Ensuring the Stability of the Belgian Grid With a Special Protection System

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Abstract—**Elia, the transmission system operator in Belgium, is responsible for the transmission of offshore wind generation and international high-voltage direct current (HVdc) power importing and exporting through a corridor. Most of this electrical power (~3 GW) has only this one corridor through which to flow into the European grid.**

The corridor is monitored by an advanced special protection system (SPS). In 20 milliseconds after the loss of the main 380 kV transmission path, the SPS ensures that the wind generation and the HVdc link are isolated and takes appropriate actions on the remaining corridor to prevent wide-area instabilities and damage in the islanded power system. Such instabilities could cause damage to the wind or HVdc installations and greatly affect the integrity of the Belgian and European grids, possibly causing blackouts or brownouts.

The SPS uses fully redundant components to ensure the security and dependability of the system for any single component failure and, for some functions, multiple component failures. Dependability is ensured by a distributed architecture for contingency detection (including detecting the sudden loss of the corridor) and tripping decisions. Arming logic and a voting scheme ensure the security of the system. The SPS uses a combination of Parallel Redundancy Protocol (PRP) and software-defined networking (SDN) in order to comply with cybersecurity and reliable communications requirements.

This paper discusses the challenges, the solutions, and the design details of the SPS, the focus on security and availability, and the hardware-in-the-loop testing of the whole system before it was commissioned.

The SPS has been in service since January 2019 and has not yet operated, which is normal for this type of scheme. The SPS has shown the appropriate security and restraint to external events and power system operations that require transmission line switching. Without the SPS, the power in the corridor would not be allowed to flow. The SPS ensures that the loss of the corridor does not impact Belgian power system integrity.

I. Introduction

Elia is a transmission system operator (TSO) and is active in electricity transmission. With main subsidiaries in Belgium and northeast Germany, Elia operates 19,300 km of high-voltage connections and 800 substations that supply power to 30 million end users, which makes the Elia one of Europe's top five largest TSOs [1].

Elia is connected to the continental European synchronous network, which is the most powerful synchronous electrical grid in the world (26 countries and 860 GW). Elia is at the center of it and a very important link for international power flow, which is increasing as generation becomes more decentralized.

A European goal is to achieve carbon neutrality before 2050. Consequently, integration of renewable energy sources is drastically increasing (specifically wind for Elia). Integration of more power electronics (renewable energy resources [RES] and high-voltage direct current [HVdc]) into the power system is creating challenges that must be solved with special engineering solutions.

II. Background

Members of the European Union are investing greatly in nonconventional sources. In Belgium, offshore wind generation projects have concentrated electric power generation on the ocean in the northwestern part of the country. Moreover, Belgium integrates with the United Kingdom (UK) through a dc cable, requiring an inverter (HVdc) installation in the same geographical area.

Elia performed steady-state and unusual electromagnetic transient (EMT) studies before construction to identify low-probability contingencies on the corridor impacting the Belgian system (e.g., blackout and/or brownout). These instabilities come from two nonconventional sources (wind and HVdc), which represent a challenge because unusual operating conditions leading to a low short-circuit ratio could result in damage to the wind and HVdc installations and blackouts in Belgium.

Elia is the operator of the power corridor that transports the associated energy. To reliably operate the corridor and protect against power system contingencies, Elia decided that a special protection system (SPS) was required.

III. The Power Corridor

Fig. 1 shows the single-line diagram of the Belgium power corridor. At peak generation, the offshore wind generation can reach 2,000 MW, injected into the system at Substation 1 (Sub 1). The exchange with the UK, at its peak, can reach 1,000 MW, injected at Sub 2. These two sources of power are delivered to Europe and Belgium through the substation axis formed by transmission lines from Sub 1 to Sub 4. The European interconnected grid is linked into Sub 4. The 380 kV lines and cables that carry the power, mostly in the direction shown in Fig. 1, are capable of carrying the maximum generated power, even individually. The alternate path of the power, via the 150 kV grid, is not capable of transporting the flow.

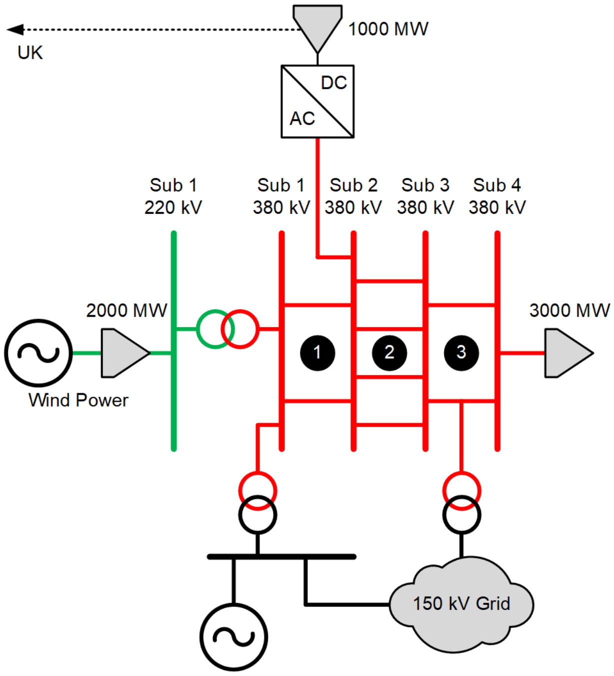

Fig. 1. Elia Power Corridor in Belgium

Having unconventional sources in the power system requires unusual considerations. Assuming, for example, the power flows through the corridor of the 3,000 MW in the same direction (towards continental Europe) as shown in Fig. 1, the power corridor is the only path for this power to flow through.

Wind power and the HVdc link do not have the mechanical inertia of rotating machines; rather, they have specialized control loops to fire the power electronics to invert the power flow from dc to ac. These control loops are feedback schemes that use the measurement of the voltage for reference (governed by the main grid). Moreover, wind generation is not a single machine, but hundreds of units in the offshore installation. Understanding and modeling the behavior of these wind generators when islanded from the main power grid is a very difficult engineering task. Further, the second major inverter source (HVdc link to the UK) is also controlled by feedback loops based on the reference voltage measurement governed by the main grid. It is a difficult task to estimate the interaction between the wind generation and the HVdc link when these are operating without the main path [1]. However, Elia was able to do modeling, perform simulations, and make some educated assumptions to show very quick and significant power oscillation that can lead to a cascading effect when the main path is lost. These studies also showed significant overvoltages and frequency oscillation that could damage equipment when wind farms and HVdc are islanded together.

