remote control center (see Fig. 4).

The gateway hardware, with no moving parts for ventilation, is based on a rugged computer that is hardened to meet 1613 IEEE Standard Environmental and Testing Requirements for Communications Networking Devices in Electric Power Substations and C37.90 Standard for Relays and Relay Systems Associated with Electric Power Apparatus. The gateway selected for this project has an observed MTBF

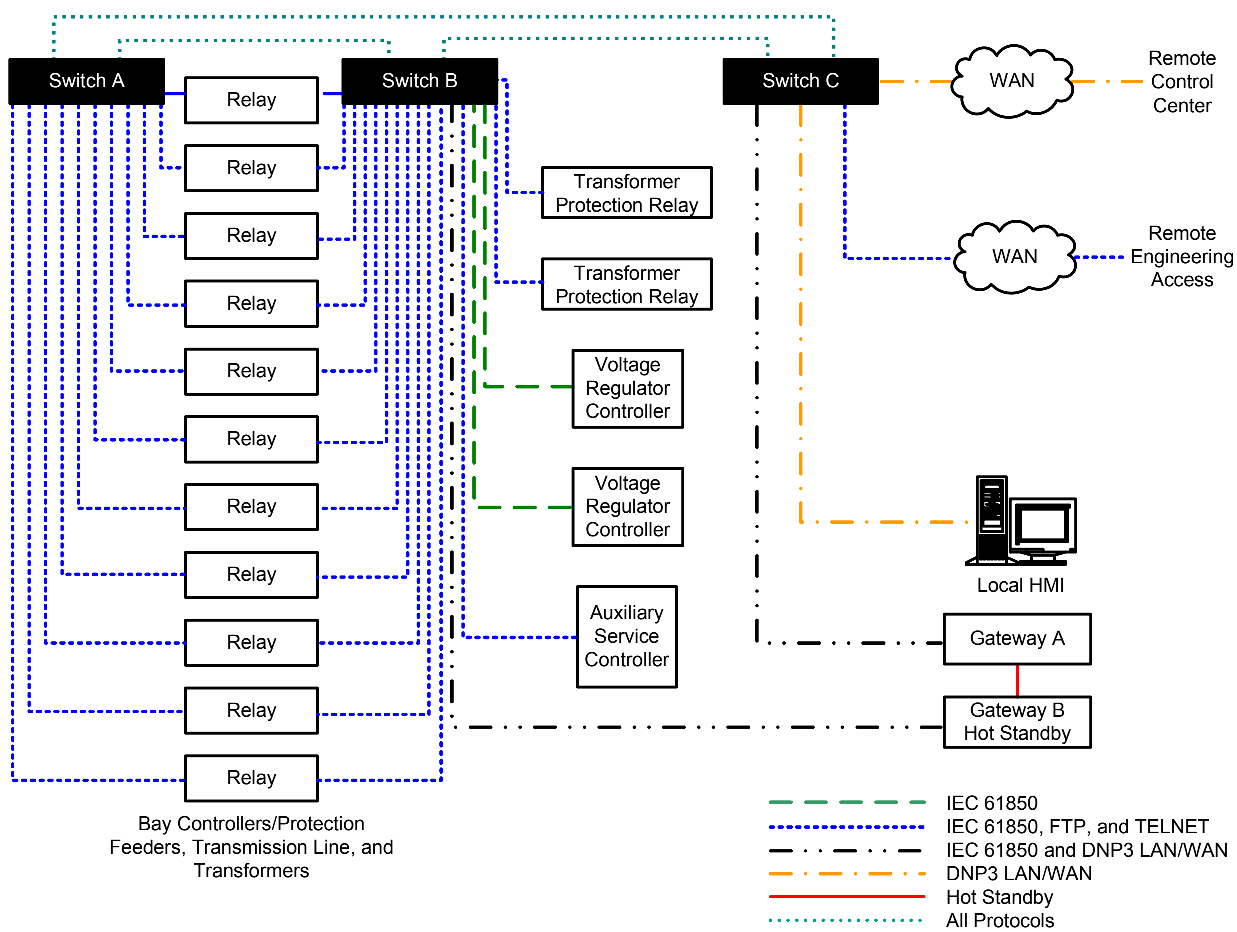

Fig. 3. Network Architecture Adopted for the Automation System

of 280 years, which is high compared to conventional gateways.

The SAGE software program was chosen to carry out data collection via IEC 61850 MMS, concentration, and conversion to DNP3 LAN/WAN. This software was developed by Centro de Pesquisas de Energia Elétrica (CEPEL), a Brazilian government research agency. It has several modules, including SAGE/SCADA, SAGE/EMS (Energy Management System), and SAGE/AGC (Automatic Generation Control). CEPEL developed a special version of SAGE to be used as a gateway and for installation on this rugged computer.

Fig. 4. Elektro's Remote Control Center

The combination of this rugged computer and SAGE gateway version software is known in Brazil as SAGEBox, a gateway that can integrate IEDs and SCADA systems with various protocols, such as: DNP3, DNP3 LAN/WAN, Modbus® RTU, Modbus TCP, IEC 60870-5-101, IEC 60870-5-103, IEC 60870-5-104, IEC 61850, Conitel, ICCP, SINSC, etc.

SAGEBox runs on the Linux® operating system, which was installed on the computer platform equipped with 2 gigabytes of flash memory instead of a conventional rotating hard disk, increasing the reliability of the gateway.

Based on Elektro's experience with other gateways, the automation system specification required the installation of two gateways, working in a hot standby redundancy scheme. This means the database of the two gateways is updated and synchronized, but only one gateway sends data to the local HMI and the remote control center. However, if a failure occurs in the primary gateway or in the communications between the gateway and Ethernet switch, the backup gateway will carry out all the tasks automatically and in an imperceptible manner to the operator, with no loss of information. Data exchange between the gateways is conducted through a direct Ethernet connection. This connection between the gateways is shown as Hot Standby in Fig. 3.

For reasons of standardization, two gateways were installed in each substation, even though the gateways used in this project are more reliable than the ones previously used by Elektro.

There is a local HMI in the substation that provides total control and supervision over the substation. The HMI hardware is composed of a rugged computer platform, 17-inch touchscreen monitor, and a keyboard with an integrated trackball mouse. The DNP3 LAN/WAN protocol connects the HMI to the gateway.

A satellite communications channel connects the substation to the remote control center also using DNP3 LAN/WAN.

The controls associated with the IEC 61850 standard protocols have more attributes than the controls for DNP3; therefore, the IEC 61850 messages are more complex [1], but this gateway converts DNP3 to IEC 61850 MMS with relative programming ease.

All the IEDs were connected to Ethernet switches that meet the IEEE 1613 standard. All are manageable, and the connections with the bay controllers, protection relays, gateways, local HMI, etc., are by fiber-optic cable. The switches form a ring to reduce the impact to the substation automation system that a failure in an Ethernet link could cause.

