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UTILITIES IMPLEMENT INCREASED MONITORING OF DISTRIBUTION NETWORKS AS THE PRECURSOR TO INTELLIGENT CONTROL AND ASSET MANAGEMENT IMPROVEMENTS

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INTRODUCTION

Power companies that are at the forefront of the change process needed to traditional distribution system operation and network asset management have all initiated vast increases in network monitoring as the foundation for delivering this change. Whether as part of a Smart Grid initiative or as part of regulator pressures for reliability improvement and better planned asset utilization, many power companies have been able to justify installing monitoring equipment at their medium voltage/low voltage substations. The main benefits of the associated business cases developed by a number of power companies are justified on the availability of an integrated sensor and monitoring system. These benefits have dictated the fundamental requirements of a monitoring system to be an integrated approach for both fault identification and load current measurements. These facilities are provided in a third generation distribution monitoring system.

DISTRIBUTION NETWORK MONITORING SYSTEMS

First generation distribution monitoring systems were essentially for control using small FRTUs retrofitted to primary switches along feeders. These intelligent electronic devices (IEDs) communicated directly back to one master SCADA at central control. They enabled remote opening and closing of the switches as well as the passing of certain alarms for health checking of the control cabinet (battery life, temperature, loss of voltage). Analogue measurements were not included either because primary CTs did not exist, or because their output was not accessible and the protocols were restricted to digital signals. The lack of primary current measurements is a drawback in extending first generation (1G)* monitoring systems. Second generation (2G)* monitoring systems started to take in signals from other ancillary devices, such as FPIs, and communicated their operation back to the control room. Both first and second generation systems remained focused on real-time operation and providing operations data to the control room. Third generation (3G)* monitors perform all the first and second generation functions, but in addition produce timely load measurements on a continuous basis required for asset management systems, with the communication function to transmit appropriate data to different sources at selectable time intervals.

** The positioning of 1G/2G and 3G generations of distribution monitors is summarized in Figure 1.*

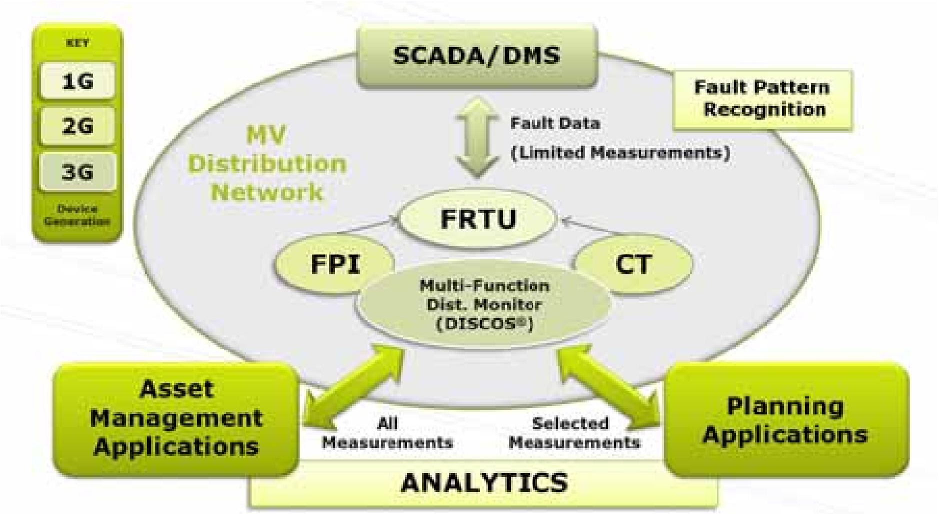

Figure 1, 3G multi-functional monitor replaces traditional earlier generation single device solutions (FPI, CT, FRTU) with a single integrated intelligent unit.

The following key functional requirements that must be met by a 3G distribution monitor:

- Primary current sensor that can be noninvasively installed on MV cables and overhead conductors
- LV current sensors for LV cables
- Intelligent electronic unit to:
    - Locate and identify faults of different types
    - Compute power quantities from current sensors and voltage measurements
    - Process alarm and switch control signals for feeder automation (remote switch control)
- Flexible and configurable communication module able to selectively route information to different destinations at different intervals.

