Upgrading From a Successful Emergency Control System to a Wide-Area Monitoring, Protection, Automation, and Control System for the Country of Georgia Power System

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Upgrading From a Successful Emergency Control System to a Wide-Area Monitoring, Protection, Automation, and Control System for the Country of Georgia Power System

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Abstract—**Prior to recently added transmission lines, the country of Georgia power system was subject to severe instability when any of the 500 kV lines were lost because of power system faults and/or accidental disconnections. Two islands were formed, requiring load shedding in the load center and generation shedding in an important power center of the system.**

Several years ago, a distributed emergency control system (ECS) was installed to quickly provide an inexpensive solution for the worst failure modes. The system rapidly and safely balances generation and load during system events in order to prevent failures. The ECS requirements were defined by system studies performed at Georgian State Electrosystem (GSE). Because of several blackouts during the summer of 2010, the system needed to be in service before the peak load of the summer of 2011.

The ECS was implemented with customized logic; off-the-shelf protection, control, and monitoring devices; and high-speed IEC 61850 Generic Object-Oriented Substation Event (GOOSE) messages. Human-machine interfaces (HMIs) were used by operators for system control, monitoring, and management of the power threshold settings. In the months following the successful installation and commissioning, the ECS successfully prevented power system total blackouts five separate times in two weeks.

Recently, GSE requested an upgrade to the capabilities of the ECS to create a wide-area monitoring, protection, automation, and control (WAMPAC) system, also known as a remedial action scheme (RAS). The original design and installation of the ECS was conducted with the knowledge that future additions would be made. This paper describes how the in-service system was updated, commissioned, and tested to become a full WAMPAC system. Expansions included a wide-area network (WAN) multiplexer system to support communications for numerous GSE systems over fiber-optics and new centralized control strategies working in parallel with the distributed emergency control strategies. The central controllers collect comprehensive power flow information and have a much broader system awareness than the distributed controllers. This situational awareness makes possible the WAMPAC logic and communications. The system is continually in service and has operated many times. In fact, the success of the WAMPAC system was demonstrated when it successfully operated four times in the first eleven days of 2016, preventing GSE system failures from power system events associated with Georgia's neighbors.

I. Introduction

The country of Georgia is located east of the Black Sea. It borders Russia to the north, Turkey to the southwest, Armenia to the south, and Azerbaijan to the southeast. Most of the electrical load is consumed at the capital city, Tbilisi, located in the southeast of the country. In the west of the country, an important hydroelectric plant in Enguri generates the majority of the power to be transmitted to Tbilisi.

Fig. 1 shows the major Georgian transmission lines and substations. Georgian State Electrosystem (GSE) ensures electric power transmission over the entire territory of Georgia. GSE is responsible for operations, management, and dispatching within the Georgian power system and has responsibility for the operation of the 500 kV, 220 kV, 110 kV, and 35 kV transmission facilities while maintaining power system stability. The system comprises 3,000 km of transmission lines (500 kV, 220 kV, and 110 kV) and 89 substations dispersed throughout Georgia.

The Enguri power plant in the Imereti power plant region, shown in Fig. 1, generates the power that is delivered to the Tbilisi load region via the 500 kV Imereti and Kartli 2 lines. The flow in the 220 kV system to the Tbilisi region is considered secondary compared with the 500 kV backbone.

Prior to the addition of 500 kV circuits in 2015 and 2016, if any part of the 500 kV transmission backbone failed, the power system effectively divided into two electrical islands (considering the 500 kV system only) and, as a consequence, the 220 kV system could become overloaded. The Tbilisi load region would lack generation, and the Enguri power plant region would have a power surplus; therefore, the two electrical islands would be unstable. In the Tbilisi load region, loads needed to be shed to mitigate the generation deficit. At the Enguri power plant, the excess generation needed to be reduced by shedding the appropriate number of generators.

In the summer of 2010, this scenario occurred several times, leading to the blackout of a large percentage of the power system. Traditional underfrequency schemes are too slow to guarantee the stability of the system under these circumstances. The average recovery time for these incidents was more than 1 hour.

Occurrences of instability and long recovery times from blackouts are not acceptable in modern power systems. GSE therefore proposed a wide-area protection scheme, referred to as an emergency control system (ECS), to provide fast-acting stability control of the power system. This paper, an expanded version of [1], provides an update on this project's communications infrastructure and application capabilities.