V. Time Synchronization

The design uses IRIG-B for time synchronization of the IEDs, gateways, and local HMI, ensuring accuracy of ±10 microseconds in the high-resolution oscillography timetags for the bay controllers and feeder relays. It also allows for future use of synchronized phasor measurement, which is incorporated in the bay controllers and feeder relays.

The SNTP (Simple Network Time Protocol) standard was not considered as an alternative for the project because the accuracy is on the order of several milliseconds and because of the possibility of variations in the accuracy due to the data traffic in the communications network. Future changes to the IEC 61850 standard may recommend a method to accurately set the time through an Ethernet network. An IEEE working group is revising the 1588 IEEE Standard for a Precision Clock Synchronization Protocol for Networked Measurement and Control Systems, which may provide microsecond time-synchronization accuracy over Ethernet [1]. But for now, Elektro chose IRIG-B, the only protocol currently available.

VI. Controls

Elektro operations personnel want the capacity to trip and close the circuit breakers and disconnect switches in the event of an IED, Ethernet switch, gateway, or Ethernet cable failure. To achieve this goal, the two gateways run in hot standby mode, linked to different switches. The bay controllers and the feeder relays have redundant physical Ethernet interfaces working in fail-over mode, linked to different switches (see Fig. 3).

These measures prevent single-point failures in the switches and Ethernet communications cables from affecting control by the remote control center. However, it would not be possible to control the bay equipment associated with any given IED if it fails, its power supply fails, or it is removed for preventive maintenance or settings changes. To provide redundancy, the circuit breakers and 138 kV disconnect switches at the IED level must be controlled by more than one IED. This was accomplished—the 138 kV disconnect switches and circuit breakers can be controlled by any one of the three bay controllers, as shown in Fig. 2.

Each one of these bay controllers has an LCD screen with a mimic display to aid the operator in his task of executing local controls. Fig. 5 shows the mimic programmed in Bay Controller 1. In this IED, note that it is possible to control the following equipment shown in Fig. 2 by using the mimic: circuit breaker CB1 and disconnect switches DS1, DS2, DS3, DS4 and DS5. The disconnect switches DS6 and DS7, not shown in the mimic, can be controlled through the IED-specific logic programming.

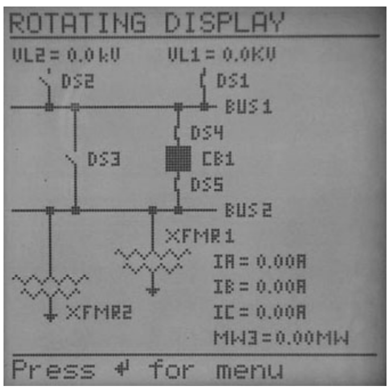

Fig. 5. Bay Controller 1 Mimic Display

Fig. 6 shows the mimic in Bay Controller 3. It is possible for this IED to control the following equipment shown in Fig. 2 by using the mimic: circuit breakers CB1 and CB3 and disconnect switches DS1, DS2, DS3, and DS7. The disconnect switches DS4 and DS5, not shown in the mimic, can be controlled through the IED-specific logic programming. The same observation is true for Bay Controller 2, in which it is possible to control circuit breakers CB1 and CB2, disconnect switches DS1, DS2, DS3, and DS6, and disconnect switches DS4 and DS5 through the logic schemes.

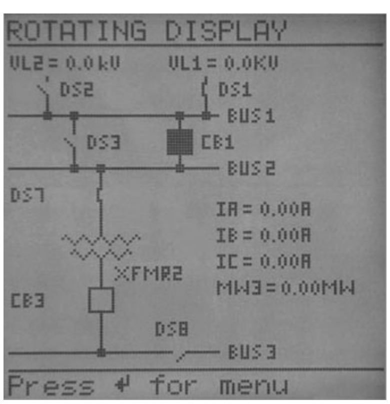

Fig. 6. Bay Controller 3 Mimic Display

VII. Local HMI and Remote Control Center

As mentioned previously, the local HMI is composed of a rugged computer platform, 17-inch touchscreen monitor, and a keyboard with an integrated trackball mouse. The local HMI panel is shown in Fig. 7.

The supervision software used in this HMI is the same as that used in the remote control center, so the screens of the two systems are very similar and have the same functionalities. The main screen of the local HMI is shown in Fig. 8. Displayed on this screen are the main measures, the status of all equipment, several control sequences, the gateway's communications channel with the IEDs, the gateway in operation, any blocked protection functions, etc. The supervision software, installed in the HMI, constantly monitors the status of the communications with each of the bay controllers. If a failure in the communications system is detected while the operator is performing the circuit-breaker trip or close command, the supervision function will automatically direct the control to the other bay controller that can perform this control, that is, to the other bay controller whose communications system is functioning. For example, redundant controls are required. Any one of the 138 kV sector bay controllers can control the incoming circuit breaker, so if the supervisory software detects that there is no communications with Bay Controller 1 when the operator executes any control related to this circuit breaker, the supervisory software will automatically direct commands to Bay Controller 2, sending the control commands to the circuit breaker via hardwired connection.

