ADVANCED FAULT LOCATION IN COMPENSATED DISTRIBUTION NETWORKS

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ABSTRACT

This work describes the design, implementation and evaluation of a novel fault location system for compensated networks. The work is performed as a part of the ongoing EU FP7 project called DICERN, involving five distribution network operators and several manufacturers and research institutes in Europe.. In order to achieve its main goal of finding optimal level of intelligence in distribution grids the demonstration sites play a key role in achieving the central goals of the project. The aim of the Swedish demonstration is to gain knowledge on smart grid network operations and find a cost effective solution for monitoring the medium voltage (MV) network using "simple" sensors. The main objective is to geographically pinpoint faults in the distribution network and furthermore to evaluate the functionality of MV monitoring for fast and reliable fault identification and indicating distance to faults.

INTRODUCTION

DISCERN is a demonstration project [1,2], carried out by Vattenfall, Iberdrola, UFD, RWE and SSE, within the European Union Seventh Framework Programme. The project has recently completed the final verification tests and hence all results are not achieved yet. The overall objective of the demonstration project is to provide guidance, about the optimal level of intelligence suitable for electric grid operation and control, to distribution system operators across Europe, by answering to the following complex questions:

- How much intelligence is needed in order to ensure a cost effective and reliable operation of a distribution network?
- How is this intelligence, cost-efficiently, implemented in the network?
- How should the information and communication infrastructure be designed in order to best serve the requirements of the control centre staff?

In order to provide better understanding of smart grid solutions for monitoring and control of the low- and medium voltage grids, best-practice solutions were implemented at four demonstration sites during the course of the project [3].

This article will discuss one of these demonstrations - detection and location of earth faults in electric grids with high impedance grounding. The demonstration was carried out on a test site including a 70/10kV primary substation and a 10 kV feeder in a rural part of the distribution grid on the island of Gotland. This is part of the GEAB grid, which is a subsidiary of Vattenfall and the DSO on the island of Gotland in the Baltic Sea.

In the high impedance grounding of the electric grid on Gotland, a tuned Peterson-coil, in parallel with a resistor, is used to limit the earth fault current to a fraction of what is common in directly grounded networks and much smaller than nominal load current. Detection and location of earth faults, in these types of systems, is, due to the limited fault currents, challenging and often involves measurement of both currents and zero sequence voltage. In this demonstration, however, a new approach, including recently developed intelligent electronic devices and Fault Passage Indicators, is evaluated.

A special feature of the Fault Passage Indicators evaluated in this project is that voltage measurement is omitted by use of a patented technique where the changes in, rather than the magnitude of, the current is used for detection of earth faults.

The aim of the demonstration is to use information from the technical equipment, in combination with algorithms and a user interface, to inform the operator about the distance to a faulted feeder. Faster and more accurate fault location should significantly improve both the duration and frequency of the interruptions in the area, thus correspond to the third and sixth Key Performance Indicator of the overall project – to improve the interruption duration index (SAIDI, i.e., security of supply) and reduce the time required for fault awareness respectively.

METHOD

System Set-up

Two different types of devices were used in this project - intelligent electronic devices (IED) and Fault Passage Indicators (FPI). Intelligent electronic devices, which are equipped with microprocessors, was installed on the medium voltage side in the switchgear in order to calculate power flows and store current and voltage data related to network faults (32/16/8 samples per cycle).To ensure sufficient coverage for the project Fault Passage Indicators were installed at five branching points on the medium voltage feeder (see figure 1).

Fault location based on information from devices mounted in the overhead line pole and equipment in the substation depends on high availability communication channels. A schematic figure of how fault records from the substation monitors and the Fault Passage Indicators are sent over public mobile network using separate 3G/GPRS uplink routes to a central SCADA system in the control center, can be seen in figure 2 and figure 4. Once a fault record has been retrieved, the substation automation management system, calculates the distance to fault, which is presented for the control center staff. Depending on however the line was modelled as one single or two sections in the calculation, the substation automation management system presented slightly different distances to the fault.

