Differential protection of multi-ended transmission circuits using passive distributed current sensors

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Abstract

Circuit protection for multi-ended feeders is traditionally implemented via distance protection or line differential protection based on data communication with proprietary protocols between multiple relays. Distance protection is often used in areas where there are poor or no communications; however, this method is not 100% accurate due to the throttling factor effect, and the setting strategy can be quite complex. This can lead to incorrect tripping due to accuracy levels or to drifting zone reach. Line differential protection, on the other hand, requires a protection relay at each feeder-end plus a robust telecommunications infrastructure. Often it also requires a reliable synchronisation system (GPS, 1PPs or others) at each line-end for the correct synchronisation of measurements in each remote relay device. This duplication of protection, and telecommunication equipment at each line end results in significant total costs for implementation of line differential schemes. Additionally, and particularly in older substations, space constraints can also limit the use of line differential protection. As such, operators seeking to protect multi-ended circuits are often required to utilise distance protection, resulting in complex system setting calculations and a reduction in the resilience and increase in the operate time of the scheme, and it is of interest whether new PAC technologies could address the issues associated with both approaches.

Distributed electrical sensing is a technology platform developed in the UK by Synaptec Ltd (a spin-out technology company from the University of Strathclyde). The approach allows measured values from up to 50 current transformers to be acquired passively using a single optical fibre core over a distance of up to 50 km. These measured values can then be utilised as part of centralised PAC schemes, or communicated to traditional PAC devices for analysis via IEC 61850-9-2 / 61869-9. By centralising current measurements, this method eliminates the need of having multiple protection relays at each line ends, complex time synchronisation systems at measurement points, and complex telecommunications equipment among the distributed PAC devices. SSEN and Synaptec are collaborating in the UK to demonstrate the application of this technology to the challenge of multi-ended circuit protection, with the goal to demonstrate reduced overall equipment costs, reduced infrastructure requirements, and faster installation of the protection scheme. By enabling line differential protection to be deployed on multi-ended circuits, the approach will offer improved protection accuracy in locations where distance protection would previously have been required due to space, cost, or telecommunication bandwidth constraints.

In this paper, SSEN and Synaptec report on the technical approach taken to design a passive, single-ended protection scheme for multi-ended circuits based on an innovative use of distributed sensing and the IEC 61850 process bus. The measurement system will output sampled value streams locally to protection relays supplied by major vendors which will deploy suitable protection algorithms. The paper will also set out the installation and testing plan: SSEN's Training and R&D Centre at Braco (Scotland, UK) will be the site of integrated testing to evaluate compatibility between equipment using the IEC 61850 standard. Following successful testing, the scheme will be installed on a live SSEN Networks 132 kV substation for operational testing, and will shadow the existing protection scheme.

The system will be monitored and analysed during operational testing to benchmark the approach against existing protection methods.

This project represents the first time that passive distributed sensors have been deployed for multi-ended circuit protection, and therefore this paper is likely to be of interest to PAC practitioners challenged with delivering affordable and resilient protection of multi-ended transmission circuits.

1 Introduction

1.1 Challenges of conventional schemes

Circuit protection for multi-ended feeders is traditionally implemented via distance protection or line differential protection based on data communication with proprietary protocols between multiple sites. Plain Distance protection is often used in areas where there are poor or no communications; however, this method is not 100% accurate due to the throttling factor effect, and the setting strategy can be quite complex. This can lead to incorrect tripping due to accuracy levels or to drifting zone reach.

Line differential protection, on the other hand, requires a protection relay at each feeder-end plus a robust telecommunications infrastructure. Often it also requires a reliable synchronisation system (e.g. GPS synch via PTP, PPS) at each line-end for the correct synchronisation of measurements in each remote relay device. This duplication of protection, and telecommunication equipment at each line end results in significant total costs for implementation of line differential schemes. Additionally, and particularly in older substations, space constraints can also limit the use of line differential protection. As such, operators seeking to protect multi-ended circuits are often required to utilise distance protection, resulting in complex system setting calculations and a reduction in the resilience and increase in the operate time of the scheme, and it is of interest whether new PAC technologies could address the issues associated with both approaches. The present technology being offered on the market is limited to 3-ended line protection only. Solutions beyond 3-ended lines require a more robust telecommunication infrastructure and may compromise on tripping time which is critical for transmission applications.