Fig. 7. Local HMI Panel

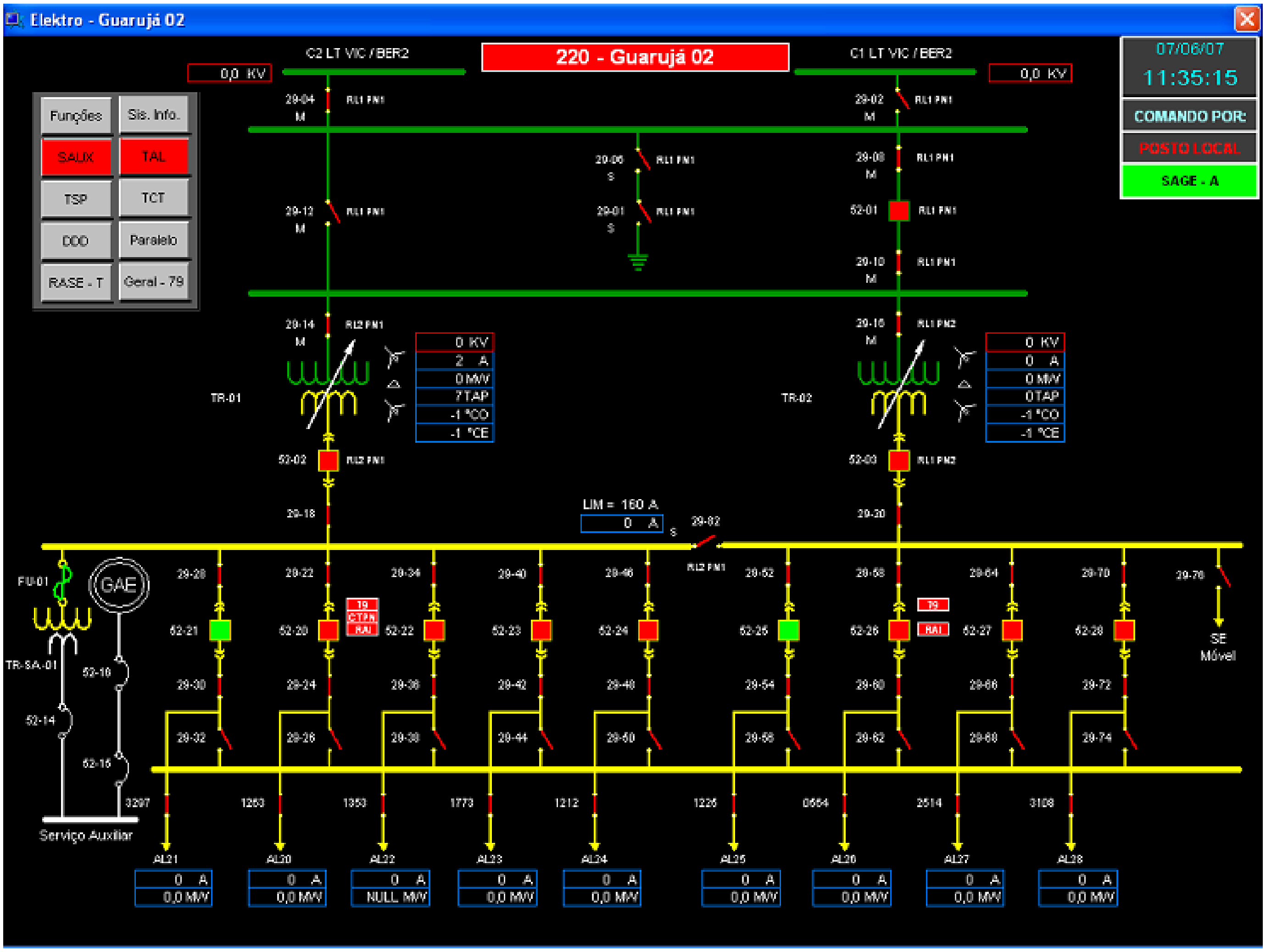

Fig. 8. Local HMI Main Screen

An operator can display a pop-up menu by clicking the mouse on any circuit breaker, as shown in Fig. 9. Through this pop-up menu, it is possible to perform commands to open and close the circuit breakers, view analog measurements, enable/disable commands, view the alarms related to circuit breakers, and enable/disable the reclosing function and any automation associated with the circuit breaker.

Fig. 10 shows the analog quantity screen related to the feeder. Measurements include current, phase-neutral and phase-to-phase voltages for three phases, real and reactive power, power factor, frequency, each phase current during the last feeder fault, number of reclosings for each reclose shot, accumulated wear on the circuit breaker, last electrical trip operation time, and fault location.

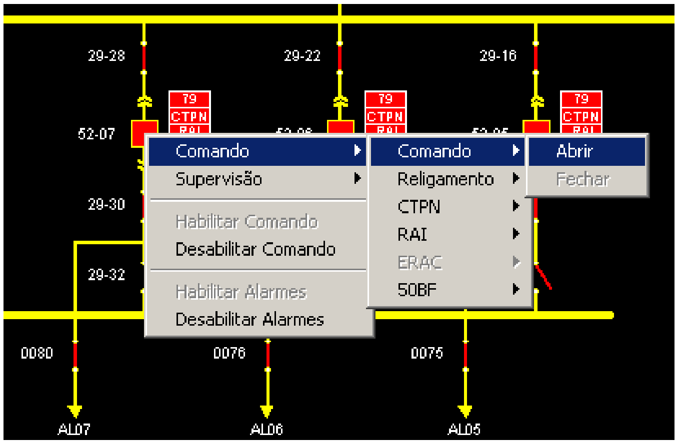

Fig. 9. Pop-Up Menu for Circuit Breakers

Fig. 10. Feeder Analog Measurements

The following tables will help with translating Fig. 9 and Fig. 10.

TABLE I
TRANSLATION FOR FIG. 9

Portuguese	English
Comando	Control
Desabilitar alarmes	Disable alarms
Desabilitar comando	Disable control
Religamento	Reclosing
Supervisão	Supervision

TABLE II
TRANSLATION FOR FIG. 10

Portuguese	English
Corrente fase	Phase current
Distância da falta	Fault location
Fator de potência	Power factor
Potência ativa	Real power
Potência reativa	Reactive power
Primeiro ciclo de religamento acumulado	Accumulated number of closes for the first reclose shot
Segundo ciclo de religamento acumulado	Accumulated number of closes for the second reclose shot
Tensão fase	Phase voltage
Última corrente de falta fase	Last fault phase current
Último tempo de abertura do disjuntor	Last electrical trip operation time

The alarm and the sequential events recorder (SER) screens are shown in Fig. 11 and Fig. 12. Filters can be applied to find a specific event or alarm by date, severity, alarm text, bay, etc. Both the alarms and the sequence of events are shown with a resolution of 1 millisecond.

The dc system is also monitored through an IED. A programmable automation controller was used for this purpose. Both the rectifier and the set of batteries are monitored by this IED, which also communicates with the IEC 61850 suite of protocols. The following points are monitored:

- DC to ground
- DC low
- DC high
- Battery discharging
- AC power supply to rectifier abnormal
- Rectifier failure

Each one of the IEDs in the system also monitors its own dc current supply. This monitoring was enabled in the IEDs, so any alarm generated in the IED is sent to the supervisory system using the IEC 61850 MMS messages. These data will appear in the list of alarms and SER. The monitoring screen for the dc system is shown in Fig. 13.

