# Third generation monitoring system provides a fundamental component of the Smart Grid and next generation power distribution networks

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*Abstract*-Experience with a third generation monitoring system based on cost effective optical sensing for MV/LV electric power networks is described. The unique linear characteristics of the sensor over a wide current range allow a total monitoring solution for real-time analogue measurements including fault identification. The ability to record harmonics from the fundamental to 50$^{th}$ opens up possibilities through analysis to determine fault location for difficult faults such as earth and fallen conductor incidents. Benefits derived from present installations for operations and asset management are summarized.

## Introduction

World-wide there is a determination to improve the performance of electric power distribution networks both economically and technically. Although this goal may not be a new one it is both the environment and the new direction that is being proposed that is new - namely an environment of aged network assets and a direction that must accommodate distributed generation under "smart grid" concepts being initiated through the EEC.

Most electric power networks in Europe consist of aged network assets that have reached the end of their original amortized life. Figure 1 shows a typical asset age profile of such assets and suggests that if original replacement times were to be exercised the majority of gear would have to be replaced in a short interval. The capital required to for this replacement is not economically feasible and thus selective replacement and

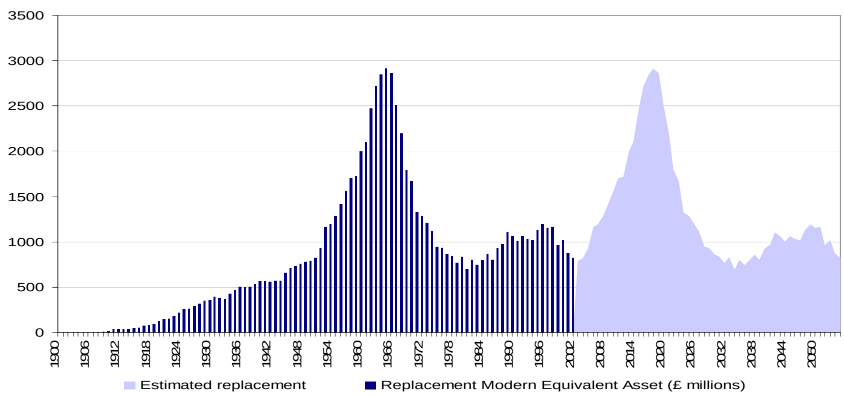


Figure 1 Typical Electrical Power Distribution Network Asset Age Profile

condition based life extension becomes a necessity. The maintenance of a reliable network of aged assets becomes more challenging in eastern Mediterranean countries such as Cyprus where hot summers encourage increased use of air conditioners and in rural areas where irrigation pumping is used to boost agricultural output. In urban areas the summer peak can exceed 10% of normal loads and when combined with load growths in the 4-5% range impose significant stress in the utility resources requiring well informed and optimized expansion planning of network capacity.

In addition to providing sufficient capacity utilities are expected to deliver reliable supply. In Europe figures for average customer minutes lost range from approximately 300 to 50 minutes (Figure 2). The worst performing utilities are being expected by their respective regulators to improve network reliability towards the best performing companies.

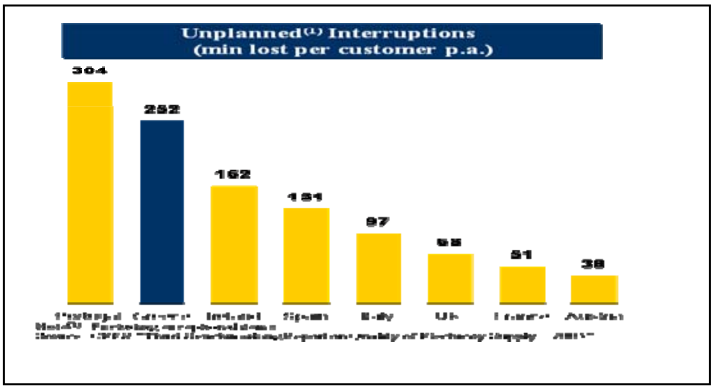


Figure 2  Performance Statistics from selected European Utilities

The smart grid initiative focuses mainly on two areas that of improved metering using an Advanced Metering Infrastructure (AMI) allowing increase demand response and consumer choice as well as load control by utilities.  The other area which will impact present distribution networks is the accommodation of distributed generation in many forms.  Photovoltaic generation will probably be the most common form in the sunny eastern Mediterranean.  Distributed generation requires a complete revision of present unidirectional distribution network architecture impacting present control and protection practices.