EXAMPLE: 3G MONITORING SYSTEM

Third generation monitoring systems must be configurable in a modular fashion in order to integrate selected functions previously provided by individual standalone non-communicating devices - functions that have been justified by the associated business case. A 3G monitor now in use at a number of power companies, described below, is comprised of the following modules.

SENSORS

The optical current sensor provides 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 on CTs for current measurement. 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 5-20,000 amps (Figure 2).

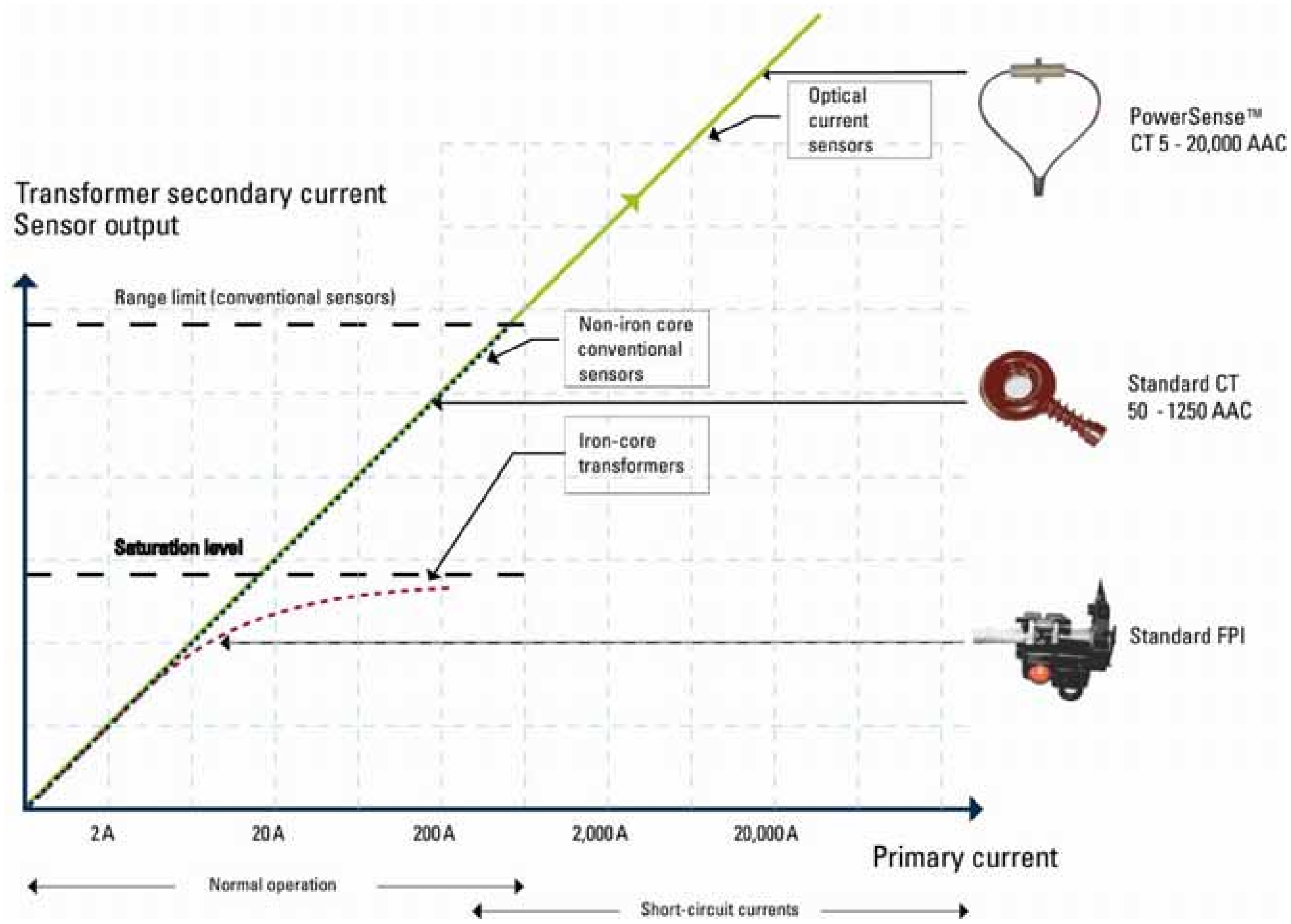

Figure 2, Linearity of sensor response to current magnitude compensated for temperature and ageing.

