Performance analysis of centralized protection and control solution for a distribution substation

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1. Introduction

Centralized protection and control is a promising new concept for distribution substations, which has several benefits in comparison to the conventional relay-based approach. Consolidating multiple relays into one device reduces network complexity and introduces effective ways to control protection functions of the network. It is cost-effective and modern solution that also offers an interoperable platform, based on open standards like IEC 61850, for developing new network functionalities required in the future. However, before wider deployment of such solutions is feasible, it is important to analyze the performance carefully, so that most critical requirements in terms of protection functionality are fulfilled with this new concept.

Caruna, the largest electricity distribution system operator in Finland, and ABB piloted a concept where the protection system in Noormarkku substation was upgraded with a new centralized protection and control solution, ABB Ability Smart substation control and protection for electrical systems, SSC600. Caruna was looking for a flexible and future-proof solution for their network. As they invested more heavily in weatherproofing, underground cabling was added. Caruna needed additional protection and a more flexible solution. They chose to pilot ABB's new smart substation control and protection device. To meet new protection requirements and to benefit from the latest developments in relay technology, SSC600 was installed in Caruna's substation in Noormarkku.

2. Centralized Protection and Control concept

Modern medium voltage distribution grids impose multiple challenges for protection and control system:

- Primary equipment in the switchgear has longer lifetime than modern protection devices. This introduces the need to cost-efficient replacement of the secondary equipment.
- Renewables and distributed generation changes the grid during the switchgear operating lifecycle. This results that the behavior of protection must change more frequently than before.
- Lower SAIDI is required which forces changing overhead lines to cabling and higher level of automation. This causes that protection devices on existing substations need to cover different applications than before.

Main idea of centralized protection concept is to move protection and control from multiple bay level devices to a single central processing unit. As the advanced functionality is centralized, it makes updating and extension of protection and control simple and cost-efficient compared to modifying all the bay level devices. This high level of flexibility helps in all the challenges listed above.

Centralized protection and control concept itself is not new but only the advancements in CPU technology and international standards makes it possible to replace a modern protection and control system with centralized protection [1,2]. Complexity of modern protection algorithms requires extensive processing power and capability to ensure the real-time requirements of protection. Standards like IEC 61850 and IEEE 1588 enables highly compatible centralized protection systems but also demands quite much from communication networks and again processing capabilities. Because of the new technologies and high performance needs, it is essential to compare traditional protection and control to a new centralized solution. Simulation based viability assessment for the centralized concept can be found in [3].

Traditionally the protection has been distributed in multiple different devices ('Decentralized' in Figure 1). but in centralized protection and control all the safety critical intelligence is in one place ('Centralized' in Figure 1). For risk mitigation it is extremely important to consider possibilities for redundancy. Also, in centralized protection the modifications to the protection device might cause downtime for the complete substation if the device needs to be taken out of use.

