GSE Experience With a Country-Wide Distributed Remedial Action Scheme for Power System Protection and Control

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***Abstract*—Georgian State Electrosystem (GSE) has implemented a distributed remedial action scheme (RAS) to maintain power system stability in the Republic of Georgia power system. This RAS was based on customized operating principles devised specifically for Georgia's power system. The scheme grew from a simple system in two main substations to a mesh of more than 30 distributed controllers in all of the main 500 kV substations.**

This paper describes the genesis of the project, the initial requirements, and the reason a distributed architecture was selected. During several years of successful operation, the project evolved as GSE added controllers to the system and as new transmission lines and substations were added to Georgia's power system. The paper explains the evolution of the RAS logic and describes the stability criteria and power system studies that were performed to specify requirements for the RAS. It also describes the controller logic for identifying contingencies and explains the unique arming logic for providing security during power system operations. The arming logic has prevented unintentional operation of the RAS on several occasions.

The paper also discusses the evolution of the communications facility. The original network scheme evolved to a more secure and efficient time-division multiplexing (TDM) scheme, providing communications bandwidth to the RAS and other power system protection functions. Traffic is engineered to route control messages based on virtual local-area network (VLAN) IDs. A human-machine interface (HMI) and cybersecurity features complement the operation of the system and provide GSE with an alternative way of monitoring its power system. The commissioning and testing phases of the scheme are discussed. The distributed system has to coexist with a centralized RAS, and this interaction is described as well.

The RAS scheme has been in successful operation since 2011. The paper presents performance indicators and operation examples.

I. Introduction

Georgian State Electrosystem (GSE) operates the transmission system of the Republic of Georgia (see Fig. 1). Reference [1] describes the origins of the emergency control system (ECS), or remedial action scheme (RAS) needed for the reliable operation of the power system. Reference [2] describes the overall impact of the ECS on the reliability of Georgia's power system and the country's economy. Georgia, which was experiencing multiple blackouts and brownouts prior to the installation of the ECS in 2011, benefitted socially, technically, and economically [2].

Georgia has been steadily investing in the improvement of its power system [3]. During the last few years, new substations, back-to-back converters linking to Turkey, transmission lines, and so on have strengthened the power system. However, an ECS is still required for contingencies that threaten system stability. Georgia's ECS has evolved with its power system. It grew from a simple and small ECS to a more sophisticated system that covers multiple contingencies and implements two system architecture philosophies [1].

A distributed logic ECS was implemented in the earlier power system [1]. Complex load-selection logic prompted GSE to implement a centralized system architecture. GSE presently operates with two ECSs (one distributed and one centralized) in a primary and standby fashion, as described later in this paper.

As the wide-area scheme requirements evolved, so did the communications network requirements. The original project was implemented on an open Ethernet network [1]. To better use the fiber bandwidth and improve cybersecurity, the communications network evolved to a time-division multiplexing (TDM) network, where GSE implemented the ECS network and other required protection channels.

The system installed in 2011 has prevented many blackouts and brownouts [2] (see Table I).

TABLE I
ECS Blackout and Brownout Prevention

Year	Blackouts	Brownouts	Total
2014	14	11	25
2015	2	16	18
2016	9	15	24
2017	10	8	18
2018*	2	5	7

*As of July 2018

To maintain the stability of Georgia's power system, the critical reaction time is around 100 ms. The distributed ECS discussed in this paper operates in around 20 ms [1].

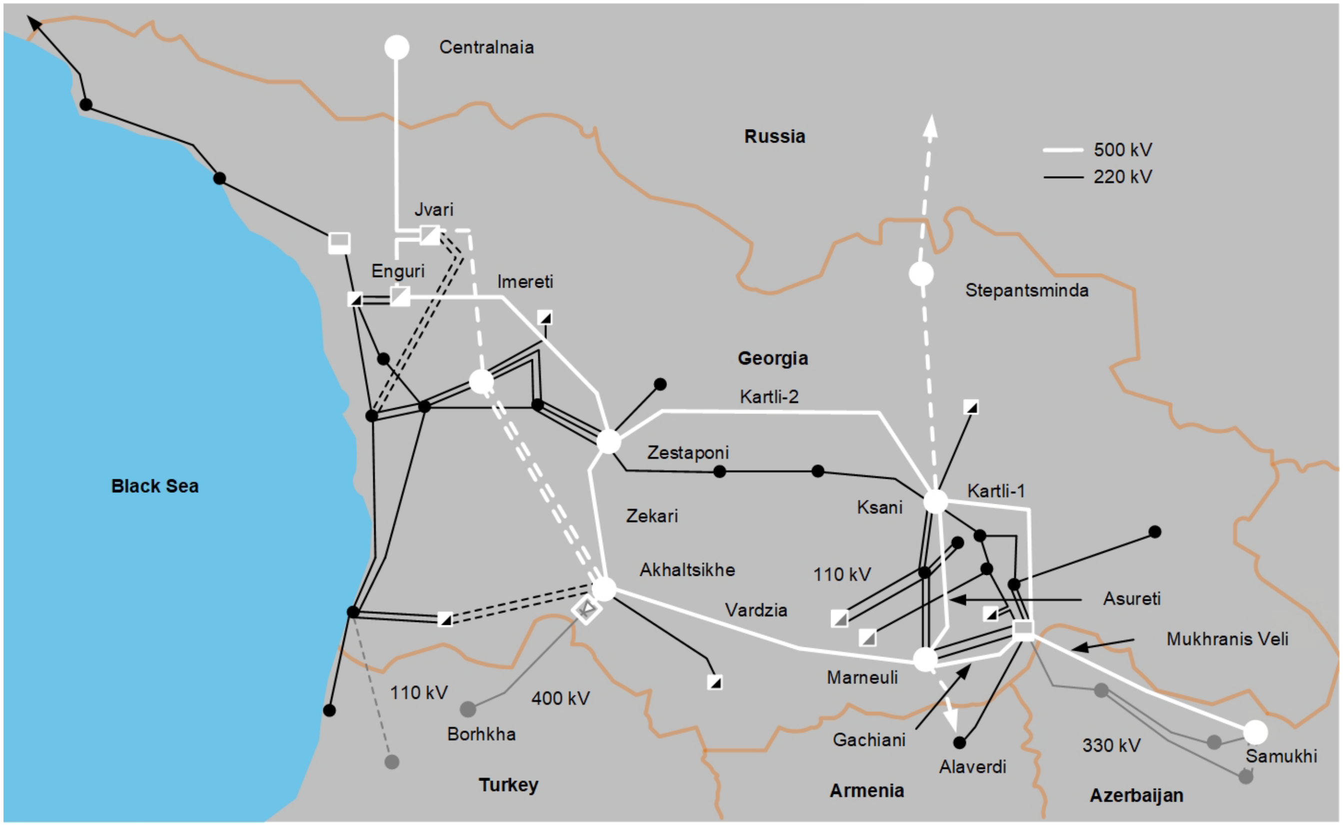

Fig. 1. GSE Transmission Network (dashed lines show future 500 kV lines)

II. Power System

Fig. 1 shows the state of Georgia's power system at the writing of this paper in 2018. Georgia's main load is in the east in the metropolitan city of Tbilisi. The 500 kV transmission system is the backbone of the power system. The secondary transmission level is 220 kV. The recent construction of new 500 kV and 220 kV transmission lines has strengthened the transmission network.

The main generation source is the Enguri hydroelectric power plant (HPP) located on the western side of the country. The Enguri HPP represents 1,300 MW of the total 4,059 MW of Georgia's power system. For the system as a whole, almost 80 percent of the generation is hydraulic. During the summer, high-level water flow makes hydroelectric power more efficient than thermal generation.