Fig. 11. Alarm Screen

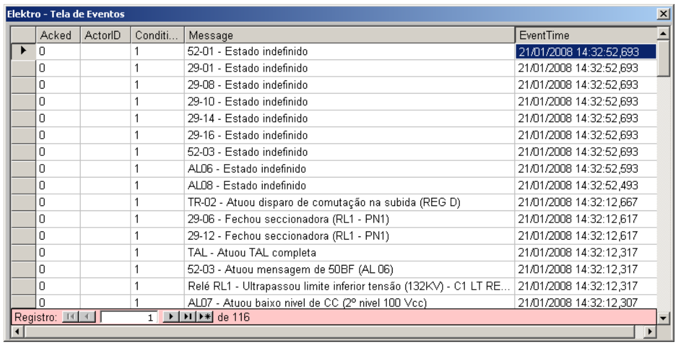

Fig. 12. SER Screen

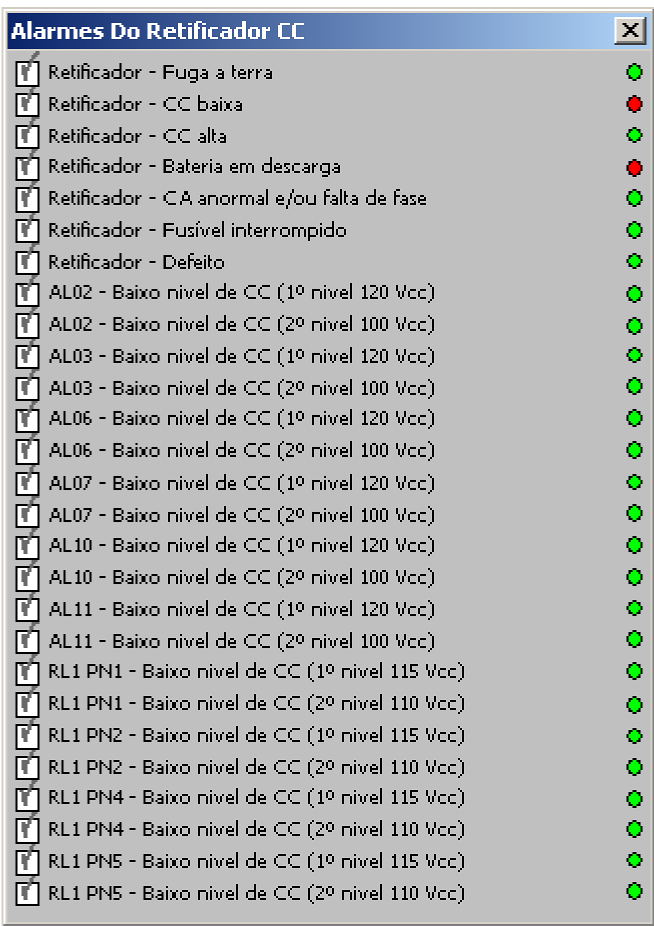

Fig. 13. DC Alarm Screen

The following table will help with translating Fig. 11, Fig. 12, and Fig. 13.

TABLE III
TRANSLATION FOR FIG. 11, FIG. 12, AND FIG. 13

Portuguese	English
Alarmes	Alarms
Alta severidade	High severity
Atuou mensagem de 50BF	50 BF tripped
Atuou TAL completa	Automatic line transfer automation successfully completed
Baixa severidade	Low severity
Baixo nível de CC	DC low level
Condição ativa	Alarm condition present
Data/hora	Date/time
Estado indefinido	Undefined status
Fechou seccionador	Disconnect switch closed
Média serveridade	Medium severity
Mensagem	Message
Não	No
Operador	Operator
Reconhecido	Acknowledged
Retificador – CA anormal e/ou falta de fase	Rectifier – AC abnormal and/or loss of phase
Retificador – CC alta	Rectifier – DC high
Retificador – CC baixa	Rectifier – DC low
Retificador – Defeito	Rectifier – Failure
Retificador – Fuga a terra	Rectifier – DC to ground
Sim	Yes
Ultrapassou limite de tensão	Low-voltage limit was violated

VIII. AUTOMATION, INTERLOCKING, AND PROTECTION FUNCTIONS

One of the major benefits of implementing the IEC 61850 standard in this project was the use of peer-to-peer IEC 61850 GOOSE protocol for exchanging messages between different IEDs and applying these message data in automation and interlock logic schemes.

Elektro's previous experiences in digitalization projects for substations showed that the IEDs associated with power transformers were critical points. The number of digital inputs and outputs available to exchange all information required for implementing the desired logic schemes was insufficient.

The new project philosophy made possible the development and implementation of all logic and automation functions using the inputs and outputs available on each relay.

The improvement of substation operating conditions, with the use of automation to perform equipment switching that previously required an operator to execute, resulted in an increase in system reliability, safety, and availability, as well as a large reduction in the interruption time that customers experienced.

All of the schemes discussed in this section are implemented with GOOSE messages.

A. Breaker Failure (50BF) Protection

The purpose of the 50BF protection function is to minimize damage to the system and other equipment during a fault in which a circuit breaker fails to open after receiving a protection trip command. In other words, when a fault occurs in the feeder, the relay sends a trip command to the respective circuit breaker. If the circuit breaker does not open in a specific amount of time, the relay sends a trip command to the power transformer's secondary circuit breaker, which is the 13.8 kV busbar incoming circuit breaker in this example. In the past, there was a problem when the 13.8 kV busbar tie disconnect switch (DS8 in Fig. 2) was closed. In this case, the trip command issued by the feeder relay 50BF function must be sent to the power transformer circuit breaker that is connected to the feeder busbar, which could be either one or both of the two power transformers.

Using GOOSE messages allowed the logic scheme to operate according to the system configurations. In other words, if the 13.8 kV busbar tie disconnect switch is closed, the trip command is sent to both power transformers. If the secondary circuit breaker of one of the power transformers is already open, nothing changes; if the circuit breaker is closed, it will open and the fault in the feeder clears.

To allow for occasional equipment maintenance testing, this logic scheme includes the capacity for blocking and unblocking by remote command using IEC 61850 MMS messages or by local mode using the front panel of the feeder's IEDs.

Fig. 14 illustrates the use of GOOSE messages to send the trip command to the power transformer secondary circuit breaker in the event of a feeder circuit breaker failure.

As mentioned in Section IV, the relays are connected to two Ethernet switches, providing redundant connections between the IEDs. This is very important for the circuit breaker failure scheme, because it significantly increases the reliability of the scheme in case of a failure of one of the routes, as shown in Fig. 15. Even if there is a failure in one of the communications cables or in one of the Ethernet switches, the trip command to open the power transformer secondary circuit breaker is issued.

B. 13.8 kV Busbar Protection

A logic selectivity scheme was adopted to provide high-speed protection against internal substation faults, as in the 13.8 kV busbar example. This logic involves the exchange of information between the power transformer bay controllers and the feeder relays via the communications network.

A close-in fault in any of the feeders is cleared quickly by the instantaneous overcurrent element of the feeder relays (see Fig. 16).