The most prudent action to take is to totally disconnect the wind generation and HVdc conversion to avoid unwanted consequences when the power corridor is lost.

The SPS mission is to separate the power electronics as fast as possible when the loss of the power corridor is detected, as shown in Fig. 1.

IV. SPS Design

Given the importance of the power corridor, Elia determined demanding requirements for the design of the SPS in terms of speed, reliability, security, and redundancy.

No single point of failure was allowed in the whole scheme, and it required at least two equal systems in parallel. The failure of a single device should not prevent the flow of electrical power in the corridor.

The design needed to consider a voting scheme where the input status and output trip commands to the breaker had to be voted on, so a "two out of four" logic was implemented.

The operating speed of the SPS had to be less than 44 ms without the breaker operating time. The SPS should be designed with appropriate hardware to have fast reaction times.

Cybersecurity was an important consideration. The SPS scheme influence spans a wide area and includes several substations; unknown data traffic should not be allowed. The SPS measurements and control commands should not be able to be hacked or even allow unauthorized access.

The design included distributed controllers in the four substations. Human-machine interface (HMI) and configuration facilities had to be accessible in each substation, as well as from the Elia control center.

A. *Distributed Architecture*

The design is based on a distributed architecture that complies with the requirements in the previous section. In each of the four substations of Fig. 1, controllers executing SPS logic and monitoring are provided.

To account for the redundancy requirement, two equal and independent schemes are used. Certainly, this is the simplest answer to achieve continuity of service, even when an important component is lost. For the purposes of identification, the systems and their controllers are identified as A and B.

As this was a new installation, the corridor transmission lines were equipped with a significant number of fiber-optic pairs, with two pairs dedicated to the SPS. Fig. 2 shows the fiber-optic communications paths. The fiber connections of Sub 4 are physically connected to Sub X.

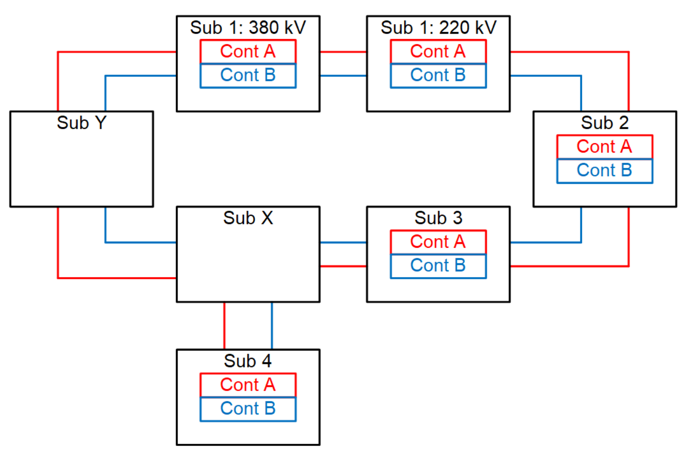

Fig. 2. Distributed Architecture and Fiber-Optic Communications Facilities

Fig. 2 illustrates the placement of the two logic controllers in each of the project substations for a distributed architecture, as well as the communications fiber-optic loop available for the project. The two systems are interconnected through their respective communications fiber optics. The measurements and status from any substation are available at the other substations. In a distributed architecture, the decision-making devices make their own decisions with the data from remote sites.

The use of the architecture allows for the programming of the controllers basically with the same program. The controllers execute the same program in all the substations. Minor differences are unavoidable, such as the binary output signal assignment to trip the breakers in the substations and the IP address of the device, but other than that, the controllers have identical programs running.

The fiber-optic loop provides redundancy in the communications. If the fiber breaks in some part of the loop, there is still a path from substation to substation.

Each line in both terminals has two line-monitoring devices: Line Monitor A (Linemon A) and Linemon B. In each substation, the line-monitoring devices measure power flow and breaker status information. These data are published in both networks and subscribed to by the local controllers and all the controllers in other substations. Fig. 3 illustrates the flow of information for the line-monitoring function. Each terminal has System A and System B line monitors. These publish the measurements to both of the local controllers (Cont), as illustrated in Fig. 3 in Terminal L. The local controllers use the information, as illustrated in Fig. 3.

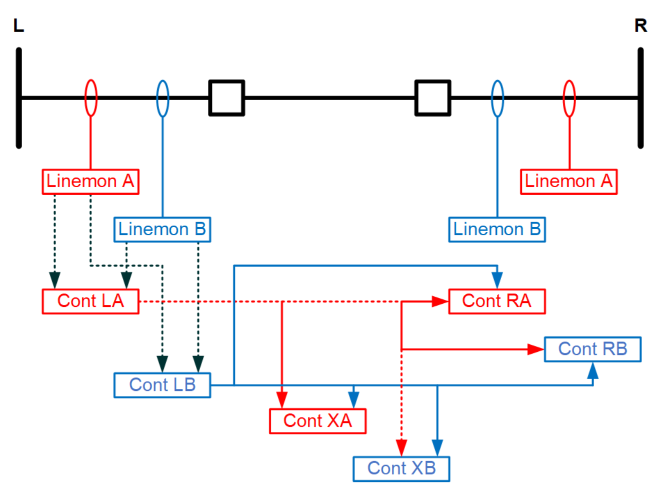

Fig. 3. Line-Monitoring Data Flow

There is no single point of failure in the architecture, and the failure of any single device in the architecture does not impair the operation of the SPS.

B. *Cybersecurity and Control Messaging*

Fig. 2 shows the availability of two equal fiber-optic loops. To provide redundancy in the communications, Parallel Redundancy Protocol (PRP) was selected [2] [3]. PRP transmits the same data message in the two networks. The receiving device uses the first message that arrives and discards the second one.

PRP requires that all the devices be compliant to the protocol. The Ethernet data packet is slightly modified to tag the messages from device to device. PRP ensures that packets are delivered if a single network fails (which could be the failure of a switch or a single fiber-optic connection).

Cybersecurity was very important in the expectations of the SPS. The design demanded that the traffic in the network be only monitoring and control commands. No other protocol or connection was allowed. Elia manages a company intranet that reaches all the substations and wanted to keep the access managed through its network. The SPS network is fully dedicated to the SPS communications.

Software-defined networking (SDN) is the appropriate technology to use to ensure restricted flow of monitoring and commands and to provide quick reconfiguration [4] [5].

SDN allows the engineering of the proper traffic in the network. It does not modify the Ethernet frame, and it interprets it and guides the data frame to the predetermined route. It implements deny-by-default security, meaning that any traffic that is not allowed by the network programming is rejected and not transported. It can be programmed with alternate paths if the main path does not allow the flow, and the reconfiguration takes less than 0.1 ms [4] [5], which is two or three orders of magnitude faster than Rapid Spanning Tree Protocol (RSTP).