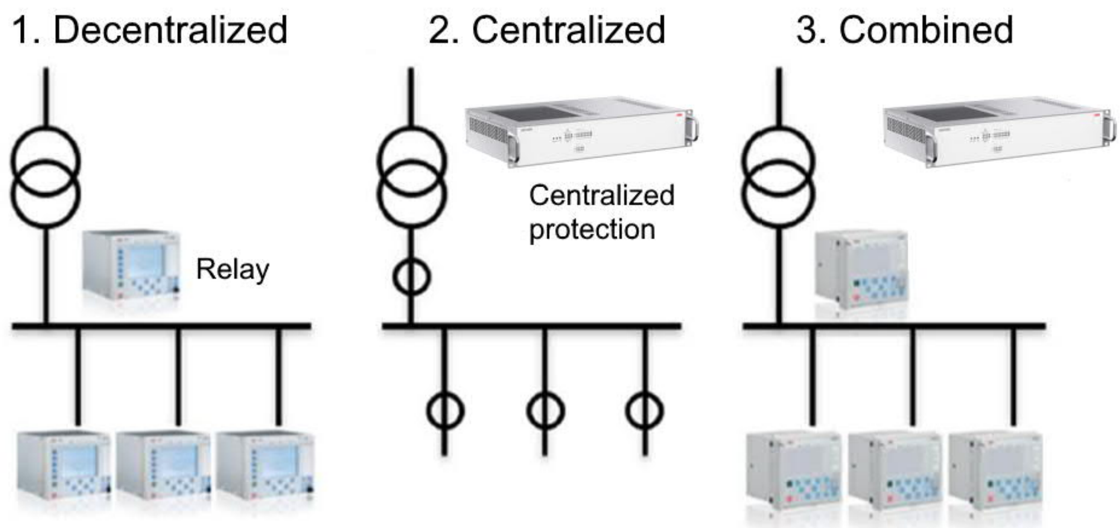

Figure 1 Substation architecture alternatives

Most obvious redundancy possibility is to duplicate the central device. This ensures that in case of device failure there still is a fully functional protection available. As the central protection devices can have identical configurations, the engineering and maintenance is still efficient. Also, during update procedures and testing, the redundant unit can handle protection while the other unit is out of service. For completely new installations this kind of duplicated central protection seems to be optimal solution.

Another redundancy possibility is to combine the good parts of both approaches by using bay level backup protection with the centralized protection. This approach is shown in the Figure 1 as 'Combined'. The idea on combined solution is to use simplified protection on bay level and all the substation-wide and advanced protection in the central device. Protection system still has the flexibility of central protection and control concept as new functionalities and extensions can be updated in a single location. Combined solution is also a good possibility for existing installations as adding just the central device can introduce new functionalities for the complete substation.

3. Pilot description

The pilot for the centralized protection and control was realized in cooperation with ABB and Caruna during 2017-2018. The main driver from Caruna side was the massive underground cabling that was being done for the network. Changing large shares of the network from uncompensated overhead lines to compensated unground cabling forced also changes to the automation system. Caruna was looking for a future-proof automation system, that could efficiently adopt to this and potential other future changes. A pilot was realized to evaluate, if centralized protection and control device SSC600 would help with these needs.

The pilot was realized in the substation of Noormarkku, near the city of Pori in Finland. The substation is 110kV/20kV substation with double bus-bar and one power transformer. The Single Line Diagram and feeder details, including the existing protection and control relays are shown in *Figure 2* and *Table 1*.