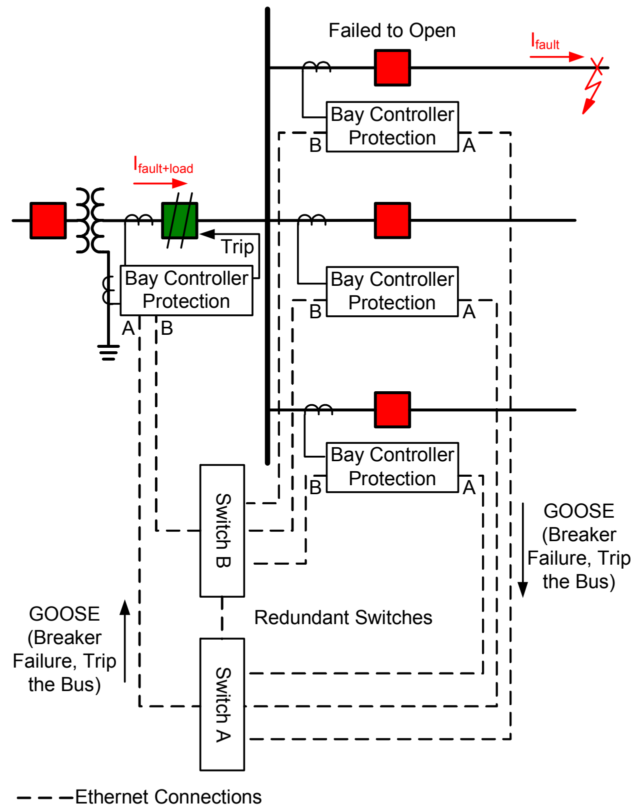

Fig. 14. Breaker Failure Implementation Using GOOSE Messages

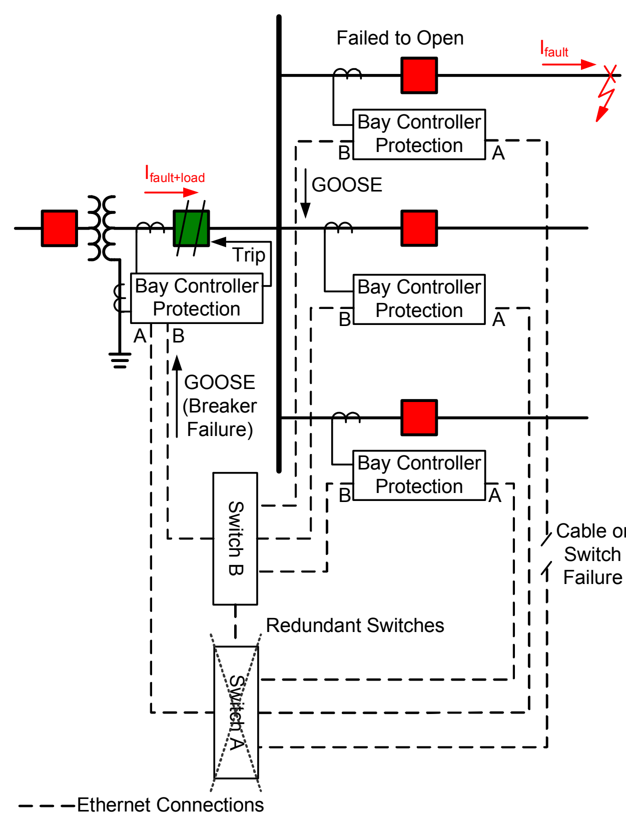

Fig. 15. Breaker Failure Scheme in the Case of Cable or Ethernet Switch Failure

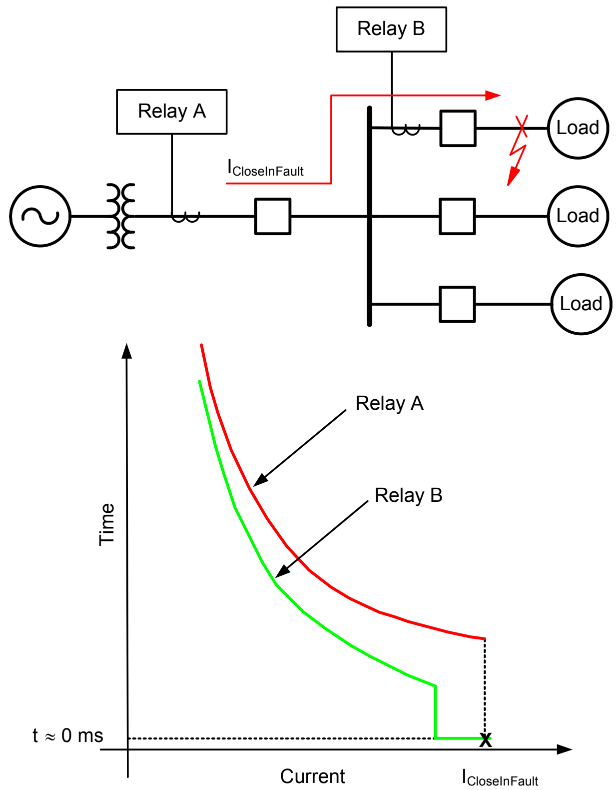

Fig. 16. Time to Clear a Close-in Fault in the Feeder

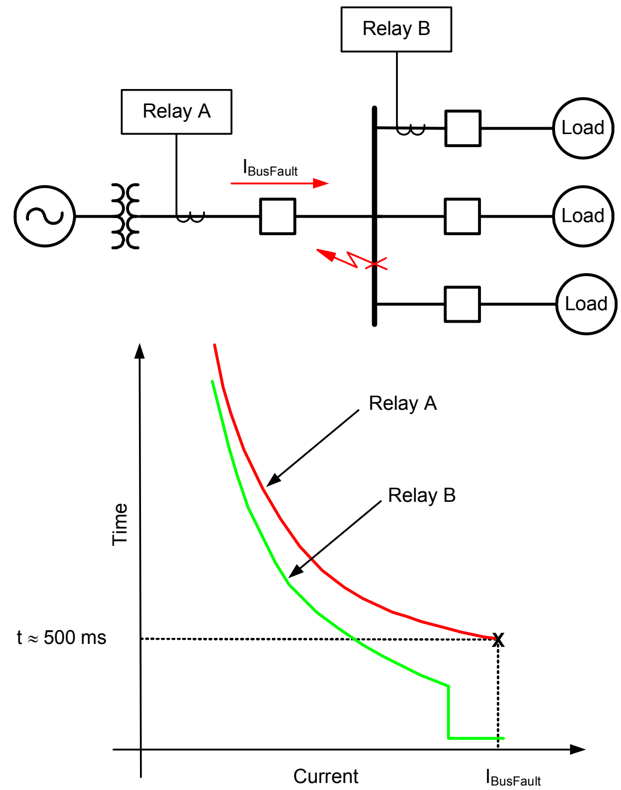

Fig. 17. Traditional Coordination Takes Too Long to Clear a Bus Fault

In a traditional coordination scheme, the instantaneous overcurrent element of the power transformer secondary relay is blocked because it is not possible to coordinate it with the feeder overcurrent function. Faults that occur in the 13.8 kV busbar are cleared in a relatively long period of time, around 500 milliseconds (see Fig. 17).

A logic selectivity scheme quickly clears the faults in the 13.8 kV busbar, improving personnel safety, minimizing damages, and extending the substation equipment lifetime.

In this scheme, a definite-time overcurrent element is enabled in the power transformer secondary relay to detect faults in the 13.8 kV busbar. The time delay is set to 100 milliseconds. To prevent this definite-time overcurrent element from operating in an uncoordinated manner on a fault in one of the feeders, the feeder relays send a signal to block this definite-time overcurrent element whenever a fault is detected within their operation area. GOOSE messages are used for this purpose. Fig. 18 illustrates an example of the philosophy adopted for this function.

The GOOSE message exchange is based on multicast application association. If the value of one or several *DataAttributes* of a specific functional constraint (for example, *st*) in the *Dataset* changes, the transmission buffer of the publisher is updated with the local service "publish" and the values are transmitted with a GOOSE message. See [2] for additional information.

