SUBSTATION COMPONENTS
PLUG AND PLAY INSTEAD OF PLUG AND PRAY
The impact of IEC 61850

M.C. Janssen
KEMA T&D Power

C.G.A. Koreman
KEMA T&D Power

1. INTRODUCTION

For almost two decades electric utilities throughout the world have implemented substation automation systems in their transmission and distribution substations. Utilities decided to invest in new technologies for the control of their substations based upon promises that for example engineering would become easier and operation and maintenance costs would be lower.

Based upon the first experiences with substation automation systems both utilities and manufacturers have found that most of the initial promises could not be fulfilled. It proved that especially the “learning curve” for both manufacturers and utilities was longer than expected. Furthermore the lack of international standards in certain areas such as telecommunications for substations as well as the proprietary approach chosen by most manufacturers led to many debates regarding the applicability of automated systems in substations.

Nowadays utilities strive to be competitive and therefore wish to improve their efficiency and reduce costs. At the same time the manufacturers can no longer afford to invest in the support of proprietary solutions used by their competitors. We therefore are at the point of no return in this industry where the "old ways of doing business" must change.

All of these factors have led to a situation where the overall life cycle costs of the high voltage infrastructure and its components are key. When considering systems for protection and control the initial investment, time to build, operation and maintenance, refurbishment and the systems flexibility are the main aspects that utilities and manufacturers struggle with.

In the new corporate culture, utility engineers must consider changing the traditional approach to engineering. Fundamental changes may be required to meet the competitive challenges of today. The development of microprocessor based Intelligent Electronic Devices (IEDs) has provided the utility engineer with the ability to meet these challenges in new ways not previously envisioned. The application of microprocessor relays provides significant cost savings over the previous generations of static and electromagnetic relays. The integration of digital based station IEDs on a common substation LAN provides even more functionality and reduced costs.

The introduction of higher level protocols in IEDs has enabled basic communication in the substation. However, due to the proprietary nature of the applied protocols, only communications between like devices was possible, without the use of protocol converters. The IED protocols were also limited in capability including speed, functionality and services. The capability of these devices to provide necessary throughput of data was limiting possible substation applications. This profusion of protocols required the engineer to understand the varied protocols as the IEDs are applied in substation protection schemes. It is apparent that a non-proprietary, standard, high speed, protocol, offering sufficient services was required. This would enable a robust, integrated substation communications network, without protocol converters.

With the introduction of IEC 61850, “Communication Networks and Systems in Substations”, the capability to integrate station IEDs is now possible and justifiable through <u>standardisation</u>. The standardised high-speed communications between IEDs allows the utility engineer to eliminate many expensive stand-alone devices and use the sophisticated functionality and the available data to their full extend.

2. UTILITY REQUIREMENTS FOR PROTECTION AND CONTROL

The introduction and application of new technologies in high voltage and protection and control systems in substations depends on various factors. These factors are determined by the strategic environment where the utility has to perform its business and the organisational structure involved. In particular their view on cost, reliability, maintenance and operational need to play a crucial role.

Nowadays the electric utility industry is experiencing a period of rapid and unpredictable changes. External forces mainly cause these changes. As in other fields, governments are moving away from direct control of the electrical industry, and are encouraging competition. The response of the electric utility industry to these changes is not uniform. There is a group that welcomes these changes and strongly believes that the changes will be attended by unprecedented dynamics in the electric utility industry. On the opposing side there are others who associate changes with a threat and believe that the current high efficiency of the electric utility industry is endangered. Anyway on both sides it is believed that these changes will positively influence the rate of deployment of new technologies.

Constraints for protection and control

The management of the existing power system assets is a major task for power companies and utilities. The introduction of new digital technologies in substations has to contribute in a positive sense to this target. Several factors emanate from the power system that influence the configuration and the acceptable level of new technologies within substation protection and control equipment.

All utilities and companies operating power systems have a variety of existing substation designs. Some of these variations are due to substation size and voltage level; others are due to different switchgear technologies being deployed, such as air blast or SF6, the location of the equipment within the substation, etc. Before installing any new technology, end users need to assess how well the offered solutions fit the variety of substations under their control.

In general substations can be divided into two main types depending upon whether the protection and control equipment is centralised in one location, or decentralised around the site. In the decentralised case, three further subdivisions exist, each with a recognised construction:

- on MV circuit breakers, the protection and control equipment can be mounted directly onto the circuit breakers
- with gas insulated switchgear, the panels for protection and control can be placed adjacent to the GIS to form a complete integrated module with the high voltage system
- with large open terminal substations, it is common to employ relay houses or bay kiosks close to the high voltage installation to house the bay level equipment

Modern methods of substation construction favour those types that demand less floor space. Non-conventional solutions and designs such as tapped transformers become more and more common. Apart from that there is a preference to maximise the construction work done at the manufacturer's factory and minimise the activities at the construction site, the GIS module being one example of this approach. The protection and control system has to be applicable to both existing and new substations, therefore the need to consider all types of construction remains.