The potential capability to measure all harmonics, from the fundamental to the 50th,would be available for advanced applications, such as power quality measurement, earth fault identification in compensated networks and fault detection for fallen conductors in high impedance fault conditions. The core of the monitor is the optical sensor which is based on the Faraday effect principles. The light beams are interpreted by the optical unit which has the intelligence to compensate for temperature and aging variations, also to interpret the light signals into real amperes. This electronic module also calculates other power system parameters such as real and reactive power. Further network specific fault identification filters can be implemented to determine different types of fault such as short circuit, earth faults, open conductors and cross country faults. The sensor is installed noninvasively by attaching it to the outside insulation of any cable close to the termination in ring main units. Figure 3 shows a typical installation. Optical sensors can be cost- effective for MV/LV transformer station monitoring, provided the LV side cable/bus connection is accessible. In cases where monitoring of all LV feeders by phase is required, split core CTs in conjunction with a special I/O module are preferred. The voltage reference required for making power quantity calculations is obtained from the LV bus of indoor substations through the LV Interface module.

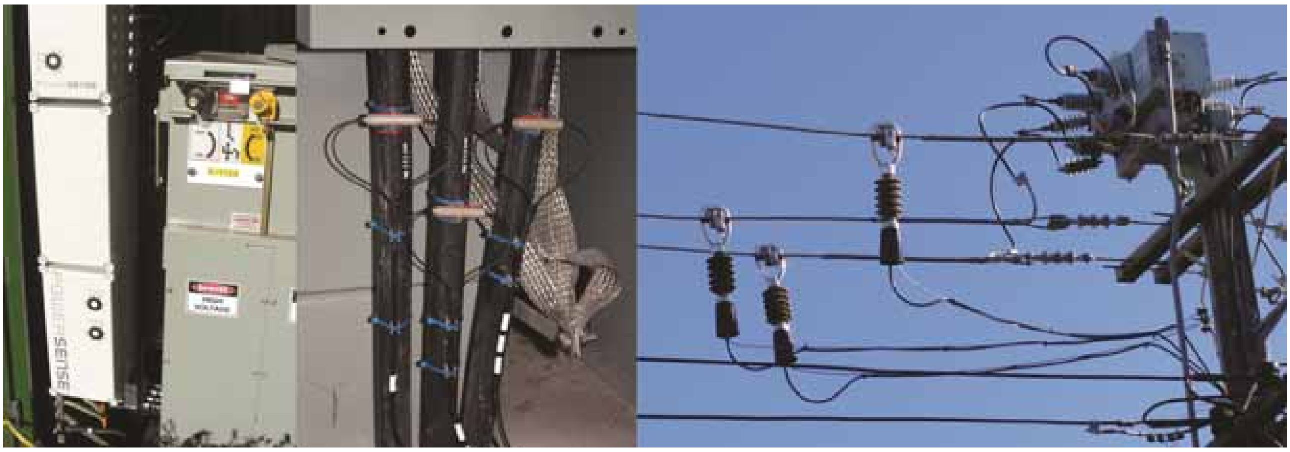

Figure 3: IED cabinet mounted in a kiosk substation, HV cable and overhead optical sensors.

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.

SWITCH CONTROL

Sufficient digital I/O capability is integrated within the electronics of the monitor to allow complete control of any switch associated with the monitoring locations, and also to pass any other alarms such as primary network fault occurrences and multi health checks of the monitoring system. The device therefore provides sufficient distribution automation functionality, eliminating the need for a further FRTU.[1]

INTERFACE MODULES

Various interface modules can be added to the configuration, depending on the voltage source (MV or LV interfaces) and for current input from traditional open core CTs (I/O module) typically used on LV feeders. These latter modules incorporate power quality analysis to full IEC standards.

