

THESIS ON POWER ENGINEERING,
ELECTRICAL ENGINEERING, MINING ENGINEERING D64

**Measurement and Data
Communication Technology for the
Implementation in Estonian
Transmission Network**

IGOR METS

TUT
PRESS

TALLINN UNIVERSITY OF TECHNOLOGY
Faculty of Power Engineering
Department of Electrical Engineering

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Supervisor: Director of Department of Electrical Engineering
Prof. Dr. Tõnu Lehtla, Faculty of Power Engineering,
Tallinn University of Technology, Estonia

Opponents: Prof. Dr. sc.ing. Dean of the Faculty of Power and Electrical
Engineering Oskars Krievs, Riga Technical University, Latvia

PhD. Member of the Management Board Kalle Kilk, Elering AS,
Estonia

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Declaration:

Hereby I declare that this doctoral thesis, my original investigation and achievement, submitted for the doctoral degree at Tallinn University of Technology has not been submitted for any academic degree.

/Igor Mets...../

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ENERGEETIKA. ELEKTROTEHNIKA. MÄENDUS D64

**Mõõte- ja andmesidetechnologia
uurimine ja rakendamine Eesti
kõrgepinge ülekandevõrgus**

IGOR METS

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ABBREVIATIONS

AC	alternating current
AR	automatic reserve switching
ASCI	abstract communication service interface
AMR	automatic meter reading
BALTSO Lithuania	Baltic transmission system operators – Estonia, Latvia, Lithuania
BRELL	Belarus-Russia-Estonia-Latvia-Lithuania transmission network
CID	configured intelligent electronic device description
CT	current transformer
DC	direct current
DER	distributed energy resources
DSO	distribution system operator
DUT	device under test
ENTSO-e	European Network of Transmission System Operators for Electricity
EU	European Union
FAT	factory acceptance test
GPS	global positioning system
GOOSE	generic object oriented substation event
HEA	high energy analog output
ICD	intelligent electronic device capability description
IED	intelligent electronic device
IID	instantiated intelligent electronic device description
LAN	local area network
LD	logical device
LEA	low energy analog output
LN	logical node
MAC	media access control
MMS	manufacturing message specification
MT	measuring transducer
MTBF	mean time before failure
MU	merging unit
NCIT	non-conventional instrument transformer
PC	personal computer
PP	power plant
PTP	precision time protocol
RES	renewable energy sources
RCC	remote control centre
RTU	remote terminal unit
SAS	substation automation system
SAT	site acceptance test
SCL	substation configuration language
SLD	single line diagram
SCADA	supervisory control and data acquisition
SED	system exchange description
SCD	substation configuration description
SSD	system specification description

SS	substation
SW	switch, computer network device
TARS	power transformer automatic reserve switching
TSO	transmission system operator
TUT	Tallinn University of technology
VLAN	virtual local area network
VT	voltage transformer
WAN	wide area network
XML	extensible markup language

SYMBOLS

A	initial value of the direct current component (A)
B	magnetic flux density or induction (T)
d	length of the light path (m)
E	strength of electric field ($V \cdot m^{-1}$)
$\Delta\phi$	angle between plane-polarised lights (rad)
H	magnetic field strength ($A \cdot m^{-1}$)
$i_{d.c.}$	direct current component of short-circuit current (A)
I_k	steady state short-circuit current (A)
$I_k^\#$	initial symmetrical short-circuit current subtransient initial (A)
i_p	peak short-circuit current (A)
K	specific coefficient depended on electrical and optical properties
λ	wave length of light beam (μm)
L	thickness of crystal (m)
μ	absolute magnetic permeability ($H \cdot m^{-1}$)
μ_0	permeability of the vacuum ($H \cdot m^{-1}$)
μ_r	relative permeability
π	constant
τ	time constant
V	Verdet constant ($rad \cdot T^{-1} \cdot m^{-1}$)

LIST OF AUTHOR'S PUBLICATIONS

(The Author's surname was changed in year 2012 to Mets. All the publications are signed with the former autor's name - Dmitrenko. See the materials in Annex)