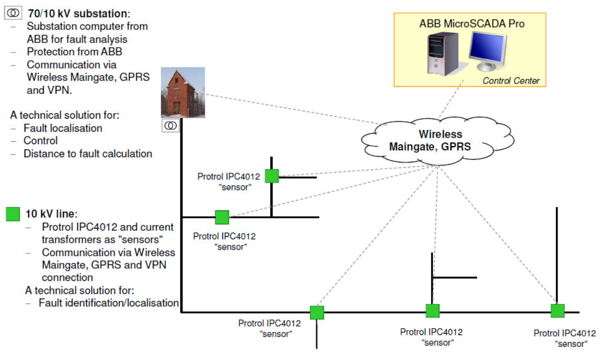

Figure 1: DISCERN Gotland demonstration (Vattenfall) – System overview. Green squares represent the five Fault Passage Indicators installed at branching points on the medium voltage feeder.

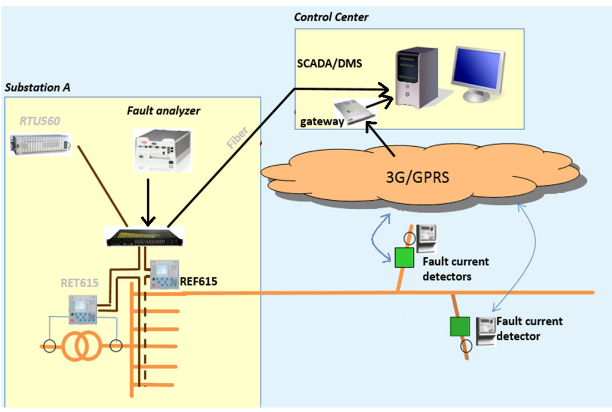

Figure 2: Demo equipment including the communication links to central SCADA/DMS.

Within DISCERN the IEC Smart Grid Architecture Model (SGAM, which is standardised in IEC 62357-1) was used to provide a structured framework for representing and analysing solutions implemented within electricity utilities companies, see figure 3.

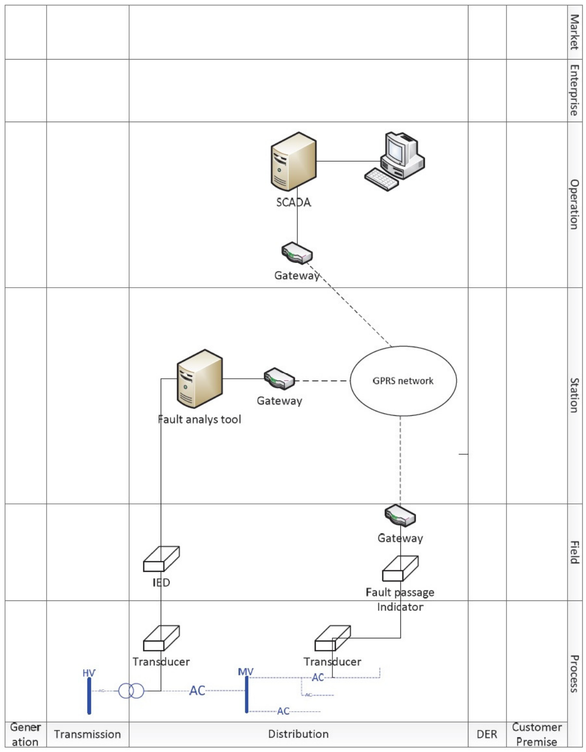

Figure 3: DISCERN Vattenfall demonstration (Vattenfall) - SGAM component layer.

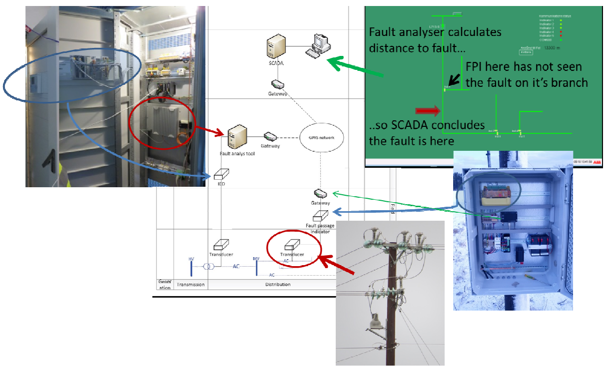

Figure 4: Equipment, communication channels and processes in the DISCERN Vattenfall demonstration

CHOICE OF FAULT INDICATOR DEVICES

Several FPIs were evaluated during the procurement phase, and the chosen product has a unique, patented technique which only uses current to detect an earth fault. This looks at changes in current rather than the magnitude. The drawback to using this approach is that the earth fault detection will not work for a switch onto fault. For a short circuit the functionality is the same as for normal feeder protection, since then only the magnitude is considered.