Fig. 4 shows data flowing in the network using PRP and SDN. Each device in the system transmits data through two identical SDN networks, which PRP requires. The Ethernet packets are not modified but are qualified and routed by SDN, allowing only the monitoring and control flow.

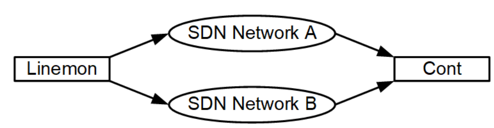

Fig. 4. Line Monitoring Data Flow

The choice of the above communications architecture provides the isolation of the control data flow from the Elia intranet and totally prevents any intrusion to any asset in the Elia system. It is a control systems network only.

With the PRP and SDN, there is no single point of failure in the fiber-optic network, not even when there is a rupture of an optical ground wire (OPGW). When the SDN ring is healthy; the ring sends the data counterclockwise in Fig. 2. If there is a break in the ring, SDN has alternate flows preprogrammed that route the data clockwise in less than 0.1 ms. Control protocols such as IEC 61850 GOOSE continue operating transparently, so the flow is continuous.

Since the flow of data and ports of the switches are clearly defined, any attempt to push data not preprogrammed can be identified and sent to a central SDN controller.

C. *SPS Functionality*

For successful contingency detection, every bay in the power system in Fig. 1 must be monitored, and power measurements and breaker status must be obtained.

1) Contingency Detection

The line-monitoring unit monitors the line and cable bays. The breaker status (52b) and line disconnect switch (89a) are also monitored. The voltage and current of the line are measured to monitor the power flow and the direction. The line monitor does not open, nor it does not have decision capabilities; it only reports the status of the bay.

The line monitor implements a simple contingency detection logic that signals the sudden opening of the line. It considers three arming and two qualifying conditions. The arming conditions require a few seconds for the flow to be in steady state (no transients), that the flow is above a minimum threshold, and that the breaker has been closed for a while. Once the logic is armed, the breaker status is monitored and qualified by the absence of current to declare a breaker open. Moreover, a sudden change of the power flow is required above a minimum threshold to ensure a proper decision. The contingency detection logic ensures security under operating conditions [6].

2) Voting Scheme

The measurements and binary statuses of the bays are sent to all the controllers in the system. Fig. 5 illustrates the exchange and redundancy.

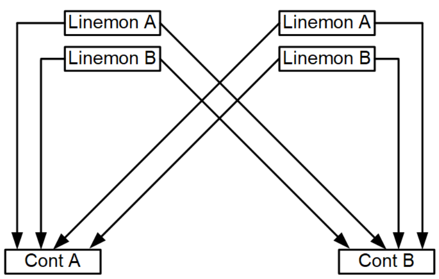

Fig. 5. Bay Status and Measurements Sent to All Controllers

The bay status is required to determine the line status. To determine that the line has suddenly opened, a voting scheme is implemented in the controllers. The idea is to provide an additional layer of security for decision-making. Fig. 6 illustrates the logic; it is essentially a two-out-of-four logic to assert the internal controller bit.

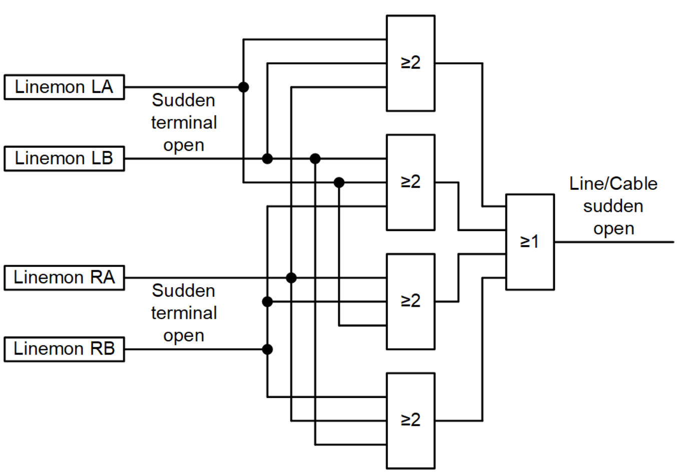

Fig. 6. Two-Out-of-Four Decision Logic

The two-out-of-four comparison is executed in every controller of the SPS, and for the analog values. The analog values are treated differently, however, because they need to be within a tolerance band, and the average is an output from the good values.

3) SPS Logic

The logic that enables the decision-making in the controllers is relatively simple.

The sudden-open (SOP) signal is the loss of the line under load, as described previously. The logic also considers the parallel lines out of service (open) to arm the SOP detection.

A tripping logic is used to assign the trip output contacts to open the breakers in the appropriate substations.

During the normal operation of the power corridor, there are different operating topologies possible. Certain breakers and buses can be disabled with disconnect switches, and the corridor can be split into two corridors. All the usual topologies can be covered with the logic described previously. Very special topologies not covered by the logic are covered by exploitation rules and procedures.

D. Operating Speed

A key parameter to the operation of an SPS is the operating speed. Usually, the breaker operating times are not considered, and it is only the decision-making time that needs to be documented. Most SPS and wide-area protection and control schemes base their requirements on power system studies [6]. In large power systems, it is common to require operating times of less than 0.1 second. In the SPS described in this paper, the request was for a system with an operating time of less than 44 ms. Due to the high-speed communications used (IEC 61850 GOOSE) and the fast controller operating time, the operating speed obtained was in the range of 14 to 20 ms after a line disconnected the corridor. The preliminary calculation considered 15 ms in the line monitor, 5 ms transmission and GOOSE message processing, and 3 ms in the controller, plus a margin. The measured time was better than the estimate.

E. HMI Operation

One of the challenges to overcome was the implementation of an HMI in all the substations. The HMI needed to be reproduced in every single controller. Taking advantage of the distributed architecture allowed the exchange of all measurements and status among all the SPS controllers. These ten controllers subscribe to the data published by other controllers. The multicast nature of the IEC 61850 GOOSE protocol and the SDN network allows the traffic from and to all the controllers in the SPS. The line-monitoring devices publish only to their local controllers.

Any parameter pertinent to the operation of the SPS, such as disabling the SPS or forcing a particular bay out of service, is first applied to the controller being operated and then published for updating to the other controllers and a synchronization logic to ensure each controller has the latest data are implemented.

F. *Security and Dependability*

Security and dependability are objectives in any power system protection scheme. As will be described in following sections, the hardware-in-the-loop (HIL) testing proved many of the concepts proposed for the scheme. The system was made secure by the "two-out-of-four" logic and the arming logic described previously.

