# SMART FAULT HANDLING IN MEDIUM VOLTAGE DISTRIBUTION GRIDS

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## ABSTRACT

*This paper presents first results from a pilot project on using fault indicators and self-healing in medium voltage distribution grids. Directional earth-fault indicators were chosen and deployed in real environments to test their functionalities and quantify their benefits for efficient grid operations. Self-healing concepts using these indicators will be tested in the described project. Different communication schemes will be explored in order to find the most cost-effective solutions. Theoretical potentials of the expected benefits of the fault indicators located at different positions in the grid were modelled and will be compared to the results from field tests.*

## INTRODUCTION

Smarter distribution grids will include new concepts based on intelligent sensors in the grid and efficient communication between these sensors and the distribution management system (DMS) [1]. One area that has drawn considerable attention is efficient fault handling in so-called self-healing grids [2]. This includes location and isolation of electric faults and automated restoration of the power supply [3].

We present here first results of the FASaD[1] project that prepares for large-scale implementation of a self-healing grid in a real environment. The main aim is to demonstrate that the use of directional earth-fault **indicators** connected to the Supervisory Control And Data Acquisition (SCADA) system, combined with remotely controlled switches and calculated distance to fault reduces the duration of fault location and thereby the interruption duration (SAIDI) and interruption costs considerably [4]. This combination is also expected to reduce the number of switching processes during the faults, resulting in fewer short interruptions (SAIFI) during the sectioning and fault isolation. The project is a cooperation between SINTEF Energy Research and five Norwegian distribution system operators. Field tests in the distribution grids of Hafslund Nett (HN) and Skagerak Nett (SN) are complemented with calculations of the theoretical potential for improving reliability of supply with a self-healing grid scheme. The underlying question in the project is whether the business proposition to invest in this new type of hardware in order to achieve more efficient grid operations is valid in this case.

## FAULT LOCATION

For a correct fault location, calculations based on short-circuit currents in the transformer stations are combined with signals from directional fault indicators that are deployed at strategic points in the grid. The short-circuit currents are taken from measurements in overcurrent protection relays (as opposed to impedance protection relays) in order to make use of existing infrastructure without the need for expensive physical upgrading. In general, all solutions are based on regular short circuit calculations with impedance as the unknown parameter instead of short circuit current. When properly implemented, the calculations, together with data from the Network Information System (NIS), give the distance of the fault from the transformer station.

Accurate results, however, require good data quality on impedances and topology. Special attention was given in the project to improved data accuracy and degree of automation of the calculations. It was found, for example, that some transformer stations do not have current transformers on all 3 phases on all feeders, which makes it challenging to distinguish between 2-phase faults (on the measured phases) and 3-phase faults. The effect of these uncertainties for real life faults was investigated and possible methods for overcoming this problem were evaluated. Examples of such methods are the use of parallel calculation of both 2-phase and 3-phase fault impedances on the actual feeder, as well as investigation of the use of PQ-units (e.g. Dranetz Encore) measuring phase currents at the transformers secondary outputs.

In a complex grid topology, the calculated distance to fault often results in an ambiguous position as several locations on a given branched radial can have equal distance relative to the transformer station. The fault indicators solve this problem by revealing the direction from the sensor in which the fault has occurred. Thus, the combination of both techniques allows precise fault location as illustrated in Figure 1.

[1] Norwegian acronym for the research and innovation project *Handling of faults and interruptions in a smart medium voltage grid*.

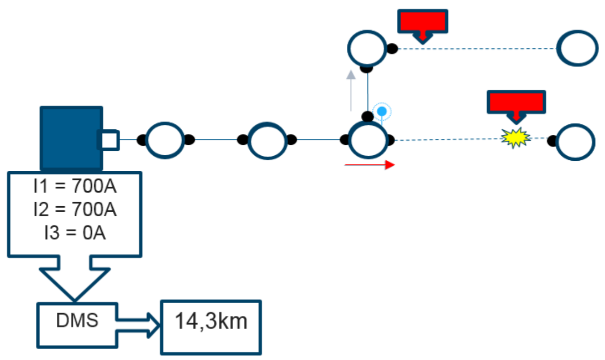


*Figure 1: Combination of fault indicator (red arrow) and distance calculation for exact location of faults in the grid. Red boxes indicate the ambiguity of fault location by calculating the distance only.*

Some fault types, such as 1-phase earth faults, are not trivial to be located with methods for distance calculation. Fault indicators with additional directional algorithms for earth faults can be used for location of this type of fault.