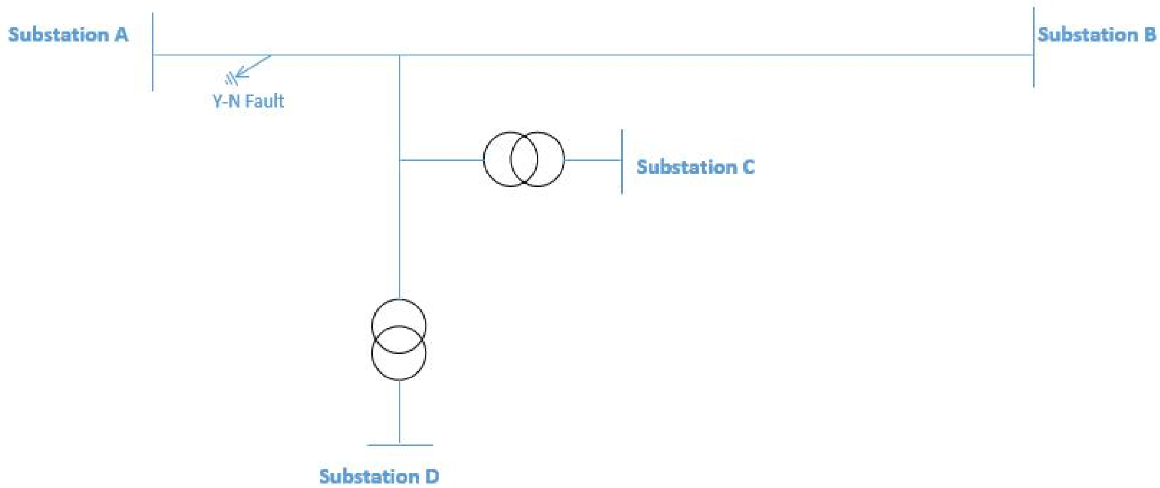

Figure 1. Existing case study network arrangement

To illustrate the challenges associated with conventional approaches, we provide the following case study. A system disturbance was recently observed on a UK transmission network, which saw a 132 kV circuit tripped by the main line protection at Substation A (Figure 1). The faulted phase was the yellow phase, contributing approximately 2 kA from Substation A, with the location estimated (via the travelling wave technique) to be 1.37 km from Substation D. The fault was cleared by the main line protection Substation A, with successful intertrip delivered to Substation B, Substation C, and Substation D. The following observations were made:

1. Substation B aided distance relay failed to operate, raising questions around the effectiveness of the relaying technique deployed, i.e. overreaching or underreaching due to superimposed (exporting/importing) load and/or fault resistance level.
2. The use of phase conductors in the fault return path raised questions about earth system performance.

Attention was drawn to the time taken for an intertrip to be received (125 ms). It was strongly suspected that Substation B's distance relay did not detect the fault (despite being within the zone 2 reach), and that the intertrip signal receive was simply the Substation A trip triangulated back on itself. This further suggested confirmation of the throttling effect observed during the trip.

1.2 Throttling Effect

Historically, most faults on multi-ended circuits are on the tee'd section towards Substation D in Figure 1. In this case when each respective relaying end is making its Distance to Fault (DTF) calculation (using relay-measured voltages and currents), it can't make an allowance for the infeed from the other end, and therefore the DTF result is naturally flawed. Therefore, considering the Substation A end:

1. The relay (or the DFR) calculates the impedance DTF based on volts and amps measured at Substation A
2. However, as the fault is on the Substation D leg, the relay at Substation A cannot consider the current from Substation B
3. Therefore, the calculation in 1. gives rise to a higher perceived impedance from the Substation A end than is the case.

This is a problem as it can cause distance relays to under-reach, which explains why the relay at Substation B failed to operate. This should not be characterised as a "Substation B fault" – rather, it is symptomatic of the network design.

The results read from different sources at the Substation A end:

- DTF from "TWS": travelling wave: 40.56 km
- DTF from "IDM": Digital Fault Recorder: 54.8 km
- DTF from Relay: 55.2 km, B-N

Summarising the results from the Substation B end:

- DTF from DFR: 94 km

The fact that both impedance-based techniques perceive the fault to be further away than the TWS demonstrates throttling in action.

The overreaching/underreaching behaviours of distance protection relays are caused by superimposed exported/imported load to fault currents and to the level of the fault resistance. Correct settings would require system studies considering superimposed load currents to fault currents and deep competence on dynamic behaviour of the distance protection relay used. This competence is often only available at the relay manufacturer. As user, the final choice is to set-up system studies where the relay protection behaviour is analysed, with real time network simulation and hardware (the protection relays) in the loop. These studies require a correct mathematic model of the power system that needs to be simulated (source impedances, line impedances, earth return impedances), they can be very costly and demand a lot of resources and competence.

1.3 Earth System Performance

The disturbance record from the Substation A clearly shows the yellow phase to be the faulted phase; however, there is significant involvement from the red and blue phases as well as the neutral current.