COMMUNICATIONS MODULE

The final component is the communication capability that is specifically designed to stream selected data to different destinations as required by the particular application. A variety of different standard SCADA (DNP 3, IEC 60870-5-101/104, 61850 etc.) and Enterprise IT bus protocols (IBM MQTT/MQ Advanced Enterprise Service Bus (ESB)) are supported and can be deployed through at least two communication channels using different communications media (GSM, CDMA, WIMAX, RS232) to fiber, wire or wireless). This Linux-based module allows reconfiguration of the communication system's front end to

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[1] FRTU- Feeder Remote Terminal Unit

accommodate customer-specific requirements with relative ease. Data can be categorized as alarm data or asset data accordingly and streamed to different locations using an alternate protocol for each path.

BUSINESS CASE

Creating a business case considers the combination of hard and soft benefits. Those that can be quantified and those that are intangible but are known to influence performance. Benefits are also direct and indirect to distinguish from those that are derived directly from the application and those that are derived from an associated function. Economic justification of distribution system monitoring has been shown by those power companies embarking on such implementations, to be predominantly dependent on the following hard direct benefits:

- ***Manpower Savings*** as a result of eliminating annual or twice-yearly visits to MV/LV substations to read maximum demand meters. Eliminating the need to perform load surveys.
- ***Improved Planning*** as a result of accurate time-based load data which has resulted in delay of network reinforcement.
- ***Improved Asset Management*** as a result of accurate asset loading that allows the development an optimum asset replacement startegy now that a very large percentage of assets in most power companies have reached their life expectancy limit.
- ***Loss Reduction*** through reducing LV imbalance.
- ***Reliability improvement*** through reduction in SAIDI as a result of faster fault type identification and location.
- ***Reliability improvement*** through reduction in SAIDI due to faster switching for fault isolation and system restoration. This is really a benefit from Feeder Automation (AIL) but is an integral part of the 3G monitor capability.
- ***Customer Power Quality*** through continuous monitoring of LV voltage conditions, which will reduce complaints and provide savings in complaint investigations.
- ***Distibuted Generation*** will demand knowledge of directional power flows.

The degree of monitoring in any distribution network can be stated as the Monitoring Intensity Level (MIL) defined as either the percentage of MV load points, monitored out of the entire population of load points, or the number of load points monitored per feeder. This is a similar concept to the Automation Intensity Level (AIL) [1] which applies to the percentage of switches outside primary substations that are remotely controlled, or the number controlled per feeder. The easy of justification for implementing 3G monitors will depend upon whether significant stage 2[2] distribution automation has already been implemented (high AIL), and also the deployment of communicating Fault Passage Indicators (FPIs). Existing feeder automation is justified on reducing SAIDI and, if analogue measurements are available, will provide data monitoring and online logging to deliver indirect benefits through better planning and

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[2] Stage 2 automation states that both digital and analogue measurements have been implemented whereas stage 1 is limited to switch operation only.

asset management. These benefits will be mainly associated with the automation points and will be limited compared to those obtained from a high MIL. Additional monitoring will only provide incremental benefits to those already assessed from automation.