## TESTING FAULT INDICATORS

To evaluate the different possible deployment locations for the fault indicators, feeders where faults were likely to occur during the test phase were identified, based on failure data from the last years. Average yearly number of failures, the year-to-year trend and standard deviation were considered to evaluate a location's suitability for testing the equipment (Table 1). In addition, we did a qualitative assessment including grid topology, grounding type and expected digging activity that could increase failure probability.

*Table 1: Fault statistics for five of the test locations in SN's medium voltage distribution grid.*

| Feeder | No of faults 5-yr avg. | Std dev. | Trend[2] | Interrupt. Costs (kNOK) |
|---|---|---|---|---|
| **Feeder 1** | 5.4 | 9.5 | 1.8 | 304 |
| **Feeder 2** | 3.2 | 3.5 | 0.4 | 906 |
| **Feeder 3** | 0.6 | 1.5 | 0.5 | 255 |
| **Feeder 4** | 3.6 | 6.0 | 1.1 | 1 815 |
| **Feeder 5** | 0.8 | 1.5 | 0.6 | 232 |

Twelve different fault indicator models from six different suppliers were deployed in the project for testing in HN's and SN's medium voltage grid. The fault indicators were chosen based on the specific algorithm they use internally in order to identify the direction of the fault, the sensor technology and their ability to automatically adapt to changes in the network configuration.
The algorithms supported by the different indicator models were investigated. There are big differences in the number of supported variations between many models. An overview is given in Table 2.

*Table 2: Investigated earth-fault detection principles and algorithms.*

| Detection principle | Algorithm |
|---|---|
| **Fundamental frequency (50 Hz)** | *cos*(φ) (wattmetric method) [5]<br>*sin*(φ) (varmetric method) [5] |
| **Frequency spectrum** | 'Half rectified currents'-method [6] |
| **Transients** | Transient-method [7]<br>ICC-method [6]<br>Qu2- and Qui-method [8] |
| **Other methods** | 'Fast pulse'-method [9] |

In cooperation with the fault indicator suppliers, the indicators were parameterized to identify the optimal combination of algorithms. Based on these investigations it was found favourable to complement the traditional *cos(Φ)*-method with the transient method to increase the success rate on indication of both high-impedance and intermittent earth faults.
Two types of indicator implementations were deployed: models based on conventional current and voltage sensors and pole-mounted models based on measurements of the total electromagnetic field.
The hardware cost was only moderately assessed for this pilot run but is of course highly relevant for further large-scale adaption.
During the actual test periods information will be collected to analyse and verify the functionality of the fault indicators, the calculation of distance to fault, and the communication solutions. Data from the indicators themselves will be collected through the log lists. In addition to actually using the new functionality during fault handling, the operator checks if the fault indication and calculation of distance was correct or not, and if the communication functioned as expected. These data will be used to quantify the potentials, in terms of reduced number of switching and thereby reduced number of interruptions, as well as reduced interruption duration and interruption costs and be compared to the values predicted by simulations (see below).
The communication solutions are based on 4G/LTE from the remote terminal unit (RTU) through the SCADA protocol to the control centre. However, communication cost (RTU, modem, engineering) quickly becomes the limiting factor when it comes to the question of further deployment of fault indicators: The cost for communication equipment and setup may be many times higher than for the actual indicator itself. This is one of the reasons for also testing indicators with integrated communication in the project (e.g., Schneider F200C, Protrol, NorTroll LineTroll2500). In addition, possible integration of fault indicators into the radio based advanced metering system (AMS) now under

[2] *Trend* means the slope of a linear regression fit to the number of faults over 5 years, i.e. a positive number means an increasing number of faults.

implementation in Norway, using the EU standardized 870 MHz frequency spectrum is considered, thus limiting communication cost by making use of existing infrastructure. Considerably reduced communication costs are fundamentally important for future cost effective deployment of fault indicators on a scale that will give significant results in terms of reliability of supply.