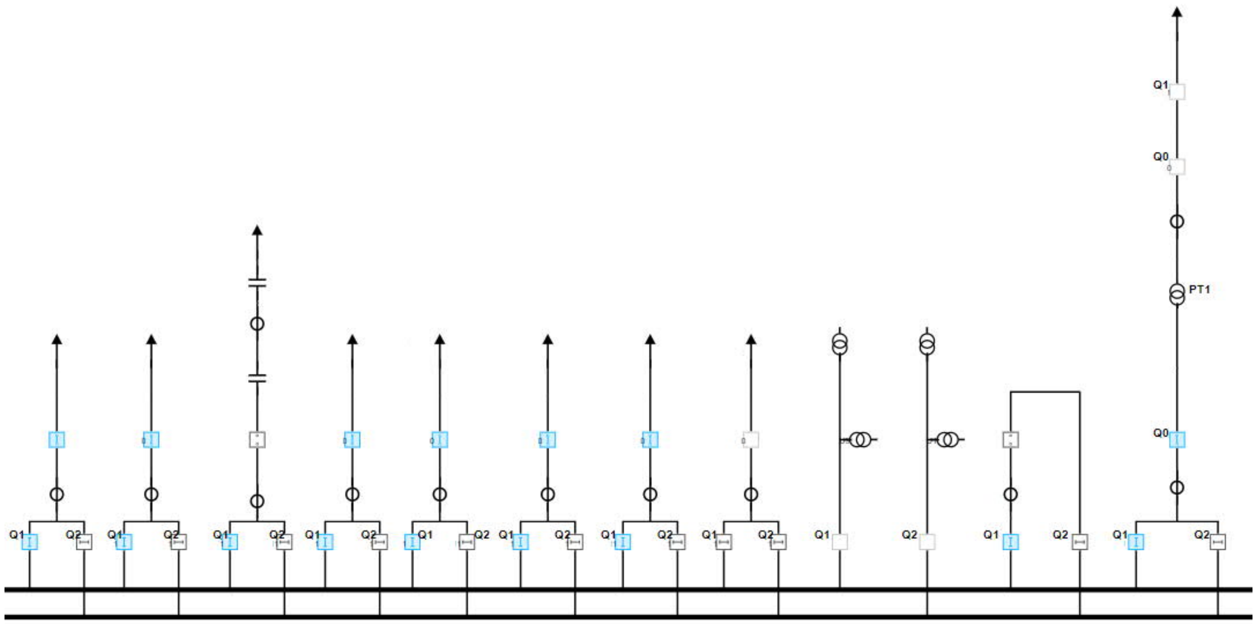

Figure 2. Single Line Diagram of Noormarkku

Bay	Description	Relay
#01	Incomer	RET630 (main protection) REF615 (backup protection)
#02	Feeder	REF615
#03	Bus-coupler	REF615
#04	Self-supply of the substation and voltage measurements	2 * REF615 (one for both busbars)
#05	Feeder	REF615
#06	Feeder	REF615
#07	Feeder	REF615
#08	Feeder	REF615
#09	Feeder	REF615
#10	Feeder	REF615
#11	Feeder	REF615
#12	Feeder	REF615

Table 1. Feeders in Noormarkku substation

Functionally the target in the pilot was to upgrade the automation functionality in the substation without large modifications to the existing protection and control relays. Due to extensive underground cabling there was a need to improve the earth fault protection in the substation, but otherwise the functionality in the existing relays was sufficient to current needs. SSC600 was made the main protection device and bay level devices remained as backup. Both REF615s and SSC600 had also identical protection settings, so that in SCADA level there was an opportunity to compare the approaches from the event list. Exceptions are listed below:

- SSC600 only hosted protection functionality. Control, Autoreclosing and Interlocking functionality remained only in the REF615s. The reason for this exception was, that only protection functionality required updates, existing control scheme was sufficient and did not require changes.
- SSC600 contained new multi-frequency admittance protection as the main earth fault protection [4], in REF615s only the traditional EF protection was present. Due to this the pilot was also a showcase of protection retrofit – an alternative way to bring new functionality to the substation without major change to the relay configurations.

For SSC600 device to communicate with REF615 relays in the substation, following extensions were needed to REF615 configuration. No firmware change was needed for the relays

- IEC 61850-9-2 LE Sampled Measurement Values (SMV) publishing was enabled from the REF615 relays
- IEC 61850-8-1 GOOSE sending was enabled in relays. All Circuit breaker and Disconnector position statuses were sent to SSC600. All Control functionality remained in REF615 relays, but the status information was used for SLD visualization.
- IEC 61850-8-1 GOOSE receiving was enabled in relays. A separate 'Remote trip' GOOSE signal was added to all REF615 relays, so that SSC600 had the possibility send trip signal via GOOSE messaging

An essential aspect of the pilot was to efficiently manage aspects related to cyber security. All substation devices including SSC600 were installed in a secure internal network, without direct connection to internet. Secure remote maintenance access with VPN and Firewall was realized by ARG600 Wireless Gateway product from ABB. In addition, the powering of the Wireless Gateway was set to be controllable via SCADA communication, with the principle that maintenance connection was normally powered Off and powered On only temporarily based on identified needs.

4. Commission and testing process

Commissioning was done in May 2017. The commissioning and testing had to be done in a live substation without interruptions. The network status at Caruna was such, that it was not possible to completely replace the substation with backup connections. Instead two feeders at a time were disconnected and commission tested.

Both SSC600 and relays were tested similarly based on standard commission testing procedures. A dedicated test equipment was connected to analogue inputs of the bay level relay. When fault current was injected to relay inputs, the relay was simultaneously publishing the measurements according to IEC 61850-9-2 LE and executing own internal protection functions. The acceptance criteria for each case was, that trip events both from bay level relays and SSC600 devices were correctly received by SCADA system, and that SSC600 device would not be slower than bay level protection.