3G MONITORING IMPLEMENTATIONS

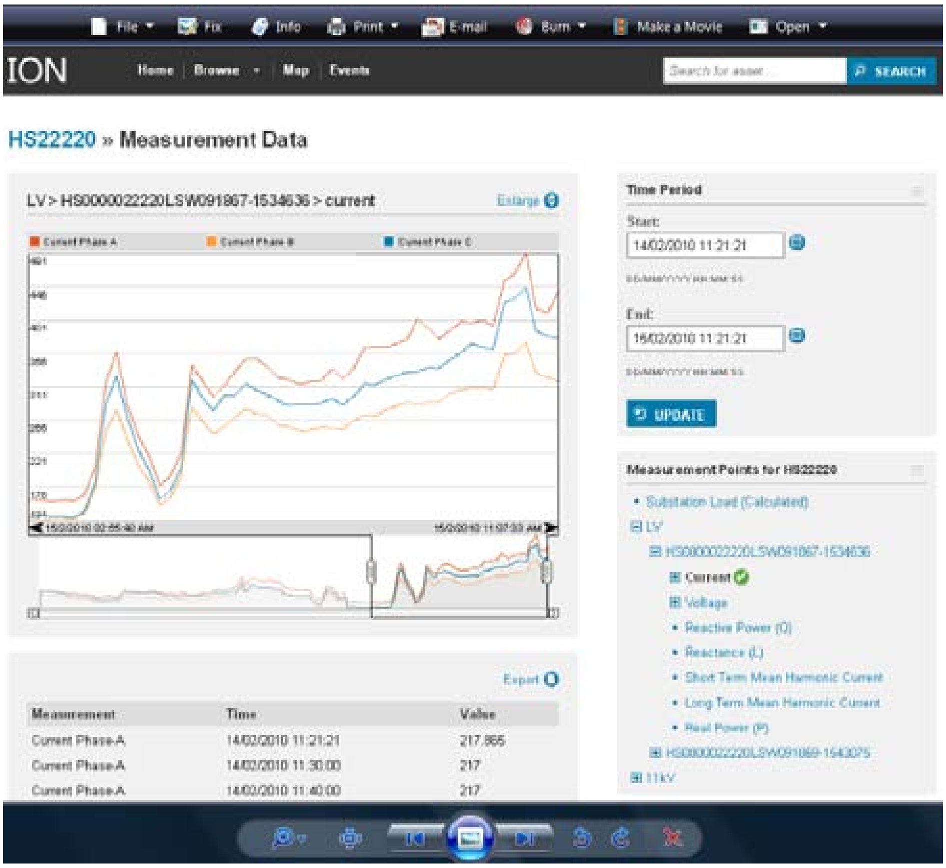
The number of significant monitoring projects is growing rapidly with SmartGrid initiatives and the potential for increases in distributed generation penetration at the distribution level. The following contains a small sampling of some significant projects implementing 3G monitoring systems.

DONG ENERGY A/S, DENMARK

DONG Energy A/S is the power company supplying to the Danish capital, Copenhagen, and to much of the surrounding area. It is an amalgamation of the former NESA A/S, which was the pioneer in developing innovative monitoring solutions for distribution networks. They were the originators of the 3G monitoring solution, incorporating a non- invasive sensor. Over the past four years they have installed well over 400 of their substations with such monitors. At DONG Energy A/S two configurations of 3G monitors have been installed. Type A monitors included control and were installed at switches capable of being retrofitted for remote control. Type B monitors had monitoring only where it was impractical to convert the existing switching devices to remote operation. Type A monitors contribute to the AIL and improve restoration time through faster fault isolation by remote switching. Type B monitors contribute to the MIL and improve 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 most optimal of the investigated scenarios. Addressing asset replacement or premature reinforcement, the benefits gained from improved planning analysis were estimated be reduce reinforcement by 81-98%, basically a 1-2-year delay in reinforcement. The benefits analysis over a 20-year planning horizon showed a ROI within five years.

ENERGYAUSTRALIA, SYDNEY

EnergyAustralia is one of the largest power companies in Australia, serving the City of Sydney and the surrounding area as far north as Newcastle. As part of the power company’s “Electric Thinking” network transformation strategy to prepare for the future, they have identified a need to extensively monitor their MV/LV distribution substations. The business case justification was based on hard direct benefits of a reduction in manpower cost by eliminating MDI readings and load surveys contributing 24 % of the benefits. Improved planning and asset maintenance strategies contributed a further 7 % with the major contribution amounting to 65 % provided by reliability improvements. EnergyAustralia was able to place such a high benefit value on improving reliability since little feeder automation and communicating FPIs had been implemented. This dictated the functions that were configured into the 3G distribution monitor, which was deployed with optical sensors on three phases of the MV side of the substation with fault identification logic and split core CTs on every phase of all outgoing LV feeders, which could amount to 16 feeders in some substations. In addition, provision for additional digital I/Os was included to allow remote switch control (feeder automation) to be implemented at a later date, when switchgear had been “automation prepared”. The business case set the justification price at $5,000A for this configuration and the MIL at 40% or 12,000 substations of the entire MV/LV (11kV/415v) substation population, meaning that this deployment would be the largest in the world to date. Parallel with the roll out of monitors, a central database using PI historian and graphic visualization was also instigated, a typical display being shown in Figure 4.