The number of indicators needed to demo the functionality was agreed between manufacturer and Vattenfall/GEAB as a result of a study on the feeder in question, and five FPIs were installed at five branching points on the feeder to ensure sufficient coverage for the project. Drawbacks for the selected solution is the size and weight of the pole mounted devices that required reconstruction of the overhead line poles, affecting cost efficiency and resulting in a noticeable power outage for the customers during which time reconfiguration of the grid is required. Also, its use on overhead lines with the chosen CT solution that includes a disconnector makes installation complicated.

However, the selected device appeared to be the only suitable device available on the market suitable for the purpose at the current time. If the tests have been performed in another country with less compensated neutral or on a higher loaded feeder in Sweden other product could be suitable, and if the sensors (CT) had been installed on the ground, the installation cost could have been reduced, but as the project involves overhead lines this was not possible.

PERFORMANCE INDICATORS

The most important data items to be collected in order to evaluate the solution for short-circuit failures were three phase current (binary) values and the distance to fault (meter) for each fault occurrence. Additionally, for ground faults, voltage values are important. For trial purposes faults were provoked by earthing conductors of the overhead lines during a dedicated test session. The data collected is shown in Table 1. All data is communicated over the IEC 60870-5-104 protocol.

Table 1: Data collection detail at the DISCERN Gotland demonstration site.

Name	Equipment	Unit	Resolution	Frequency
Distance to fault data	Station computer (Fault analyse, COM600)	Meter	Analogue value	On occurrence
Fault passage indication (Binary signal)	Fault Passage Indicator	Binary	1/0	On occurrence
Disturbance record from the feeder protection (REF615) to station computer (COM600)	Fault Passage Indicator	COMTRADE file	ms	On occurrence

Based on the obtained information, the SCADA presents the fault location to the operator in the control centre. This is done in a HMI with a single line, as previously shown in Figure 4.

Primary Line Fault Tests

A primary line fault test was carried out in order to verify the accuracy of the fault localisation. The test was carried out by injecting faults at three different locations (see figure 5) in the medium voltage grid network. The faults was injected by connecting the overhead line to ground through a resistor.

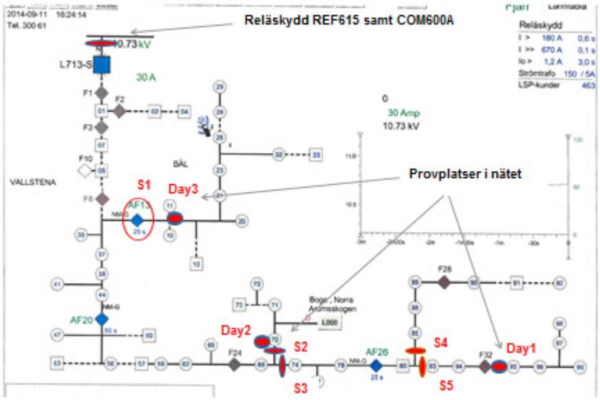

Figure 5: Locations for fault injections in the medium voltage grid network.

The tests showed that communication between all system components (relay to station computer, station computer to SCADA and FPI to SCADA) worked satisfactory and with small time delays of mere seconds, which is fully acceptable to operators. The tests further showed that the FPI work well and as expected in detecting all faults encountered during the test period.

REQUIRED IMPROVEMENTS FOR OPERATIONAL SYSTEM

The settings and algorithm used in the field test are part of the R&D work for the fault analysis software. In the demo the correct distance to fault could not be verified in the field trial. Instead the staff from the vendor of the station computer took part in the field test in order to update the parameters and fault location process to improve the first results obtained. During the test, disturbance reports where collected from the relays in order to evaluate the required parametrization of the fault analyser in the station computer. Based on the test results the settings of the station computer and the distance to fault calculated in the vendors software simulation environment were modified.