Georgia's power system has international interconnections with Russia, Turkey, Azerbaijan, and Armenia. The largest exchange of power is with Russia and Turkey. Importing power is particularly important during the winter period. During the summer, which is characterized by large water flows, a surplus of generated energy is exported.

Georgia's blackout/brownout history (Table I) illustrates that the power system can become unstable. Power flows are determined mostly by the angular differences between buses in the power system. Angular stability can relate to catastrophic events experienced by the power system in previous years (Table I).

A. *Angular Instability*

The analysis of angular instability using the basic maximum power transfer is well described in the literature [4] [5]. Fig. 2 summarizes the theory with a simple description of the real power flow through a lossless system (no resistance) and the equation describing the power flow. For real power flow (MW), there is an associated angle (δ) between the sending voltages (V_S) and the receiving voltages (V_R). The maximum real power transfer occurs when the angular difference between the two sources is 90 degrees. X is the reactance connecting the sending bus (with V_S voltage) to the receiving bus (with V_R voltage).

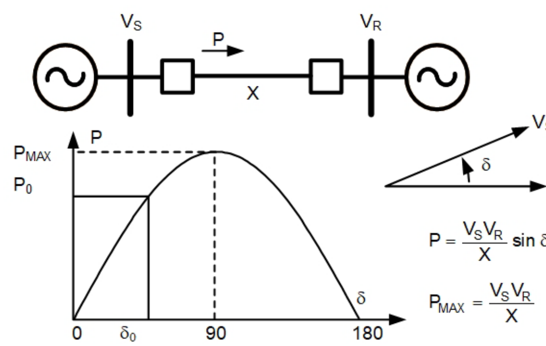

Fig. 2. Relationship of Angle to Power Flow

The theory shown in Fig. 2 helps explain the origins of angular instability in Georgia's power system. The situation is illustrated in Fig. 3.

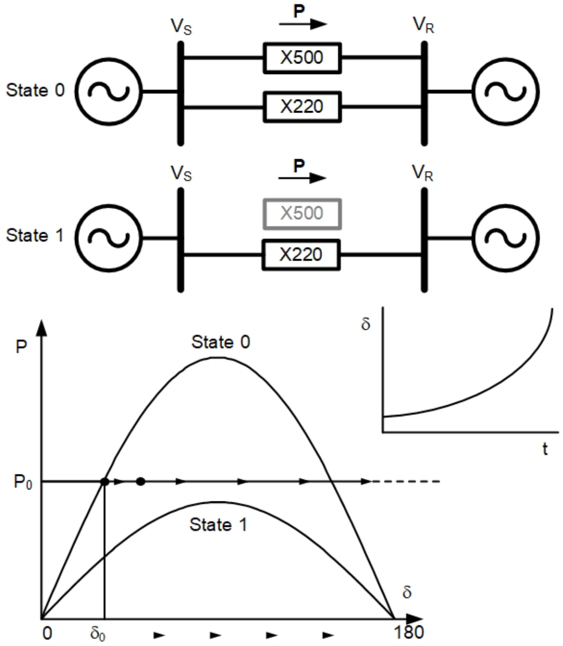

Fig. 3. Angular Instability

The X500 and X220 represent the reactances of the 500 kV and 220 kV equivalent transmission systems with losses ignored. When both systems are transmitting power in parallel (State 0), the equivalent power transfer capability curve is related to a low angular difference (δ_0). When the 500 kV system is lost, the 220 kV system is the only path available. The maximum power transfer capacity of the 220 kV system in State 1 is below the requirements (P_0). The 220 kV equivalent system impedance is too large for transmitting at any angular difference. With no possible intersecting angle, the angular difference grows without bounds over time.

For large load flows (for example, in summer), the loss of the 500 kV corridor ends in the instability of the power system. A fast-acting ECS is therefore needed to take remedial actions. The lack of transmission capacity across the 220 kV system creates a power unbalance between the west side of the country (more generation than load) and the east (less generation than load). This effectively changes area frequencies, which accelerate in the west and decelerate in the east from nominal frequency. To balance the overall system, the ECS acts to shed generation in the west (Enguri HPP) and shed load in the east.

This is a simplified explanation of the instability that the GSE power system experiences. The phenomena in the real power system is more complex and requires advanced software simulation tools to assess the impact of different contingencies.

B. 500 kV Backbone

As stated earlier, the 500 kV transmission system is the backbone of Georgia's power system (see Fig. 4). It transports a significant amount of generation from the Enguri HPP and the flows to and from Russia when interconnected. The ECS considers contingencies in the 500 kV network to keep the power system stable.

Over the years, GSE has taken a special interest in strengthening its 500 kV network [3]. Georgia's power system was originally part of the Soviet power system. A single 500 kV corridor crossed Georgia from west (the Soviet power system) to east (Azerbaijan, formerly part of the Soviet Union as well). Georgia's independence from the Soviet Union left an isolated system with serious power system stability issues. The situation has improved over the years. Bottlenecks in the topology of the power system were found in the Kartli-2 and Imereti lines (Fig. 4). The Kartli-2 line issue was solved by constructing parallel paths in the eastern region (the Zekari and Vardzia lines). The Imereti line bottleneck will be solved in the next few years with the Jvari-Tskaltubo-Akhatsikhe path (Fig. 1). This alternate path will also allow the export of extra power to Turkey.

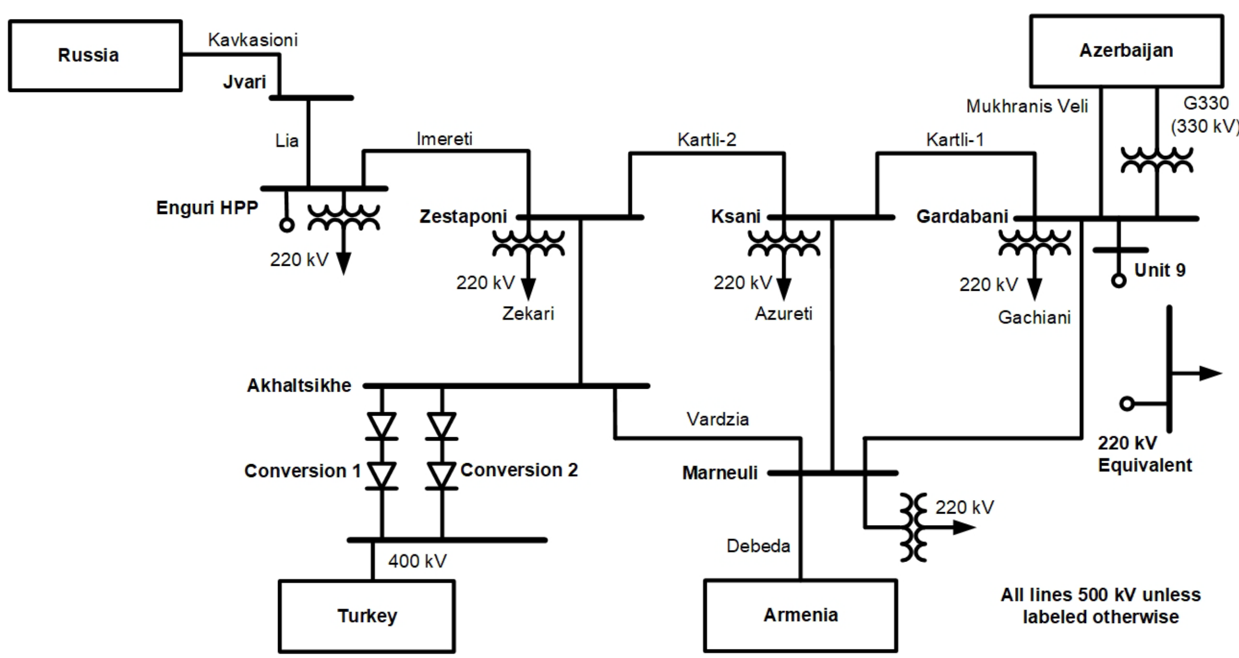

Fig. 4. Georgia's 500 kV Transmission System

Strengthening of the 500 kV power system and the ECS are making Georgia's power system more resilient and reliable. The topology changes create challenges for contingency detection by the ECS, but at the same time they are making the power system less dependent on the ECS. However, as new power plants and renewable energy sources are added to strengthen the system, the ECS is still expected to be an integral part of the power system operation in Georgia. Moreover, the strengthening of the power system will take time, and the ECS will be required during this process.