## TESTING SELF-HEALING

A natural next step after deploying sensors and remotely controlled switches is to fully automate the process of isolating the fault and restoring power supply to the healthy part of the grid. This type of automatic system is commonly referred to as a self-healing system [2, 3].
There are two main approaches to self-healing grids and both are tested in FASaD: centralized and de-centralized self-healing (Figure 2) [10]. Both are based on collecting information from sensors distributed in the grid and decide proper actions based on this information and logic for self-healing. The main difference between the two approaches is where the logic is located. For a *centralized* system the logic/algorithms are integrated in the SCADA/DMS system in the control centre [10, 11]. For the *de-centralized* system, the logic is implemented in the RTUs [10]. The centralized system is closer to the traditional control centre (system and operations) and can be considered as a development of control centre functionality. The decentralized system is closer to the protection units and RTUs and may be considered as a merge of protection relays' and RTUs' functionalities [10]. Both centralized and de-centralized systems must be capable of responding to different types of faults and events, such as small local incidents like failure of a single component, chain-reactions where one failure leads to another and larger events like storms where many failures occur within a short time span. The systems must respond either with the appropriate actions or with a system inhibition. The latter is important to avoid automatic system reactions to faults which it is not designed to handle.

### Centralized self-healing

Centralized self-healing systems can be implemented in the control centre. Traditional systems like SCADA or DMS are examples of systems that may have this kind of functionality. These systems normally interact with operators that monitor the condition of the grid and take necessary actions when faults occur. With functionality as e.g., fault location, isolation and restoration (FLIR) the process is partially automated [11]. The centralized self-healing system uses the same communication network as DMS / SCADA to communicate with remote devices such as substation communication or AMS communication infrastructure. As the system is normally inside the same security zone as the control centre and the remote devices are normally on the outside, communication must pass the barriers in and out of the security zone.

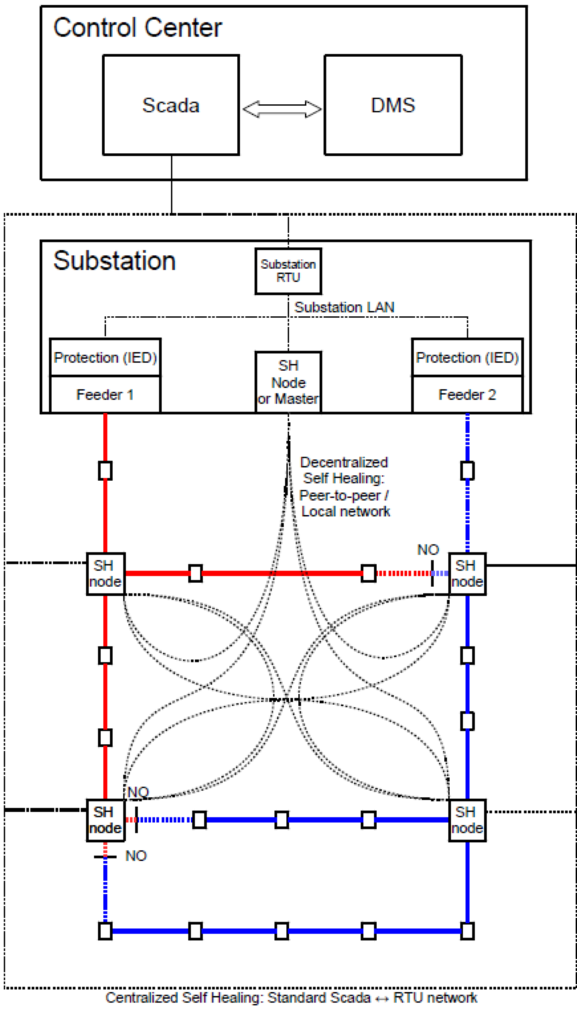


*Figure 2: Communication paths in decentralized and centralized self-healing networks. NO – normally open, SH node – self-healing node.*