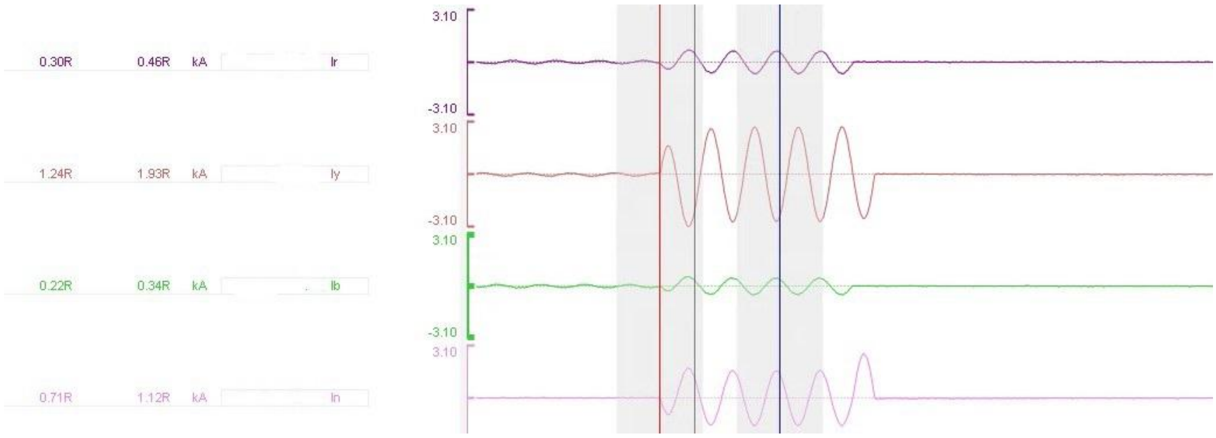

Figure 2. Fault Traces from DFR

It has been possible to sum the un-faulted phases and I_n for this event and overlay them on to the yellow phase current waveform, as shown in Figure 3.

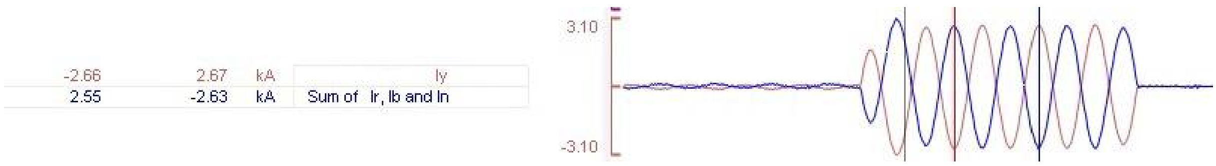

Figure 3. Summation figure

As can be seen, the currents are in anti-phase and demonstrates that the return path is established through a combination of the neutral (earth wire and general mass of earth) and the un-faulted phase conductors. Of the 1.9 kA delivered to the fault, 1.1 kA was returned via the neutral, and 800 A was returned through the un-faulted phase conductors.

This example serves to illustrate the following points:

- Line and power system parameters are fundamental for the correct settings of the line distance protection. They are not easy to estimate, especially in complex geographical situations. Especially for the earth return impedance, which is function of positive sequence and zero sequence impedances of the line/lines.
- The response of the distance protection relay to fault current levels, fault resistance values and through loads have also to do with relay settings (especially for load discriminator and/or resistive reach of distance protections)
- A differential relay would make the job in these complex situations much easier, even if it would lack the possibility to offer a back-up protection for external fault, but this can be achieved with simple overcurrent relays if it is necessary.

2 Description of passive current sensing mechanism

2.1 Background (LPIT, previously known as OVTs and OCTs)

Optical current transducers (OCTs) – a type of Low Power Instrument Transformer (LPIT) according to the IEC TC 38 definition – are now relatively well established and are developed by a range of manufacturers for their passive and highly accurate measurement of electrical current [1,2]. Presently, the most successful design is based on either spun or annealed optical fibre (to reduce shape-induced linear birefringence) that is coiled around the conductor or current path. The contour integral of the circulating magnetic field then yields a polarimetric or interferometric measurement of enclosed current based on the Faraday effect [3] that is immune to the influence of external or stray fields. Optical voltage transducers (OVTs) have also been developed, primarily based upon either the electro-optic (Pockels) effect or the piezoelectric effect [2,4].

Both established OCTs and OVTs rely on interferometric or polarimetric measurement techniques, and thus the distance from interrogator to a single measurement location cannot be greater than around 10-20 km. Additionally, as with conventional electrical transducers (CTs and VTs), it is not possible to discriminate between superimposed sensor responses, and thus serial multiplexing is not possible.

For these reasons, wide-area coverage, measurement over long distances, and high numbers of sensors are not presently achieved by optical current or voltage measurement schemes. It is therefore of interest whether a new technology can be utilised to develop wide-area sensor networks or efficient and safe sensor networks along complex or hybrid circuits.

2.2 Passive, wavelength-encoded current and voltage measurement

A platform was developed to allow standard single-mode fibre (conventionally used in digital telecommunication networks) to be utilised as a medium to serially-multiplex a high number of passive current or voltage sensors throughout a power network. In this section, a description of this core method is provided to enable the reader to understand the measurement mechanisms, benefits, and limitations of the technology.