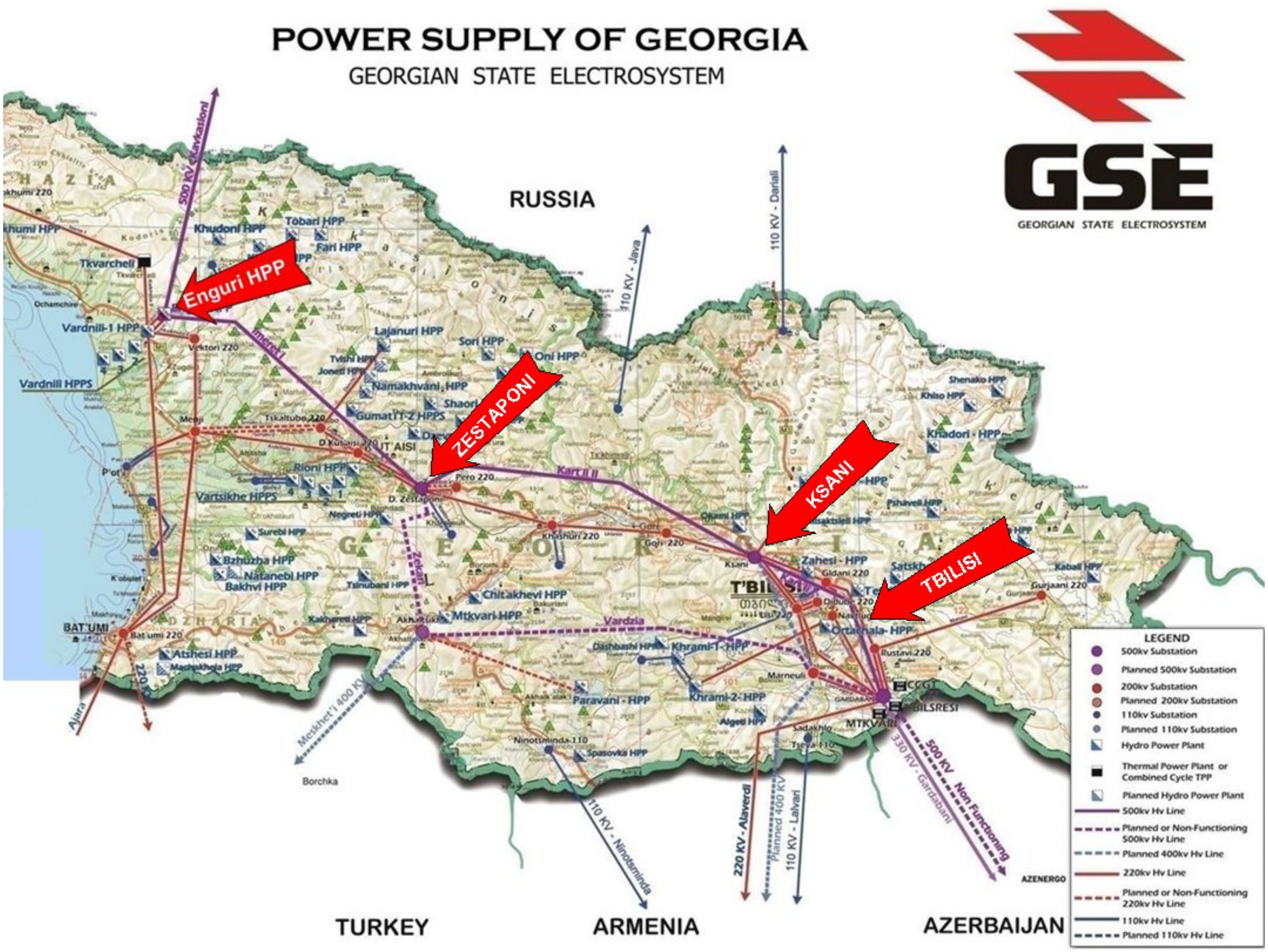

Fig. 1. The Georgian Power System

II. ECS Description

The ECS requirements were defined by system studies performed at GSE. Because of several blackouts during the summer of 2010, the system needed to be in service before the summer of 2011. Design simplicity and field implementation were necessary to simplify deployment.

Based on stability studies and considerations, the ECS is required to operate by shedding appropriate loads and generation in less than 100 ms, excluding breaker operation time. The load and generation shedding systems consider the power flow at the time of the loss of the 500 kV line and compare it with three predetermined thresholds linked to the amount of load and generation to be shed.

A. Contingency Recognition

The loss of either the 500 kV Imereti or Kartli 2 transmission line and the overload of the 220 kV circuit can effectively split the power system in two. The system must therefore quickly and reliably recognize the opening of breakers associated with these transmission lines. The lines are subject to frequent transmission line faults during the summer, and the line protection systems clear the faults by opening the breakers.

Single-pole tripping relays and breakers are used, but the opening of a single pole of the breaker is not a contingency. However, for multiphase and permanent faults, the protective relays open the three phases of the breakers. This is recognized as a contingency.

Fig. 2 is a simplified diagram of the power system shown in Fig. 1. The Imereti line loss is detected at the Zestaponi substation. The Kartli 2 line loss is detected at the Ksani substation.

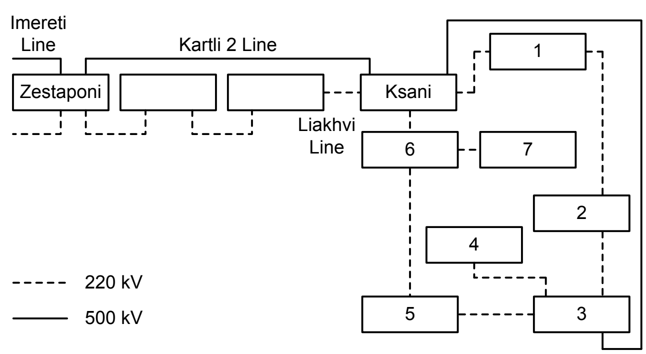

Fig. 2. Simplified Georgian Power System

At both the Zestaponi and Ksani substations, the power flow is constantly monitored and recorded to provide pre-event measurements in the event of line loss. These measurements are used for calculating the load-shedding signals sent to seven substations in the Tbilisi region. The severity of the load shedding is based on the comparison of the measured power flow with three defined power thresholds. These three severity levels are used to decide which loads to disconnect among the seven substations in the Tbilisi region, as shown in Fig. 2.

The system also uses the three severity levels and the load shedding to determine if it needs to initiate disconnection of generation units in the Enguri power plant.

The ECS uses two decision-making devices located in the 500 kV Zestaponi and Ksani substations. These devices, referred to as ECS processors, are the "brains" of the ECS. Their main purposes are to measure power flow; determine the severity levels based on the power flow; detect the loss of the 500 kV lines; and provide indications, oscillography, and sequential events records.

The ECS requires a human-machine interface (HMI) to interrogate the ECS processors to collect and display system operational data. The graphical interface allows operators to configure the thresholds for the different severity levels.

B. Communications Infrastructure

GSE is the owner of a single-mode fiber-optic network linking the majority of the substations in the country. The ECS project was implemented using a single fiber-optic pair to complete the entire scheme. IEC 61850 Generic Object-Oriented Substation Event (GOOSE) messages were selected for digital transmission of the severity limits to mitigation substations. These messages and all other required Ethernet traffic coexist on the fiber-optic network. IEEE 802.1 network segregation and message priority methods are used to allow the GOOSE messages to travel efficiently and with more deterministic behavior. The fiber-optic pair provided for this project can be separated from other forms of communication using other fiber-optic pairs from the bundle. The availability of a fiber-optic pair for exclusive use by the control system is essential for the precision and speed required to perform protection-grade emergency controls.

A comprehensive, long-range engineering design was created for the communications network of the initial ECS and to support future additions. The design team created an initial mission-critical communications network for fast installation to support the ECS messaging needs. The network was designed and installed specifically to allow the future insertion of multiplexers to support additional traffic and capabilities while preserving the protection-grade performance of the ECS controls.

The system uses the fiber-optic pair to create a large, flat, distributed Ethernet local-area network (LAN) by connecting each of the substation LANs together. IEEE 802.1Q virtual LANs (VLANs) are used to segregate traffic and deliver messages to their intended destinations. The future addition of multiplexers was anticipated to allow more messaging among the substations and the control center. Information in these messages allows for more comprehensive decision making and actions within GSE. The architecture of the network does not change if other communications are multiplexed onto this fiber-optic pair via time-division multiplexing (TDM). The addition of TDM multiplexers at each station allows the same fiber-optic pair to multiplex numerous communications with the determinism and dependability required for the high-speed ECS [1].

C. Additional Considerations

The requirements were defined after blackout events in the summer of 2010, and the system needed to be ready and installed before the summer of 2011. Using protection, control, and monitoring specialized for mission-critical applications simplified the implementation, allowing the complete solution to be designed and implemented in just four months.