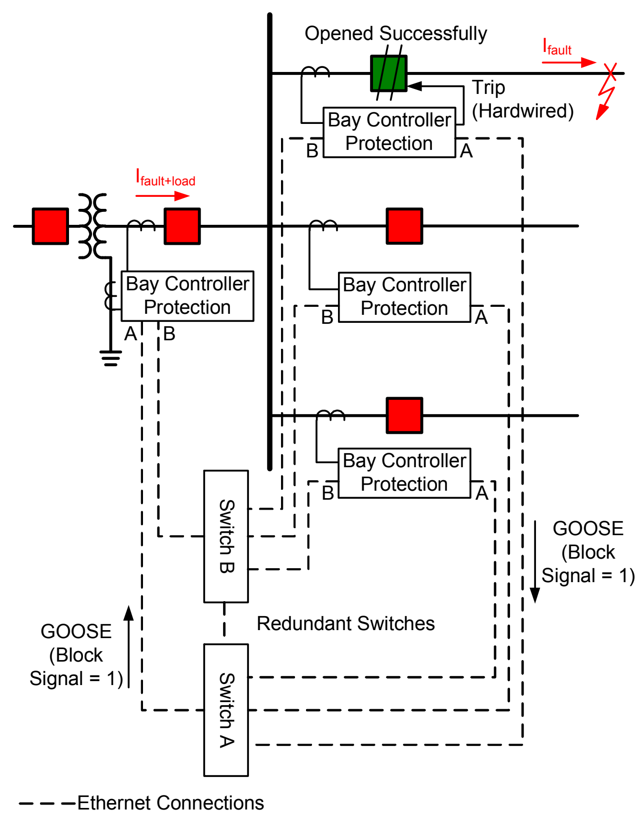

Fig. 18. GOOSE Message to Block the Fast Overcurrent Element of the Incoming Feeder

When there is no change in the value of any of the *DataAttributes* of a specific functional constraint in the *Dataset*, GOOSE messages are transmitted at predetermined time intervals in accordance with the setting "Max. Time" shown in Fig. 19. The Max. Time setting represents a time period in milliseconds. The Max. Time is the interval between GOOSE messages after exponential decay and where there are no changes in the GOOSE *Dataset*.

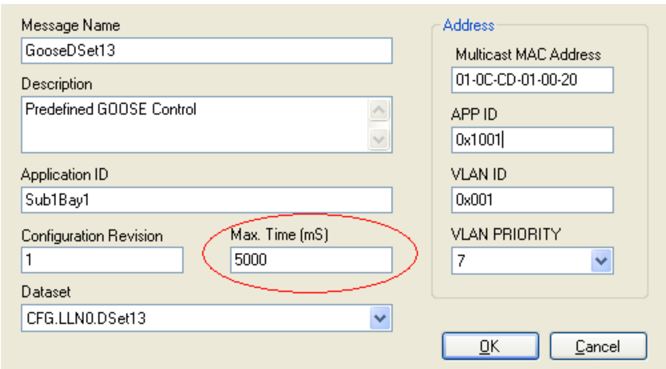

Fig. 19. Transmit GOOSE Message Settings

The IED that receives the message (Subscriber IED) knows the value for Max. Time, so it can detect if the GOOSE message has not been received within the maximum expected time, which may indicate a failure in the communications network. The IEDs applied in this project have a specific variable to detect this failure condition. This variable, Message Quality, is highlighted in Fig. 20. It is not transmitted in the GOOSE message but is created and controlled by the Subscriber IED. Each GOOSE message subscribed to any given IED has a Message Quality variable associated with the condition of the message receipt. In Fig. 20, note that the Message Quality in the GOOSE message published by IED AL20 (Feeder 20) is associated with the variable CCIN048 of IED RP1TR1 (Transformer 1 bay controller). The CCINnn variables represent virtual binary inputs that can be used in IED internal logic.

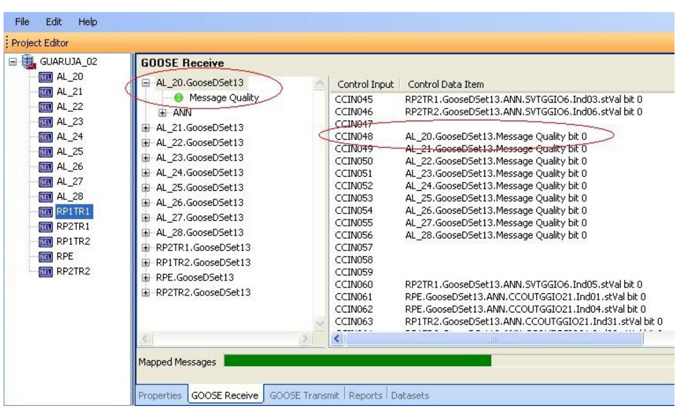

Fig. 20. Message Quality Assigned to a Communications Card Input

The engineering team used the Message Quality variable to generate alarms in the HMI, thus indicating failures in the reception of GOOSE messages. Message Quality appears in the logic selectivity scheme to block the trip of the fast overcurrent element of the power transformer secondary relay in case of a communications system failure, because this situation would create an uncoordinated condition between the feeder overcurrent and the power transformer secondary protection (see Fig. 21). When a communications system failure occurs, the operation time of the overcurrent elements is that of the traditional coordinating scheme.

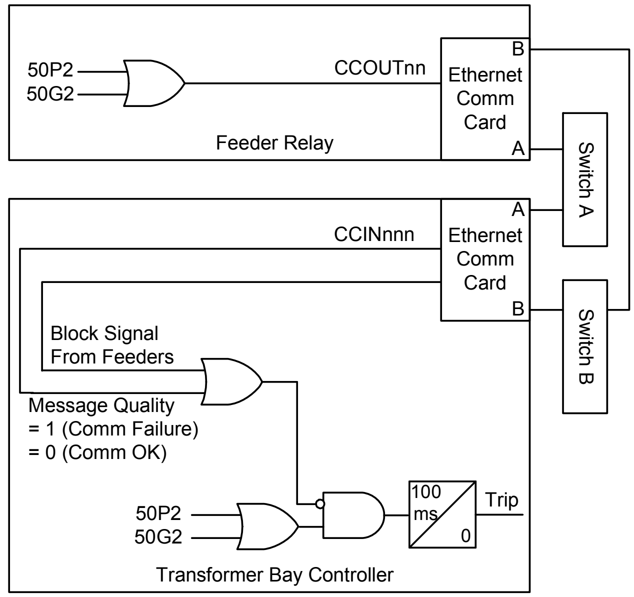

Fig. 21. Bus Protection Logic

C. *Automatic Line Transfer*

To meet quality indicators for electrical energy supply, voltage interruptions in substations can last no longer than one minute. Longer outages jeopardize quality indexes. Normal operations of substations in Elektro's current project are conducted with two energized lines, with only one disconnect switch closed. In Fig. 2, observe that only one of the disconnect switches, DS1 or DS2, remains closed during normal operating conditions. If a voltage interruption occurs in the 138 kV transmission line that supplies the substation, the line transfer should be performed in no more than 30 seconds, that is, the adjacent 138 kV line should restore the substation, as long as there is voltage in this line.

The automatic line transfer logic developed for the 138 kV bay controller uses GOOSE messages to receive and send information to/from other IEDs with the following functionalities and premises:

- When the automatic line transfer is initiated, the automatic line transfer scheme should be blocked automatically if one of the other automation schemes of the substation has been initiated previously and could interfere with this specific logic.
- Conditions that impede the reenergization of the power transformers should block the automatic line transfer scheme; however, if the disconnect switch of this power transformer is open (DS6 and DS7 in Fig. 2), the scheme blocking conditions related to the power transformer can be ignored, and the remaining

power transformer can be energized, providing voltage for the 13.8 kV busbar.