A. Fibre Bragg gratings (FBGs)

Fibre Bragg gratings (FBGs) are periodic perturbations of the refractive index along a fibre core, having peak optical reflection at a specific wavelength, known as the Bragg wavelength [5], and a typical physical length of 5–10 mm. In sensor applications, their wavelength-encoding nature, coupled with their simple reflected spectra, means that FBGs are relatively easy to interrogate and multiplex, and are effectively immune to the problems of intensity fluctuations and attenuation [6]. For these reasons the FBG is now ubiquitous in the field of optical instrumentation [7].

Peak optical reflection from FBGs occurs at a wavelength λ equal to twice the grating period, i.e. at $\lambda/n = 2\Lambda$ where n is the fibre refractive index and Λ is the pitch of the grating. Thus, straining or compressing the fibre longitudinally at the location of the grating shifts up or down, respectively, the peak reflected wavelength. Illumination of the FBG by broadband light, and some form of peak wavelength detection and tracking, may therefore be employed to utilize the FBG as a strain sensor.

B. Passive measurement of voltage and current using FBGs

The authors have previously developed fibre-optic voltage and current point sensors, based on FBG technology, that have been applied successfully to power system plant diagnostics [8]. The complete optical sensor system has been shown to be capable of measuring dynamically changing signals and has been successfully used for detecting higher order voltage and current harmonics [9].

The transducer utilizes an FBG bonded to a multilayer piezoelectric stack, while the current sensor uses a small, high-bandwidth current transformer monitored by a dedicated voltage sensor as shown in Figure 4. In both cases an FBG peak wavelength shift can be calibrated in terms of voltage or current, while a temperature measurement can also be performed simultaneously using the same sensors to allow for active compensation of thermal sensitivity changes over a broad range of environmental temperatures.

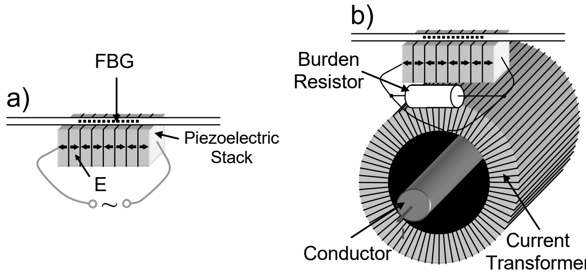

Figure 4. (a) Schematic of piezoelectric/photonic voltage transducer mechanism (b) Schematic of current sensor using CT and voltage sensing mechanism

It was demonstrated previously that these fibre-optic voltage and current sensors can be used for measuring variable frequency voltage and current waveforms for use in future aero-electric power systems [10].

2.3 Central multi-point measurement acquisition and processing

The generic architecture of an FBG sensor scheme is illustrated in Figure 5. Light from an optical source is guided by fibre to an array of serially-multiplexed FBGs. Reflections from all FBGs are returned via a coupler to the interrogating device, at which the peak reflected wavelength from each sensor is extracted.

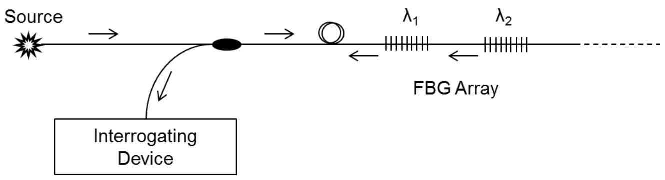

Figure 5. Schematic of general measurement topology illustrating the multiplexed and reflection-mode topology. λ1 and λ2 are peak reflected wavelengths.

The interrogating device can be thought of as a generalised implementation of a "merging unit", or merger, interrogating multiple multiplexed sensors by illuminating them and continuously analysing the light reflected from each sensor. Figure 6 illustrates the general architecture of a current measurement scheme based on this platform, where the merger is deployed in a substation (having an available auxiliary power supply and time-synchronisation source) and the sensors are deployed in the field where no power or supporting infrastructure is available.

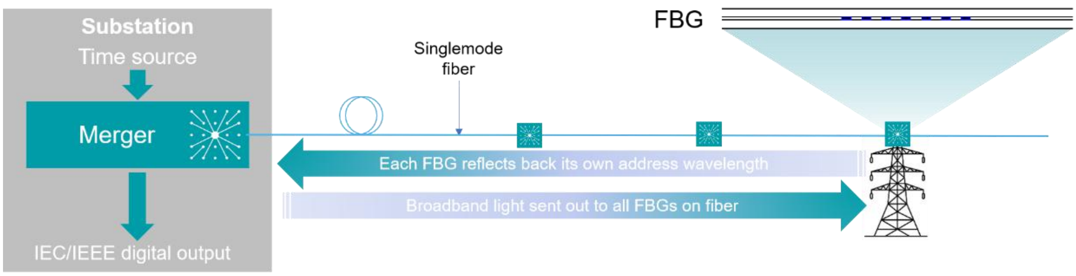

Figure 6. Example of current measurement topology on generic transmission line. A single merger is capable of measuring signals from 50 sensors over a maximum distance of 100 km.