Like all transmission lines, the 500 kV lines in Georgia are subject to power system faults resulting from weather and insulation failures, and the consequences to the stability of the power system can be severe if these lines are damaged. The main protective relaying system used is current differential, and the breakers have single-pole trip capability.

For the majority of the line faults detected (which are primarily single-line-to-ground and transient), the tripping-and-reclosing scheme keeps the 500 kV transmission system available and the power system secure. For permanent single-line-to-ground faults, the three phases of the breaker are opened after a failed reclosing attempt. For multiphase faults as well, protective relays open the three phases of the breaker permanently. As such, the transmission capacity through the line is lost after a permanent fault or multiphase fault. During the summer, there are higher probabilities of transmission line faults resulting from weather events and increased lightning activity.

C. Power System Studies

GSE constantly studies the power system to identify problems [3]. Given the criticality of the 500 kV system, the lines of exceptional importance to the country have been identified. Studies have been completed that consider the loss of transmission lines or transformers, for example, fulfilling the N-1 criterion [3].

Highly probable contingencies include the loss of a single generator, transmission line, transformer, dc link, and so on. Medium probability contingencies (like the loss two or more generators in a power plant) and low probability contingencies (like the loss of two transmission lines in different locations of the power system) are not considered. GSE has used this approach for several years, and there has been no indication that it is insufficient.

The power system studies conducted are power flow, short circuit, voltage collapse, stability, and harmonics. These consider the single contingency (N-1) criterion to assess the possibility of an nonsecure power system. The contingency does not necessarily have to produce cascading tripping (angular and frequency stability) or overloads in equipment (thermal overload). The power system voltage levels need to stay within permissible margins after the contingency.

D. ECS Contingencies and Actions

Fig. 4 illustrates the main 500 kV lines. The Enguri HPP is the main source of power in the system. In certain scenarios, the connection to Russia is also a considerable source of power. The loss of the transmission corridor from the west side of the country (generation) to the east side (load) is the main concern for power system stability.

Another concern is the loss of the tie lines to Russia or to Azerbaijan. The power system will generally be connected to one of the two countries. Very seldom will Georgia be connected to both countries at the same time. Therefore, the loss of ties to Russia or Azerbaijan implies switching from a synchronized and larger power system to an islanded mode of operation.

The loss of generation (especially the Enguri HPP and the eastern Unit 9 power plant) is another concern. Losing generation unbalances the power system. As new power plants are commissioned in the future, the ECS will have to consider more generator loss contingencies, and the actions will be significant.

The criteria used to determine the actions that the ECS should perform consider the power balance after a contingency in the west (generation shedding) and in the east (load shedding). The precontingency power flow determines the actions that are necessary.

For example, if the Imereti line is lost, the line precontingency loading determines the amount of load to disconnect as well as the amount of generation to shed. The details of the logic are described in the following sections.

Georgia plans to participate in the European Union power market. Therefore, contingency detection and actions need to be coordinated with neighboring countries. For example, in Turkey a similar scheme detects the loss of generation and a signal is sent to the ECS to take action. These external signals (from other power systems) are also contingencies that the ECS must consider and act upon.

III. Evolution of the ECS

GSE operates a very unique ECS. It represents the evolution of the system since the ECS was installed in 2011. The system started with a very simple distributed logic scheme [1] and later a sophisticated centralized logic scheme was added, keeping the distributed logic scheme as a backup.

A distributed logic scheme does not concentrate the decision logic (rules of the ECS) in one device. The action logic is instead distributed in many devices on the power system. Fig. 5 illustrates the design.

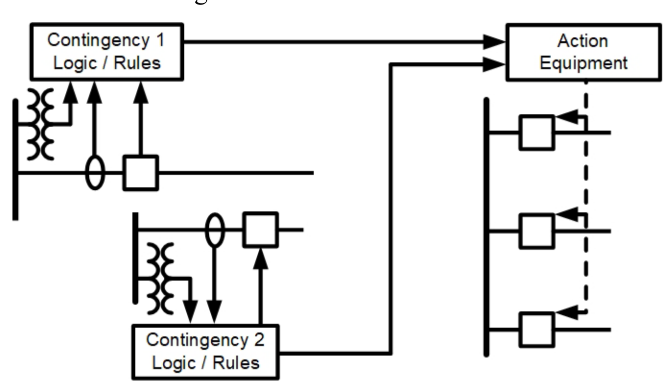

Fig. 5. Distributed Logic Architecture

The distributed ECS has proven to be very reliable for GSE. It was designed to make the appropriate decisions mostly with local measurements. In this scheme, the detection of the contingency and the interpretation of the rules reside in a local controller.

The centralized architecture, shown in Fig. 6, concentrates the logic and rules of all the contingencies detected. For this architecture, monitoring and detection equipment are in each location where the contingency is detected. The fact that the logic resides in a single device makes the centralized architecture more suitable for using the wide-area information coming from SCADA. GSE uses the power system information, for example the real power flow, in the load feeders and generator output measurements to feed to the central controller. These SCADA measurements can be used in a distributed architecture, but with a lot more effort. Centralized architecture is more suitable for this interface to SCADA.

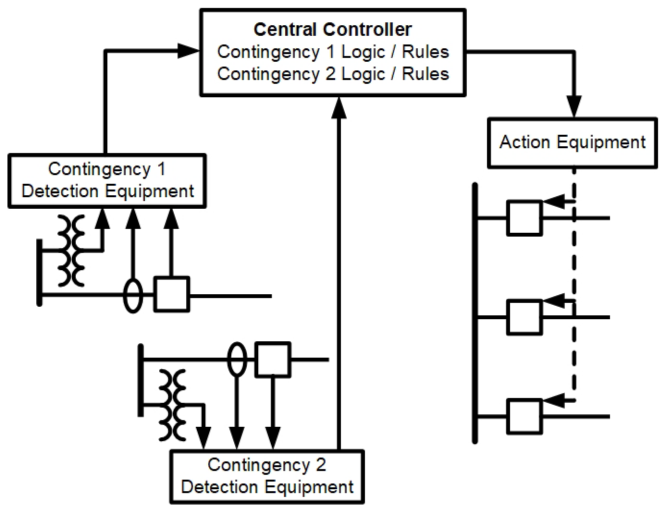

Fig. 6. Centralized Logic Architecture

Wide-area protection and control schemes tend to be centralized [6] [7] [8]. The distributed architecture is ideal for smaller schemes, simpler logic, and as a starting point in the evolution toward more advanced protection and control schemes.

A. Genesis of the Georgia ECS

At the time of the original ECS implementation, Georgia's power system was subject to multiple blackouts and brownouts per year [1] [2]. The transmission infrastructure was significantly weaker than it is now (Fig. 1). The power from Enguri HPP had only one path in the 500 kV corridor. The loss of either the Imereti or Kartli-2 transmission lines meant a high probability of the power system becoming unstable, especially during high power flows.