During the first month SSC600 unit was only in monitoring mode. It was sending protection events to SCADA system, but it was configured not to send GOOSE trip signals to relays. After the monitoring period a set of field tests was made with a specific fault generation equipment, both permanent and intermittent earth faults were tested, see *Figure 3*.

Figure 3. Test equipment for intermittent earth faults

After the field tests were passed in June 2017, SSC600 was set as the main protection device of the substation and relays were left as backup protection.

5. SCADA integration

One additional question in the pilot was how to model a centralized protection and control device in SCADA level. All earlier substation projects had been based on bay level protection and control devices, and also in the case of Noormarkku the requirement was to keep existing relays and only add SSC600 to the SCADA configuration.

The SCADA system supported three level hierarchy for the data points from the substation – named B1, B2 and B3. With following definitions:

- B1-name 8 characters (substation level)
- B1-text 5 characters
- B2-name 8 characters (voltage level)
- B2-text 6 characters
- B3-name 8 characters (bay level)
- B3-text 20 characters

Traditionally with bay level relays the naming convention with the hierarchy has been according to *Table 2.*

<B1-text>	**<B2-text>**	**<B3-text>**	**<Element text>**
NOO	20kV	Bay #01	Overcurrent protection I>>
NOO	20kV	Bay #01	Earth Fault Protection Io>->

Table 2. Existing SCADA naming convention

In practice B2-level has not really been used for other purpose besides voltage level indication. For SSC600 purposes Caruna decided to separate SSC600 from rest of the system be defining a separate B2-level entity for centralized protection and control device SSC600, this is shown in *Table 3*.

<B1-text>	**<B2-text>**	**<B3-text>**	**<Element text>**
NOO	SSC600	Bay #01	Overcurrent protection I>>
NOO	SSC600	Bay #01	Earth Fault Protection Io>->

Table 3. Updated SCADA naming convention

In this way functionality within SSC600 can be distributed to different bays by using different B3-level titles, and it is still clearly identified which event comes from a station level device SSC600.

6. Analysis of the piloting period

The analyzed piloting period was 28.6.2017 – 2.1.2019. It started from the moment when field tests were finalized and SSC600 was set as the main protection system of the substation and ended based on initial agreement at the end of 2018.

During the piloting period there was in total 99 short circuits and 69 earth faults. From the short circuits 74 were cleared by the low stage protection, and 25 by the high stage protection. Summarized table of results is shown in *Table 4*, which also indicates which devices sent the trip signal.

Trip Device	**Earth Fault**	**Short Circuit**
SSC600 and relay	52	99
SSC600 only	17	

Table 4. Summary of analyzed faults

During the piloting period there were 17 earth faults which were only tripped by SSC600 and not by relays. No malfunction was found in SSC600 device, relay functionality either did not trip early enough or the fault criteria was not fulfilled. Also, the multi-frequency admittance based protection in SSC600 is more sensitive to some fault types, especially to intermittent earth faults, which may result in faster fault reaction. One such example of intermittent earth fault is shown in *Figure 4*, a case that was noticed by SSC600 but did not cause a protection system to operate.