In the centralized system, the algorithms can be complex and may cover a large scope of different scenarios. Changes to the grid are normally implemented in these systems, thus further adjustment is not needed to adapt the self-healing system to changes in the grid. While the centralized system is able to cover a small or a large part of the grid to isolate faults, down-time for the system impacts the functionality for the complete grid. As most DMS / SCADA systems today are based on open communication protocols, centralized self-healing systems are mostly non-proprietary.
The systems used to test centralized self-healing are *Siemens Spectrum SP4* (HN) and *Trimble DMS* (SN). In both cases, the DMS will collect information and select the appropriate actions to isolate the faulty part of the grid, and restore supply to the healthy part of the grid. However, as the actual operations will need to be carried out in the SCADA system, the autonomy depends on communication between SCADA and DMS on a level which is currently not available. To account for this, the centralized systems will be tested with an operator

transferring the operations from the DMS to SCADA, thus maintaining full control over the operations.

## Decentralized self-healing

Decentralized self-healing is normally implemented in distributed units like RTUs or IEDs (Intelligent Electronic Devices) such as protection relays. The systems can be based on either a main unit located, e.g., in the substation communicating with a number of sub-devices in the downstream feeder(s) in a local network or it can be based on a number of devices on a feeder communicating with each-other in a peer-to-peer network (Figure 2). Both types cover a limited part of the grid such as one or two feeders under a substation. One of the characteristics of such systems is the ability to be autonomous and independent of communication with the control centre. With both information and logic handled locally, the extent of the system is limited and can be adapted to each specific case, but will also be unable to act on faults outside of the system scope such as faults in upstream distribution or in other feeders connected to the same substation. Since the system does not depend on the control centre, it will increase overall robustness.
For the decentralized system, several suppliers offer systems with self-healing functionality but the specific solution differs between suppliers. The solution to be tested in this project will include two operation modes: One is based on interaction with the control centre so that the operator can verify the operations before they are executed. The second is based on autonomous operation, but with inhibition criteria such as autonomy blocking from the control centre.

# VERIFICATION OF POTENTIALS FOR IMPROVED GRID OPERATIONS

An important part of the project is to verify potentials for improving the reliability of supply. This verification will be performed in two ways: 1) for the test cases by collecting information during testing of fault indicators and self-healing, as described in the previous chapters, and 2) by a theoretical study of potentials using a methodology and tool for reliability of supply analysis, which is under development in the project.

## Reliability methodology

This methodology is based on the RELRAD-methodology [12] and the approach described in [4]. It is further extended in the project, incorporating the fault location procedure and taking the possible failure of the fault indicators themselves into account. This methodology will be used to study the grids where the tests are taking place and for fundamental studies for different types of grids.
In order to illustrate what kind of potentials can be expected, an example is described in the following.

## Sample grid configuration

The grid configuration used in the calculations is shown in Figure 3. It contains a single feeder from substation T1 with four distribution transformers (L1-L4). The feeder has back-up connections to a second substation (T2) in the same grid with open switches at L2 and L3 and to a different grid (R1) with an open switch at L1. There are two circuit breakers E1 (next to T1) and E2 (in the branch to L4). Simplified calculations of duration and costs of interruptions were done for manual switching and four different levels of automation:

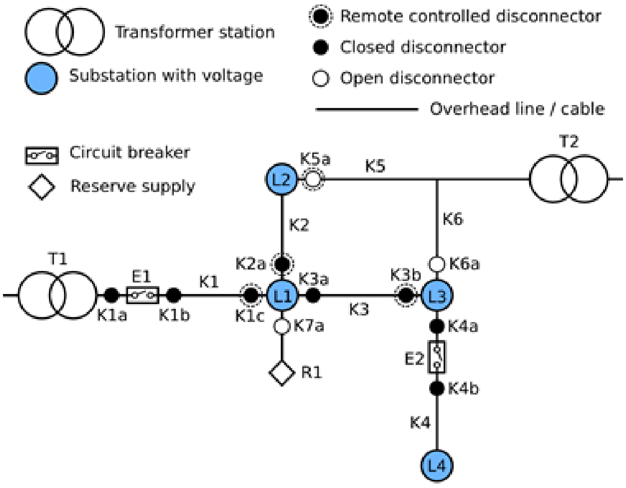


*Figure 3: Single line diagram of the sample grid used in the simulations.*

*Case A:* All switches manual, no sensors deployed.
*Case B:* All switches manual, fault indicators deployed.
*Case C:* Four switches remotely controlled, no sensors deployed.
*Case D:* Four switches remotely controlled, fault indicators deployed.
*Case E:* Full automation, self-healing grid.

