RELIABILITY ANALYSIS METHODOLOGY FOR SMART FAULT HANDLING IN MV DISTRIBUTION GRIDS

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ABSTRACT

Fault current indicators for detecting grid faults are important elements in smart distribution grids. The indicators can be used for smarter handling of faults and enable faster restoration of electricity supply, giving potentials for reducing both frequency and duration of interruptions in the electricity supply. A novel methodology for reliability of supply analysis has been developed, focusing on the effect of combinations of fault current indicators and remotely controlled disconnectors as well as self-healing functionality. Fault indicators and self-healing solutions are being tested at several locations in the distribution grid. This paper describes the new methodology and presents promising results from case studies on real MV distribution grids. Experiences from establishing the demo infrastructures are also described.

INTRODUCTION

A smart electricity distribution grid will include new sensors, communication and self-healing solutions for efficient fault handling and automatic restoration of supply [1], [2]. This gives potentials for improved work processes, reduced interruption duration and reduced interruption costs [3], [4]. Furthermore, it will be important to find the optimal number, location and type of devices to minimise the total costs of investments and interruptions (e.g., [4]). New equipment and functionality for better fault and interruption handling are currently being tested in the medium voltage (MV) distribution grid by a few Norwegian grid companies in the FASaD project. The first results of the project were reported in [5] . This include directional fault current indicators communicating with the control system, calculation of distance to fault based on various measurements in the grid, remotely controlled disconnectors and combinations of these into self-healing functionality. This will reduce the time needed for fault localisation and provide decision support for the operators enabling faster restoration of supply.

Apart from testing the equipment and demonstrating the functionality in the real grid, the project aims to verify the potentials for improving the reliability of supply, i.e., reduced interruption durations and interruption costs. To calculate the theoretical potential of the expected benefits of the new functionality, there was a need for incorporating the fault localisation procedure into the reliability of supply analysis.

RELIABILITY ANALYSIS METHODOLOGY

A novel methodology for reliability of supply analysis has been developed, focusing on the effect of combinations of fault current indicators and remotely controlled disconnectors as well as self-healing functionality. The methodology is designed for radially operated MV (11-22 kV) distribution grids, based on the RELRAD methodology for reliability analysis of distribution grids [6]. The new methodology uses event tree analysis and simulates the switching sequence for each course of events. It then calculates the fault localisation time based on the simulation of switching. By simulating the switching sequence, partial interruptions during fault localisation are also calculated. The input data for the study comprises of network topology, operating conditions, reliability data, interruption cost data and parameters for time calculations.

Simulation of events

The methodology starts by generating a list of all possible primary faults. For each primary fault the different courses of events are simulated based on the flowchart shown in Figure 1, as explained in the following.

The first three steps are similar for all faults. The simulation starts with the occurrence of a primary fault, the circuit breaker trips and automatic reclosure is performed. If automatic reclosure is successful, the primary fault is regarded temporary, and the event is closed. If the circuit breaker trips again after automatic reclosure, the fault is permanent and fault localisation starts. The fault localisation step is further elaborated in Figure 2.

The fault localisation procedure starts with identifying possible fault sections in the affected subgrid, which is the whole grid downstream the tripped circuit breaker. When selecting disconnector for sectioning, the criterion is to minimise the expected total hourly interruption cost in the

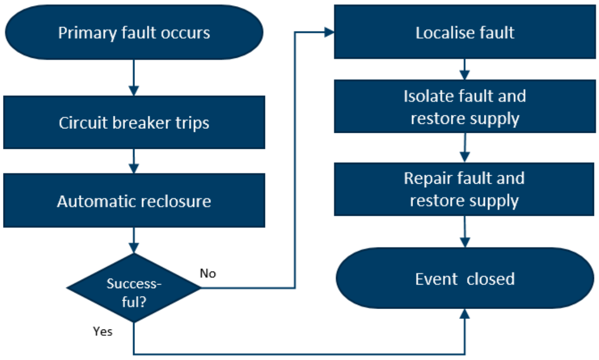

Figure 1 Flowchart for simulation of events

affected area after test reclosure. For each delivery point *n*, an average interruption cost per hour, c_n, is given. The interruption cost is calculated for different affected customer groups according to the Norwegian Cost of Energy Not Supplied (CENS) regulation scheme [7]. Total potential interruption costs in area *x* of the affected subgrid (upstream or downstream disconnector *s*) equals the sum of average interruption cost per hour for each delivery point in area *x:*

$$c_x^s = \sum_{n \in x} c_n$$

The probability that the fault occurred on component *j*, given a fault on the radial, is denoted α_j. The probability that the fault is located in area *x* of the affected subgrid (upstream or downstream disconnector *s*) equals the sum of fault location probabilities for all components within area *x:*

$$\alpha_x^s = \sum_{j \in x} \alpha_j$$

For each disconnector *s*, the expected value for the potential interruption costs within the affected subgrid after test reclosure, $E(K_s)$, is defined as

$$E(K_s) = \alpha_1^s c_1^s + \alpha_2^s c_2^s$$

where subscript 1 and 2 refer to the two areas of the affected subgrid, upstream and downstream disconnector s. The disconnector that minimizes $E(K_s)$ is chosen.

