We live in the age of the “information super highway” where instant information can be obtained immediately at the touch of a button. Technological advances have permeated our lifestyles and have had an impact on all sectors of the economy and industry.

Power utilities are no exception where challenges of ever increasing electricity consumption, coupled with regulation issues inter alia, have resulted in the introduction of innovative technologies that are aimed at ensuring that utilities are operated in an efficient and effective manner.

A number of Eskom’s substations are either due for refurbishment or upgrade, on account of having outlived their design lives. This might be an opportunity for Eskom, as well as other utilities in a similar situation, to embrace and introduce newer and emerging technologies such as substation automation and the concomitant IEC 61850 standard.

This paper discusses the practical aspects and operational challenges likely to be faced by most utilities like Eskom should they decide to implement substation automation as part of their substation upgrade strategy.

The paper is intended to create awareness of some of the issues that need to be taken into account and which are often glossed over when considering substation automation projects. It is hoped that the paper will also stimulate interest among all engineers on the evolving IEC 61850 body of knowledge which is in stark contrast to the traditional and established way of doing business in most utilities.

There has recently been a plethora of literature and articles written on the IEC 61850 standard on substation automation which was adopted as an international standard in 2004. For example, at the last Power System Protection Conference Symposium held at Eskom College in November 2006, no less than five IEC 61850 standard related papers were presented. The papers ranged from the various relays manufacturers’ submissions on their achievements and compliance of their products to the IEC 61850 standard, to operational experience learned from implementation of substation automation projects either as green fields or as part of refurbishment projects in Europe and in the USA. The topics generated a lot of interest and discussion.

What then is the significance of the IEC 61850 standard, one might ask. Those in the protection, telecontrol and communications fraternity, will no doubt be aware of the phenomenal technological changes that have taken place in terms of the functionality and processing power of protective relays that are now available on the market. Furthermore there has been a convergence of sorts in terms of functionality resulting in the modern relay being able to perform many more functions that were hitherto performed by separate devices.

To put matters into context, a brief history of relay developments is given.

To borrow from the Eskom (Distribution) lexicon, a Phase 1 relay refers to the old electromechanical type with moving parts and with no provision for data communication capabilities. These relays are, to all intents and purposes, now obsolete and are slowly being phased out from the Eskom network.

Phase 2 or static relays use solid state devices. These are analogue relays, not microprocessor based relays, which also do not have data communications capabilities.

Although a number of these relays are still functional, these relays have also come to the end of their design life and are currently being replaced within Eskom.

Phase 3 relays are sophisticated microprocessor based relays with internal self-supervision capabilities over and above their data communication capabilities.

Although these microprocessor based or digital relays contained some form of intelligence such as remote access, they suffered from one major drawback, namely that the protocols used were supplier specific. In other words two similar relays supplied by different manufacturers were unable to talk to each other and some form of a protocol convertor is then required to enable the two relays to talk to one another. Given the vast number of relay manufacturers, it is patent clear that the inability of relays supplied by different manufacturers to communicate with each other is a major disadvantage and adds to utility costs of doing business in terms of additional protocol convertors that are required to facilitate communications between the relays.

It was partly to mitigate against the above outlined constraints that relay designs have continued to develop to the present range of protective relays which are now so enhanced in functionality that they are called “intelligent electronic devices” or IEDs. The definition of an IED can be generally said to be an electronic device possessing versatile protection functions, advanced local control intelligence, monitoring capabilities and the ability to directly communicate to a SCADA system.

These IEDs can be connected via a substation Ethernet LAN network to enable communications amongst the relays as well as among other devices that are compatible. It must be said that various relay manufacturers have come up with products or devices that meet the criteria of being defined as an IED. As earlier mentioned, the snag has always been that the software used to communicate with the relays has always been proprietary such that a relay/device supplied by for example Alstom/Areva is unable to talk or communicate with a similar device supplied say by ABB.

With the international adoption and implementation of the IEC 61850 standard in 2004, relays compliant to the standard and supplied by different manufacturers are now able to talk to one another i.e. there is now interoperability between the relays supplied by different suppliers. Relay interchangeability is not yet possible though.

It is also worth mentioning that the adoption of the IEC 61850 as an international standard comes at a time when research in the introduction of newer technologies in the substation primary plant is also at an advanced stage. Specifically:
• Progress has been made in the development of non-conventional instrument transformers such as current transformers and voltage transformers.

• Concurrent to the development of the non-conventional instrument transformers cited above, are other substation devices called merging units. These are basically interfacing units that can accept analog and binary inputs to produce processed digital outputs for transmission over a process bus within the switchyard.

Given the above scenario of intelligent relays installed in a control building and networked via an Ethernet substation LAN, coupled with the installation of a substation process bus to which is wired analog and digital inputs from the substation bays, the stage is set for a substation automation implementation. This would be completed by wiring the outputs of the merging units to the substation Ethernet LAN via suitable optic fibre cabling in place of the conventional copper cabling.