HS22220 » Measurement Data

LV > HS0000022220LSW091867-1534636 > current

Measurement	Time	Value
Current Phase-A	14/02/2010 11:21:21	217.865
Current Phase-A	14/02/2010 11:30:00	217
Current Phase-A	14/02/2010 11:40:00	217

Time Period

Start: 14/02/2010 11:21:21
DD/MM/YYYY HH:MM:SS

End: 16/02/2010 11:21:21
DD/MM/YYYY HH:MM:SS

Measurement Points for HS22220

- Substation Load (Calculated)
- ⊟ LV
  - ⊟ HS0000022220LSW091867-1534636
    - ⊞ Current ✓
    - ⊞ Voltage
    - Reactive Power (Q)
    - Reactance (L)
    - Short Term Mean Harmonic Current
    - Long Term Mean Harmonic Current
    - Real Power (P)
  - ⊞ HS0000022220LSW091869-1543075
- ⊞ 11kV

Figure 4: Sample Current measurement output from the 3G monitor polled at ten-minute intervals as displayed by the IT visualization application.

FAULT IDENTIFICATION

The Metropolitan Electricity Authority (MEA) of Bangkok was embarking on an upgrade of its distribution management system, and one of the requirements was to investigate the ability of a 3G monitor to identify faults and open/fallen conductors. The devices were installed on overhead conductors (Figure5).

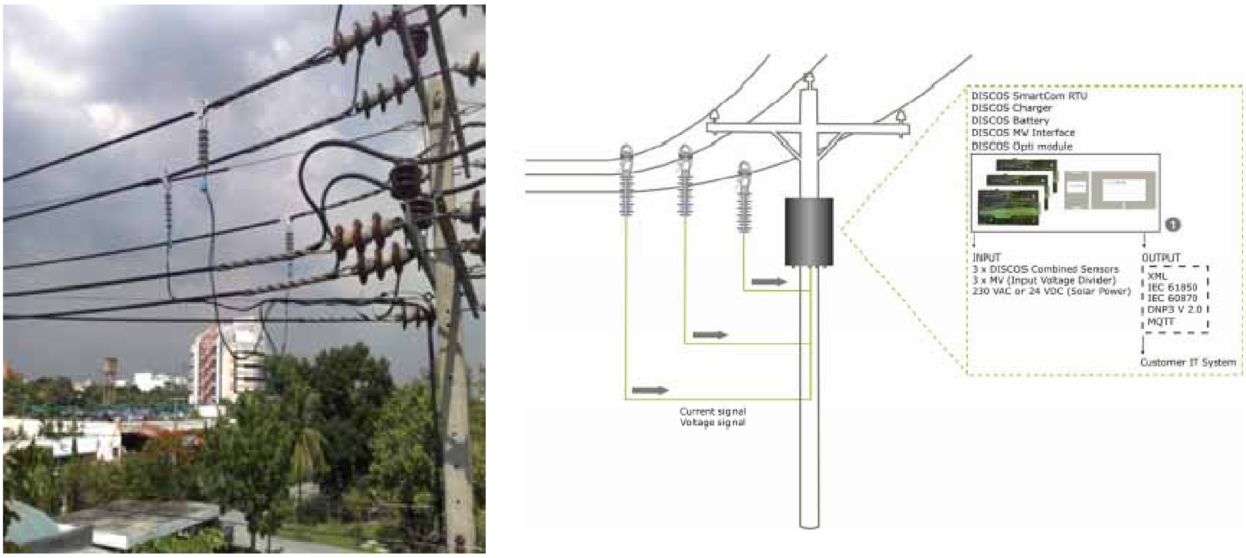


Figure 5: Showing physical installation of a 3G OH monitor with configuration schematic.

The fault identification function was implemented with a rule-based fault filter to identify open conductors. This filter can be embedded within the device, or as in this case implemented within the advanced applications of the Distribution Management System. The following rules were used and found to identify the fault: An open conductor upstream of the device was detected by a low voltage alarm on one phase, the violation threshold being set at 60% of nominal voltage. An open conductor downstream of the device was detected by a combination of filters:

- The ratio between minimum and maximum individual phase currents at each polling (variable setting) is below a set symmetry factor $K(I_{min}/I_{max})<K_{symmetry}$ (set at K=0,5)
- The mean value is above set threshold $I_{MV\ KV\ min}$ (set at 20A). This works as a filter for false alarm, because 50% difference can be a normal situation below 20A.
- All three voltages are above low voltage alarm limit (set at 21.6kV). If the voltage drops below, a “low voltage” alarm will occur instead.