Utilities are meeting the challenges by implementing both new Advanced Metering Infrastructures (AMI) and Distribution Automation comprising Distribution Management Systems (DMS) and improved network monitoring

This paper concentrates on a third generation monitoring system that when combined with both DMS and Asset Management systems helps to provide the visibility of network loading and performance fundamental to cutting traditional operating margins necessary if capacity is to be squeezed out of existing assets without jeopardizing their useful life.

## Distribution Automation and Automation Intensity Level (AIL)

The SCADA/DMS systems presently being implemented in utilities have in the majority concentrated at establishing control and monitoring of the HV networks and primary substations where immediate returns from more efficient operation can be made.  The real-time control of these networks is virtually 100% although the Automation Intensity Level is very low.

The AIL is defined as the percentage of MV feeder switches placed under remote control, the majority being outside the substation.

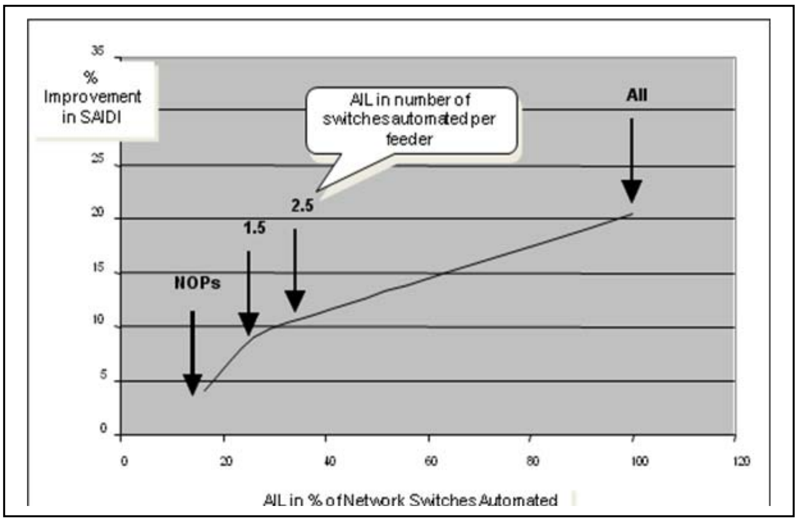


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Figure 3, Marginal outage duration improvement with increased AIL

Another definition of AIL is how many switches per feeder are automated in any one feeder (AIL values of 1, 1.5, 2, 2.5 etc.). The .5 designates the normally open point shared by an adjacent feeder. System performance in terms of outage time is improved with increase in AIL although the marginal improvement decreases as shown in Figure 3 below:

The term automation is misleading since it infers a level of self healing but the electric power industry has used the term for designating remote control and DA is defined by the IEEE as follows:

> "A set of technologies that enable an electric utility to remotely monitor, coordinate and operate distribution components in a real-time mode from remote locations"

True automation is now being added to remote control either as local automation through recloser and self-sectionalizing or via decision support tools in the central control system. Remote control and monitoring is the foundation to any true automation scheme.