The general architecture of the merger is set out in Figure 7. In the present deployment, a Xilinx Ultrascale 9EG is utilised as the core processing module, allowing functions to be deployed on an FPGA or real-time processor as appropriate. The system is based upon a broadband light source and receiving prism/CCD arrangement, with digital processing of the optical spectrum executed by the FPGA.

Voltage and current production and analysis, and the publishing of 61850-9-2 Process Bus sampled values, are managed primarily by the real-time processor. Recent work in collaboration with the University of Strathclyde demonstrated the merger's compliance with the IEC 61850-9-2 standard [11]. The project is concentrated on SV data stream according to IEC 61850-9-2 LE (Light Edition) profile for practical reasons, but aims to be able to support the protection applications profiles indicated in IEC 61869-9.

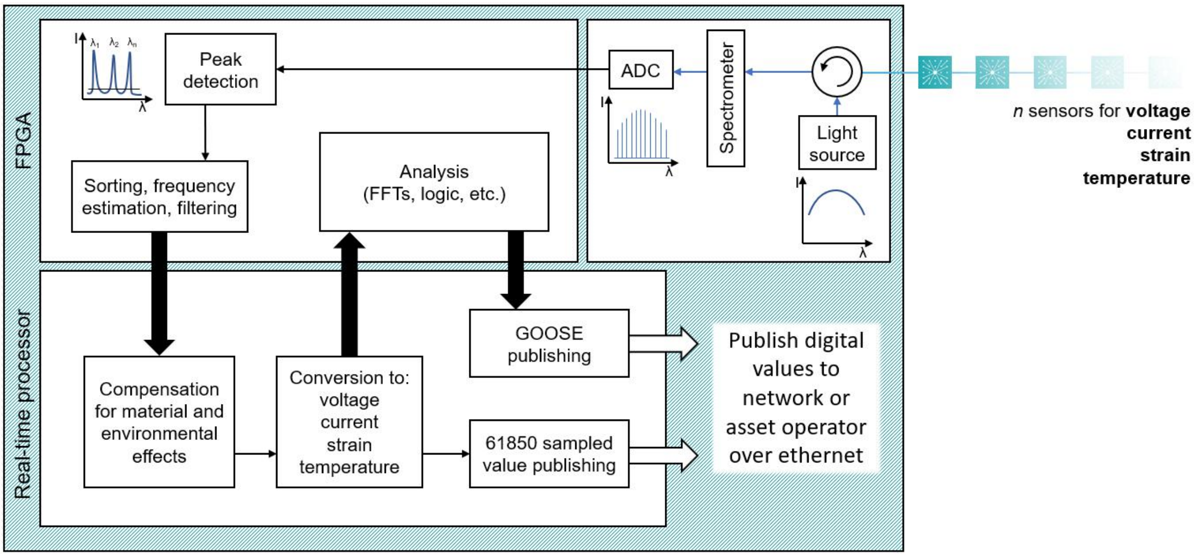

Figure 7. General architecture of Refase merger

The limitation of the present embodiment is interrogation of up to 50 sensors over a maximum distance of 100 km from the merger. This platform can be used for a variety of innovative applications on power networks to reduce costs by allowing protection and control systems to gather time-synchronised, accurate measurements cost-effectively over wide-areas or around digital substations. In the next section, we set out how the platform is being used to implement multi-ended circuit instrumentation to improve the resilience of the protection scheme.

3 Overview of multi-ended circuit instrumentation scheme

The instrumentation system detailed above will be tested as part of a UK innovation project in collaboration with the TSO SSEN and Andrea Bonetti (Megger). The system's output sampled values shall stream locally to protection relays supplied by major vendors (ABB, GE, and SEL Inc.) which will deploy suitable conventional protection algorithms. SSEN's Training and R&D Centre at Braco (Scotland, UK) will be the site of integrated testing to evaluate compatibility between equipment using the IEC 61850 standard. Following successful testing, the scheme will be installed on a live SSEN 132 kV substation for operational testing, and will shadow the existing protection scheme. The system will be monitored and analysed during operational testing to benchmark the approach against existing protection methods. Figure 8 below illustrates the multi-ended scheme to be tested and deployed.