Several non-technical issues had to be considered when proposing the ECS solution shown in Fig. 7. The budget required a simple and straightforward solution. Fig. 7 illustrates genesis of the distributed ECS in the GSE network. It was built on a network of managed Ethernet switches that link all of the involved substations, including the seven load substations in the Tbilisi (load) region that each include a load-shedding controller (LSC). Two controllers, C1 and C2, located in the Zestaponi and Ksani substations monitor the loading of the transmission lines P_{Ime} and P_{Kr2}, respectively, as well as the status of the breakers for the respective transmission lines. A generation-shedding controller (GSC) is located at Enguri HPP. Reference [1] describes this system in detail.

In this simple solution, the rules and decision-making logic are distributed. The controller (C1, C2) functionality was developed to provide security and speed in the detection of contingencies. This concept led to the expansion of the system.

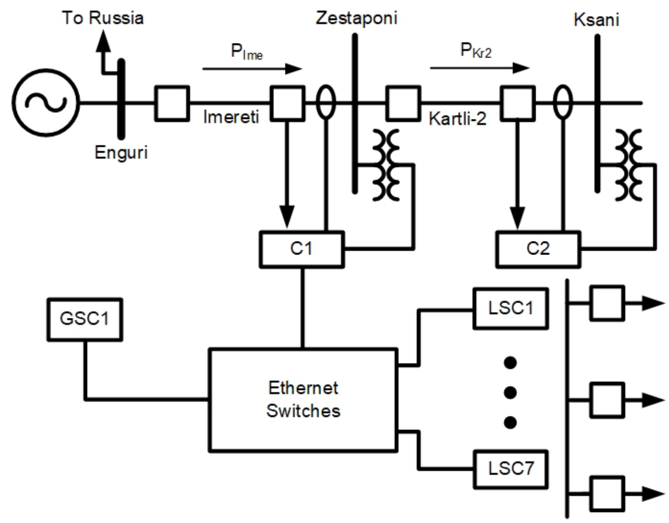

Fig. 7. Original ECS [1]

B. Controller Contingency Detection Logic

The two controllers for the system in Fig. 7 must reliably and securely detect the sudden loss of a transmission line. Manual opening of breakers with insignificant power flow should not trigger the ECS. At the same time, it is necessary to use all possible indicators to determine when a line has opened suddenly.

Fig. 8 provides a simplified diagram of the controller contingency detection logic. The contingency is the sudden opening of the line.

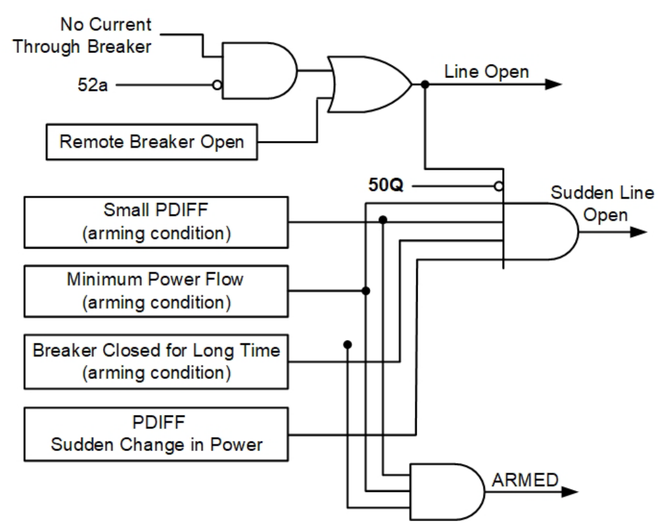

Fig. 8. Contingency Detection Logic

1) Line Open Signal

The breaker position and absence of current indicate that a line is open. To increase security, the choice was made to physically use the 52b breaker status contact (normally closed and, fortunately, the only one available in the GSE installations). This is negated in the logic to obtain the 52a signal shown in Fig. 8. This is because the loss of the dc power supply to the binary inputs of the controller does not result in an incorrect indication of the breaker being open. Moreover, supervision with overcurrent elements with a very fast reset (the same ones used for breaker failure logic) ensures quick recognition of the physical opening of the line.

The breaker status contact input should only provide indication if the three poles of the breaker are open. The three-phase 52b contacts should be connected in series and then input to the controllers. If 52a contacts are used, these should be connected in parallel.

Although a single 52a signal is shown in the figure, line disconnect switches are also considered. The disconnect switches of the line bay should be properly accounted for.

If the remote breaker indication is available, it is qualified as well with the remote breaker currents before being transmitted.

2) Negative-Sequence Supervision

A contingency is declared only when the three poles of the breaker (or breakers for breaker-and-a-half schemes, for example) have opened. GSE, and most transmission utilities, use single-pole tripping. The opening of a single pole for a ground fault, and the posterior single-pole open interval, should not activate the sudden line open signal. In Fig. 8 the 50Q negative-sequence overcurrent threshold is shown as an input to the final AND gate, but it is applied in the arming conditions.

3) Arming

Arming the contingency detection logic creates further security. When the logic is armed, the logic is ready to use physical breaker status logic and a sudden change in power to identify the contingency. Arming also ensures that the ECS is starting from a steady-state power system and not from an unstable or transitioning power system.

The three chosen arming indicators are as follows:

- Small PDIFF (change in power flow): The power flow in the line is monitored by the measuring algorithm of the controller. The measuring algorithm creates a "memorized" power flow, which has a lengthy time constant (in the range of one second). The difference between the memorized power flow and the instantaneous measured power flow is the incremental power, or PDIFF. The power system under steady-state conditions should have a very small PDIFF.
- Minimum Power Flow: There should be a minimum power flow in the line to arm the logic.
- Breaker Closed for Long Time: A timer, in the range of one second, qualifies the breaker being closed for a long time.

4) Sudden Change in Power

The ECS should declare a contingency for the sudden loss of a transmission line. The sudden loss of a transmission line carrying real power creates a very large PDIFF.

The security considerations described in this section have proven to avoid false indications to the ECS. During maintenance, substation reconfiguration, or other activities that involve work near or with the controller circuits, a false indication is not expected.

C. Distributed Controller Power Flow Logic

In a distributed architecture, rules are implemented in the controllers. GSE decided to base the controller logic on the measured power flow of the transmission line being monitored [1]. For example, the C1 controller, which monitors the power flow of the Imereti line, implements six power thresholds based on the real power flow in the line.

Based on the real power flow before a contingency happens, the C1 controller sends a signal with the encoded power level through the communications network. The load controllers in Fig. 7 (LC1–LC7) receive the encoded power level and relate it to the preprogrammed power levels for each load in the load controller. A feeder in a substation opens if the received power level is greater than or equal to the programmed level. The generation in the Enguri HPP will also be tripped so as to affect the minimum number of generators possible. No generation runback is possible because there is not enough time for the controllers to maintain the stability of the power system.

D. Growth and More Complex Requirements

Since the commissioning of the basic ECS shown in Fig. 7, Georgia's power system has evolved and it will keep doing so [3]. The ECS shown in Fig. 7 was effective in reducing the number of blackouts and brownouts [2], but it had limitations and had to evolve with the power system.

One limitation that needed to be addressed was the discrete load-shedding levels. The six levels possible in the scheme were not granular enough, and more load than necessary was shed. The generator shedding in Enguri, as well, required a more careful consideration to avoid tripping more generators than necessary.

The generator loads and the power flows of the load feeders are known in GSE's SCADA system. GSE decided to incorporate a centralized RAS (C-RAS) to provide measurements of all the load feeders and generator levels to the SCADA system. The C-RAS, being centralized in one intelligent device as described in Fig. 6, can implement complex algorithms with more data. It can accurately calculate the number of load feeders and generators to disconnect in the Enguri HPP because it has all the necessary measurements from SCADA.