Within those countries with little or no overall growth in electricity demand, utilities and power companies are not building many new substations. The need will thus shift to upgrading existing assets in the most effective way. This includes substations that are in urgent need of modernization. There are four potential approaches:

1. complete substation refurbishment
2. complete protection and control system refurbishment
3. complete function refurbishment, e.g. protection
4. individual equipment refurbishment, 'as needed'

The engineering attraction of total substation refurbishment is somewhat obvious, in that it represents the best long term opportunity to bring the complete substation up to modern standards. It also offers the least number of engineering constraints. However, the costs of total refurbishment forces the decision-makers to examine the potential of other solutions.

The limited evidence available indicates that utilities are prone to refurbish only those elements that genuinely need replacing. As it is rare for both the high voltage and protection and control equipment to reach their end of life at the same time, complete substation refurbishment is proven not to be common. Conventional protection and control equipment has a typical life time expectancy of 20 to 25 years, while primary equipment can last for 50 years. End users can also find that they have recently upgraded part of the protection and control system, e.g. the disturbance recorders. It seems illogical to throw away such equipment, and to replace it with more modern versions.

The evidence available supports the view that each utility will come to its own best refurbishment method. This may even vary from substation to substation, as the economics of different constraints are met.
Despite the diverse arguments for and against each approach, one conclusion that can be drawn is that those designs of new protection and control systems that cope well with partial refurbishment are likely to meet the broad range of requirements better than those that are optimised solely for new substations. The need is for flexibility to cover both new substations *and* the refurbishment of old substations.
This supports a modular approach to substation system design, where functional modules can be installed and made operational on a ‘stand alone’ basis. Where these same units can later be interconnected by serial data links to make an integrated system, the benefits of both approaches will be met. This is the optimum solution, as it meets the greatest number of the known practical constraints.

Life cycle cost control

Substation related costs break down into three main areas; initial investment, operational, and maintenance, each of which has its own impact on the overall life cycle costs of a substation. Reduction of the costs in one of these areas does not necessarily lead to lower overall life cycle cost. It is important that through combinations an optimum is achieved.

Initial investment cost: The engineering and erection costs of new substations are lower when the amount of installed hardware is less, while the construction time reduces. Pre-testing of the protection and control equipment can be carried out at the manufacturer’s site, instead of on-site. This can tighten time-scales, reduce costs, and accelerate the initial flow of revenue.

Operational cost: These costs could be reduced by the increased availability of information about the status and capabilities of the high voltage equipment. This would allow higher loading of the system and potentially delay equipment replacement or extension. Investment in new systems for protection and control could include enhanced remote control functions and / or condition monitoring of the high voltage system. It is predicted that the pressure to reduce operational manpower will create a need to automate more of the day to day operations within substations. This could become a major factor in decisions to upgrade systems. Automation can both reduce operational costs and improve quality of supply to consumers by cutting the average period of disconnection. Quality of supply is a measure that is being introduced to assess electricity suppliers.

Maintenance cost: The total maintenance cost of the installed equipment needs to be evaluated and possibly reduced. The maintenance of the protection and control equipment will probably demand higher skills because of the increased complexity of the system, especially once the substation is live.
However, the maintenance requirements for the high voltage equipment will decrease when diagnostics and monitoring tools are introduced. For example, it is forecast that the introduction of an effective condition monitoring scheme will allow utilities to move away from relying totally upon regular maintenance periods. The alternative approach being discussed is that of an event driven strategy, where the need for maintenance would depend upon detecting changes in one or more identified measurands. Within the protection and control equipment, the maintenance philosophy will be supported by further developments in the error detection and the automatic supervision of modern digital hardware.

Reliability and maintainability
Given that the protection and control system protects and controls the high voltage system, then the financial implications of a lack of reliability at the protection and control level represent monetary values far in excess of the cost of the protection and control equipment itself. It is therefore critical that the design of any system can match the operational needs, in terms of reliability and the ability to maintain all equipment. Continuation of supply to consumers, and avoidance of unnecessary outages are fundamental.

Reliability of protection and control systems: Under normal operating conditions, every function will be performed by the integrated protection and control system. However, in the event of a failure, the protection and control system will become degraded in some way. To control the consequences of failures, it is preferable if some less important functions are designed to temporarily fail so that the more important tasks remain continuously available. This means that the required reliability for each function will be different. Actual availability figures for functions cannot be given because they depend on various parameters such as the voltage level and the layout of the high voltage network.