The dependability aspect is emphasized by the repetition of the same logic in all the controllers and the redundant network. The trip commands reach the trip coils caused by the operation of the local controllers or the remote controllers that publish their trip decisions to all the devices.

The distributed architecture of the SPS allows many degrees of redundancy in different aspects of the operation. There is no N − 1 equipment failure that would prevent the system from being reliable, available, and secure.

Alarming and reporting functions are available in the HMI and to supervisory control and data acquisition (SCADA). Discrepancies in the two-out-of-four logic are reported and signaled. The alarm and reporting functionality received significant attention in the scheme to make the system reliable.

V. SPS DEVELOPMENT

Through numerous design development and review meetings, various components of the scheme were finalized, keeping in mind the speed, security and redundancy specifications. Given the criticality of the infrastructure and the need for continuous power flow through the corridor, it was imperative that the system be secure and not operate for any events other than specified contingencies. To ensure the highest level of availability, complete redundancy was preferred in the SPS. This requirement drove the necessity to use the redundancy not only at the hardware platform but also on the field data acquisition (such as independent current transformers [CTs], potential transformers [PTs], and breaker status for the A and B SPSs). Redundancy was also built on the communications architecture using PRP, SDN technology, and redundant communications paths; so, even in the majority of cases, this architecture can handle an N − 3 contingency. Cybersecurity, as discussed in the previous section, was achieved by the use of SDN and by designing the network flows in a way that only SPS traffic is allowed on dedicated optical fibers between substations.

Once finalized, the SPS design was implemented using the line-monitoring devices, SPS logic controllers, and network communication devices. The SPS design criteria called for a robust hardware platform, fast and easy-to-program controllers and line monitors, and cybersecure network communications devices.

A. *SPS Hardware*

The selected SPS hardware was packaged in the panel enclosure for each of the substations. Each substation received a dual-redundant SPS configuration (SPS A and SPS B) using identical panels. Fig. 7 shows the SPS panels with device arrangement. A single HMI monitor is shared by the two schemes. The user selects the SPS HMI from a particular SPS (A or B) through a keyboard video mouse (KVM) switch. Two panels, System A and System B, were determined upon in case of a catastrophic event on one panel at a given substation; the other remains active and no component of the other system is compromised. However, a single HMI monitor was chosen for the operator for the interaction with the SPS as a whole. A KVM switch is required to navigate from System A to System B; however, redundancy of the physical HMI in one substation is provided with laptop remote access to the HMI of SPS B.

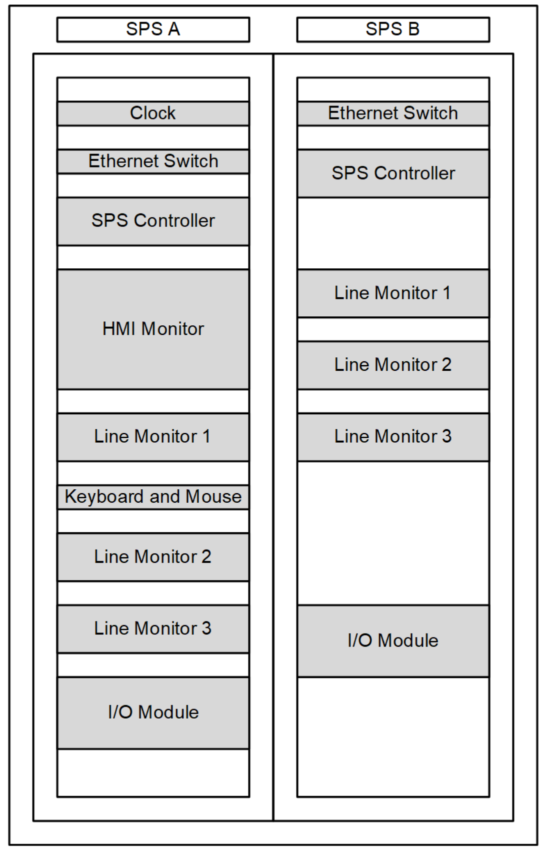

Fig. 7. Front View of SPS Panel System A (Left) and B (Right) for Sub 2

The devices within the panels were factory-wired to receive the field signals, such as line voltages, currents, breaker statuses, trip signals, and so on. SCADA commands and the SPS statuses were also wired from the panels for remote control and monitoring. Two satellite clocks, in different locations, send time signals through Precision Time Protocol (PTP) over the SDN network to all the devices in the scheme. The time distribution is fully redundant with PRP.

B. *SPS Logic and Scheme Implementation*

Various scenarios were studied during the design phase, and a base scheme was developed on the logic drawings that met all the requirements and specifications. The line-loss detection and the SPS logic, discussed previously, were then built in the programmable logic controllers.

A communications scheme for signal mapping and data sharing was designed using IEC 61850 GOOSE protocol that helped establish the connections between all the SPS devices.

A robust alarming logic was built to detect the failure of any component of the system that might render the SPS completely or partially inoperable. A minor alarm logic, indicating loss of SPS redundancy, and a major alarm logic, indicating complete loss of SPS at a given substation were developed. A logic controller in any substation is programmed to detect minor and major alarms at different substations and communicate them to the distributed control system (DCS) operator.

For wide-area communication between SPS panels, SDN flows were programmed in the network switches using PRP and a failover rerouting scheme.

A graphical representation of the Elia power corridor was designed for use in the HMI to monitor the system conditions and control the line bays to include or exclude from the SPS (i.e., put a line bay in or out of service from the SPS). The HMI also allows the user to include or exclude tripping bays (shunt reactor, transformer, etc.) from the SPS tripping so when the SPS trips, the bay that is out of service will not be tripped. The tripping bay is any bay that is tripped after the SPS detects a contingency. These specified tripping bays must open to isolate the wind generation and HVdc.

Additional functionalities, aided by the HMI, were also implemented in the logic, for example, to monitor the communications status and the health of SPS devices or enable or disable the SPS. All substation HMIs were programmed to synchronize with each other by sharing the data between the controllers so any action taken on one HMI is reflected and acted upon by all the other HMIs.

VI. SPS Validation with Real-Time Simulation

The SPS logic, using all substation panels, was tested in the lab with a real-time simulation using HIL. Real-Time Simulator Computer-Aided Design (RSCAD) software was used to build the model. In the RSCAD draft module, the Elia electrical system was modeled graphically, and data were assigned to points. A completed model, with graphics and data, was then designated as a "case." Once a power system case is built, the case is compiled on the real-time digital simulator (RTDS) hardware and then executed in the RTDS runtime module. All controls for interfacing with the model in real time are placed in this module. This includes, but is not limited to, sliders for changing set points, raising and lowering controls, breaker controls, fault controls, and plots for capturing data. The data captured from testing can be downloaded and saved for later analysis.