The existing logic in the distributed controllers (C1 and C2 in Fig. 7, for example) is still used for contingency detection. The distributed ECS logic is still implemented as a backup distributed RAS (D-RAS). Although the D-RAS may seem unnecessary, GSE has found that the scheme covers certain operational situations that the C-RAS does not, which are as follows.

1) *Loss of the SCADA Link*

GSE has experienced data loss from their SCADA system. This situation disables the intelligent load selection in the C-RAS. If more than 30 percent of the required data are lost, the C-RAS is disabled and the D-RAS takes over. The loss of SCADA information can be caused by the following:

- Loss of the direct link between the SCADA and C-RAS system (during maintenance, for example).
- Loss of the link between one or more substations and the SCADA system.
- Restart or maintenance of the SCADA real-time servers.
- Loss of a remote terminal unit or gateway in a substation.

2) *Programmed Loss of the SCADA Link*

GSE is also working on improving their monitoring facilities. The centralized SCADA system in their main building will be moved to a different location. During the move, the C-RAS will be out of service.

3) *Programmed SCADA Upgrade*

The SCADA system for GSE will be updated to a newer system, which will cause a few days or even weeks of SCADA link unavailability.

4) *After the Operation of the C-RAS*

After a contingency, the information coming from SCADA is unreliable until it is updated. While this is happening, the C-RAS is disabled. The D-RAS system can be thought of as a backup scheme.

5) *Degraded Communications Network*

It has rarely happened, but, there is a chance of the communications network breaking in two because of the topology of the fiber-optic network. One section would be unable to send the contingency detection signal to the C-RAS. The D-RAS still a chance of carrying out some or all of the ECS actions. GSE considers any action taken by the D-RAS under these conditions to be beneficial to the stability of the power system, even if under this degraded communications network condition these actions are insufficient.

The D-RAS scheme is, therefore, a very important component of power system operations in Georgia. It originated from the simple system shown in Fig. 7 and has grown into a unique distributed control scheme.

IV. Details of the Distributed Protection and Control Scheme

The present implementation of the D-RAS covers all of the 500 kV lines shown in Fig. 4, as well as autotransformers, HVdc converters, and generators in the Enguri HPP. Its actions are based on the magnitude and direction of the real power flows and the statuses of certain remote lines. The same technique was used in the original implementation in Fig. 7. There are 35 intelligent electronic devices (IEDs) for monitoring, contingency detection, and action implementation that compose the D-RAS.

Table II illustrates the system components monitored and the possible remedial actions that the D-RAS can perform. For example, there are eight 500 kV transmission lines monitored in the system, and the loss of any of them would result in load shedding, HVdc control, and generator shedding.

Table II
Type of Contingencies Monitored and Remedial Actions

Component	Number	Possible Actions
500 kV line	8	Load shedding HVdc control Generator shedding
500/400/330 kV interconnection lines	4	Load shedding HVdc control Disconnection of other interconnecting lines Generator shedding if exporting
220 kV lines	1	Load shedding Generator shedding
Autotransformers	2	Load shedding Generator shedding
HVdc converters	2	Load shedding if importing Generator shedding if exporting
Generators	6	Load shedding

The D-RAS controllers implement the contingency detection logic described above, which is also used in the C-RAS.

A. *Redundancy*

Little or no redundancy was provided in the original design of the ECS. The original hardware of Fig. 7 is still in service and has not failed. The availability of the hardware has been very high since the implementation of the scheme.

Although no piece of hardware has failed, there is always a risk of failure. GSE has redundant devices in storage in case of failure and can quickly replace faulted equipment if needed.

B. *Control Messages Planning*

In a distributed architecture, the interaction between IEDs is higher than in a centralized architecture. Generally, the messages published by a control IED (C1 in Fig. 7, for example) need to be received by all or a majority of the IEDs in the network.

IEC 61850 GOOSE messages were selected to send the control and state information. The details of these messages are discussed in the following section.

Each controller publishes six binary bits for contingency detection and for reporting the power flow direction and breaker status. Fig. 9 illustrates the design concept of the distributed system, which uses a common data map. A common mapping of the six binary bits is sent from the controllers to the subscribed IEDs (the LSCs, for example). This makes implementation of the design simpler and ensures that a mapped bit in any of the subscribed IEDs has the same meaning.

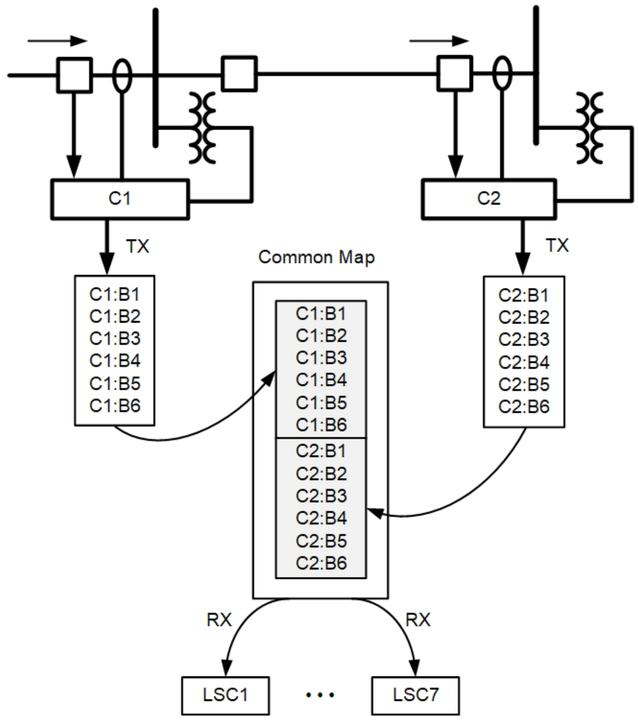

Fig. 9. Common Data Map

C. *Load-Shedding Logic*

The LSCs are subscribed to the binary bits published by the contingency detection controllers. The trip levels are determined and compared to the associate trip level programmed through the operator's human-machine interface (HMI), as illustrated in Fig. 10. If the HMI programmed level is smaller than or equal to the received level, then the trip output is activated to trip the associated feeder.

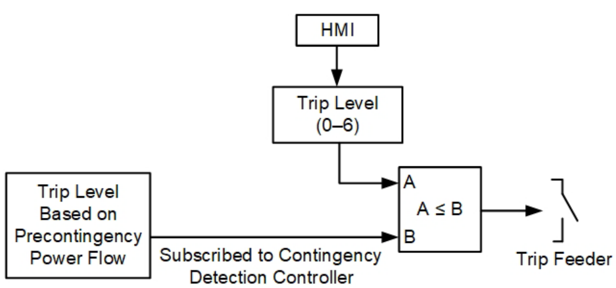

Fig. 10. LSC Logic

GSE has divided its power system loads into two regions. One region, near the Zestaponi substation (Fig. 1), uses six load-shedding levels. The other region, near the Ksani substation (Fig. 1), uses four load-shedding levels. Each load severity level is selected from the HMI (1–6 or 1–4). If a load is not to be considered for load shedding, the number assigned is 0. The load-shedding level is set by considering the maximum power that the load can consume. These load-shedding levels are replaced in the C-RAS using the information from the SCADA system of each load. The D-RAS system, with this load-shedding level scheme, requires more interaction with the user.

Physically, the ECS system provides one trip contact per load. GSE provides the means to disconnect the trip circuit using test switches. An operator in the load substation can manually disable the trip circuit to a load if necessary. During the commissioning of the ECS, the use of test switches to disconnect loads was very important.