Impact of IEC 61850 implementation on utilities

It is no exaggeration to state that in the long term, most forward looking utilities will move with the times and embrace substation automation in the course of their business. Outlined below is an analysis of some operational problems and challenges which might preclude effective implementation of these newer technologies.

The present set up in most utilities is such that there are specialists with specific responsibilities for the maintenance and upkeep of the various equipment found in a substation as outlined below:

• Telecontrol engineers and technicians, responsible for such equipment as RTUs and IDFs. Telecontrol staff draws the specifications, protocols and source the equipment for needed for telecontrol purposes.

• Protection engineers and technicians, responsible for the sourcing, specification, maintenance, data uploading and downloading of the protection and control devices found in substation.

• Telecommunications staff, responsible for the communications equipment such as the BME, power line carriers, VHF radios, etc.

• Field operational staff under the authorisation of the respective system controllers, responsible for the operational side of things, such as equipment switching either from the local or control panels depending on the extent of automation at the substation.

Currently all of the above specialists operate in an independent manner and have specialised skills and capabilities confined to their areas of expertise. The introduction of intelligent electronic devices, which now include all of the above mentioned functions of protection, telecontrol, communications and metering functions, now presents a dilemma of who is to be responsible for the sourcing and maintenance of these devices.

Most power utilities are presently experiencing a dearth of specialist staff notably in the field of power system protection, and the situation can only be exacerbated by the introduction of newer technologies. It is submitted that unless utilities take appropriate proactive measures to ensure that staff of the right calibre is identified and trained, utilities will forever be reacting to events and playing catch up on substation automation related matters.
This unfolding scenario is perhaps a wake-up call to utilities’ specialists to embrace multiskilling as the way forward. Instead of viewing oneself as a protection engineer or a telecontrol engineer, the need for versatility is emphasised.

It will also become imperative for management to adopt a paradigm shift in mindset in terms of embracing substation automation and its attended ramifications. As indicated above, the functional overlap inherent in these devices calls for a rethink and redefinition of present day specialists. In future there will be no separate RTU, neither will there be a standalone protection relay or a BME panel. All of these devices are incorporated into one device and that begs the rhetorical question: where do you draw the line between the various specialists. Who is going to be responsible for specifying the merging units, the process bay and substation Ethernet LANs with the associated accessories? LANs are normally the forte of IT personnel who unfortunately have little or no experience of power system substation requirements.

One of the benefits of substation automation has to do with automated switching operations. Although it might sound somewhat esoteric, the network can be re-configured automatically in response to certain exigencies e.g. a transformer can be completely isolated and earthed without human (operator) intervention at all.

Existing operating regulations similar to the Eskom ORHVS will have to be drastically reviewed to incorporate the emerging technologies. Revision of the operating regulations will entail amongst others, reauthorisations of personnel in order to ensure that they fully comprehend the newer operational requirements and technologies. Unless properly coordinated, the exercise could turn out to be taxing and time consuming. The controllers at the control centres on the other hand, will also need to be retrained with regard to the whole process of issuing and managing switching procedures as most of the activities that used to be carried out manually will now be automated.

Utility maintenance policies and procedures might have to change in order to embrace the modern equipment. This is on account of the fact that IEDs have inherent features such as primary plant e.g. circuit breaker condition monitoring capabilities. Implicit in this condition monitoring capability of the IED, is the fact that utilities might see an advantage in performing maintenance on a needs basis as opposed to adoption of a time based maintenance policy.

Yet another challenge brought about by adoption of substation automation has to do with the need to learn the newer technical terms and jargon associated with the technologies – substation automation geek, so to speak. Terms such as GOOSE (generic object oriented substation event) messages, MUs (merging units, peer to peer messaging, substation configuration language (SCL), etc., are vogue terms that have to do with the IEC 61850 standard. It thus behoves all personnel involved in the installation, commissioning and operation of these devices to familiarise themselves with these new terms and fully understand their meaning.

Conclusion

Implementation of substation automation using IEDs, via a substation Ethernet LAN is now possible, and utilities are now able to assess the viability as well as verify the financial benefits to be derived from total integration of functionality offered by the new devices.

Whether the projected financial savings arising out of the reduced amount of copper cabling, when compared to the installation of a substation LAN, inclusive of accessories and other contraptions, will actually be realised or not is a moot point.

What is certain however, is the fact that a utility that follows the substation automation route faces real challenges of an operational and technical nature. Old ways of doing things just won’t do and the offerings embedded within the new products need to be exploited to the full.

The much talked about need to conserve energy in light of the looming power deficits in the Southern Region due to rising power demand is well known. The point is made that careful selection and operation of a substation control and automation scheme can assist utilities to run their networks efficiently to the benefit of all stakeholders.

As mentioned elsewhere in this paper, a total change in the way the system is managed and controlled is required if the benefits of investing in substation automation are to be realised in full. This change in approach towards system control will affect personnel from across the entire spectrum of utility staff from top management to the Controllers and operators on the ground. The need for more staff to be au fait with computers cannot be overemphasised – the HMI interface at the substation will assume a critical role as the interface between the process and control areas.

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References

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