III. ECS Design

The foundation of the ECS design was simplicity and efficiency. In order to quickly and locally configure the system and execute the ECS logic, easily programmable ECS processors and complementary HMIs were installed at the Ksani and Zestaponi substations. At the mitigation substations and Enguri power plant, programmable input/output (I/O) modules supporting GOOSE messaging were selected.

A. Communications Considerations

The availability of fiber-optic links between substations makes it easier to implement a system with modern protocols. Two possible solutions were analyzed. The first used Mirrored Bits® communications as a peer-to-peer protocol recognized as high speed with triple-redundant payload integrity [3]. The second used GOOSE messages. For this type of control system over a wide area, security and low latency in the delivery of the control signals are required.

The main advantages of Mirrored Bits communications are its successful history in similar ECS projects for more than a decade [4] and the direct connection of devices via a simple serial-to-optical converter. No additional communications equipment is required.

Although the serial Mirrored Bits communications protocol can send control bits in as little as 4 ms, point to point, in this solution some of the devices would have acted as repeaters to downstream devices, adding delays to the system. It was evident that, for this wide-area protection scheme, the use of this serial protocol would not be efficient for system expansion. Another consideration was that Mirrored Bits communications did not support the multiplexing of other protocols on the same communications link for additional functionalities, such as engineering access.

Having the fiber-optic pair available over long distances allowed the possibility of an Ethernet network. IEC 61850 GOOSE messaging was selected as the solution for sending the severity signals. The decision-making ECS processors and action-taking shedding processors therefore needed to have Ethernet ports and provide IEC 61850 connectivity.

Fig. 3 shows the implemented Ethernet network. Managed substation-rated Ethernet switches with single-mode optical ports are used. The network uses redundant paths where possible. There are additional switches in intermediate substations because of the long distances involved and for future mitigation substations. For the link between Zestaponi and Enguri, the signals are sent via two different paths, one as shown in Fig. 2 through a fiber-optic Ethernet link and a second through a power line carrier system as a backup.

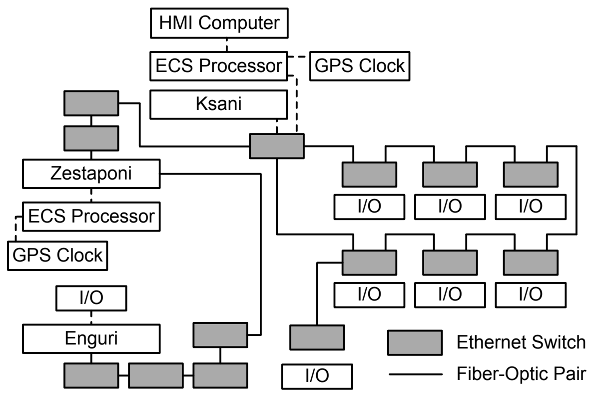

Fig. 3. ECS Ethernet Network

It is a benefit to use fast IEC 61850 GOOSE messaging that is multicast (i.e., published simultaneously to multiple devices on the network) with high priority on the network [5]. This multicast feature requires disciplined use of IEEE 802.1p and IEEE 802.1Q VLAN GOOSE message priority and segregation in the protection, control, and monitoring intelligent electronic devices (IEDs) and Ethernet switches for fast and dependable delivery. The low latency in the Ethernet switches means that the control messages arrive at the shedding processors from the ECS processors at effectively the same time.

The Ethernet network also provides the following benefits.

1) TCP/IP

File Transfer Protocol (FTP) and Telnet are used to interrogate remote ECS devices for engineering purposes. Other protocols native to the ECS processors are also implemented over the network.

2) Remote Access

The HMI computer can easily access each of the remote ECS devices to configure them and retrieve sequential events records and oscillography.

3) Expansion Opportunities

If additional mitigation substations are to be included in the scheme, the addition to the network is straightforward.

4) Fast-Acting System

Because GOOSE messaging is multicast, the severity signals are sent to all network nodes simultaneously. Settings within Ethernet switches allow these messages to reach the appropriate devices and be easily delivered to new mitigation substations as they are added without affecting the source device or requiring repeating.

5) System Settings

It is easy to modify the number of thresholds and severity signals by making slight changes to the present GOOSE messages to add more discrete signals to the payload.

6) Redundancy

The system can be easily modified to duplicate the I/O programmable modules at each mitigation substation for redundancy purposes.

7) Interoperability

The system can accept devices that support IEC 61850 GOOSE messages that are from different manufacturers.

B. Device Selection

All of the devices in the ECS were required to have Ethernet ports. All of the devices except the HMI computer were required to have IEC 61850 GOOSE message capabilities.

1) Ethernet Switches

Managed Ethernet switches with IEEE 802.1p priority and IEEE 802.1Q VLAN tagging were selected. The priority tagging is used by IEC 61850 GOOSE messages to send control messages with higher priority than regular Ethernet traffic. The selected switches have single-mode fiber ports to allow long-distance communications.

2) ECS Processors

The devices selected to act as the logic processors for the ECS are capable of measuring power system currents and voltages for two lines. With the measurements, the power flow in each line can be calculated. Logic gates, timers, and arithmetic operations are available for the programming of the ECS logic. The ECS processor has its own binary I/O. Breaker status and disconnect switch status information can also be incorporated in the scheme.

The selected ECS processor runs the main logic every one-eighth of a power system cycle. The ECS processor automation scheme is a deterministic process focused on high-speed logic applications.

3) Shedding Processors

The selected shedding processor supports IEC 61850 with high-performance GOOSE messages and provides discrete I/O, as well as the ability to implement programmable logic. The device outputs are substation grade for connection to the trip circuitry of the selected loads.

4) HMI Computer

A substation-hardened computer runs the ECS HMI to interface with the user. The substation computer system also runs engineering software tools for the collection of event reports and relay parameterization.

5) GPS Clock

The sequential events records and measurements are synchronized in both of the ECS processors by a GPS clock. Synchronized oscillography and sequential events records are valuable as analysis tools.

C. Ksani Contingency Detection

The Ksani substation is at an important location in the system and includes the HMI computer interface for the system. It is also where a Kartli 2 line outage is detected.

Fig. 4 shows the 500 kV monitoring bay at Ksani. It is a double-bus arrangement with two breakers. Both breaker position (52b) contacts are brought to the ECS processor to detect the opening of the Kartli 2 line.