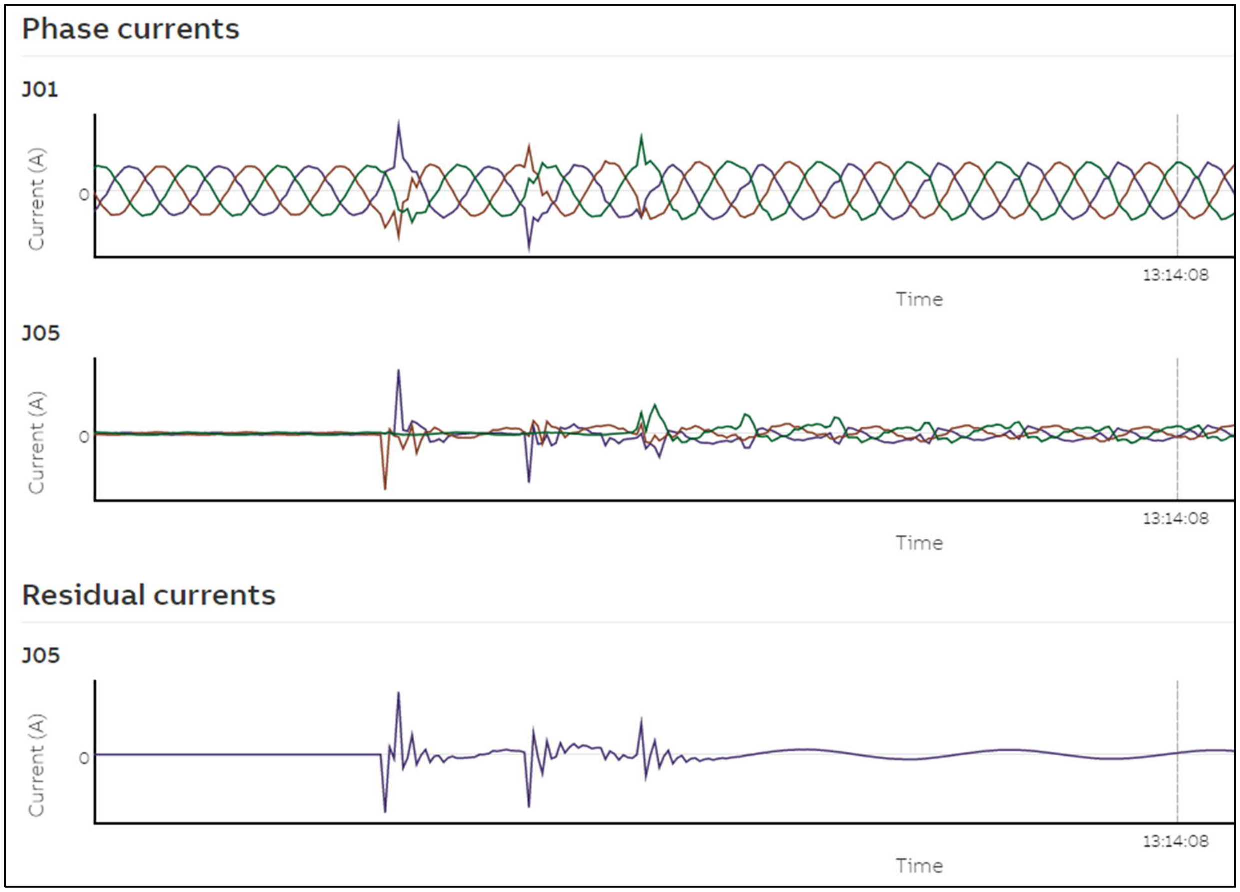

Figure 4. Example intermittent fault case from the piloting period

A more detailed fault breakdown by feeder bay is indicated in *Table 4*, which also shows that there were real network faults in all bays, so the application was extensively tested.

Bay	Earth Fault	Short Circuit
#06	13	5
#07	30	43
#08	14	3
#09	6	9
#11	3	27
#12	3	12
All	69	99

Table 5. Bay-level breakdown of analyzed faults

7. Summary

The pilot of centralized protection and control has been now operational for 1.5 years. In short, the results show that the centralized protection and control system has been reliable and efficient. During the piloting period there has been 99 overcurrent faults and 69 earth faults, which all have been successfully handled by the new solution. Operation is comparable to conventional relays, and the communication performance of IEC 61850-9-2 LE and IEC 61850-8-1 GOOSE fulfilled the protection needs.

The pilot was also a showcase of a modern retrofit project because the existing relay-based protection was preserved, and new earth fault protection functionality was introduced to the substation within one new SSC600 unit. Existing relays were left as back-up protection, it was not required to remove or replace them since they already supported IEC 61850-9-2LE process bus. This means that upgrade of substations can be cost-efficiently managed with centralized protection and control devices.

References

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