There are be two stages of automation where stage 1 uses simple digital communications to operate devices and take back binary signals from fault passage indicators. Stage 1 is now giving way to a second stage –Stage 2- that allows real-time analogue measurements to be brought back from the remotely controlled switches as well as digital control. This increase in operation has been made possible by the advance and cost reduction in the communication links

As the industry now strives to justify additional monitoring of the system to better manage the network assets, the measurement of the amount of monitoring without control can be introduced as the Monitoring Intensity Level (MIL) defined as the percentage of locations (device) where monitoring of typical network loading parameters (current, voltage, power, energy, power factor etc.) is achieved remotely. The value of MIL industry wide is very low at present since the cost of retrofitting monitoring alone to existing devices is relatively expensive even if CTs are accessible - in many cases, where CTs have not been incorporated into the original equipment, it maybe totally impractical. The solution of replacing aged equipment with new Automation Ready devices may also be difficult to justify for monitoring only and particularly as any replacement plan is unsupported by sound knowledge of network component loading information which can only be provided by increased monitoring. A high MIL is one of the prerequisites in the intelligent Energy Network (Grid) or Smart Grid that will emerge as distributed resources and generation are deployed in the future.

## Third Generation Monitoring with Innovative Optical Sensor Technology.

Third generation monitoring systems integrate many functions that previously have been provided by individual standalone non communicating devices. Third generation monitoring systems include sensors for medium voltage application, fault identification capability for many types of fault and current measurement for asset management. In addition primary switch device control is an integral part of the intelligent electronic device (IED) thus complimenting the functionality for complete intelligent remote control at the selected AIL and CILs. The final component is the communication capability that is specifically designed to stream selected data to different destinations as required by the particular application. Fault indication should be transmitted to the control centre as soon as it occurs while massive amounts of loading data for asset management can be streamed to enterprise applications at a slower rate and less frequently. The communication module must be able to comply with all present standards such as IEC 61850, 60870/101and 104 as well as DNP 3.0.

The optical current sensor is at the heart of third generation monitoring systems providing an innovative cost effective solution for monitoring of the power network, particularly at the MV/ LV transformer stations. The ability to determine incoming and outgoing currents on both sides of the transformer, under normal and fault conditions, facilitates the location of outages and the management of the network asset. Traditional monitoring units rely of CTs for current measurement and are essentially low end remote terminal units. They are limited under fault conditions by the saturation of the CTs. In contrast the optical sensor has 1-2% accuracy over the entire current range of 1-25,000amps (Figure 4).

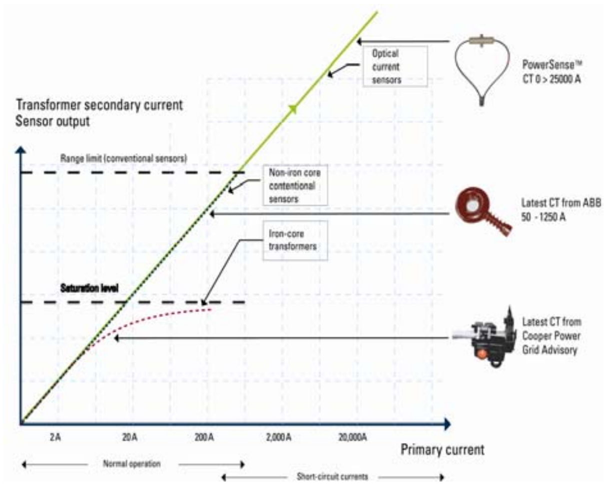


Figure 4, Linearity of Sensor response to current magnitude

Further the capability to measure all harmonics from the fundamental to the 50th is available for advance applications such as power quality measurement, earth fault identification in compensated networks and fault detection for fallen conductors in high impedance fault conditions.

The optical sensor which uses Faraday's effects and an optical unit. The sensor is easily strapped to the outside insulation of any cable close to the termination in ring main units and reference voltage for calculations and power supply is obtained from the LV side of substations. The overhead version is packaged with a voltage divider and clamp so that the entire sensor is self contained and the reference voltage is at the same point as the current measurement (Figure 5).