- Redundant status indications of the main circuit breaker and the line incoming disconnect switches are required and are collected by the bay controller of the 138 kV line and the transformer bay controllers. The IEDs associated with the power transformers also acquire the status of the substation incoming equipment, making it possible to check and address inconsistencies in IED information associated with the 138 kV bay.

If the 138 kV bay controller is released for maintenance, the bay controllers of the power transformers can take on this function, since this scheme was also programmed into them, ensuring redundancy.

D. Load Transfer Between Power Transformers

The load transfer automation scheme consists of sequential operations to automatically execute the switchings needed to release a power transformer for maintenance by transferring load to an adjacent power transformer without interrupting energy supply. For example, when the maintenance of the power transformer is finished, the automation scheme returns the substation configuration to the normal operating condition. The objective is to prevent human error that could occur when performing load transfer switching operations.

This logic scheme is more complex than that of the automatic line transfer. In addition to involving the exchange of GOOSE messages, MMS messages need to be exchanged between the IEDs and the gateway. For example, the automation executes the following steps to release the power transformer TR1 (refer to Fig. 2):

1. The bay controllers of the power transformers send the value of the present power demand to the gateway using MMS messages. The sum of the present power transformer demand should be less than the maximum power threshold of the power transformer that will receive the full load in order for the logic to be executed.
2. When the logic starts, a GOOSE message is sent to the other IEDs to temporarily block any other automation logic in the substation.
3. The gateway sends an MMS message to the voltage regulator controllers, blocking the automatic voltage control and putting the automatic voltage regulation system in the manual position.
4. The gateway sends commands, using MMS messages, to the voltage regulator controllers to keep the load-tap changers (LTC) of both power transformers in the same position.
5. The gateway verifies that the LTCs of both power transformers are in the same position.
6. The gateway sends the command to the power transformer bay controller to close the DS8 busbar tie disconnect switch.
7. The gateway sends the command to the power transformer bay controller to open circuit breaker CB2, located at the low-voltage side of the power transformer TR1.
8. The gateway sends the command to the power transformer bay controller to open the disconnect switch DS6 on the high-voltage side of power transformer TR1.
9. The gateway sends a command to the voltage regulator controllers so they can return the voltage control to the automatic position. At this stage, the power transformer TR1 is released for maintenance.
10. The final step of this automation is to unblock the other automation schemes that were blocked at the beginning of the process.

E. Automatic Reestablishment of the Substation

As observed in Fig. 2, when the differential protection or the internal protection of one of the power transformers operates, all feeders are de-energized because there is only one circuit breaker in the 138 kV sector.

This automation scheme is designed to isolate a power transformer under fault by opening the 138 kV disconnect switch and the secondary circuit breaker of the respective power transformer, enabling the reclose of the 138 kV circuit breaker to reenergize the feeders.

This logic starts with the protection operation of one of the power transformers, which trips the 138 kV circuit breaker (CB1) and the secondary circuit breaker of the defective power transformer (CB2 or CB3). From this point, the automation scheme will be responsible for isolating the defective power transformer and reestablishing the load of the entire substation through the other power transformer.

For example, the logic performs the following steps when the power transformer TR1 protection trips (refer to Fig. 2):

1. The protection trip opens the CB1 and CB2 circuit breakers, and the automation scheme is started.
2. The 138 kV bay controller sends a GOOSE message to the other IEDs to temporarily block any other automation in the substation.
3. The 138 kV bay controller sends a GOOSE message to open all the feeders.
4. The 138 kV bay controller sends a GOOSE message to the power transformer bay controller to close the DS8 busbar tie disconnect switch.
5. The 138 kV bay controller executes the command to open the disconnect switch DS6, located on the high-voltage side of the TR1 power transformer.
6. The 138 kV bay controller executes the command to close the CB1 circuit breaker, reestablishing the power supply to the feeders.
7. The 138 kV bay controller sends GOOSE messages to close the feeders, one by one.
8. The final step of this automation logic is to unblock the other automation schemes that were blocked at the beginning of the process.

F. Neutral Protection Automatic Transfer

During the transfer of load from one feeder to another (bypass switching), the bypass disconnect switch must be opened and closed in a monopolar manner. This action causes the appearance of residual current that is measured by the protection relays of the two feeders involved in the bypass process. The objective is to release the circuit breaker of one of the feeders for maintenance.

In the release of Circuit Breaker 52-20, as shown in Fig. 1, transferring the load to Circuit Breaker 52-22, the load transfer process consists of the following:

1. Close Disconnect Switch 29-26, which is monopolar, that is, the pole of each phase will be closed one at a time.
2. Close Disconnect Switch 29-38, which is also monopolar. Residual currents will then be measured by the two feeder overcurrent relays. If the neutral overcurrent element is not blocked, it may be activated, depending on the value of the load and the distribution of the currents.
3. Open Circuit Breaker 52-20.
4. Open Disconnect Switches 29-22 and 29-24, releasing Circuit Breaker 52-20 for maintenance.

The neutral overcurrent protection of the two feeders must be blocked during the load transfer process. If a single-phase fault occurs in one of the feeders during the switching, the power transformer secondary relay will issue the trip, de-energizing the entire 13.8 kV busbar, which is an undesirable situation.

To avoid this situation, an automation scheme was developed to transfer the neutral protection of the feeders to the power transformer secondary relay during the load transfer process. This automation scheme permits a safe transfer of load between the feeders. When the load transfer process starts, the automation scheme is activated in the following sequence:

1. The bay controllers of the two feeders send GOOSE messages to the power transformer bay controller, informing it that a transfer switching is being executed and the neutral protection of both feeders are blocked.
2. The power transformer bay controller activates a neutral overcurrent function to substitute for the neutral overcurrent function of the feeders.
3. If the neutral overcurrent element of the power transformer bay controller detects a fault and no blocking signal from the feeders, this indicates that the fault is located in the 13.8 kV busbar or in one of the feeders involved in the transfer switching, because the neutral overcurrent elements of these feeders are blocked.
4. The transformer bay controller sends a GOOSE message to open the circuit breakers of the feeders involved in the transfer switching.
5. If the fault is not eliminated, the transformer bay controller sends a command to open the power transformer secondary circuit breaker.

The automation logic of this scheme is illustrated in Fig. 22.