A. HIL Test Setup

The electrical model developed included all the substations on the corridor and transmission lines and cables connecting these substations. In addition, the offshore wind farm system and the dc link connecting to the UK were modeled using the manufacturer's data and previously studied models from the library of simulation software. The built system was completely validated using the short-circuit and load-flow studies to achieve accurate testing results. Moreover, another validation was made between the RTDS model results and those from offline simulation on PSCAD using library models provided by manufacturers of HVdc and wind farms, when available. Fig. 8 shows the test system modeled in the RSCAD.

On the control side, the model also included simulated protective relaying, tripping, reclosing, and interlock tripping to observe the interaction of the SPS with the existing protection system. In addition, breaker-failure and pole-discrepancy protection were simulated to observe the interaction with the SPS.

Line voltages, currents, and breaker status from the simulation were wired to the line-monitoring devices for each of the lines on the corridor as they would be in the field. Trip signals from the SPS logic controller were fed back into the simulation to complete the HIL setup. RTDS hardware (analog and digital input/output [I/O] cards) was used to facilitate this hardware and software interface. The RTDS testing of the complete SPS was one of the critical requirements for the deployment of the SPS in the field. The testing provided insight on the power system dynamics and proved the benefits of the SPS, including speed, security, etc. Fig. 9 shows the HIL setup that was built in the laboratory. All 11 SPS panels were positioned adjacent to each other in the lab, and the SDN switches in each panel were interconnected by the fiber-optic cables in the ring configuration. Two network rings, A and B, were formed. A test rack behind each panel facilitated the panel power supply and the digital signal connections to the I/O cards in the RTDS I/O cubes. The cubes shown in the setup also house the analog output cards that transmit the analog signals from the simulation to the line monitors in the SPS panels. All the I/O cubes then communicate with the RTDS hardware racks to transmit and receive the simulation data.

The key benefits of the HIL testing include the ability to test the real-time dynamics of the power system, study the system for extreme contingencies, save and study the results to validate the logic, and fine-tune the SPS logic parameters [7]. The closed-loop testing also allowed for testing the HMI functionalities and improving the ease of use for system operation and maintenance in the field, reducing the risk of human error. The operator training was conducted to quickly identify system alarms and failures on the system and perform basic operations.

During HIL testing was the only time when all the 11 panels were in the same room and where it was possible to simultaneously inject into all the cubicles. Now that panels are in the field, it is impractical to simulate full-system contingencies with the real panels.