Dependability and security: Protection specialists divide reliability into two further sub-classes, referred to as dependability and security. This is because protection rarely operates, and when it does, it has important consequences. Basically, by tripping circuit breakers, protection disconnects major parts of the grid, and any incorrect operation can lead to an unnecessary loss of consumer supplies.
When a fault occurs, the protection in charge of the faulted 'zone' of the power system *must* operate, but all other protection looking after other zones *must* restrain from operating. Consequently, if protection operates when it should, then it is 'dependable'. If protection remains stable, and does not operate when it is not meant to, then it is 'secure'. The two factors are inter-related, and design actions to improve one quality normally reduce the other.

Redundancy: It has been standard practice within protection and control systems to use redundancy to improve the reliability of critical functions. Generally it takes three forms:
- redundancy to cover a defect in a device
- redundancy in protection functions by using alternative operating principles
- redundancy to cover planned outages

Being safety and / or power system stability related the reliability demanded for protection functions is usually much higher than for other functions. In another context, the need to have a reliable fault clearance can demand alternative systems. This approach can be observed for instance in generator protections.
Given the high voltage system consequences of a lack of protection and control system reliability, it is expected that end users will continue to demand equal or better reliability for all critical functions.

Self checking: With traditional segregated protection and control systems, few functions are lost when a hardware unit fails. Such failures are likely to remain undetected until the next required operation or until the unit is maintained. This is not acceptable when many functions are integrated into the same device. Consequently, these new technologies can only be considered where the overall availability of the hardware is improved by the use of automatic self-test and continuous supervision techniques. Fortunately, more sophisticated supervision facilities are becoming part of modern numerical protection and control systems.

Software maintenance: Being new to end users, maintenance of substation related software is expected to demand special care. Software should comply with the following requirements:-·
- reliable, safe operation & consistent response times
- flexible in relation to software upgrading
- software documentation generated automatically
- efficient and comprehensive diagnostic system
- easy system access for modification
- modular application programs
- provide on-line diagnostic tools

To improve software maintainability, the functional units of the modular software design need to be capable of being isolated in some way from the rest of the system. Each function or module must be capable of being fully tested, with the inputs and outputs being clearly identified. This feature will have to be built into the design of the entire system. It is evident that dedicated user-friendly software maintenance tools have to be available with on board help facilities.

New technologies and standardisation

It is evident that the introduction of new technologies on protection and control in high voltage substations depends on numerous factors. Only when all factors are satisfied the utilities will consider the large scale introduction. The availability of a practically usable international standard for communication between functions within substations will clearly support this introduction.

3. STANDARDISATION OF COMMUNICATION BETWEEN IEDS - IEC 61850

IEC 61850 is based on the need and the opportunity for developing standard communication protocols to permit interoperability of IEDs from different manufacturers. Interoperability within IEC 61850 is defined as the ability to operate on the same communication path and share information and commands. From a utility point of view there is also a desire for IED interchangeability or the ability to replace a device supplied by one manufacturer with a device supplied by another manufacturer, without making changes to the other elements in the system.

Objective

The objective of IEC 61850 is a communication standard that meets performance and cost requirements, and which will support future technological developments. Key to the usefulness of the standard is the free exchange of information between IEDs. The communication standard must support the substation operations functions and therefore, the standard has to consider the operational requirements. The purpose of the standard however is neither to standardize (nor limit in any way) the functions involved in substation operation nor their allocation within the substation automation systems. The operational functions are identified and described in order to define their impact on the communication protocol requirements (e.g. amount of data to be exchanged, exchange time constraints, etc.).

The communication protocol standard IEC 61850, to the maximum extent possible, makes use of existing standards and commonly accepted communication principles.

Logical interfaces

Substation automation systems normally incorporate functions for control, supervision, protection and monitoring of the high voltage equipment and of the grid. Other functions are related to the system itself, e.g. supervision of the communication. Functions can be assigned to three levels: the station level (level 2), the bay level (level 1), and the process level (level 0). Communication between these levels consists of physical mappings of logical interfaces. Figure 1 shows the applicable logical interfaces in a substation and forms the basis for the IEC 61850 standard series.

Logical Nodes (LN)

In IEC 61850 all known functions in a substation automation system have been identified and split into sub-functions or so called logical nodes. A logical node is an instance of a function, or more commonly, a sub-function located in a physical node. From the communication point of view a logical node is the smallest logical entity, which exchanges data with other separate logical entities. Therefore, a logical node is the smallest sub-function that can be addressed and whose data has to be standardised to reach interoperability. Logical nodes may reside in different devices and at different levels. To create a meaningful overview, all logical nodes have been grouped according to their most common application area, a short textual description of the functionality, a device function number if applicable (IEEE Standard C.37.2 1996) and the relationship between functions and logical nodes.