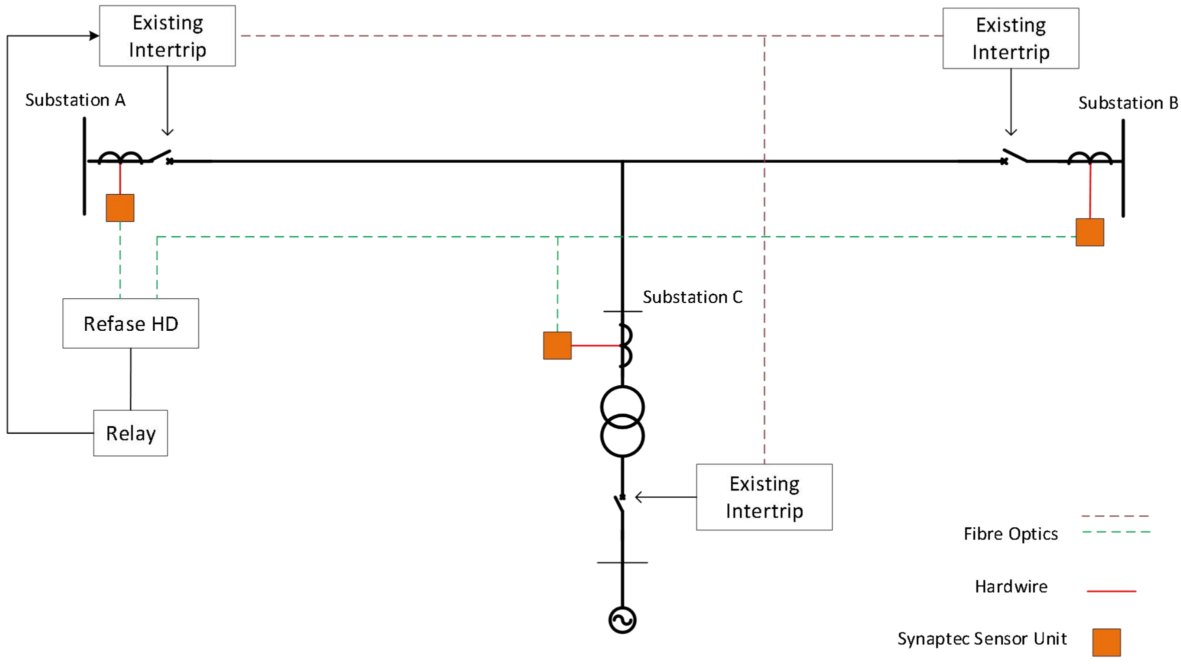

Figure 8. Overview of deployment in SSEN multi-ended circuit scenario

The instrumentation system ('Refase HD') shall acquire passive (no power supply) measurements of the phase currents at each terminal of the chosen three-terminal transmission circuit. These measurement data are published in 61850-9-2 sampled value format at a single end, where an appropriate protection algorithm shall run on a selection of 61850-enabled relays provided by protection IED vendors (Figure 9).

The system will be monitored during the operational testing and the data gathered will be assessed by the relevant teams. An evaluation will be completed at the end of the trials; with recommendations of the system's suitability for transfer to business as usual.

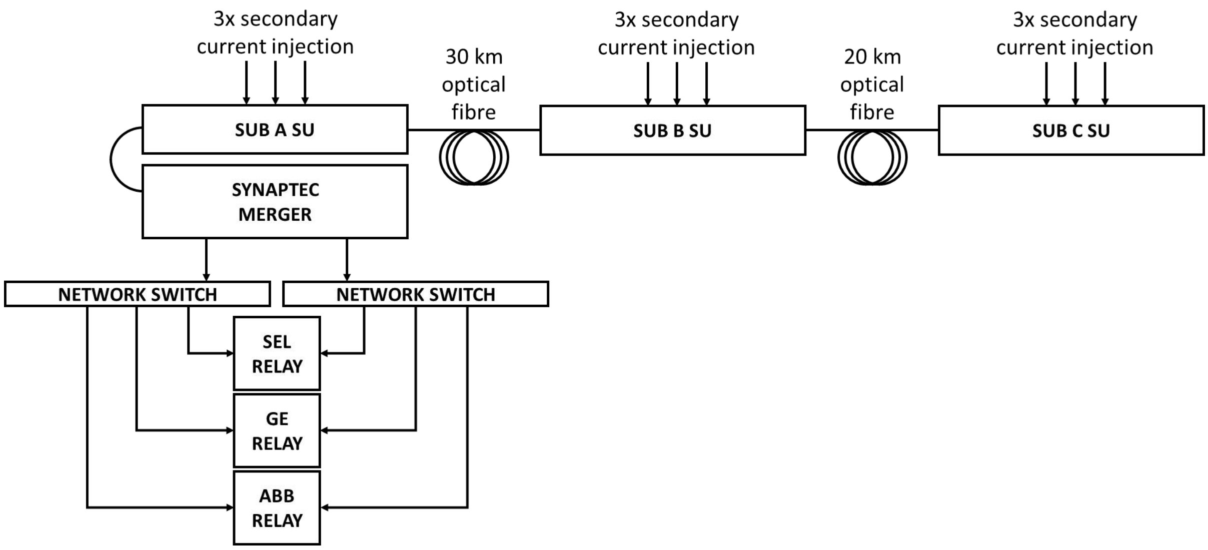

Figure 9. Schematic of system under test at Braco R&D Substation. SU is Sensor Unit.