Displays from the DMS Advanced Applications show the detection of open conductor fault during live tests.

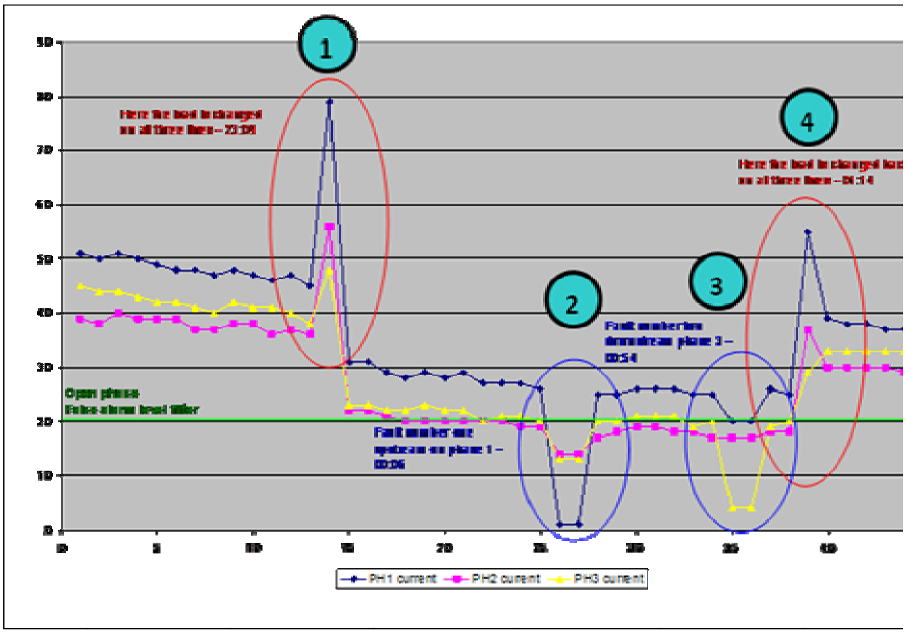


Figure 6: Current readings on individual phases showing pre- and post-test load shedding and restoration (1 & 4) and the two faults (2 upstream, 3 downstream). An open phase current false alarm level filter was set at 20A (green line).

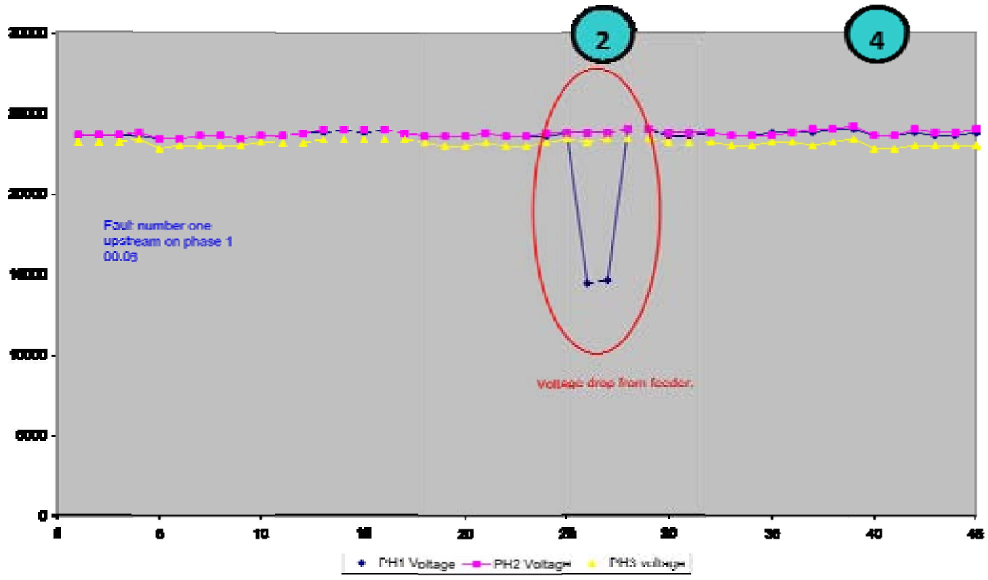


Figure 7: Current readings on individual phases showing pre- and post-test load shedding and restoration (1 & 4) and the two faults (2 upstream, 3 downstream). An open phase current false alarm level filter was set at 20A (green line).