Logical nodes fall into two groups:

- logical nodes representing primary equipment (e.g. a switch); one logical node shall represent one and only one primary equipment
- logical nodes related to substation functions (e.g. protection function); one logical node may represent one and only one basic function.

Dynamic requirements

Because the free exchange of data to perform certain functions must meet several dynamic requirements the „dynamic" requirements on transmission of explicit pieces of information including their attributes like the required data integrity have been elaborated by WG 03 of the CIGRÉ Study Committee 34; the result has been published in a report and have been used in IEC 61850.

Physical interfaces

Logical interfaces may be mapped to physical interfaces in several different ways. A station communication bus normally covers the logical interfaces 1, 3, 6, and 9, a process bus may cover the logical interfaces 4 and 5. The logical interface 8 („inter-bay-communication") may be mapped to either or to both as can be seen in figure 2. This mapping will have a major impact on the requirements on the overall performance (through-put). Mapping of all logical interfaces to one single communication bus is possible, if this satisfies the performance requirements.

Communication independent interface

It is often debated that a standard may not represent the state-of-the-art at the date of publication, because of the time needed for standardization. Proprietary, vendor specific solutions often have a better performance than standardized protocols and thus may be considered "de-facto" standards. Given the fact that vendors and utilities focus on maintaining application functions that are optimised to meet specific requirements and that have reached a high degree of maturity and quality it has been decided that IEC 61850 should decouple applications from communication, i.e. to design them independent from communication so they are able to communicate by use of different communication protocols. Therefore in IEC 61850 a neutral interface between application and communication and "application objects" and the related "application services", allowing a compatible exchange of data among components of a substation automation system have been standardized. Figure 3 shows the basic reference model.

At the neutral interface, called ACSI , data prepared by the application is being specified including the related communication services which are to be used. Since the application layer of communication protocols provides not all the needed services, a mapping to available services has to be done and the data objects have to be mapped according to the protocol's facilities. This mapping is shown in Figure 3 as "SCSM". According to the property of the related application layer, the effort for the mapping can be different.

Logical nodes can only interoperate with each other if they are able to interpret and to process the data received (syntax and semantics), and if the communication services used are harmonized. Thus it is necessary to standardize data objects assigned to logical nodes and their logical addresses. Data and services of an application can be modelled in three levels. The first level describes objects and their relationship to logical nodes, levels 2 and 3 define data objects and their attributes.

Level 1: Abstract Communication Service Interface (ACSI)

The ACSI specifies the services used for access to these objects, which are independent from the objects. Communication services provide mechanisms not only for reading and writing of object values, but also for other operations e.g. for controlling primary equipment.

Level 2: Common data classes

The second level defines "common data classes" and attributes to be applied to data objects. The attributes specify type definitions, and values or ranges of values.

Level 3: Compatible addressing of logical nodes and data objects

This level defines compatible objects, which do not need any additional specification, as their identity and meaning (semantics) are defined. They are strongly assigned to a logical node. Data objects of this level are similar to objects defined in IEC 60870-5-103. An example for a data object is “current phase L1 with quality and time stamp”.

Other topics addressed by the standard

If a utility is planning to build a substation automation system, and is intending to combine IEDs from different vendors, it expects not only interoperability of functions and devices, but also a homogeneous system handling. This is the reason why IEC 61850 covers not only communication, but also qualitative properties of engineering-tools, measures for quality management, and configuration management.

IEC 61850 covers quality assurance for system life cycles, with definition of utilities’ and vendors’ responsibilities. It also deals with guidelines for environmental conditions and auxiliary services, with recommendations of the relevance of specific requirements from other standards and specifications. Quality requirements are defined in detail, such as reliability, availability, maintainability, security, data integrity and others that apply to the communication systems that are used for monitoring and control of processes within the substation. Other “general” requirements are geographic requirements.

Plug and Play

Over the years one of the major thresholds to use IEDs to their full extent was the proprietary nature of the communication interfaces. Especially the use of multiple IEDs from multiple vendors on a single network was virtually impossible without the use of special gateways and converters. These gateways and converters furthermore tend to limit the functionality of the overall systems. The concept of logical nodes together with a standardization of the data contained within a logical node in so called data objects allows interoperability between IEDs or in other words plug and play capability of IEDs in order to share information and commands on a single network. In figure 4 the relationship between the process and the communication interface is shown.

How does the concept work?

Lets suppose that a utility is using a Time Overcurrent Protection in bay 1 of a substation called Substation 1and wishes to use the three phase trip command to start another application.

The Time Overcurrent Protection device contains a Logical Node called Time Overcurrent or PTOC. This PTOC logical node contains several data objects that can be addressed as is shown in table I below. Now each of these data objects is associated with a data object class and contains a number of predefined attributes that can have a value.