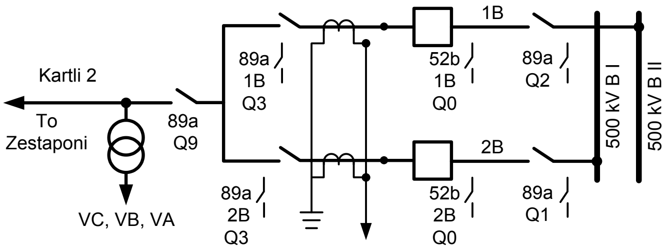

Fig. 4. Ksani 500 kV Kartli 2 Line Bay

For security, in addition to the breaker position, current sensing (the absence of current) is used with sensitive undercurrent detectors, denoted by LOPH*x* in Fig. 5. While the logic described does not fully avoid the dependence of the contingency detection on simple binary input circuitry, it provides sufficient security for this project. Other more sophisticated methods are possible to add security to the detection [6].

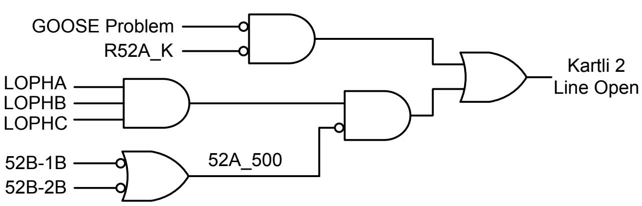

Fig. 5. Kartli 2 Line-Open Contingency Detection

The breaker status bit from the remote terminal (located in the Zestaponi substation) is also received and incorporated in the logic. The R52A_K bit is part of the GOOSE message received from Zestaponi and qualified by the GOOSE integrity bit. This GOOSE integrity bit monitors the integrity of the GOOSE communications. It is normally deasserted and blocks the remote breaker position signal (R52A_K) when a problem with the GOOSE message transmission is detected.

An additional check is for a sudden change in power transfer. If the measured power decreases suddenly (as it would for the sudden opening of the breakers), the loss of the line is qualified.

There are four arming conditions that should be present for a determined time before enabling the contingency detection logic. These conditions are shown in Fig. 6. The arming pickup and dropout times, as well as the thresholds, are settable in the ECS processor. While they are not crucial for the description of the logic, it is worth mentioning that the pickup times are in the range of 1 second and the power thresholds are on the order of 20 MW. These were engineering choices in the design.

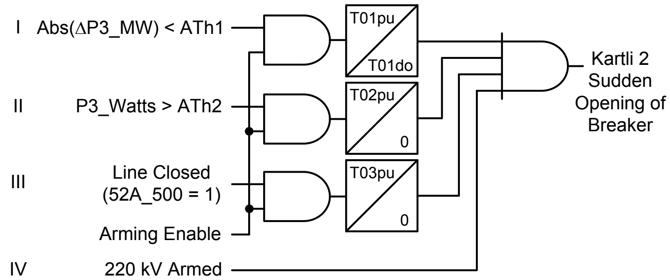

Fig. 6. Ksani Arming Conditions

Condition I requires that the change of measured power be less than a threshold (ATh1). The comparison is between the instantaneous measurement and a recorded measurement with a long time constant. Condition II requires a minimum power flow in the line to arm the logic. Condition III requires sensing that the breaker is closed. Condition IV identifies the 220 kV Liakhvi line as in service or out of service with a qualifying time.

The arming enable signal is used to supervise and disable the arming logic under certain conditions. The position of the disconnect switches (e.g., 89a contacts in Fig. 4) is used to disable the logic.

The 220 kV Liakhvi line is monitored for its power flow. The power in this line is alternately considered to be additive or subtractive when considering the load to be shed. Moreover, when it is out of service, the line should not be considered for use in stability algorithms. The ECS processor at Ksani considers the binary status of the elements shown in Fig. 7. The 220 kV Liakhvi bay is considered as well as the transfer bay (TB). The transfer of the 220 kV currents is monitored via external auxiliary relays and is transparent to the scheme. The disconnect switches (89a contacts in Fig. 7) are used to declare the bay out of service.

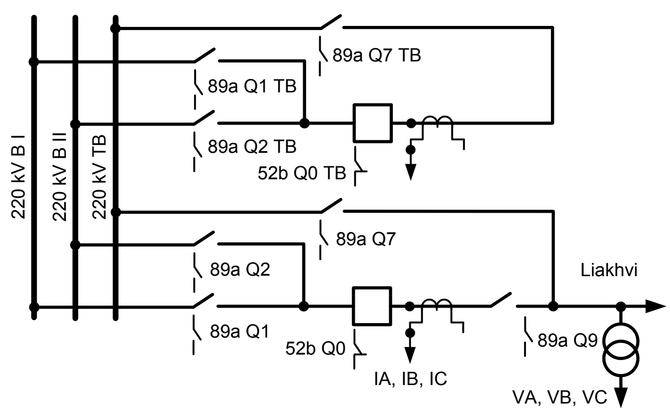

Fig. 7. Ksani 220 kV Liakhvi Line Bay

D. Ksani Severity-Level Thresholds

The Ksani ECS processor computes the power flow in the 500 kV Kartli 2 line and the 220 kV Liakhvi line. Fig. 8 illustrates the block diagram.

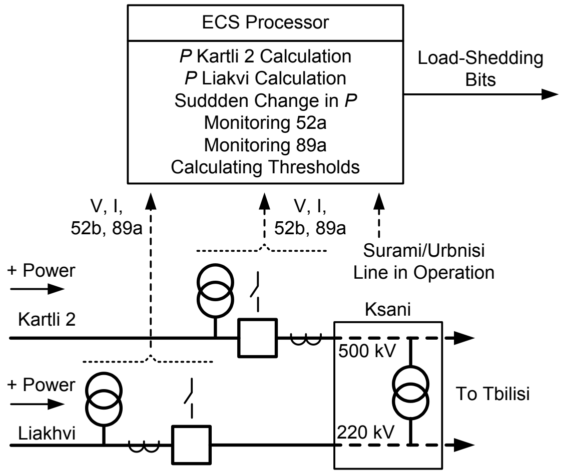

Fig. 8. Ksani ECS Processor Block Diagram

The ECS processor monitors voltage levels and calculates the power flow with the appropriate direction for both of the 500 kV Kartli 2 line and the 220 kV Liakhvi line. The loss of the 500 kV power requires calculating the severity of the loss, sending the appropriate commands to the load substations, and sending the generation-shedding commands to Enguri.

The severity levels are calculated continuously. As shown in Fig. 9, when the 220 kV Liakhvi line is in service, the severity-level bits (SB01, SB02, and SB03) are determined by comparing a memorized sum of power flow in the 500 kV and 220 kV lines to three thresholds (Th01, Th02, and Th03).