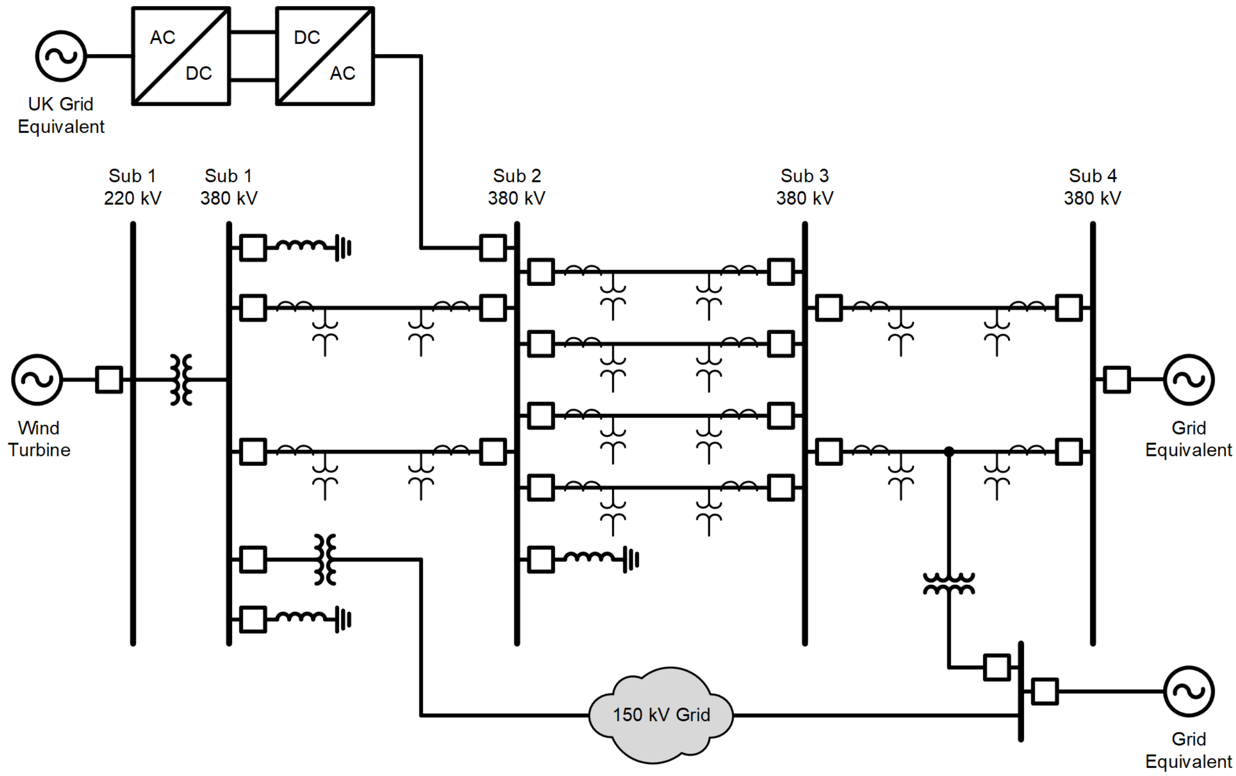

Fig. 8. Elia Test System for HIL Testing

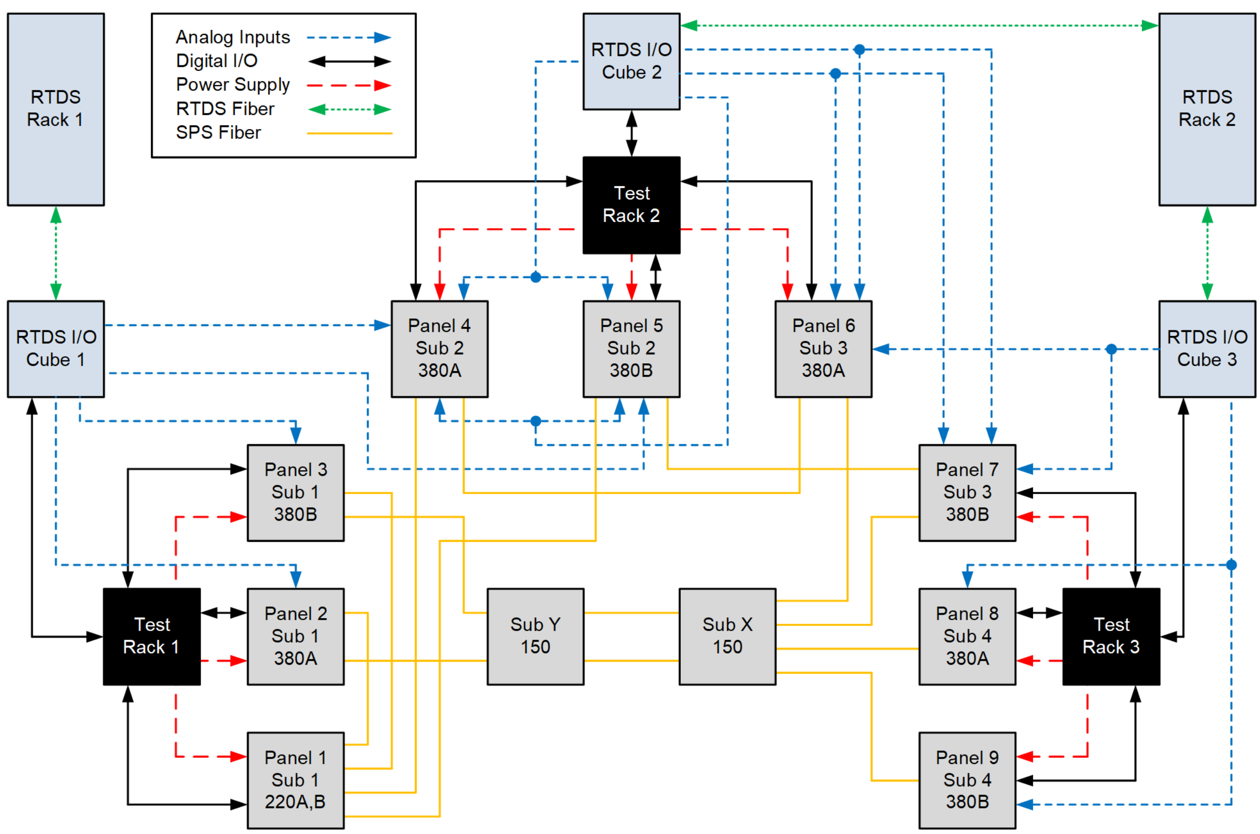

Fig. 9. Laboratory Test Setup for HIL Testing

B. SPS Verification and Results

All the SPS panels built for the field deployment were used for the lab testing. This gave an opportunity to test the SPS completely for various aspects such as logic, speed, failure, device integrity, and system operability. A structured approach was used for the testing.

1) SPS Panels Operational Testing

Point-to-point testing was performed to ensure the panel wiring was done according to SPS design drawings. Operational testing was performed to verify that all the devices were in working condition, the inputs and outputs were operational, and the satellite clocks were functional and distributed correct time stamps to SPS devices. After the operational verification, all the configuration files were programmed into the devices to perform the functional testing and network verification to ensure the SPS devices were communicating with each other.

Once the simulation was interfaced with the panels using HIL, verification was done to ensure transmission of correct signals to the line monitors. Signal mapping for the GOOSE signals was then verified to make sure that the controllers were subscribed to correct signals from the line monitors.

2) HMI Operational Verification

As discussed previously, the SPS HMI is used for monitoring the SPS status and performing control operations such as enabling or disabling the SPS or putting in or out of service any line or tripping bay for maintenance. Operational verifications were performed to make sure the SPS HMIs in different substations were synchronized. The following sections describe the verification.

a) Device Status Monitor Screen

Device status monitor screens were verified in all the HMIs to show the correct statuses of SPS devices. This was performed by plugging the communication cables in and out and power-cycling the devices. Fig. 10 shows the device status monitor screen during the verification testing. The devices highlighted in red indicate offline status.

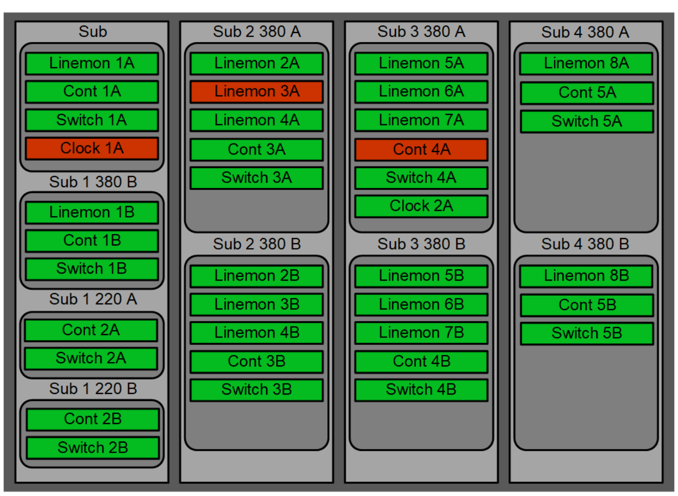

Fig. 10. SPS Device Health Status Monitor Screen

b) Line Status Monitor Screen

Line status monitor screens were verified in all the HMIs to show the correct statuses of the lines (e.g., bays in or out and breaker status). This was performed by issuing a control command from any one SPS HMI locally or via remote operation. When a line bay is taken out of service, it is not considered in the SPS contingency detection logic. Fig. 11 shows the status of the lines in the corridor along with the power flow through each line and the breaker statuses. The red box around the line breakers indicates the manual out-of-service status of the line.

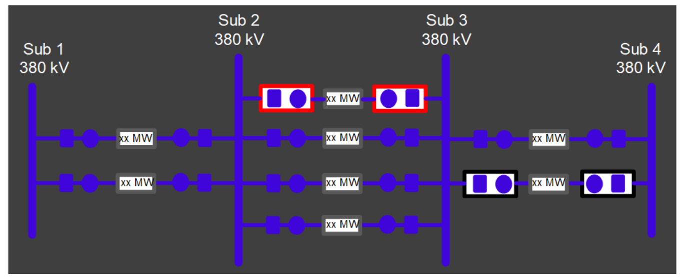

Fig. 11. Line Bay In/Out Status Monitor Screen

c) Trip Bay Status Monitor Screen

Trip bay status monitor screens were verified in all the HMIs to show the correct statuses of the tripping bays (i.e., bays in or out). When the tripping bay is taken out of service, it is not considered in the SPS trip logic if the contingency occurs. Fig. 12 shows the tripping bay status screen during the verification testing. The devices highlighted in red indicate out-of-service trip bays.