LN: Time Overcurrent Ref: PTOC (ANSI: 51) Group: P (protection functions)			
	Data Object (DO) Name	**DO-Ref**	**DOClass**
measurand Identification			
	Currents INP (neutral, polarised)	ANeut	MV
	Currents INR (neutral, residual)	ARes	MV
	Currents INP (neutral, polarised)	ANeut (2)	ASP
	Currents INR (neutral, residual)	ARes (2)	ASP
system commands and system return information			
	LN ON (not OFF)	EnaFct	SPC
	Blocking of LN function	BlFct	SPC
	Set “Test mode“	Test	SPC
	Blocking information exchange	IEBl	SPC
	activate characteristic	Ch	ISC
	reset operation counter	OperCntR	ISC
	reset operation hours	OperhR	ISC

LN: Time Overcurrent Ref: PTOC (ANSI: 51) Group: P (protection functions)			
	Data Object (DO) Name	**DO-Ref**	**DOClass**
system information			
	general interrogation	GI	SPS
	LN not ready	NtRd	SPS
	parameter setting	PaSet	SPS
	operation counter, not resetable	OperCnt	ISI
	operation hours, not resetable	Operh	ISI
protection fault indications			
	alarm L1	AlA	SPS
	alarm L2	AlB	SPS
	alarm L3	AlC	SPS
	alarm N	AlN	SPS
	trip L1 L2 L3	TrABC	SPS
	trip I>	TrPTOC	SPS
	trip I>>	TrPIOC	SPS
	trip IN>	TrPTOCN	SPS
	trip IN>>	TrPIOCN	SPS
	earth fault L1	EFA	SPS
	earth fault L2	EFB	SPS
	earth fault L3	EFC	SPS

Table I: Logical Node Time Overcurrent (PTOC)

The three phase trip command is of data object class Single Point Status or SPS. The data object class SPS contains the attributes given in table II.

Single Point Status or SPS Common Data Class Definition				
Attribute Name	**Attribute Type**	**Attribute Char.**	**Value / Value Range**	**M/O**
stVal	BOOLEAN	st	TRUE | FALSE	M
q	Quality	st		M
t	TimeStamp	st		M
l	Description	dc	ASCI Text	O

Table II: Data Object Class Single Point Status (SPS)

The value of the three phase trip command is contained in the stVal attribute. If we wish to address this attribute we follow the naming structure defined in IEC 61850. This naming structure of a logical node object and its subordinate data objects is as follows:

<Plant Function>/[<Subplant Function>]<LN Class>[<LN Instantiation Id>].<Data Object>.<Data Attribute>

So in our example we would have access to the value of the three phase trip command through:

Substation1/Bay1PTOC1.TrABC.stVal

Since the addressing is based on the naming conventions given in the standard the addressing of data elements becomes independent of the telecommunication technology used. With the use of standardized objects the data contained in a device, and available on the network for further use, is known up front and since the naming of data

is independent of the actual device used, applications can be defined using the standardized data without knowledge about the actual device.
As long as the manufacturers implement the logical nodes, data classes, data object and data elements as specified in the standard we know up front which data will be present from a communication point of view. If we now add the capability of self-description of logical nodes and therefore of devices in which the logical nodes reside and it becomes clear that plug and play is possible.

It is apparent that manufacturers will provide devices that contain extension of functions and/or functions that are not (yet) modelled in IEC 61850. To assure interoperability with these specific extensions the standard contains rules on how to model extensions so that the data contained in these specific extension can be made available over the communication network in a pre-defined way.

4. UTILITY REQUIREMENTS VERSUS IEC 61850

Constraints for protection and control

The introduction of logical interfaces allows the design of all possible architectures for protection and control systems in a substation. Especially the free allocation of these logical interfaces to real networks supports an optimised system design based upon the requirements for a specific system and the available communication technology.

The hereby achieved flexibility can be used to its full extend in new substations or when extending or refurbishing substations. It is obvious that applying new technologies in new substation has many benefits. In Europe however the need for new substations is minimal. Therefore the acceptance of new technologies depends on their applicability for the extension and especially refurbishment of existing substations.

Given the four potential approaches for refurbishment mentioned earlier it is clear that applying IEC 61850 provides full benefits when refurbishing a complete substation or protection and control system. Because of a smaller scope, applying a new technology on complete function refurbishment or individual equipment refurbishment the initial benefits are limited. However when doing so a utility is preparing its systems for transition into the new technology. This can therefore be seen as a strategic decision to be taken by a utility as part of a migration plan for its substations.

Life cycle cost control

As mentioned earlier substation related costs break down into three main areas; initial investment, operational, and maintenance. The effect of the application of the new technology as defined in IEC 61850 has the following effect on these costs.

Initial investment cost: The initial investment costs for protection and control systems can be considerably lower when applying IEC 61850. It is expected that the prices for equipment will go down because of the lower development costs for manufacturers and an increased competition. Furthermore the initial investments can be lower due to less engineering and the fact that interoperability between IEDs can reduce the installation and commissioning time.