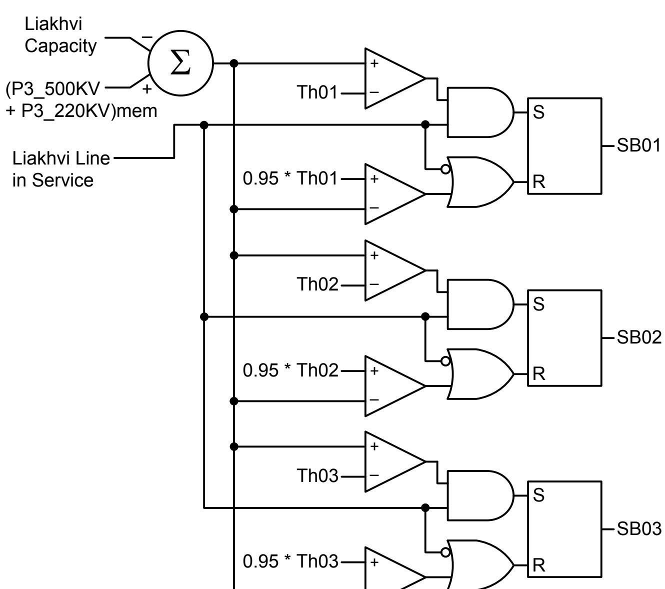

Fig. 9. Ksani Substation Severity Bit Calculation

One of the elegant features of this simple but effective ECS is that the threshold values are parameters that are set by the operator via the HMI. Therefore, as stability conditions change, the sensitivity of the ECS can be tuned via operator settings. A logic calculation similar to the one in Fig. 9 is implemented when the Liakhvi line is out of service. The threshold comparisons are implemented with latches, as shown in Fig. 9, with a reset threshold at 95 percent of the operating threshold, providing hysteresis in the measurement and avoiding chattering near the decision point.

The three bits (SB01, SB02, and SB03) are multicast via GOOSE messages. Within each of the mitigation substations, a shedding processor subscribes to the multicast message, receives the bits, and interprets the shedding level. Fig. 10 illustrates a simple block diagram of the required logic.

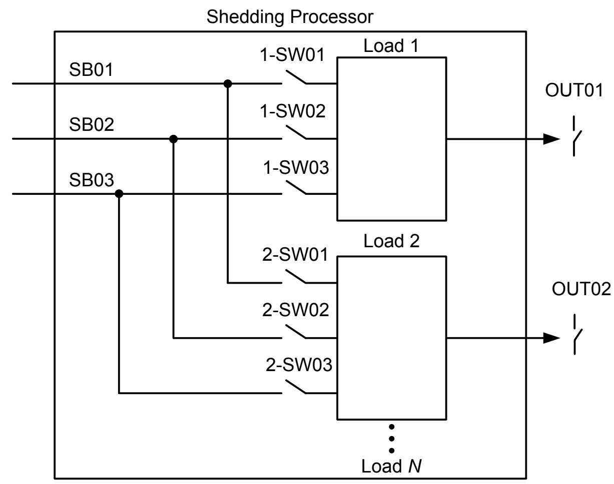

Fig. 10. Shedding Processor Block Diagram

For each load, the bits are interpreted according to the conceptual position of load-shedding selection switches (SW01, SW02, and SW03). The load-shedding selection switches are implemented in programmable logic, and their position is a setting in the shedding processor. This logic is also tuned via operator setting changes in the HMI so that each load is selected to be shed at one or more severity limits based on present power system stability parameters. Inside the shedding processor, assignments to physical outputs are programmed, and these outputs control the breakers to open.

E. Zestaponi Contingency Detection and Logic

Zestaponi is the second substation where an ECS processor is installed. This location does not have an HMI computer because the one at Ksani provides HMI access for all devices across the network.

The ECS processor at Zestaponi monitors the 500 kV flow in the Imereti transmission line and detects the loss of this line. The functionality is similar to and based on the logic already described for the Ksani substation.

The ECS processor at Zestaponi transmits three other severity bits to the shedding processors at the mitigation substations and the Enguri power plant. In the mitigation substation shedding processor logic, the severity-limit signals generated at Zestaponi are connected by OR gates to the severity-limit signals generated at Ksani.

F. GOOSE Message Programming and Shedding Processor Interface

The load-shedding signals are multicast from the two ECS processors at Ksani and Zestaponi to all mitigation substations using IEC 61850 GOOSE messages. Every substation checks the quality of a message before using it to trip the respective loads. The loads are shed depending on the overload severity-level signal and a load-shedding selection table set on each I/O module from the HMI. The GOOSE message quality indicator is used to supervise all of the logic that depends on received control bits. In the selected IEDs, a message quality parameter is calculated based on message statistics, message receipt performance versus predicted delivery, and the time-to-live attribute within the message that declares how long the payload should be considered valid. Message quality provides real-time supervision of the health and performance of the digital message delivery of system condition, threshold, and shed indications, which adds security to the scheme.

Each I/O module also stores a sequential events report that is retrieved by the HMI for post-event analysis and maintenance purposes. Additional loads can be added to each I/O module, or more units can be added to each substation with minimal engineering effort.

There are also dedicated maintenance control signals within the GOOSE message specific to each substation to confirm its operation. Each I/O module sends a GOOSE message to be received by the monitoring unit to confirm the correct operation of the maintenance control signal through the network. This feature was used during commissioning and later during maintenance.

Any problems with GOOSE messages are immediately detected and indicated as a major alarm in the system.

G. HMI

The HMI, shown in Fig. 11 and Fig. 12, contains a collection of objects that represent power system devices.