Only line faults are included in the calculations. It is assumed that it will take 1 minute to operate the remote controlled switches, and 5 minutes for the manual switches, respectively. In addition, there is a turn-out time of 2 min/km. For case A, the estimated time needed for manual test switching and sectioning is based on assumed switching sequences: 28 minutes for K1, 19 min. for K2 and 20 min. for K3, respectively. For K4, only switching and turn-out time is taken into account and no test switching, due to the circuit breaker E2. In *Case B*, no test switching is needed due to the fault indicators. In *Case C*, the test switching and sectioning using the remote control is assumed to take only 3 minutes. *Case D* is similar to *Case C*, but no test switching is needed. Remote sectioning will take 1 minute. In *Case E*, all switches are remotely controlled and the sequence is fully automated.
Average interruption duration and costs at L1-L4 for the different cases were calculated and the results are shown in Figure 4 and Figure 5, respectively. As input to the reliability calculations, failure data from the Norwegian FASIT system is used [13]. Interruption cost data is taken from the Norwegian regulation, as described in [14,15].

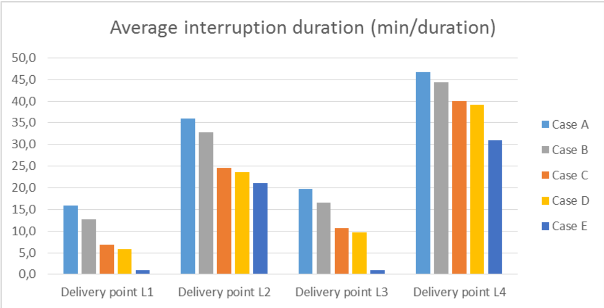


*Figure 4: Average interruption duration for the manual case and different levels of automation (see text for details.)*

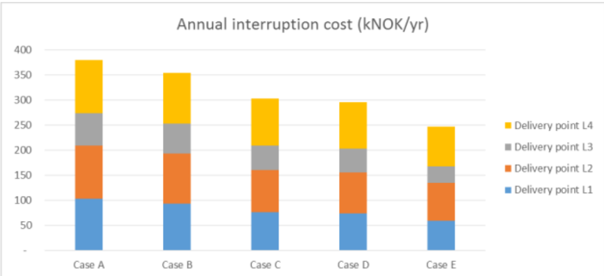


*Figure 5: Average interruption costs for the manual case and different levels of automation (see text for details.)*

There is a considerable reduction in the average interruption duration from *Case A* to *Case E* for all delivery points. The interruption cost is reduced by 35 %. Even in this simple example the benefits of the different steps from all manual (*Case A*) to fully automated (*Case E*) highly depend on the delivery points and the topology of the grid in question. This stresses the importance of careful analysis of the grid to find the best locations in order to guarantee the most cost-effective solution. In addition, the different automation steps generally have different effects on grid operations. While the introduction of fault indicators into an all-manual grid (*Case A* → *Case B*) has a significant effect both in terms of interruption duration and interruption costs, the introduction of the same indicators in a grid with remotely controlled switches (*Case C* → *Case D*) gives almost no added value without an automated switching algorithm (→ *Case E*).

## CONCLUSIONS

This paper presents first results from a pilot project on fault indicators and self-healing in medium voltage distribution grids. The choice of indicator model depending on the specific detection algorithm(s) used was described and the potential test locations were evaluated. At this point in time the deployment of the hardware is completed and the collection of data is about to begin. To supplement the field tests, a methodology for estimating the benefits of the technology was developed. It shows high potential <u>if</u> the location and automation scheme are chosen correctly. The results from this project will be implemented in methods and design guidelines for planning automated fault handling in smart grids and present a key success factor in optimizing grid investments in the future.

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