Furthermore up front conformity and interoperability testing of devices and functions together with new engineering tools ensure functioning systems.

Operational cost: The push for improvement of the operation efficiency of the electric infrastructure leads to the need for new functionality. The flexibility of the new technology provides that new functionality. Typical functions such as condition monitoring and overload prediction can thus more easily be incorporated in substation automation systems. This leads to a situation where the necessary operation data can be obtained from the IEDs virtually without additional engineering. Furthermore the plug and play capabilities allow for relatively quick changes to installed systems allowing timely adaptation to new operational needs.

Maintenance cost: Because of the capability to monitor the equipment and function behaviour, together with more sophisticated maintenance tools, will allow for the implementation of condition based maintenance. This in combination with the fact that for maintenance of new functions only the external behaviour has to be known allows for a simplified maintenance philosophy to be implemented. If then also remote monitoring of functions and equipment is implemented even more substantial savings can be reached.

Reliability and maintainability
The reliability and maintainability of systems depend to a large extend on the systems architecture and can therefore not completely be covered by a standard. However due to the open systems approach of IEC 61850 duplication and other forms of redundancy are supported.

The sharing of functions on the same hardware creates dependencies with respect to the individual function reliability. The standard however supports the splitting of functions and hardware, due to availability considerations.

With the implementation of sophisticated systems for protection and control more and more functions reside in software. With regard to the reliability and maintainability of these systems software design and maintenance become an issue. It is apparent that capabilities are needed to separately test and modify software modules and functions are a necessity. In IEC 61850 general guidelines are given for the design and the testing of software however concrete solutions based on practical experiences are yet to be defined.

5. PRACTICAL EXPERIENCES

With the introduction of the concepts laid down in IEC 61850 consensus exists that there is a need to prove these concepts in pilot projects to support both vendor developments as well as the end-user acceptance of the new technology.

Worldwide several pilot projects are being performed in parallel to the development of the IEC 61850 standard to provide a prove of concept. Examples of such pilot projects are the EPRI’s UCA Substation Communications Demonstration Initiative project in the United States of America, the OCIS project in Germany and the PINOCIO project in The Netherlands.

EPRI’s UCA Substation Communications Demonstration Initiative project
In parallel to the IEC activities, the UCA.2 specifications have been created with a similar scope and have been published as IEEE Technical Report. Independent of some different requirements of European and US utilities IEC and IEEE are in a process of harmonising both drafts and to publish one standard.

The UCA Substation Communications Demonstration Initiative project will implement recommended solutions based on the Utility Communication Architecture or UCA documents at, at least, 12 sites. The results will be used to verify the correctness of the solutions and modifications will be fed back to update current UCA documents. At this writing, there are 25 funding, participating North American and European utilities, and 15 participating vendors. Since the UCA documents form a basis for IEC 61850 this project will provide important feedback on the IEC 61850 standard as well.

The OCIS Project
The Open Communication In Substations or OCIS pilot project was established by FGH, VEW, ABB, ALSTOM and Siemens in 1998 to compare and to test the drafts of IEC 61850 and UCA.2 for so called station bus communications, review the standard drafts with respect to feasibility, applicability and efficiency, assist the standardisation efforts and to consider the European requirements.

The results of this project are being forwarded to the standardisation committees in order to support the standardisation work from an implementation point of view. From this collaboration between the utilities, members of the responsible IEC committees and the vendors an international standard will arise, which is also important for the future of the German market. The project is subdivided into several independent tasks ranging from the comparison of standard drafts with help of a defined substation, simulations with PC set-ups to realistic situations with new developed IEDs.

In order to achieve a situation as close to reality as possible, a part of a MV substation, consisting of three bays and a substation control unit, was defined to serve as reference substation. The MV level was chosen due to the following reasons:

- The number of MV substations is considerably high. So the standard has special importance for the MV level.
- Minor requirements for control systems and communications in comparison to HV substations.
- The process of integrating primary and secondary technology is most advanced on MV level.
- The higher pressure of costs.

The PINOCIO project

The Pilot project In the Netherlands for Open Communication In substatiOns or PINOCIO pilot project was established by KEMA, EnergieNed, ABB, ALSTOM and Siemens in 1998 to compare and to test the drafts of IEC 61850 for so called process bus communications, review the standard drafts with respect to feasibility, applicability and efficiency, assist the standardisation efforts and to consider the European requirements.

The project was split into three phases:

- Phase I, evaluation of the generic object models for feeder and substation equipment (GOMSFE)
- Phase II, protocol evaluation
- Phase III, pilot project and demonstrations

This was done to be able to discuss the feasibility of UCA version 2.0 and the object models defined in GOMSFE with the Dutch utility industry as well as to prepare the necessary background information for the project.