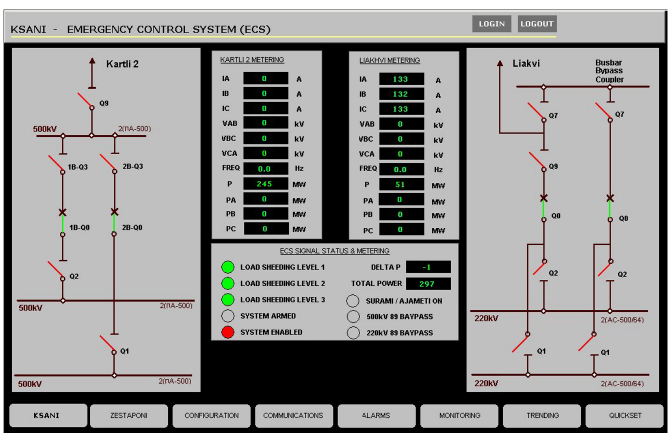

Fig. 11. ECS Status – Operator Screen

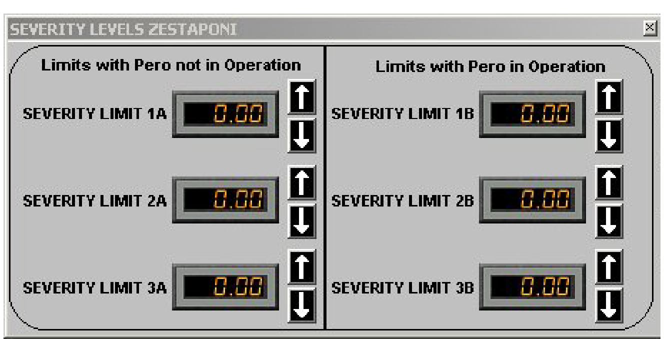

Fig. 12. ECS HMI Severity-Limit Settings – Engineering Screen

The animation of these objects represents status and conditions; displays analog values; and provides input fields for analog values, dialog boxes, and message boxes that help the operator maintain and control the ECS. The HMI continuously monitors the status of the different field devices in the system. It updates the screen on a periodic basis and maintains a diagnostic alarm history. System tuning is allowed through password-protected screens. These security features prevent unauthorized access and limit access based on user groups.

IV. Commissioning and Validation

The field deployment time schedule required a smooth installation and commissioning process. Steps were taken to prevent unforeseen circumstances when commissioning the system.

A. Laboratory Simulation

The ECS logic described previously is contained in the ECS processors, and the contingency-detection logic schemes can be isolated in each processor. In a laboratory environment with a relay test set, the logic was properly simulated and debugged. Initial logic problems were encountered and fixed in this environment.

Testing in the laboratory environment provided the first verification of the speed of the system. The requirements were fully satisfied with ample margin, as compared with the original 100 ms operating time requirement. In fact, typical operate times were between 10 and 20 ms. The results were used as validation of the project proposal and design. The laboratory experience proved valuable in the implementation of the scheme and saved implementation time by exposing a few ineffective logic operations that were quickly fixed.

B. Network Installation

In the field, the installation of the Ethernet switches and devices with their corresponding network addresses was the first step. At each of the participating substations in Fig. 3, the adequate transmission and reception of the optical signals were verified.

Because this is a closed network with no routing, appropriate IP addresses were selected for each device. The mitigation substation I/O modules were shipped from the factory with all of the default settings, IP addresses, and logic settings. The IEC 61850 Configured IED Description (CID) files were downloaded to each unit onsite at the time of installation to avoid any conflicts. Connectivity to each device from the ECS processors was then verified from both monitoring substations. Once the connectivity to the remote substation was established, the proper logic settings and the CID files describing GOOSE publications and subscriptions were reconfirmed remotely.

The high-level operation testing was performed by using a dedicated maintenance command. Within the GOOSE message, one signal is dedicated for each substation. This discrete Boolean signal operates a test output that is physically wired to a test input. The status of this input is transmitted back, confirming the operation of the output and the performance of the GOOSE message. Other tools, like the GOOSE diagnostic reports available within these devices, were necessary to verify GOOSE operation and integrity.

The second step of the commissioning process was to configure the monitoring substations and verify installation settings, logic, and communications.

C. Commissioning in the Field

ECS processors, shedding processors, and switches were in place for commissioning. The proper polarities of the analog inputs were verified, ensuring that the measurements of the power flow were correct. The breaker position binary inputs were properly verified together with the disconnect switch inputs.

GOOSE message exchange was verified by sending test severity bits through the network and verifying the shedding processor outputs.

With relay test sets, the same types of tests as in the laboratory environment were performed, validating the scheme again.

The access to the network for each of the involved IEDs was a big advantage. It allowed the modification of small pieces of logic (e.g., I/O assignments and disconnect switch interlocks) from the HMI location.

During the testing and installation, it was confirmed that the system reaction time was less than 15 ms from line-open detection at the monitoring substations to the opening of the tripping contacts at the mitigation substations.

D. Staged Country-Wide Blackout

The commissioning of the system proved to be very straightforward. GSE decided to test the system and response times with a staged in-service test. The test was conducted at 1:41 a.m., as shown in the oscillographic record in Fig. 13, in order to affect as few people as possible if it did not work correctly.

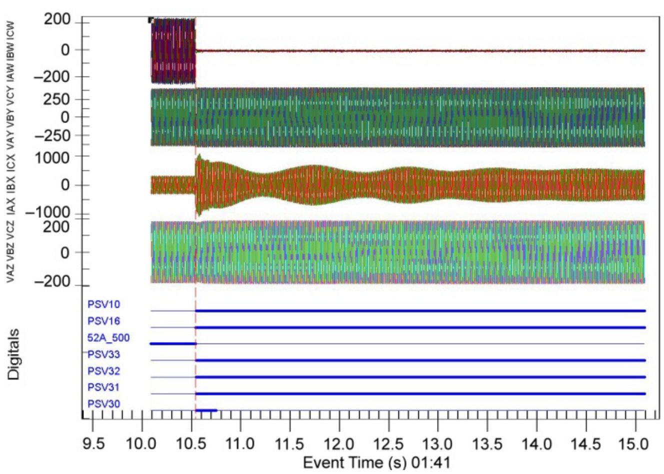

Fig. 13. Staged ECS Test Oscillography

Fig. 13 displays the oscillography record from the Ksani ECS processor. The 500 kV Kartli 2 line breaker was opened manually and the power thresholds adjusted very low to account for the low power flow at the time of the test. The severity bits (SB01, SB02, and SB03) were sent to all shedding processors, and load was shed according to the HMI set logic. In Fig. 13, PSV31, PSV32, and PSV33 correspond to the severity bits after the logic determined to send the bits. The test was effectively a staged country-wide blackout that proved to be successful because the system operated as expected, very quickly, and mitigated a full blackout.

V. Field Operation

A. Importance of Oscillography

The ECS processors at the Ksani and Zestaponi substations are capable of storing oscillography. This function allows GSE to observe and verify the operation of the ECS and the power system.

For the commissioning testing and the staged blackout attempt, the oscillographic records proved to be very useful in confirming the operation of the system. The effects of opening the breakers on the 500 kV line (shown as waveform IAW-IBW-ICW in Fig. 13) and the overload in the 220 kV system (shown as waveform IAX-IBX-ICX) were easily verified. The ECS shedding commands (shown as PSV31, PSV32, and PSV33 in Fig. 13) operated breakers at Tbilisi 12 ms after the 500 kV breaker opened to reduce some but not all load. The 220 kV system can be seen taking on additional remaining load, oscillating slightly, and then holding at the higher power flow to prevent the blackout.