The fault recordings collected could also be used for secondary injection test. Here a test set would play back the recording of a realistic fault and should enable the tripping of the relay with realistic current and voltage variations. This in turn would insure that the station computer could calculate a distance to fault from the relays disturbance record. Hence a complete fault location functionality (and accuracy) would be possible to verify. This was not the case in the demonstrator. Tests were also done with an imbalance of the reactor in order to determine the effect on accuracy. The results showed that the inaccuracy seen with an unbalanced reactor was as large as that seen with a high ohmic fault, approximately a kilometre.

During the primary line fault tests special interest was payed to the distance to fault (in meters) for each fault occurrence and voltage readings, in order to evaluate the solution for short-circuit failures.

RESULT

Measured and calculated results from the three test sites in the Primary Line Fault Tests can be seen in table 1 trough table 3. In all cases the fault was injected to the first phase except for test case 13 where the fault was injected to the second phase. All fault injections in these tests were carried out with a balanced reactor. In the text, Model A corresponds to an assumption that the line can be represented by on single section line and in Model B, the line is instead modeled as a combination of two sections with different impedance.

Table 1: Results from test day 1. Distance to the fault was 15 510m.

Test No.	U_0 (V)		Device ID	Model A		Model B	
	Before fault	After fault		Distance (m)	Accuracy (%)	Distance (m)	Accuracy (%)
12	30	30	S3, S5	16520	6	15980	2
13	50	50	S3, S5	15200	-3	14780	-5

Table 2: Results from test day 2. Distance to the fault was 12 835m.

Test No.	U_0 (V)		Device ID	Model A		Model B	
	Before fault	After fault		Distance (m)	Accuracy (%)	Distance (m)	Accuracy (%)
23a	35	35	S2	11260	-10	11170	-11
23b	35	30	S2	11760	-7	11620	-8
23c	45	40	S2	11820	-7	11690	-7

Table 3: Results from test day 3. Distance to the fault was 5 870m.

Test No.	U_0 (V)		Device ID	Model A		Model B	
	Before fault	After fault		Distance (m)	Accuracy (%)	Distance (m)	Accuracy (%)
32	45	45	S1	4370	-10	5000	-6
33	45	34	S1	5570	-2	11620	1

Please note that after the unsatisfactory result of test number 23a, the calculation procedure was changed to concern a single phase ground fault, rather than a three phase short circuit, which improved the accuracy significantly.

DISCUSSION AND CONCLUSION

It has been demonstrated that a system of Intelligent Electronic Devices and Fault Passage Indicators, and related communication with the control centre SCADA user interface, can be used to detect and estimate location of earth faults in a compensated network. It was, furthermore, showed that information about earth fault was presented in a way, and within a time range, that is fully acceptable to the control centre operating staff. The distance to fault calculation, was not as good as was expected. However, the inaccuracy may be good enough in some networks.

The two KPI reductions can be quantised to an annual saving for the demo site of 1,3kEUR (KPI 03a) and 0,38 kEUR (KPI 06). At present the cost per sensor is relatively high, even with the estimated cost reduction for material and installation for large scale deployment is 45% compared to the costs seen in the demo project. The payback period would be too long when calculated for a single overhead line. Instead the KPI need to be calculated for entire grid area based on cheaper sensors. Also built in modems in sensor are essential as the demos external modems themselves have costs comparable with the KPI savings found in DISCERN.

An obvious drawback of the selected solution is that reconstruction of the overhead line poles was required due to the size and weight of the devices. Reconfiguration of the grid affect the cost efficiency of the installation and involves a noticeable power outage for the customers.

Another drawback is that Fault Passage Indicator, that triggers on changes in voltage (rather than on the magnitude), is unable to detect switch-onto-faults.

REFERENCES

[1] DISCERN final report

[2] DISCERN project we site: http://www.discern.eu/

[3] DISCERN D7.2: http://www.discern.eu/datas/20160219_DISCERN_WP7_D7_2_v3.pdf