After each test reclosure, the probabilities α_j are updated. For each test reclosure, one of the areas *x* is confirmed healthy, the affected subgrid is reduced, and the possible fault sections are updated. Further, a check for possible reserve connections is carried out. If there are sections that can be isolated from the affected subgrid and the critical path between the circuit breaker and the affected area, and that can be resupplied by use of remote switches, these sections will be resupplied.

The fault localisation procedure is first carried out using only remote disconnectors. When there is only one possible fault section that can be isolated by remote disconnectors, the procedure is repeated for manual disconnectors within that section. When the fault section is localised, it is isolated by the closest disconnectors. After isolating the fault, manual reconnections are carried out and the fault can be repaired. The event is closed when all lines are re-energised, and all delivery points have been resupplied.

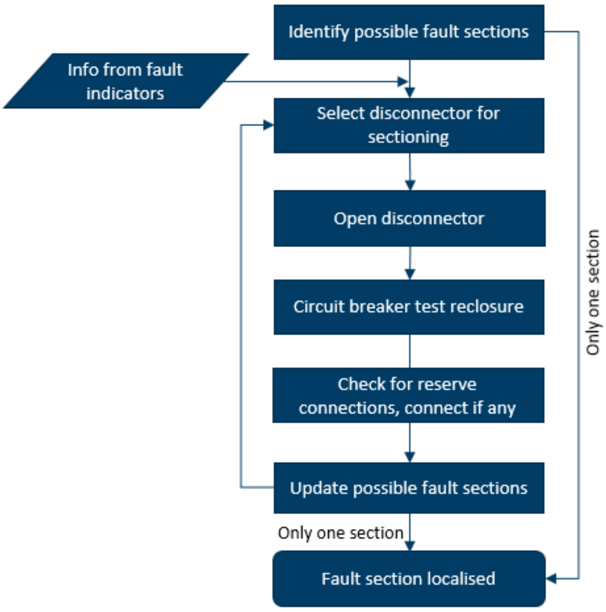

Figure 2 Flowchart for fault localisation

Fault indicators indicate whether the fault is located upstream or downstream the indicator, with an unknown probability of correct indication. In the experimental part of the FASaD project, the testing of fault indicators will give input to the reliability of the indicators. The event tree will produce different branches for correct and incorrect indication, respectively. Information from fault indicators are used as input to selecting disconnector for sectioning, by including the probability of correct / incorrect indication in the probability that the fault occurred on component *j*, given a fault on the radial (α_j).

Time calculations

To calculate the delivery points' interruption durations and the appurtenant reliability indices, the duration of each state in the event tree is calculated. Manual operations are assumed to be carried out using one car driving between the disconnectors. The following time variables are used:

Response time	Operator assessments. Time from circuit breaker trips until sectioning starts. Includes automatic reclosure.
Switching time	The time it takes to open/close a breaker or disconnector.
Turnout time	Minimum time before manual switching.
Driving start-up time	Time delay every time the car starts driving from one disconnector to the next.

Effective car speed	Car speed, considering the assumption that the car moves along the lines at constant speed.
Repair time	Time from repair starts until the component's function is restored.

For each node in the event tree, information about disconnectors (open/closed), status for delivery points (interruption/no interruption), duration of the state and branch probabilities are stored.

Reliability indices

When the event tree is established, the reliability indices are calculated based on information in the event tree. For each course of events, calculation of the indices is done by going from the leaf node (last node in the event tree) to the root node (start of the event tree), weighted by the branch probabilities.

The following reliability indices are calculated as expected values per delivery point (load point) in the grid [6] :

- Annual number of interruptions (/yr)
- Annual interruption duration (min/yr)
- Average interruption duration (min/interruption)
- Annual energy not supplied (kWh/yr)
- Annual interrupted power (kW/yr)
- Annual interruption cost (NOK/yr)

System indicators

- Expected SAIFI
- Expected SAIDI

In addition, two new indices are calculated:

- Expected annual number of partial interruptions per delivery point (/yr)
- Expected annual duration of fault handling per primary fault (min/yr)

By successful test reclosure of the circuit breaker in the fault localisation phase, some delivery points will be resupplied for a short period before a new interruption occurs due to further sectioning of the grid. These partial interruptions are counted as a new indicator. **Annual number of partial interruptions per delivery point incl. interruptions during sectioning/ reconnections (/yr)** are calculated as

$$l = \sum_j \lambda_j l_j$$

where
λ_j = fault frequency for primary fault on component *j*
l_j = number of partial interruptions for the delivery point by permanent fault on component *j*

For each course of events the duration of fault handling is calculated as the duration from the circuit breaker trips until the fault is repaired and the whole grid is re-energised. The expected **annual duration of fault handling per primary fault (min/yr)** is calculated as

$$V_j = \lambda_j \sum_i p_i v_i$$

where
λ_j = fault frequency for primary fault on component *j*
p_i = probability for course of events *i* given a primary fault on component *j*
v_i = duration of course of events *i*

The methodology has been implemented in a prototype tool and has been tested on a sample grid and on real MV distribution grids in Norway as described in the following.