Together with the sequential events records synchronized with the GPS clock, the oscillographic records provide all the documentation required for analysis and verification of the load-shedding levels by the operators and planners at GSE.

B. ECS Operations

The ECS was commissioned at the beginning of the summer of 2011. Summer is a critical period of the year for the power system. The load is high in the 500 kV systems, and the probability of faults on the 500 kV Imereti and Kartli 2 lines is high. Even though the lines are equipped with line differential systems with single-pole trip capabilities, high-resistance ground faults can force the opening of the three poles. This is shown in Fig. 14, which illustrates the operation of the ECS processor on the Zestaponi side. A high-resistance ground fault required the opening of the three poles with sufficient load in the line to activate the ECS Level 1 (PSV31) threshold.

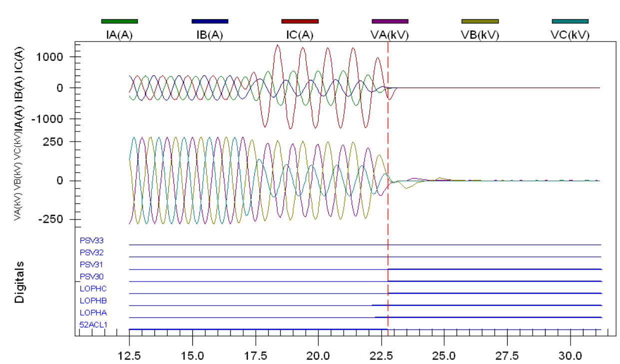

Fig. 14. Loss of the Imereti Line

The event shown in Fig. 14 illustrates a real system event. Similar events occurred five times in July 2011, and the ECS responded by properly shedding the predetermined load levels. For this ECS, as for others, a single successful operation paid for the cost of the project.

VI. From Emergency Control to True Management

A. Adding a Remedial Action Scheme

In the summer of 2013, the GSE ECS design team worked with a special protection systems team to start designing a more comprehensive scheme. This centralized solution adds another level of power system management. It provides a big picture of how electric power migrates and behaves from generation plants to load centers throughout the country and uses that visibility to protect the country even more. This system uses communications to provide a remedy to the system after a localized protection or ECS application takes action. The centralized wide-area solution is called a remedial action scheme (RAS).

1) Objective of System Additions

The main objective of the combined ECS and RAS was still protection against power system breakdowns. The system was also tasked with maximizing transmission through the energy corridors to neighboring countries, which required real-time monitoring for efficient use and reliability. Fast and precise decision making and control were expected to secure uninterrupted export or transfer based on multiple transmission system topologies, generation availability, and contractual commitments.

The Georgian transmission system configuration after 2013 was adapted to the future role of the Georgian system as a major regional energy hub. Energy exchanges use conventional extra-high voltage ac synchronous interconnections as well as high-voltage dc back-to-back links that require the implementation of remedial actions based on the control of the high-voltage dc power flow.

The ECS upgrade project included the addition of a monitoring and control system based on synchrophasor measurements collected at major system nodes and streamed to the National Control Center in Tbilisi. The system included real-time functionalities not possible with conventional supervisory control and data acquisition (SCADA) and energy management systems (EMSs), including the following:

- Prevention of the propagation of disturbances between interconnection partners.
- Enhanced security of the transmission system in case of multiple outages and simultaneous contingencies (N-2 and beyond).
- Prevention of system separation in the event of severe power deficits in a particular area of the system.

2) Design Principle

The GSE philosophy was to design a system that was as decentralized as possible but centralized as required. A decentralized local RAS was accomplished at strategic parts of the system in distributed power system nodes. Each node consists of ECS processors performing event recognition and logic processing and phasor measurement and control units.

Central RAS controllers and synchrophasor processor systems are located in the National Control Center and hierarchically above the local systems. The central RAS controllers process the system-wide remedial action logic considering nonlocal events, limitations, constraints (technical and contractual), and real-time topology information.

B. Centralized Control

The centralized-controller RAS was designed to run in parallel with the regional ECS controllers. It sits in the National Control Center and collects all of the information from every device throughout the country. It interfaces with the existing SCADA system to monitor voltage, power flow, generation, and load levels. It automatically modifies power thresholds based on operator settings, and it sees every action from primary and secondary equipment. With this information, the RAS makes more informed, intelligent, and quantitative decisions about how best to keep the power system stable, without any human interaction.

Fig. 15 shows a high-level architecture that illustrates the data flow on the system. This addition elevates the GSE system from emergency control to true management. With the ECS, each relay is only able to take care of one line. This is great for emergencies, but a RAS is more capable and sophisticated. It makes better decisions for the entire country simply because it is aware of the entire country, not just its immediate surroundings.

With both an ECS and a RAS, the goal during a fault is to shed just enough load or generation to keep the system stable and no more. The RAS has more information and makes more nuanced decisions; it chooses, in a more granular fashion, which load is the best match to a particular unbalance of power. Because of its limited control options, the ECS makes fast, but less precise, decisions.

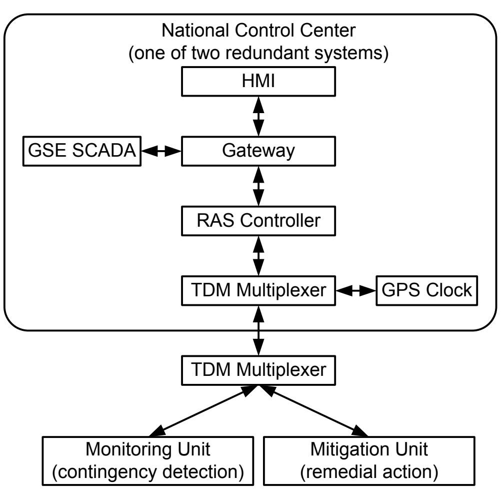

Fig. 15. GSE RAS Communications Flow

The RAS makes more finite decisions by adding more points of control. It grew from the existing ECS, and the two are essentially layered together. The ECS was expanded by increasing the number of thresholds and transmission lines the system takes into account. The RAS did not require a large number of hardware updates in the substations because most of the required data acquisition and control devices were already installed for the ECS. The addition of the RAS was largely an information and control technology enhancement. A few devices were installed to better understand regional loads so that the RAS controllers can make the best decisions.

The overall system has 16 contingencies related to the 500 kV backbone, the interfaces to the neighboring countries, and the statuses of hydroelectric and thermal power plants. The RAS logic also takes into consideration other conditions, including the direction and magnitude of power flow on connected lines defined by GSE that affect remedial actions. This increases the number of scenarios to 61 when all the combinations are considered.