Using the reported technique compared with line differential protection could substantially reduce capital expenditure per installation since the method negates the need for multiple protection relays, GPS Grandmaster clocks and other communications infrastructure. The system could also offer improved protection accuracy in locations where distance protection would have been required due to space or communications constraints. Using the reported technique in place of distance protection could reduce the likelihood of incorrect tripping at specific locations.

4 Discussion of platform and interoperability

In this section, a brief discussion is provided on the performance and interoperability testing that will be conducted by the authors on the platform as used to underpin multi-ended circuit protection.

Three differential protection relays from three different manufacturers operating on the same data offered by the central processor (Refase's "merger"). In this work, the central processor (Refase's "merger") can be seen as a Stand Alone Merging Unit (SAMU [12]), where the input analogue quantity is the secondary current of one (or more) conventional CTs, and the digital output is according to the SV protocol IEC 61850-9-2 LE (and/or IEC 61816-9 in the future [13]). While interoperability at protocol level between the Merger and Protection IEDs is not expected to create any particular problem, the functional interoperability between SAMU and IED is of much interest from the correctness (dependability and security) of the protection algorithm point of view: i.e. the selectivity to correctly operate for internal faults (dependability) and stability for external through faults (security) or in presence of no fault at all, but maybe load with harmonics, frequency deviation etc. The IEC standard for SAMU has not yet been published for use (IEC 61869-13) but a lot of information is already available in IEC 61869-6 [14] and other standards of the same series. The dynamic behaviour of the SAMU, or of any Merging Unit (MU) in general, is of fundamental importance for the relay protection algorithm [15], especially for those with instantaneous trip decision. It is for this reason that the data from the is delivered at the same time to three different differential protection relays from three different manufacturers, to be able to study the behaviour of three different protection algorithm implemented by three different manufacturers, in respect to the same behaviour of the Merger.

It could be expected that some adaptations in the output transfer function of the instrumentation system might be necessary, or in the digital filters of some protection IED or in both protection devices and SAMU, to optimize the behaviour of the protection system.

It has also to be noticed that many relevant IEC standards where dynamic performances of process bus are involved are not ready yet, at TC 38 level (Instruments transformers) and also at TC 95 level (Measuring relays and protection equipment). From the relay protection standards available today (IEC 60255-1xx series, from TC 95 / MT 4), it is understood that performance testing with process bus applications shall be carried by mutual dialog between the parties involved, merging unit manufacturer and protection device manufacturer, together with the system integrator and the final customer [16,17].Tests of the protection system will foresee steady state accuracy tests, where the measuring and time synchronisation systems are accurately checked. Also, it is of interest to check or verify the transfer function of the SAMU (Merger), in accordance with IEC 61869-6. After that, dynamic tests will be performed, where the dependability and security of the protection system will be proven for the dynamic conditions that the team will consider important for the protected power system (time constant of the fault currents, levels of the fault currents, behaviour for eventual evolving faults, presence of harmonics etc). These tests are inspired from the tests and definitions found in IEC 60255-1xx protection function series.

In addition to the behaviour for power system electric transients (dynamic power system behaviour), the protection system will be checked for the robustness towards analogue data (sampled values, SV) transmitted in non-nominal conditions, this means for example when the Merging Unit detects an internal failure or detects other events that require it to deliver analogue data (SV) with invalid or questionable quality to the protection devices, during normal load transfer conditions. Another example is the failure or loss of time synchronisation. This seems to be not a serious problem for this particular application as the SAMU is only one device, and the Sampled Values data streams delivered by it do no strictly require the presence one external time synchronisation, as the device can count on its own clock for synchronizing all the data streams. However, it is of interest how the Merger provides passive time-stamping of the remote terminal measurements, and therefore how the IEC 61850-9-2 contents should be adapted for devices that provide absolute time-stamps.

5 Conclusions

This project represents the first time that passive distributed sensors have been deployed for multi-ended circuit protection, and therefore the authors hope that this paper is of interest to PAC practitioners challenged with delivering affordable and resilient protection of multi-ended transmission circuits.

The paper has described a methodology for passive (power supply free) measurement at line ends without complex telecommunications and with reduced equipment requirements. We have also described the general architecture for deployment and discussed the considerations given to acceptance testing and integration of such a new approach into the established IEC 61850 architecture.

This project is one example of cooperation between instrumentation and relay protection manufacturers, under the umbrella of the final user, in this case a TSO. Fully in accordance to the spirit indicated by IEC 60255-1xx relay protection series, in applications for process bus, until the IEC 60255-1xx series will be fully integrated with requirements for IEC 61850 (non-conventional) applications.

Results from the acceptance testing of the combined instrumentation and protection scheme will be able to improve the performance of all the components of the protection chain, but also to feed the IEC groups that are actively working on creating standards for IEC 61850 protection applications (TC 38, TC 95 in particular).