CASE STUDIES

The methodology was first tested on a small sample grid consisting of a single feeder with four delivery points. Preliminary results were presented in [5].

After receiving promising results from the example grid, the methodology has been tested on real grids from a Norwegian DSO, to calculate potential reduction in interruption costs for different levels of automation. The methodology has been tested on four different grids with different length of the radially operated MV (11-22 kV) grid in the south-eastern part of Norway. The cases represent both underground cable and overhead grids, and the combination of both. Here, we will present in more detail the results from two cases from the same substation. A simplified single-line diagram of the grid is shown in Figure 4. The substation has two feeders, the green and the purple lines. The filled circles indicate the disconnectors and the open circles indicate the MV/LV substations.

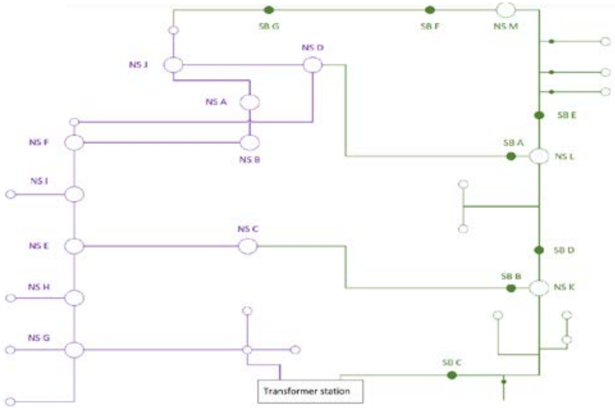

Figure 3: Real 11 kV grid for case study of the methodology. SB = disconnector, NS = substation. The large open circles indicate the most important substations[8]

Figure 5 shows the reduction in annual interruption costs (NOK/year) for different combinations of remotely controlled disconnectors and fault indicators on the green feeder. The maximum reduction in annual interruption costs of 46 % is achieved for the case with six remotely controlled disconnectors and two fault current indicators.

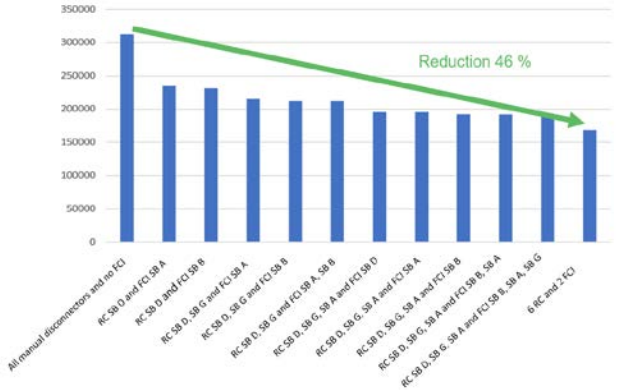

Figure 4: Potential reduction of annual interruption costs for real grid (green feeder) [9]. RC means upgraded to remotely controlled disconnector and FCI means upgraded with fault current indicator(s), referring to locations in Figure 4.

The purple feeder in Figure 4 has been studied to find the optimal number of locations to upgrade from manual to remote switching including fault current indicator. Figure 6 shows that with three upgraded locations, a reduction of 45 % in the annual interruption costs is achieved. Further upgrades reduce the annual interruption costs marginally; by upgrading five locations instead of three, the annual interruption costs are further reduced by only 2.5 percentage points. This shows that a careful analysis of the grid is necessary to find the most cost-effective locations. The analysis shows that the most beneficial locations are close to branches where there are possibilities for reconnection, and close to loads with a high interruption cost.