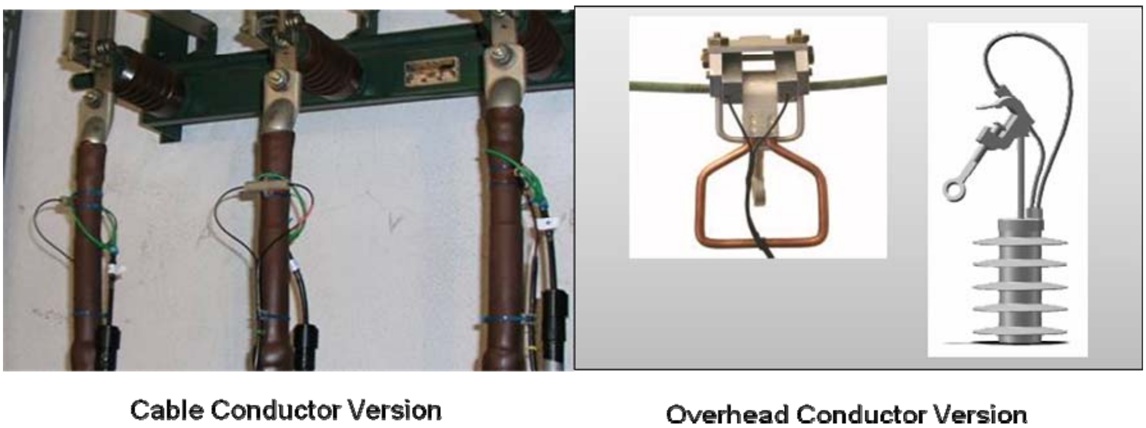


Figure 5, Cable and overhead conductor versions of optical sensor

The light beams are provided from the optical control unit which has the intelligence to compensate for temperature and aging variations, also to interpret the light signals into real amperes. An additional master module completes the sensor and provides calculations, analogue output and limited digital control through a standard modem using a number of standard SCADA protocols (IEC 60870-5-101, MODBUS, DNP 3.0). An interface to the IBM MB/MQ Advanced Enterprise Service Bus (ESB) and other suppliers middleware data buses facilitates integration into an enterprise wide information structure. The master module is designed to provide flexibility in selecting different destinations for the signals thus fault information can be steamed directly to the SCADA/DMS system whereas non critical asset loading information can be streamed to enterprise information applications such as planning, network asset management(NAM) and computerized maintenance management (CMMS) applications. Typical outputs from a laptop based application are shown in Figure 6.

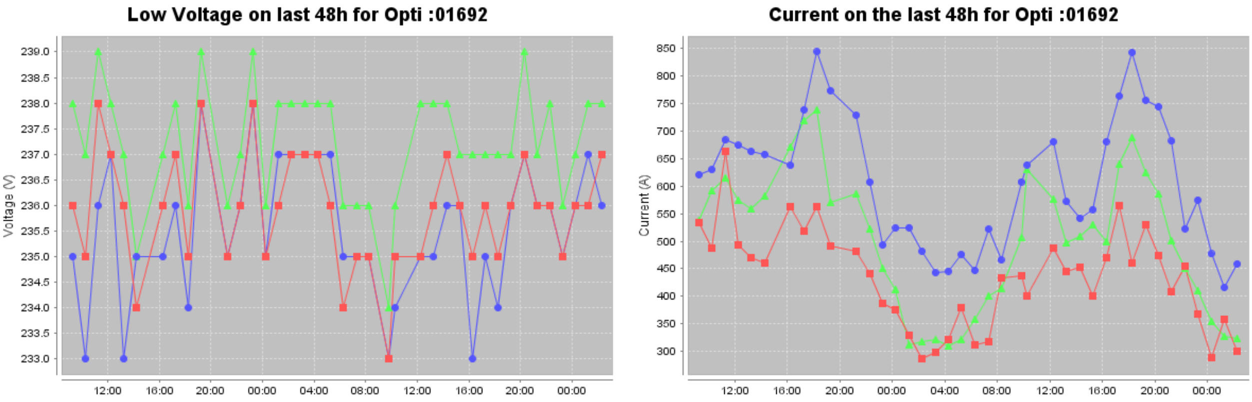


Figure 6, Typical voltage and current output from the Laptop applications showing unbalance between LV phase