It has to be noted that IEC 61850 is a core standard for Smart Grid, according to IEC. There is no electrical grid that doesn’t need to be protected, so any improvement in protecting high voltage power systems, is an important piece of improvement for protecting the smart grid.

It is expected that the work presented in this paper will lead to follow-on work on the use of such platforms for combined differential and distance protection, investigation of the dynamic behaviour of the instrumentation system, and demonstration of other novel protection functions including auto-reclose blocking on hybrid circuits or centralised busbar back-up protection.

An important follow-up to this project would be the implementation of the system on real time power system simulators, where the transient response of the merging unit (Refase) is modelled in the simulator. The output, in sampled value format, is then delivered to the Hardware in the Loop (HIL) protection devices that are tested in real time, reproducing events observed in the existing physical system. This would be an important step towards the implementation of models for the merging units. These models are very important, similar to CT and CVT models, for relay type-testing, relay acceptance testing, and the determination of relay requirements for CTs and for merging units.

6 About the authors

Philip Orr is the Managing Director and co-founder of Synaptec. He is a member of the IEC SC86C working group on fibre optic sensors, and co-inventor of Synaptec’s core technologies. Prior to founding Synaptec, Philip was a Royal Academy of Engineering Enterprise Fellow, based at the University of Strathclyde’s Institute for Energy and Environment. He holds a PhD in photonic instrumentation for fusion reactors in collaboration with the UK Atomic Energy Authority, and is the recipient of various engineering awards, including the Sir William Siemens Medal and the EPSRC Doctoral Prize. He has around 35 publications and three patents in the areas of photonic sensing and power system instrumentation.

Ahmed Mohamed is Graduated as an Electrical Power Engineer from Helwan University- Egypt on 2005. He is working as Protection and Control Engineer since 2006. Started in Egyptian Electricity Transmission Company (EETC) then moved on 2008 to Dubai Electricity and Water Authority (DEWA) and from 2013 till date is working in Scottish and Southern Energy Network (SSEN), Glasgow, UK. He is working in the Transmission sector as a P&C Engineer for the large Capital Projects and involved in a different innovation projects which is handling/utilising the digital Input for the protection relays and Process bus implementation.

He is a member of the IEC TC 95/WG 2 “Protection functions with Digital input/output".

Mohseen Mohemmed is an Engineering Manager working for SHE Transmission plc in Glasgow, UK. Sharing responsibilities for Protection & Control aspects for delivery and innovation projects within Transmission. He took his career in Transmission sector after graduating from Robert Gordon University, Aberdeen in 2002. He gained various experiences within the industry by working on contracts with wide range of utilities for over a decade. During this period of work with Balfour Beatty Engineering Services, he worked on all transmission voltage levels. He is involved with innovation team looking at the prospects of using emerging technologies for current and future projects of SHE Transmission plc.

Contributed in the first commissioned fully interoperable IEC 61850 station bus substation in SHE Transmission which is only the first of kind for UK. Now reviewing the task of next stages for full IEC 61850 implementation starting with process-bus trails.

Andrea Bonetti graduated as electrotechnical engineer at Sapienza University of Rome, Italy, in 1993, after having studied the first two years of engineering at Universitá di Trento, Italy.

After five years in ABB Italy as protection engineer, Andrea worked 10 years as HV relay protection specialist at HV relay protection manufacturer ABB Grid Automation Products in Västerås, Sweden, for relay post-fault analysis, relay settings, commissioning support and training for distance protection, line differential protection, with IEC 61850 and conventional applications.

From 2008 to 2013 Andrea worked at Megger in Stockholm, as product manager and technical specialist for relay test equipment, dealing with the development of IEC 61850 test set and tools, test algorithms for distance protection and transformer differential protection relays.

From 2013 to 2018 Andrea worked as consultant in Relay Protection and IEC 61850 Applications: procurement specification for TSOs, IEC 61850 specification and attendance for FAT/SAT, IEC 61850 troubleshooting in operative substations, trainings, IEC 61850 top down specification and engineering process, development of IEC 61850 test equipment and tools.

From April 2018, Andrea works at Megger in Stockholm, as senior specialist in relay protection and IEC 61850 applications.

Andrea holds a patent in the area of IEC 61850 testing tools and algorithms.

Active member of the IEC TC 95/MT 4 since 2006, Andrea has been sub-group leader for the development of the IEC 60255-121 standard and has received the IEC 1906 Award in 2013. He is also member of the IEC TC 95/WG 2 “Protection functions with Digital input/output".

Since 2008 Andrea is a guest lecturer at KTH (Royal Institute of Technology, Stockholm) for IEC 61850 for substation automation applications.

Neil Gordon is the Lead Engineer at Synaptec, and previously was a doctoral researcher at the University of Glasgow. Neil contributed to the Nobel Prize-winning first detection of gravitational waves in 2015 and has over 30 publications in the areas of photonics and instrumentation.

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