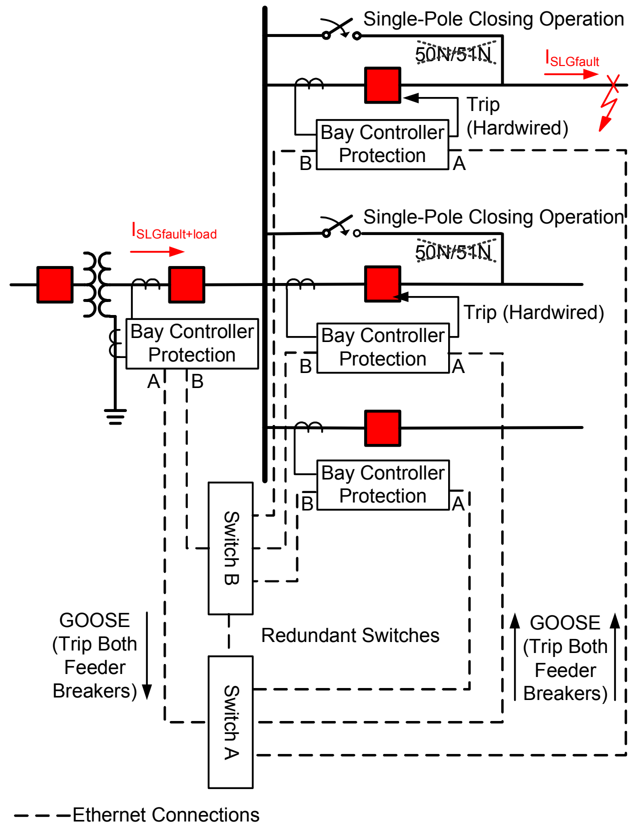

Fig. 22. Feeder Ground Overcurrent Protection Transferred From the Feeder Relays to the Transformer Relay During the By-Pass Process

IX. Test Platforms

A complete replica of a typical substation automation system was created in the supplier's automation laboratory to perform the platform tests of the project. All circuit breakers, disconnect switches, sensors, etc., were simulated in this system. This platform will be used for the implementation of the project for all substations for four years.

The objectives of the platform are to conduct all the approval tests of the system, to validate the system as a whole, and to exhaustively verify the consistency of the logic schemes for each of the 30 substations before each one is energized. Using this platform, Elektro can observe and validate information, such as communications speed between the IEDs and system data traffic. The test platform is shown in Fig. 23.

Fig. 23. Platform for Testing in the Laboratory

The test platform accelerates the commissioning tests and reduces errors found during field tests. This ensures that all the logic schemes are validated at the beginning of the commissioning and no modifications will be needed during the field tests. It is important to note that it is not necessary to change the wiring of the test platform for different substations, because the exchange of information between the IEDs is conducted through GOOSE messages; therefore, only the IED settings are changed.

X. Conclusions and Results

After the practical experience observed in the first operating months of the modernized Guarujá 2 Substation, the results are entirely satisfactory, not only due to the reduction in the number of maintenance interventions in new equipment, but also due to the significant reduction in the interruption of power supply to customers as a result of the quick restoration of the system after a disturbance. Situations that in the past needed two to three hours to be identified, analyzed, and released for reenergization can now be reenergized almost immediately because of the robust automation schemes implemented.

Elektro has noted these additional benefits:

- The remote engineering access and the automatic acquisition of oscillography contribute to quick analysis and decision making.
- The monitoring of equipment allows more intelligent and economical maintenance.
- The standardization of projects and logic schemes, the use of the IEC 61850 GOOSE protocol, and the tests carried out beforehand in the laboratory reduce the automation system commissioning time by 40 percent for each substation.
- The use of IEC 61850 GOOSE protocol reduced the volume of copper cables used in the modernization project by 50 percent as compared to traditional solutions.
- The reduction of fault-clearing times contributes to increased power quality, because it reduces the time of voltage sags. It also contributes to an increase in equipment lifetime, especially regarding power transformers.

The logic scheme for automatic reestablishment of the substation enables the reenergization of loads through the nondefective power transformer, improving quality indexes. In a real event after the modernization of the substations, 17,000 customers had their energy reestablished by this automation scheme in a few seconds. Without this logic, the interruption time for customers would have been approximately 1.5 hours.

XI. References

[1] J. Alzate, D. Dolezilek, V. M. Flores, and D. Espinosa, “Case Study: Design and Implementation of IEC 61850 From Multiple Vendors at CFE La Venta II,” proceedings of the 9th Annual Western Power Delivery Automation Conference, Spokane, WA, April 2007.

[2] Communication Networks and Systems in Substations, IEC Standard 61850, Aug. 2007.

XII. Biographies

Sérgio Kimura is an automation engineer at Elektro Eletricidade e Serviços S.A., Brazil. He received a degree in electrical engineering from Centro Universitário Salesiano de São Paulo–UNISAL. At Elektro, he has ten years of experience in automation of distribution substations and is responsible for preparing the specification for automation systems for distribution substations (69 kV to 138 kV). Presently, he is involved with the implementation of the automation and protection of the integrated system for 30 substations using IEC 61850 protocol.

André Campos Rotta is a consultant to the Engineering Department of Elektro Eletricidade e Serviços S.A., Brazil. He completed his first degree in electrical engineering in 1990 at Escola Federal de Engenharia de Itajubá, Brazil, and specialized in electrical power systems at Unicamp–Universidade Estadual de Campinas. He has 18 years of experience working with projects and construction and is responsible for the design, protection, control, and automation of all the new substations at Elektro.

Ricardo Abboud received his BS degree in electrical engineering from Universidade Federal de Uberlandia, Brazil, in 1992. In 1993, he started work for CPFL Paulista S.A. As a Protection Engineer in the Protection Equipment Division, his responsibilities included maintenance, commissioning, specification, studies, and relay settings of power system protection. In 2000, he left CPFL and joined Schweitzer Engineering Laboratories, Inc. (SEL) as a field application engineer covering the entire country of Brazil. His responsibilities included training and assisting customers in substation protection and automation efforts related to generation, transmission, distribution, and industrial areas. In 2005, he became field engineering manager, where he coordinates SEL’s engineering staff in Brazil.

Rogério Menezes de Moraes is an electrical engineer, earning his BS degree in 1993 from the Universidade Federal Fluminense, Brazil. He joined Schweitzer Engineering Laboratories, Inc. in 2007 as a system sales engineer. He has 24 years experience in technical/economical assessment of protection and SCADA systems projects for electrical power systems. His experience includes the development and definition of new functional requirements for design, tests, and integration of protection and SCADA systems.

Eduardo Zanirato is an application engineer, earning his degree from Escola Federal de Engenharia de Itajubá, Brazil. Since 2005, he has worked at Schweitzer Engineering Laboratories, Inc. His experience includes electric power protection and control. He has provided technical support to Brazilian customers on protection and control applications and relay technical training. Presently he is the technical coordinator in the implementation of the IEC 61850 integrated system for 30 substations for Elektro Eletricidade e Serviços S.A., Brazil.

Juliano de Sant'Anna Bahia received his BS in electrical engineering and telecommunications at the Universidade Federal da Bahia, Brazil, in 2002. Juliano joined Schweitzer Engineering Laboratories, Inc. as an integration application engineer. He provides technical support to customers on integration and control applications, technical training and seminars. His experience includes testing of systems using DNP3, IEC 870-5-101/104, Modbus, OPC, and IEC 61850. He is a member of the AG B5-51 CIGRÉ Working Group for Substation Automation and Remote Control.

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