## Experience and Benefits

The complete monitoring solution described above is the DISCOS monitor initially developed within the Danish utility Industry and now supplied by PowerSense. Over the last 2 years more than 5000 DISCOSs sensors have been deployed at various sites in a number of utilities. Reliance Energy in Delhi is trialling the solution at 2 MV/LV substations and will be considering another 20 stations in the pilot. The most significant implementation of DISCOS is at DONG Energy (NESA) in Denmark where over 150 MV/LV transformer stations have been fitted with the sensor and the results brought back to a reporting application through the IBM ESB. A typical substation implementation is shown in Figure 7 where two MV incoming feeders and all outgoing feeders at the LV bus are monitored.

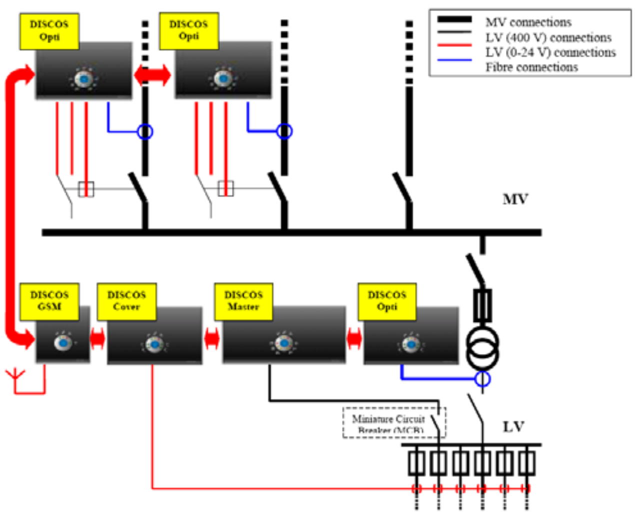


Figure 7, Typical Monitoring Solution for a single transformer MV/LV Distribution Substation

At DONG Energy (formerly NESA A/S) two types of DISCO have been installed. Type A included control and were installed at switches capable of being retrofitted for remote control and Type B had monitoring only where it was impractical to convert the existing switching devices to remote operation. Type A contributes to the AIL and improves restoration time through faster fault isolation by remote switching. Type B contributes to the MIL and improves restoration time by identifying fault location with a consequent reduction in travel time for crews to perform manual switching. Benefits for an AIL of 7.5% and a MIL of 10% showed a reduction in energy not supplied by 50% and the fault location search time shortened by 35%. This deployment of the sensors proved to be the optimal of scenarios investigated. Addressing asset replacement or premature reinforcement the benefits gained from improved planning analysis were estimated be reduce reinforcement by 81-98%.The benefits analysis over a 20 year planning horizon showed a ROI within five years.

## Conclusions

The DISCOS third generation monitoring system opens the door for utilities to economically increase the level of MIL and provide the benefits derived from better knowledge of the actual loading levels of the MV and MV/LV substation assets. These benefits are immense for utilities with aged assets and will allow selective deferral of replacement of equipment. The information will enable better planning leading to nearer optimal expansion of the network together with the ability to assess power quality issues. In addition the real-time capability of complex fault location identification, an integral function within the monitor, adds increase benefits. The flexibility of the system is a fundamental building block of the "smart grid". Although the DISCO system is designed to be integrated into large real-time and enterprise systems and real-time SCADA/DMSs, in its simplest form it can be deployed with monitored data being sent directly to a simple lap-top application - "from sensor to laptop".

## References

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PPC Strategic Priorites, Nov 21, 2007

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**Martin Speiermann** was born in Copenhagen, Denmark, in 1974. He graduated in power engineering in 1998 and has attended several executive management programmes. Martin Speiermann joined PowerSense in September 2006 as VP of Sales and Marketing.

Before joining PowerSense, he was Business Developer and Product Manager in the American company Magnetek PEG (Power Electronic Group) for more than 8 years. Magnetek PEG is one of the world's leading power electronic producers specialised in industrial power electronics. In 2006 Magnetek PEG was merged into PowerOne Inc.