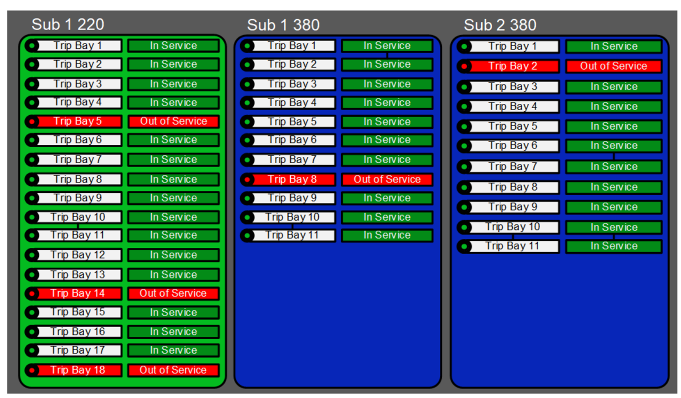

Fig. 12. Trip Bay In/Out Status Monitor Screen

During verification, SPS logic in the controller was observed in real time to ensure actions were detected and implemented by the controllers to not trip the out-of-service bays.

3) Device Alarming Logic Verification

To detect the loss or failure of any SPS devices, the designed alarming logic was tested for all the possible failures. Both minor and major alarms were simulated by various combinations, such as

- Turning the devices on/off.
- Plugging in/out the communication cables.
- Simulating CT and PT failures.
- Circuit breaker status failure.
- Loss of dc source.

These events were successfully detected by the alarming logic, and the appropriate alarms were verified on the HMI. The alarms on the HMI were declared for different categories, as shown in Fig. 13. Different colors are used on the alarms screen to indicate if the minor alarm is active and if the alarm is acknowledged. A major alarm is displayed as red when active.

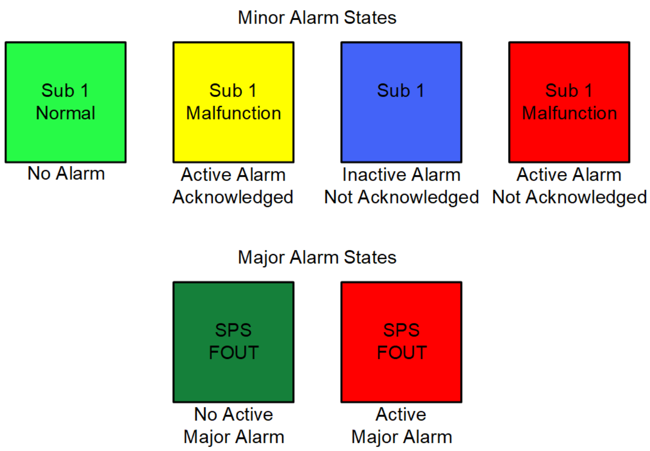

Fig. 13. SPS Alarm States on the HMI

The screen captures in the previous figures illustrate the interaction from any of the controllers in the SPS with a user. The same information is distributed to all the controllers, and substations.

4) SPS Contingency Testing

Various contingencies were simulated for the SPS logic testing. One of the scenarios tested is described in this section. The case was run with normal power flow of 1.8 GW from the wind farms and 1 GW imported on the dc link in a standard topology. The line designations are shown in Fig. 8.

A simultaneous three-phase fault was created on Line 11 and Line 12. Both Line 11 and Line 12 breakers opened at both ends in 60 ms, which included the protective relay operation time and the breaker opening time. Once the breakers opened, the line monitor detected the open position of the breaker, and the current through the breakers fell to zero. The line monitor consequently issued a SOP of the breaker signal to the controllers. The waveforms in Fig. 14 and Fig. 15 show the simulated fault currents from the wind farm models, built using library components from the simulation software. The waveforms suggest the damaging nature of the currents from the inverter-based sources. The signal names used in the plots are listed in Table I.

TABLE I
EVENT RECORD SIGNAL ABBREVIATIONS

Alias Word Bit	Signal Name
LXX_52A	Breaker closed status for Line XX
LXX_ARM	Line XX logic armed
LXX_OOS	Line XX out of service
LXX_SOP	Line XX sudden breaker opening
XASPSTR	SPS trip from SPS A of Sub X
XBSPSTR	SPS trip from SPS B of Sub X

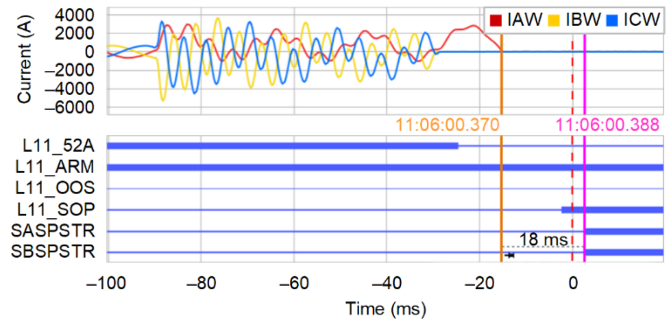

Fig. 14. SOP Detection of Line 11 (Simulated Waveforms of the Fault Contribution from Wind Farms)

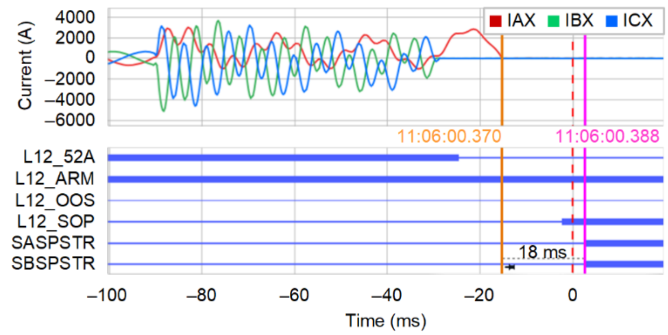

Fig. 15. SOP Detection of Line 12 (Simulated Waveforms of the Fault Contribution from Wind Farms)

The SOP bits of both lines are transmitted from the line monitors to the SPS controller via IEC 61850 GOOSE messaging. The controller logic detects a Contingency due to the presence of SOP on both lines by way of a two-out-of-four logic assertion. For this event, the SPS acted on the contingency and tripped all the breakers to isolate the wind farms and dc link from the rest of the Elia grid in 18 ms after the current on both lines decayed to zero after breaker opening.