D. *HVdc Control*

The HVdc link to Turkey, illustrated in Fig. 4, is a very important component in the overall control of the power system after a contingency. The logic to control the HVdc link to Turkey is also subscribed to the contingency detection controllers and the contingency identified. The severity (or trip) level is identified and based on this level, the logic selects a real power flow value to subtract from the actual real power flow through the HVdc.

The HVdc power output is determined by five levels called run limits. The HVdc output can only be set by these five discrete levels. The logic for the back-to-back HVdc installation identifies the new run limit from the result of the difference calculated. The whole process is summarized in Fig. 11.

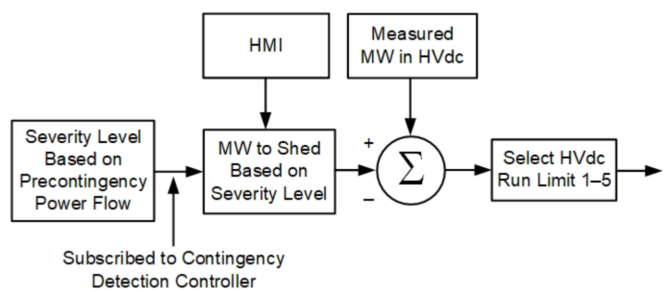

Fig. 11. HVdc Control Logic

E. *Enguri Generator Shedding*

Most contingencies in the ECS require the tripping of generation at the Enguri HPP to balance the western side of the country, where there is excess generation after a contingency. Fig. 12 illustrates the method used to reduce the amount of generation in the Enguri HPP.

Depending on the state of the power system, the contingency controller will send the required power to be shed. This is transmitted as an analog value in a dedicated IEC 61850 GOOSE message. The controller logic uses this number to calculate the number of generators that must be disconnected to match the required operating power. Once the contingency occurs, a trigger is sent from the contingency controller to start the tripping of the selected generators.

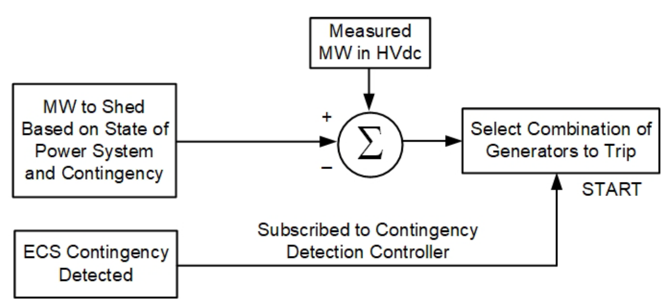

Fig. 12. Enguri Generator Shedding Logic

F. *ECS Future Functionality*

Most of Georgia's power system problems have been addressed by the ECS. GSE understands, however, that there are certain low probability occurrences that may need future consideration for the development of a more comprehensive control and protection system.

GSE is considering a backup scheme based on frequency measurements. This would ensure that if the ECS actions were not enough (or too much), the power system frequency could be used to take further action.

In some of the power system studies, simulations show voltage instability in some areas of the power system. The corrective actions to avoid voltage instability are to control shunt capacitors or reactors. This control can be considered to be part of the ECS. This remedial control logic will be implemented after the ECS has operated.

V. The Communications Network

GSE is fortunate to have a dedicated fiber-optic network for the ECS. All substations have access to the fiber network, making reliable communications possible.

The control protocol used is IEC 61850 GOOSE. It allows the transmission of binary and analog data in flexible data sets. The functionality of GOOSE is idea for a wide-area, distributed control scheme like the ECS described in this document. The transmission is multicast, from one server to all the clients subscribing to the data being transmitted. Since 2011, when the system in Fig. 7 was installed by GSE, the functionality has been as expected. The delivery of the control messages as well as the logic making use of them has been reliable.

The original system in Fig. 7, as a result of urgency at the time of its design, employed a network of managed Ethernet switches to create a wide-area network (WAN) [1]. At that time, there was very little consideration of some very important topics in the existing control networks:

- Cybersecurity: The switches were not fully configured, and it was relatively easy to access the network from any of the switches in any of the participating substations.
- Traffic engineering: The size of the system was small, and the traffic was left to the default configuration of the switches.
- Efficient use of the fiber bandwidth: The fiber-optic fiber pairs could handle a higher bandwidth than the standard 100 Mbps Ethernet traffic. The extra bandwidth could be used for other purposes.
- Time distribution: No provisions were taken to synchronize the IEDs.

The above considerations justified a utility-grade TDM network. TDM multiplexers capable of distributing time in all the substations with synchrophasor accuracy replaced the Ethernet switches. Moreover, sufficient bandwidth was assigned to implement an Ethernet WAN on the TDM network. The TDM WAN is used for ECS control messages. The additional bandwidth available in the TDM network was assigned to other critical functions, like line current differential protection for transmission lines at different voltage levels.

A. *Careful Traffic Engineering*

Technical papers like reference [9] describe proper engineering practices for Ethernet networks used for power system control and protection. Proper engineering considerations ensure reliable and secure communication of control messages using IEC 61850 GOOSE [9]. Virtual local-area network (VLAN) tags clearly identify control packets and are part of the Ethernet frame when used (see Fig. 13). Other fields in Fig. 13, like CRC (cyclic redundancy check), TPID (Type ID), and CFI (canonical format identifier) are shown for reference and are not relevant to this paper.

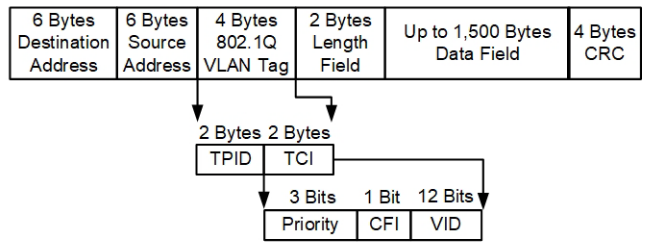

Fig. 13. Ethernet Frame With 802.1Q VLAN Tag [9]

The VLAN tag is used by Ethernet switch ports to identify packets that should be forwarded to other ports. This way, a managed switch allows the definition of the traffic that is needed in the network. Following are the most important reasons to implement traffic engineering of IEC 61850 GOOSE messages:

1) *Avoid Sending Unnecessary Packets to an IED*

The IEC 61850 GOOSE message protocol is a multicast protocol. The source IED publishes the packets and has no control over where these packets are routed. The network switches are responsible for packet distribution.

The subscribed IEDs will receive the packets and recognize them as useful information. The IEDs that are not subscribed, if they receive an unnecessary packet, still have to decode and identify the packet. This adds processing time for the IED, and if the network is used heavily, the IED runs the risk of receiving hundreds of useless packets that need to be received and decoded.

The VLAN tag in the Ethernet switches that controls port inbound and outbound traffic can be used to avoid unnecessary traffic reaching IEDs in the network.

2) *Segregating Traffic*

The ECS is implemented on a TDM network. Two Ethernet bandwidth pipes were defined to transport the necessary traffic for the system. One pipe was dedicated to the transport of VLAN ID-tagged packets. These are the control GOOSE messages, and only these are allowed in this pipe.

The second pipe transports all the untagged traffic, which includes any of the remote access protocols (e.g., FTP, Telnet, IEC 61850 MMS), to the IEDs.

This segregation ensures that non-control packets do not interfere with data packets that are transporting essential, time-sensitive control data.

3) Identify GOOSE Messages for Troubleshooting

Often troubleshooting is needed to understand the traffic reaching a certain port in the network. The VLAN tag can be unique when defining the structure of a control GOOSE message.

In the implementation of the ECS, the decision was made to clearly identify the IEC 61850 GOOSE messages by using the last octet of the IP address of the ID as the VLAN tag, the APP ID, and the last octet of the multicast IP address. For example, the IED with IP address *x.x.x*.11 is shown in Fig. 14.