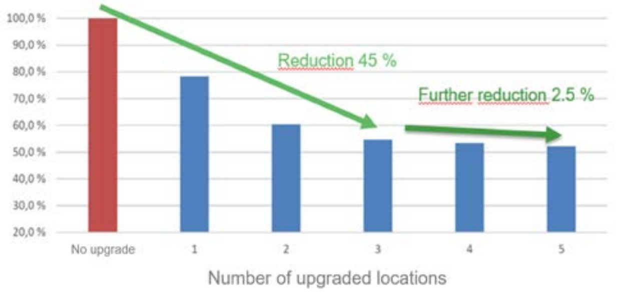

Figure 5: Reduction in annual interruption costs for the given number of upgraded locations (with both remotely controlled disconnectors and fault current indicators) [8]

Two other real grids from the same Norwegian DSO have also been studied showing a potential of reducing annual interruption costs of around 30 % for both. Based on the analysis performed, a potential reduction in interruption costs of 30 – 50 % is found for installing fault current indicators and remotely controlled disconnectors in both real grids and for the example grid. By assuming an average reduction of 35 % for installing these devices in all MV (11-22 kV) grid in Norway, and an average CENS in Norway of 350 MNOK per year [10] related to permanent faults on overhead lines and cables, the total potential savings in CENS will be approximately 125 MNOK per year (about 13 Million Euro per year).

The results in Figure 5 and Figure 6 are based on a fault probability of the fault current indicators of 10 %. By changing the fault probability to 0 % or 20 % for the fault current indicators, the maximum CENS reduction changed only ±0.1 - 0.6 percentage points [9]. Further testing and verification of fault current indicators in real grids is important to get a realistic picture of the reliability of the indicators. More analysis should be done, after achieving realistic values for the fault probability, to see how it affects the potential for reduction in CENS as well as the recommended number and location of the fault current indicators.

As part of the calculations on real grids, a few switching sequences were selected and studied in detail by the DSO in order to verify the logic of the methodology regarding selection of switches for sectioning. The sectioning methodology proved to give good and relevant results. The simulation of switching sequences can also be used as input to improving work processes at the DSOs.

EXPERIENCES FROM ESTABLISHING TEST/DEMO INFRASTRUCTURE

Twelve different fault indicator models from six different suppliers were deployed in the project for testing in two Norwegian DSOs medium voltage grid as explained in [5]. In the following, the experiences and lessons learnt from establishing this demo infrastructure will be described.

Choosing twelve different models of fault current indicators require a lot of effort and time for installation and setting up the parameters correctly. This is not "plug and play" and some models are less intuitive and needs more special tools for installation. One would recommend choosing the models with on board display for configuration possibilities, as this makes it easier to change/verify the settings in the field. This will better enable large scale use.

Several places it was found that there was not enough space to install sum-current transformers (CT), resulting in the less ideal option of three single phase CTs. Sometimes even the single phase CTs are difficult to install because of less ideal design. This was the case for some vendors and models. There should be compatibility between the vendors of CTs and fault current indicators, enabling independent choice of vendors. Compatibility will make it possible to replace/upgrade/change fault current indicator without changing CT and thus avoid planned outages.

Pole- and line mounted models not requiring external power (even not battery replacement) will have a significant impact on costs and will make large numbers of installed fault current indicators cost efficient in rural grids. To make installation easier, the pole- and line mounted fault current indicators should have integrated wireless communication modules. During implementation of one pole mounted model, there was a need for signal cable many tens of meters crossing public road and farmed field between the remote terminal unit (RTU) and the fault current indicator. This is very expensive and requires dispensation from the Directorate for Civil Protection.

Due to circumstances as those described above it is time consuming to implement the demonstration infrastructure. In this case, it has taken 3-4 years for these two DSOs and the seven selected grids, including the rather long time waiting for available contractors and installation crew. After the implementation, one must wait for quite some time for faults to occur in the actual grid. More experience is needed from operation to be able to conclude on the reliability of the different fault indicator models. After all, the demonstration shows a potential of faster restoration, reducing both partial frequency and duration of interruptions leading to an improved reliability of supply.

CONCLUSIONS

The new reliability analysis methodology has been implemented in a prototype that runs on real MV distribution grids and produces realistic results. The calculations show that installing fault current indicators and remotely controlled disconnectors have a potential of reducing CENS by 30-50%. In Norway as a whole, this technology has a potential of reducing CENS in the MV grid of app. 125 MNOK (about 13 Million Euro) per year.

Establishing a demo infrastructure is time consuming, and unforeseen challenges, particularly regarding installation and communication / power supply have caused many delays in the project. It is therefore important to collect experiences and lessons learnt from these demo projects. Further, experience from operation is needed to verify the functionality and reliability of the new equipment.

FURTHER WORK

The testing and demonstration on the infrastructure will continue as a pilot project in a national research centre for environment-friendly energy research, Centre for intelligent electricity distribution (CINELDI) working on solutions for the future distribution grid, such as self-healing.

The future work on developing extended functionality for the prototype / methodology has been identified by the FASaD project:

- Include faults on breakers and disconnectors.
- Include calculation of distance to fault.
- Implement different alternatives for sectioning.
- Implement load flow calculations to reflect capacity limitations.
- Develop an optimisation module to find optimal number, placement and combinations of equipment and functionality for smart fault handling.

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