Additionally, several other tests were conducted to completely validate the SPS logic under all expected power system scenarios. These tests included the following scenarios:

- Low power flow (near threshold)
- Reversing power flow direction to test the arming and disarming of the SPS logic
- Reclosing and breaker failure scenarios
- Maintenance scenarios with secondary CT injection on one line with fault on the other in-service line
- Special topology with decoupled buses

All the results obtained were satisfactory with consistent speed of response.

VII. The SPS in the Field

A complete factory-tested SPS was installed in all five substations. Once all the field signals for CTs, PTs, breaker status, and trip signals were connected, detailed functional tests were performed to verify that the field connections were correct. Secondary injection testing was performed for every CT and PT connected to the line monitors, and breaker operation testing was performed for every line breaker on the corridor that was providing breaker status to the line monitors.

Breaker trip tests were done to verify the tripping of the breakers from the SPS.

The SPS was functional after the connection of the fiber-optic cables. Before putting the SPS in service, a complete health check of the system was performed. The communication latency was observed and found satisfactory and within estimates.

At the time of writing this paper, the SPS is working securely and has been providing protection on the corridor for several months. It has not been called on to operate as the power system has not experienced any contingency. However, the authors were able to validate the speed of line-loss detection logic on the manual line-switching operations. The field results show a similar response on the speed of line-loss detection as obtained during the lab tests shown in Fig. 16.

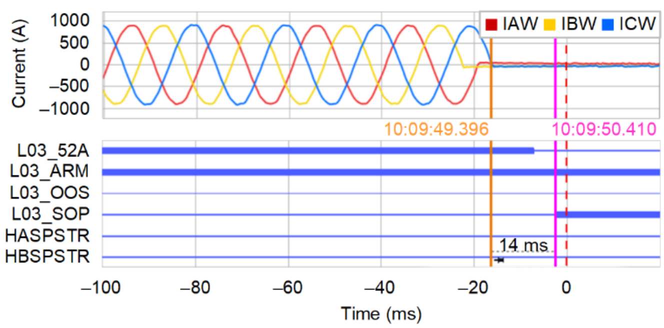

Fig. 16. SOP Detection of Line 03 (No SPS Trip)

Line 03 between Sub 3 and 4 opened manually. The line monitors detected the line loss within 14 ms after the currents dropped to zero. While Line 04 remained in service with the SPS armed, no SPS contingency was detected. See Fig. 17 for the Line 04 status.

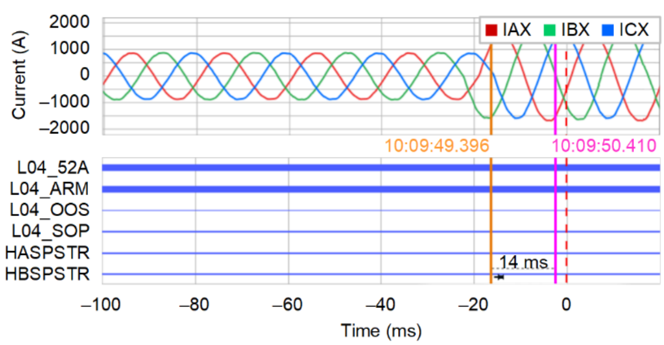

Fig. 17. Line 04 Status During the Line 03 Opening (No SPS Trip)

This event shows the security of the SPS for any event other than the specified contingencies.

VIII. Conclusion

This paper described a unique SPS scheme in detail. The considerations and requirements were solved with appropriate technologies to create a robust system.

SPS schemes are required in modern power systems to solve wide-area problems arising from the different operating conditions. In this case, it is the islanded operation of two nonconventional sources injecting significant power at the same time. The SPS described maintains the integrity and stability of the Belgium and continental European network, which is the most powerful synchronous network in the world.

Redundancy requirements yielded a high-availability system. There is no N − 1 contingency that can render the system inoperable. In fact, the communications network can tolerate many more contingencies and keep the system operational. The SDN and PRP combination creates a very robust network.

Cybersecurity was an important consideration in the design. The requirement that only control messages travel in the SDN network made it very simple.

The real-time testing was very helpful to debug the system and comply with the TSO operational practices and requirements. It allowed the fine tuning of the design.

The field experience operation of the system complied with the simulated scheme in the HIL testing.

IX. Acknowledgment

The authors are thankful for the support of Pavithra Gopinath and Chris Knox of Schweitzer Engineering Laboratories, Inc. (SEL) during the acceptance testing. The authors also acknowledge the contribution of Alicia Valero and Lidia Culianez of SEL during the field deployment and testing of the SPS.

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XI. BIOGRAPHIES

Rodolphe Hanuise manage his own engineering consultancy company specialized in electrical engineering at destination of industries and TSOs. He obtained his M.S.E.E. in 2008 from the Engineering University of Mons, Belgium. From 2008 to 2016, Rodolphe then worked for an international engineering company specialized in HV and MV network for TSOs and industries. He worked there as project manager, technical lead and manager in the following activities: electrical network design, substations design, renewable generation and OVHL design. In 2016, he joined the Belgian TSO, Elia, as Asset manager for Protection and automation being responsible of the creation, implementation and management of the related company's strategies. In this framework, he was technical lead, project manager and responsible of the SPS described in this paper. Beginning 2020, he created his own engineering company.

Cédric Moors received his M.S.E.E. (1998) and his PhD (2002) from University of Liège, Belgium. From 1998 to 2002, he took part to the development of a Special Protection Scheme against voltage instability phenomena in close collaboration with a well-known TSO in North America. In 2003, he joined the Belgian TSO, Elia, as a Protection, Automation and Control (PAC) expert. In 2009, he took the Head of the Asset Performance Analysis department, responsible for the analysis of events happening on the Belgian HV grid, including the response of PAC systems during faults. Since 2012, Cédric has been in charge of the Asset Management Secondary System department, where he currently leads the fleet strategy definition and the life cycle management of secondary systems solutions used by Elia. He is an active member of CIGRE B5 Study Committee, where he takes part to several working groups.

Fernando Calero is a principal engineer at Schweitzer Engineering Laboratories, Inc. (SEL). 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 and Light in the EMS group and Siemens in the energy automation group. From 2000 to 2019, he was an application engineer in the SEL international organization. His responsibilities included the application support of SEL products, training and technical support of customers, and internal training and mentoring of engineers. In 2020, he transferred to the R&D division and is working on analytic and operations software research and development. He holds 8 patents and has written technical papers on protective relaying, remedial action schemes, and other protection and control applications.

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