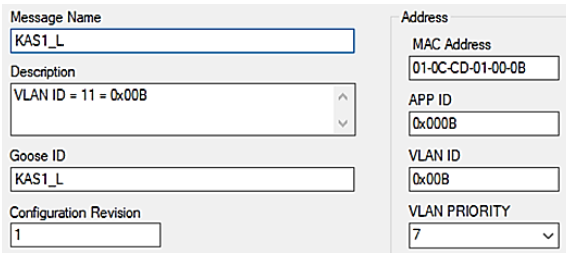

Fig. 14. VLAN ID Tag for an IEC 61850 GOOSE Message

While the VLAN tag alone is sufficient, the packets were clearly identified. Moreover, if more than one GOOSE message came out of the same IED and required a different VLAN tag, multiples of one thousand were added. For the IED in Fig. 14, VLAN tags of 1011, 2011, 3011, and 4011 were possible.

B. Time Distribution in the Network

Time for the ECS is not critical, but it can be very important for event analysis. TDM multiplexers can distribute precise time along the network. Two GPS receivers are in different substations, and the TDM network uses one of them as the reference to distribute the time to all the substations where TDM multiplexers are located and the other for backup.

VI. HMI for the Distributed ECS

The HMI of the D-RAS (see Fig. 15) has five basic functions. The first is the home screen, which has a general and simplified single-line diagram showing the entire power system of Georgia. This screen also provides access to detailed single-line diagrams of specific substations. Each diagram shows the statuses of the most important breakers and disconnectors of each substation.

The second function gives access to the D-RAS settings mentioned in Section IV-C. Over the same general single-line diagram, access is given to specific controllers and load-shedding priorities for each substation shown. Fig. 16 shows an example of the D-RAS settings function for the Kolkhida substation.

The third function is communications monitoring. HMI screens show the status of the IEDs and alarm for failures. The GOOSE subscriptions are also monitored on an HMI screen that reports any subscription failures.

The fourth and fifth functions correspond to the alarms and Sequential Events Recorder (SER) screens. The alarm screen shows a chronological list of alarm signals. When these signals are present, a blinking description shows on the screen. Each of these signals can be acknowledge or deleted.

The SER screen is a historical sequence of events of the system signals previously defined. It is stored in a first in, first out database and cannot be deleted prior to the defined time length for storage.

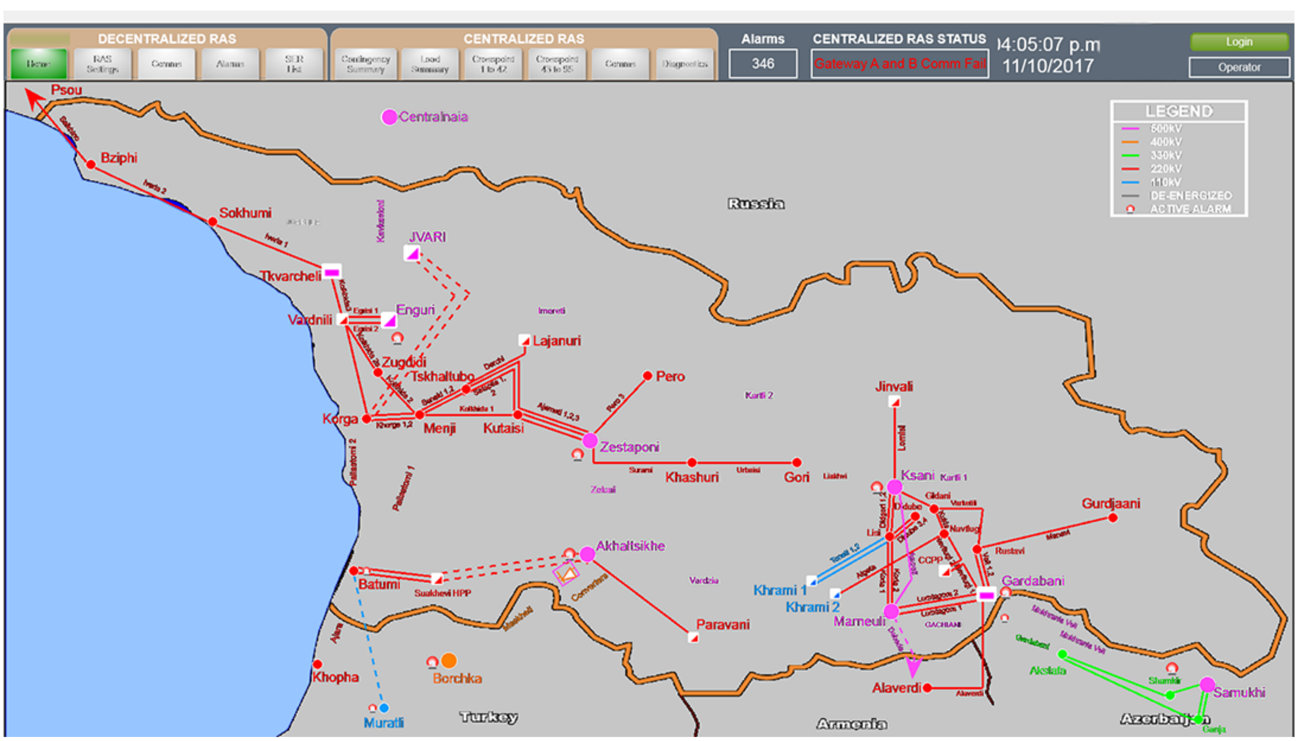

Fig. 15. HMI General Single-Line Diagram

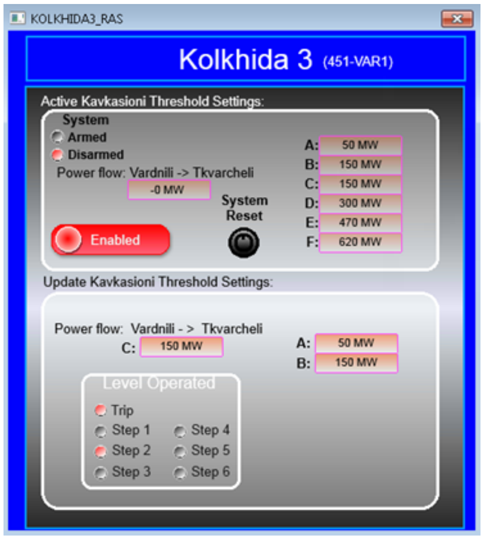

Fig. 16. Controller Setting Example for Kolkhida 3

The ECS HMI is located in the control center, and it complements the overall system SCADA HMI that system operators normally use to review the present the state of the power system. As mentioned in the previous section, SCADA information may not be available. The ECS communications channel has proven to be reliable, and the measurements and statuses of breakers are always available in this HMI. GSE system operators rely on this HMI when in doubt.

VII. Real-Time Simulation Testing

To validate the logic and evaluate the effectiveness of the D-RAS, the scheme was tested in a laboratory environment using a sophisticated real-time power system simulator. The GSE power systems studies group modeled Georgia's power system using software tools. This model provided the basis for the real-time simulation.

The advantage of the real-time simulation is that it is a closed loop. The control scheme directly influences the behavior of the power system. Fig. 17 shows the block diagram of the simulation hardware.