The goal of Phase III the PINOCIO project is to demonstrate vendor independent open communication between substation IEDs based on an IEC 61850 protocol and data-model using a process bus (inter-operability). To achieve this the project will consist of the following:

- Evaluation of the feasibility of a process bus and select a reference stack. The results will be used to define the next phases of the project
- Definition of the pilot configuration for each project phase
- Definition of the object models
- Definition of the test scenarios
- Verification of the performance and functionality to support the agreed test scenarios
- Provide information about economical aspects for the process bus
- Provide input to IEC TC 57 WG 10, 11 and 12
- Provide recommendations to the Dutch utilities
- Develop test facilities for the communication interfaces

To achieve these goals the parties will develop prototypes which will be organised in pilot configurations.

The scope of the project is to set up and test the following PINOCIO configuration steps:

STEP	DESCRIPTION
Step 0	Specification and evaluation of the feasibility of the process bus
Step 1	Distance protection (prototype device) and a CT/VT merging unit (protocol simulation) with a single communication link according to IEC 61850 part 9-2, using the universal sampled value datasets as defined in IEC 60044-8 and IEC 61850 part 9-1
Step 2a	Distance protection (prototype device), CTs (protocol simulation) and VTs (protocol simulation) with process bus communication according to IEC 61850 part 9-2.
Step 2b	Distance protection (prototype device), multiple CT/VT (prototype devices), bay control (either integrated or as separate prototype device) and circuit breaker controller (protocol simulation) with process bus communication according to IEC 61850 part 9-2.

6. CONCLUSION

It is generally understood that IEC 61850 contributes significantly to the large scale introduction of a new generation of modern systems for protection and control. The stress on competitiveness and therefore the wish to improve efficiency and reduce costs will force utilities to change their ways of doing business. The standard defines the required logical interfaces and allows for the use of object oriented techniques for data modelling. This definition together with the use of existing standards and commonly accepted communication principles, provides a solid base for interoperability between IEDs in the substation leading to more flexible and powerful protection and control systems.

With the plug and play capabilities embedded in the standard and the immediate prove of concept in pilot projects IEC 61850 promises to be a great step forward in the development and acceptance of substation automation systems world-wide. This will finally bring the real benefits of automation and integration to utilities that were originally promised years ago.

REFERENCES

[1] Substation Automation A New Approach, UCA Substations Communications Demonstration Initiative, Marco C. Janssen, John T. Robinson, 1998; 1998 Power Delivery Europe, London, England (Innovation Award winning paper)

[2] PINOCIO, “Pilot Project In the Netherlands for Open Communications In substatiOns”, Marco C. Janssen, Richard Schimmel, 1999, FgH Workshop Aktuelle Entwicklungen in der digitalen Schutz- und Stationsleittechnik, Erste Erfahrungen mit der zukünftigen Normenreihe IEC 61850, Dortmund, Germany

[3] Technological versus organisational developments in power system operation and control, H.E. Dijk, P.G.M. Giesbertz, C.G.A. Koreman, 1995, Cigré Symposium Helsinki, Finland

[4] Functional integration within substation secondary equipment, C. Guilmain, C.G.A. Koreman, S. Lemmer, C.M. Parker, 1995, Cigré Symposium Helsinki, Finland

[5] A pilot project for testing the standard drafts for open communication in substations – First experiences with the future standard IEC 61850, J. Haude, A. Janz, Th. Rudolph, Th Schäffler, H. Schubert, 2000, Cigré 2000, Paris, France

[6] Configuration and integration of substation secondary equipment, C.G.A. Koreman, S. Lemmer, M. Kezunovic, A. Newbould, 1996, Cigré 1996, Paris, France

[7] Serial communication between process and bay level, C. Brunner, A Ostermeier, 2000, Cigré 2000, Paris, France

[8] IEC 61850 Communication Networks and Systems in Substations, Part 1 – 10

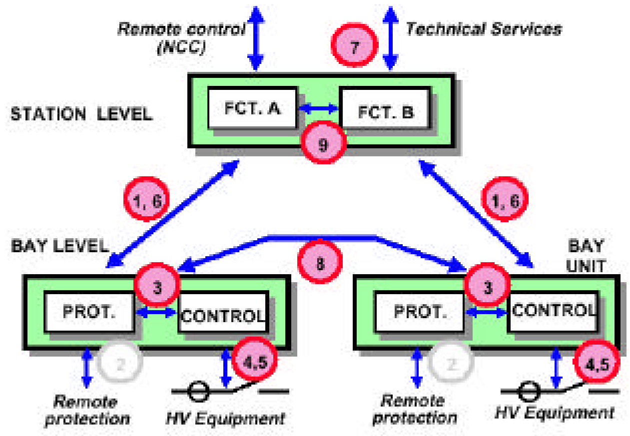

Figure 1: Logical interfaces in a substation

Note – The logical interfaces to the remote protection and to the remote control centre are out of the scope of IEC 61850.