The setting of filter threshold to reflect loading levels and prevent false indication is part of the application initialization.

CONCLUSIONS

The experience with a 3G monitoring device that includes all the functionalities previously provided by individual devices (Sensors, FPI and RTU) clearly shows the advantages. The unique component of the 3G device described here is the innovative optical sensor that can be noninvasively installed on existing cables in any location with accessibility. The major projects described in this paper show that positive business cases have been made to substantially increase monitoring intensity levels on distribution systems. It is also clear that increased monitoring will become a necessity if power companies are to transform their systems into Smart Grids, which will be fundamental to accommodating distributed generation, self healing and demand response in the networks of 21st century.

REFERENCES

[1] James Northcote-Green, Robert Wilson, ”Control and Automation of Electric Power Distribution Networks, publisher CRC Taylor and Francis, Florida 2007, ISBN 0-8247-2631-6.

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[3] James Northcote-Green, Martin Speierman, Alfred Manohar, “Innovative Optical Sensor Technology the Foundation of Cost Effective MV/LV Distribution Network Monitoring” DA Conference, Bangalore, India, October, 2007.

[4] Claus Olsen, Christian Nielsen , “ The intelligent Energy Network – From sensor to laptop” PowerSense-IBM White paper, October 2006.

METHODS

Third generation monitoring systems combine previous functions of fault passage indicators, current and voltage sensors, and RTU control and communication within one optimal cost-effective device. The sensors must be non-invasive for installation on cables and overhead conductors. The device described uses optical sensors for high voltages with an optional traditional split-core CT for low voltage applications. The entire system is configurable so that the most cost- effective solution can be implemented to suit the monitoring goals of the power company’s business case. In addition, the communications front end (SmartCom RTU) enables the user to select different destinations for alarms and asset data, to suit respective applications and their data transaction intervals. Such applications include fault alarms for the network control room and asset loading data for the back office asset management.

Business Case justification varies across power companies but predominantly implies savings in manpower used for present load data monitoring, improved relation through reduction in SAIDA (CML) and significant delays in asset replacement/expansion from improved planning.

RESULTS

In this paper, many pilot projects for proof of concept will be described, from e.g. open conductors successfully detected on a network in Thailand, over full roll-out now in progress at an Australian power company where it is planned to monitor 17,000 MV/LV substations by 2012, to the completion of a fully planned implementation in Denmark.

CONCLUSIONS

The paper will confirm the practicality and acceptance by power companies at the forefront of Smart Grid initiatives of the need to dramatically increase the degree of network monitoring, now that a third generation distribution monitoring system, using state of the art optical sensors, is available.

Please note that this paper is suitable for any of the following sessions, particularly since there may be an oversupply of papers in the Smart Grid category.

IV- 2 Smart Grid

IV-5 Intelligent Control

IV-7 DMS

It will be written accordingly with the correct emphasis depending on which category the technical committee will select.

CV

James Northcote-Green (SM 1990) was born in Penang, Malaysia 1940. He graduated from Faraday House Engineering College, London (DFH 1st Div), University of New Brunswick, Canada (MSc.E.) and MacMaster University, Canada (MBA). He worked for English Electric and then Westinghouse Electric and then continued working with ABB after their takeover of Westinghouse. He has held many positions including head of Distribution Technologies and Planning, VP Technology for Distribution Solutions and Product Manager for Distribution Management Systems. He is now retired from ABB but acts as an independent consultant presently engaged as an Executive consultant for PowerSense A/S of Denmark. He has authored or co-authored over 60 papers in Powers Systems and is the co-author of the recently published book “Control and Automation of Electric Power Distribution Systems”, CRC Press. He is a Fellow of the IET of the United Kingdom (formerly the IEE).

Martin Speiermann was born in Copenhagen, Denmark, in 1974. He joined PowerSense A/S in September 2006 as VP of Sales and Marketing. Martin deals with the world's largest power utilities and is participating actively in developing the new rules of the next generation of the global energy markets.

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

Martin graduated in power engineering (B.Sc.) in 1998 and has attended several executive management programs at booth MIT Sloan and Harvard Business School.

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