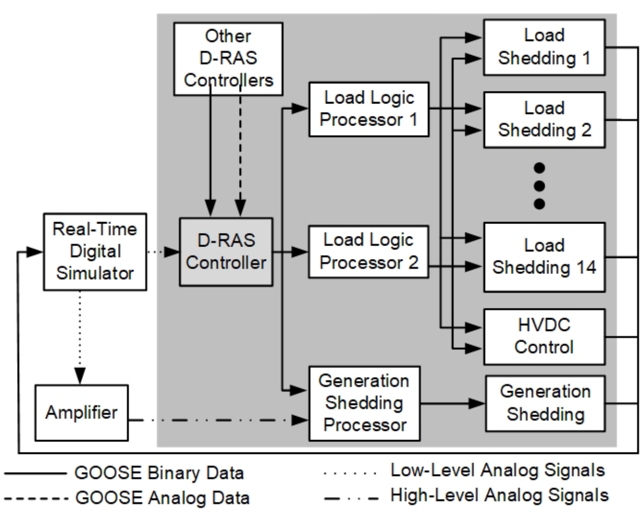

Fig. 17. Closed-Loop Test Configuration Example

The binary I/O required by the ECS controllers is simulated by hardware points wired to the devices in the system. All possible contingencies were simulated during the testing of the system. GSE was able to review the control logic programmed in the IEDs and approve the functionality. More importantly, the correct operation of the scheme during the simulation proved that the engineering of the system was proper.

VIII. Commissioning

A distributed scheme requires certain considerations for complete verification of its functionality in the field. Being distributed, the IEDs do not necessarily have to be accessed physically at each location. The communications network provides access to every IED of the scheme.

For commissioning, a scheme must be able to disable the action equipment output contacts. In the case of GSE, each load to be controlled had a test terminal, and each of the loads can be disconnected during the commissioning process.

The following steps are performed during commissioning:

- IED communications setup: Setting up proper communications to the IEDs of the scheme allows the devices to be accessed remotely.
- IED I/O verification: This step verifies that the IEDs are receiving binary values from the field (breaker statuses, disconnect switches, and so on). The information seen in the SCADA HMI can be used as starting point.
- Loading of the IED configuration: Having remote access to the IEDs allows the loading of the configuration files to the IEDs.
- Control message verification: The IEC 61850 GOOSE communications between IEDs need to be verified to confirm that the devices are exchanging data and that no data packets are lost. IEDs can report the loss of control packets and provide statistics for this critical functionality.
- HMI verification: The HMI functionality should be verified and compared to the actual state of the power system.
- Simulation of contingencies: Each contingency should be simulated and the control actions (load trips, generator trips, HVdc controls, and so on) verified and acknowledged. The behavior should be the same as that documented during the real-time simulation.
- Enabling the system: Once the contingency detection has been verified, the system can be enabled.

GSE finalized the commissioning with a staged system test. The idea was to verify the operation of the whole scheme after the above steps were finalized. GSE selected a few contingencies to test and prepared a plan based on their experience. A particular line and loading (usually late at night) was selected to force a contingency. An operator manually opened a transmission line breaker (for example) to simulate the loss of a line. The ECS operated accordingly [1].

IX. GSE Experience With the ECS

GSE has been operating the ECS since 2011. Fig. 18 shows the number of ECS operations in 2014, a typical year.

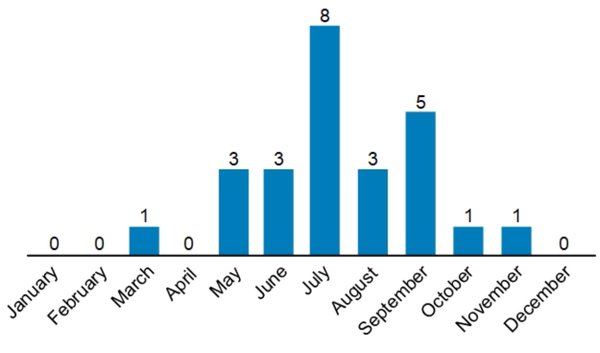

Fig. 18. Number of ECS Operations in 2014

Table III (same as Table I, repeated for convenience) summarizes the operations per year of the scheme and the number of blackouts and brownouts prevented by the operation of the ECS. The statistics include both the centralized and distributed ECSs.

Georgia's ECS saved GSE significant amounts of capital and prevented the consequences of power system would have had on the country.

Table III
ECS Blackout and Brownout Prevention

Year	Blackouts	Brownouts	Total
2014	14	11	25
2015	2	16	18
2016	9	15	24
2017	10	8	18
2018*	2	5	7

*As of July 2018

X. Conclusion

GSE has been successfully operating the ECS for the last few years and has improved the reliability of the power system [1] [2]. A distributed ECS complements a more sophisticated centralized system. The system started small and distributed. As a result of the growth of the power system, and other requirements, the system has become a very sophisticated wide-area protection and control system. GSE has learned the technology and understands its limitations and opportunities for improvement.

A reliable communications network, traffic engineering, and HMI are part of the distributed control scheme. The exchange of the control messages is well-planned. An HMI scheme is a part of the control center and is used by the operators.

A distributed control system can be the starting point of a more sophisticated scheme (based on remote measurements provided by SCADA and centralized, for example) and can serve as a backup scheme. GSE has found the distributed scheme valuable.

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XII. Biographies

Alexander Didbaridze received his diploma in electronic and control engineering from Moscow State Technological University in 1994. Upon graduating, he worked for nearly 11 years as an instrumentation and control (I&C) chief engineer for Gardabani Thermal Power Plant, a design and commissioning engineer for Enguri Dam Drain System, and an I&C engineer for Wood Group and Capital Turbines. From 2006 through 2011, he was the manager of the SCADA and emergency control system projects implemented by Georgian State Electrosystem (GSE). He has been involved in other projects linked to telecommunications systems and fiber-optic stringing on overhead lines. Since 2011, he has been the International Projects Technical Manager at GSE.

Vladimer Korganashvili received his first bachelor's degree in 2008 from Georgian Technical University in Power Energy and Telecommunications with a specialization in the management of fuel/power affairs. In 2010, he received a second bachelor's degree from Georgian Technical University. From 2010 to 2013, he served as a relay protection and automation department engineer for Georgian State Electrosystem (GSE). Since 2013, he has served in the System Automation department as head of the system automation section of GSE. He holds certifications in Power System Simulator for Engineering (PSS/E) local training and Computer-Aided Protection Engineering (CAPE) training in Germany.

Fernando Calero is a principal engineer in the Schweitzer Engineering Laboratories, Inc. (SEL) international organization. His responsibilities include application support for SEL products, training and technical support for SEL customers, and internal training and mentoring of SEL engineers. He started his professional career with the ABB relay division in Coral Springs, Florida, where he participated in product development and technical support for protective relays. He also worked for Florida Power & Light in the energy management system group and for the Siemens energy automation group. Since 2000, he has worked for SEL as an application engineer. He holds five patents and has written technical papers on protective relaying, remedial action schemes, and other protection and control applications.

Pedro Loza received his B.S.E.E. degree in 1998 from the National Autonomous University of Mexico (UNAM). He also obtained a M.Sc. degree in electrical power systems at UNAM. From 1998 to 1999, Pedro worked in the Electric Research Institute in Mexico. In September 2000, he joined Schweitzer Engineering Laboratories, Inc., where he worked as a protection design engineer and as a field application engineer in the Mexico City office. He is currently a protection engineer, working on protection electrical studies and special protection systems.

Alejandro Carbajal received his electronic engineer degree in 2008 from the Universidad Autónoma de San Luis Potosí (UASLP) in San Luis Potosí, Mexico. In August 2009, Alejandro joined Schweitzer Engineering Laboratories, Inc. (SEL) as a development engineer. After working in different areas of SEL, he specialized in automation and gained international experience working with various project architectures. In 2014, he joined the special protection schemes team in Mexico, working with remedial action scheme (RAS) projects. His specialty is programming different controller platforms for RAS automation.

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