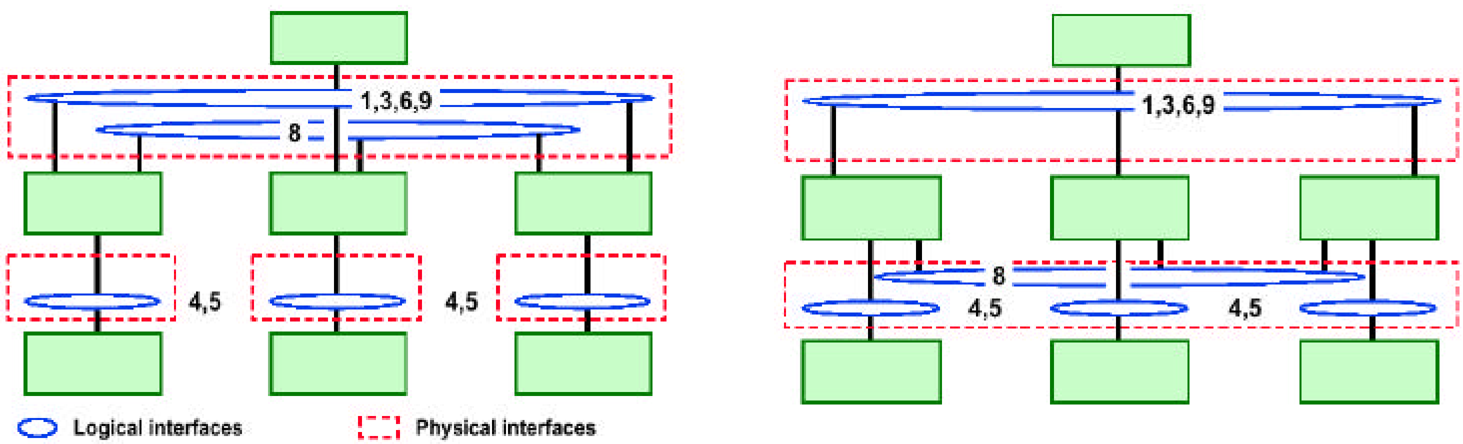

Figure 2: Mapping of logical interfaces to physical interfaces

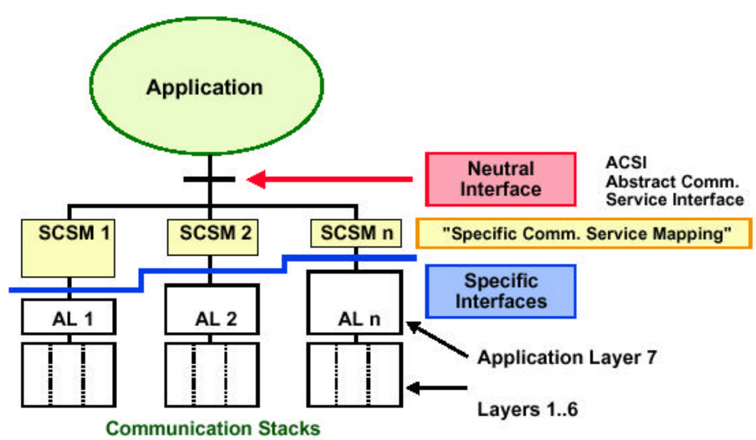

Figure 3: Basic reference model

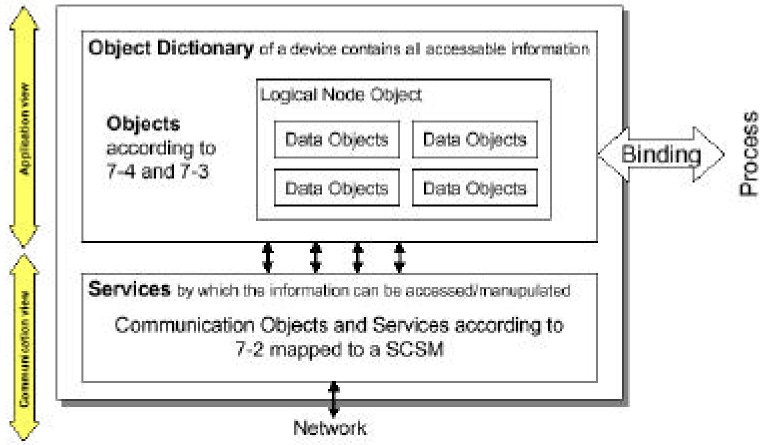

Figure 4: Relation process and communication interface