VII. Inserting TDM Multiplexers

A. Engineering RAS Messages

Similar to the ECS GOOSE messages, the new GOOSE messages to support the centralized RAS logic were configured so that all GOOSE messages in the system had unique VLANs. This ensures that the messages are correctly segregated and only delivered to the LANs where they are needed.

One of the new types of GOOSE messages was created to support infrequent, low-speed, analog set-point changes from the RAS controllers to the substations. These set-point messages contain analog power flow information and are much larger than the smaller control messages. The device configuration and message publication schedule was engineered to match the type of data being delivered. With this design, the WAN multiplexers could be provisioned correctly to avoid bandwidth saturation during message delivery.

B. Provisioning WAN Circuits for Precision

Bandwidth is often mistakenly provisioned based on throughput when networks are designed for information technology (IT) purposes. Throughput provisioning is typical and adequate for business information and often for slow SCADA systems as well. However, the throughput provisioning method calculates bandwidth by considering the total number of bits in all the messages that need to be delivered each second as bits per second. Using this method, IT staff often incorrectly provision bandwidth to be only large enough to pass the number of bits in a GOOSE message within a second, considering this as bits per second. The flaw in this method is that it allocates the amount of bandwidth necessary to use a full second to deliver the bits within a GOOSE message. This delay would lead to the failure of the ECS or RAS. Therefore, multiplexers designed for protection-grade communications were used.

When using appropriate operational technology (OT) methods instead of IT methods to calculate bandwidth, the design is based on the required specific message speed rather than information throughput. This is calculated as the number of bits in the GOOSE message divided by the required transit time. The required protective GOOSE transit time is typically 1 ms, which means that the bandwidth is calculated by dividing the number of bits in a GOOSE message by 1 ms.

In this case, once it was correctly configured, the WAN TDM system correctly and quickly delivered all of the distributed and centralized RAS GOOSE messages in addition to all of the other substation communications [7].

C. Choosing a Protection-Grade WAN

The message transit time between a RAS controller and any other relay in the GSE system was specified as 1 ms. This speed is required to manage the power system and quickly react to an event. This creates less strain on transformers, transmission lines, and other equipment and less chance of instability.

The original 100 ms fault detection, isolation, and mitigation time limit requirement from the ECS design was still in effect. To continue satisfying that time, the RAS had to run every 2.5 ms, every hour, every day, without exception, constantly understanding power flow, checking for faults, checking for messages from relays, and monitoring the system.

Most modern multiplexer technologies are not designed with an understanding of the needs of mission-critical protection systems. Protection-grade systems need to be fast both when no failure exists and also in the presence of a failure in the communications system. These devices must detect, isolate, and recover from communications failures fast enough to continue to support the ECS and RAS requirements. Most modern multiplexers target the more common and less precise business, telephone, and IT applications used by power utilities and other users. Even if they are capable of delivering messages quickly when everything is working correctly, their communications recovery time is longer than the entire ECS and RAS process time. They often have failover times of 50 ms or slower, so a protection-grade multiplexer with a failover time of less than 5 ms was used. The failover time of a communications device includes the time to detect a communications problem and find and use an alternate path.

Fifty milliseconds might be considered a fast failover time for streaming movies or delivering email, but it is inappropriate for reacting to faults in a power system. A multiplexer with a 50 ms failover time would not be able to support the 100 ms application time requirement for GSE.

D. Uninterrupted Performance

Existing and new control messages were properly supported by choosing protection-grade WAN multiplexers and then correctly designing and provisioning communications circuits. OT design methods used by the design team confirmed that adding the multiplexers in the communications design would not affect the existing ECS controls. Tests after the installation confirmed that this was true in practice. Also, testing of the newly added messages confirmed that they could be added and that they behaved correctly. The WAN multiplexers continued uninterrupted service of the ECS while providing the new RAS capabilities.

VIII. Conclusion

This paper summarizes the successful addition of a RAS to an in-service ECS in the country of Georgia. For the simple requirements for emergency control, flexible, off-the-shelf devices were programmed to make the appropriate decisions and communicate to the load-shedding and/or generation-shedding processors.

The implementation of the scheme demanded careful planning to select the appropriate devices, determine the programming requirements, select the communications medium, and perform laboratory testing and commissioning. The real power system staged blackout attempt validated the system and provided a significant trust level to GSE.

Multicast GOOSE messages, together with message quality supervision, proved to be an effective means of sending control commands and monitoring the health and performance of digital message delivery. The availability of analog quantities in the GOOSE messages can be useful in other applications as well.

With the successful operation of the system, the project cost was justified. The system is continually in service and has operated many times. In fact, the success of the RAS was demonstrated when it successfully operated four times in the first eleven days of 2016, preventing GSE system failures from power system events associated with Georgia's neighbors.

As the electrical network evolves, systematic additions to the RAS are being executed. The hardware platform was designed to adapt to transmission line additions in the future, and the logic engine was specified to support the increasing combinations of scenarios.

One of the important elements for validating this type of system is the use of modeling and real-time simulation tools. The success and lessons learned from using real-time digital simulation technology during design validation and testing illustrate that all wide-area systems of any size should be tested using these methods.

As the complexity of the electrical network increases, the number of topology combinations can grow exponentially. To add security, synchrophasor solutions can be used in conjunction with a contingency method to support corner cases. For this approach, the system needs to be characterized by archiving synchrophasor information that is used to set the appropriate thresholds on angle separation.

The use of substation-hardened devices adds several advantages to the solution, including front-end logic for arming conditions and for line-open detection that uses metering (voltages, currents, power), monitoring (status of breakers and disconnectors), communications capabilities, and time-synchronized diagnostic files.

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X. Biographies

David Dolezilek received his B.S.E.E. from Montana State University and is the international technical director at Schweitzer Engineering Laboratories, Inc. He has experience in electric power protection, integration, automation, communication, control, SCADA, and EMS. He has authored numerous technical papers and continues to research innovative technology affecting the industry. David is a patented inventor and participates in numerous working groups and technical committees. He is a member of the IEEE, the IEEE Reliability Society, CIGRE working groups, and two International Electrotechnical Commission (IEC) technical committees tasked with the global standardization and security of communications networks and systems in substations.

Diego Rodas received his B.S. in electronic and control engineering from Escuela Politécnica Nacional in 1994. He has broad experience in automation and control systems. Upon graduating, he worked for nearly 16 years in automation systems, from senior field engineering for the oil industry to senior systems design engineering for several additional industries, including food and pharmaceutical. In the last five years, he has been involved in integration and automation projects for numerous substations. Prior to joining Schweitzer Engineering Laboratories, Inc. in 2007, Diego was involved in the development of automatic machinery for process control and the validation of new technology for petrochemical data acquisition and telemetry systems.

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