- [PAPER-I] Dmitrenko, I. (2011). IEC 61850 and Measurements. Electronics and Electrical Engineering, 6 (112), pp. 106 – 110.
- [PAPER-II] Dmitrenko, I.; Laugis, J. (2010). Obstacles of Substation Telematics System. 14th International Conference of Power Electronics and Motion Control Conference (EPE/PEMC), 2010. IEEE, pp. 48 – 53.
- [PAPER-III] Dmitrenko, I.; Laugis, J. (2010). The Handle of Substation Remote Terminal Unit Configuration. Scientific Journal of Riga Technical University: Power and Electrical Engineering, pp. 63 – 68.
- [PAPER-IV] Dmitrenko, I.; Laugis, J. (2010). The substation local PC workstation. Present and future. Lahtmets, R. (Eds.). 8th International Symposium "Topical problems in the field of electrical and power engineering. Doctoral school of energy and geotechnology". II : Pärnu, Estonia, 11.01.-16.01.2010. Tallinn: Elektriajam, pp. 186 – 189.
- [PAPER-V] Dmitrenko, I. (2010). Obstacles of substation telematics proper operation. Lahtmets, R. (Eds.). 8th International Symposium "Topical problems in the field of electrical and power engineering. Doctoral school of energy and geotechnology". II : Pärnu, Estonia, 11.01.-16.01.2010. Tallinn: Elektriajam, pp. 93 – 98.
- [PAPER-VI] Dmitrenko, I. (2009). Substation telematics. Lahtmets, R. (Eds.). 7th International Symposium "Topical Problems in the Field of Electrical and Power Engineering", Doctoral School of Energy and Geotechnology. Narva-Jõesuu, Estonia, 16.06.-19.06.2009. Tallinn: Estonian Society of Moritz Hermann Jacobi, pp. 140 – 145.

1 INTRODUCTION

The quality of human life has improved throughout the last half-century. The reason behind that is directly linked to electricity. But the impact of using the traditional methods of power energy management, such as generation, transmission, distribution and utilization leads to the unsustainability of the natural energy resources, climate changes, rapid increase of contamination and pollution, energy instant losses. Thus, the nature and humans are in danger and improper use of power energy evokes additional charges that people must take into account and carry. Such kind of non-profitability is also based on electrical equipment we are using: household devices, heating devices, lighting systems that are not manufactured according to environmental rules and are ineffective and cannot save electrical energy. Similar problems occur by the examination of substation equipment. A substation contains numerous “old-fashioned” costly technical solutions. To realize these, loss of monetary resources, reliability capabilities for future upgrading occurs. For example, the costs for substation equipment are steadily growing, the constructing materials and devices: copper wiring, oil for primary equipment, primary switching devices, traditional instrument transformers, and digital/analog relay protection are becoming more expensive.

To solve problems with emissions, non-effective electrical energy treatment and traditional mono-directional generation of electrical energy, the European Union has set up the final targets to year 2020 in the middle of 2010 regarding the climate change and energy sustainability¹:

- greenhouse gas emissions 20% (or even 30%, if the conditions are right) lower than 1990;
- 20% of energy from renewables;
- 20% increase in energy efficiency.

Therefore the governments of different countries in the European Union are strongly required to make sufficient efforts to achieve the aforementioned tasks. The first steps were to broaden the percentage in energy generation on account of renewable energy sources like hydro power plants, wind generators, solar energy transforming, geothermal energy utilization etc., to reduce the dependence on main energy resources. Nowadays the most advanced states in the implementation of the above are Denmark, Germany, Norway, and the Netherlands. The renewable energy source performance and the electrical energy generation require specific approaches of control the electrical power flow from a transmission system operator point of view. Thus, the appropriated modelling of static and dynamic situations in the transmission grid depending on instantly changing capacity of renewable energy is usually pre-investigated to pre-plan the appropriated operation activities in the transmission network. There are not many opportunities how to manage electrical energy generation from wind parks by transmission system operators. It could either be controlled directly one by one from remote control centre of a transmission system operator or the sophisticated remote control automation system should be integrated into every wind park automation system to be operated as part of one virtual wind park from the transmission network point of view.

¹ European Commission, Brussels 2010. A strategy for smart, sustainable and inclusive growth

The next steps were widely promoted to integrate in private and public areas like household, farms, pools, electrical vehicles etc. These are mostly referred to as smart system automation regulating electrical power stream to the distribution network from dispersed electrical power producers. The distributed energy resources are complicated to predict, but there is still a possibility for proper output of system behavior by a modeling process. Indeed the distributed energy resources already provide working solutions today and wide expansion is expected. To help the standardization process regarding the Smart Grid, the European Union composed the standardization mandate M/490 EN, which is described as “*CEN, CENELEC, and ETSI are requested to develop a framework to enable European Standardisation Organisations to perform continuous standard enhancement and development in the field of Smart Grids, while maintaining transverse consistency and promote continuous innovation*”.

The structure of electrical energy generation, transportation, distribution, transformation and utilization is changing irreversibly, firstly from the concept point of view, when electrical power streams in the power network are becoming more multi-directional as compared to those in the past. In fact, the future power energy network sets the challenges to conceptual, structural approach, profiling, testing and promotes innovative thinking representing the new capabilities of all components in the future power energy network.

These main capabilities are the following:

- innovative exchange of data;
- specific representation of data in the digital form for digital relays purposes;
- IP-based communication principles;
- real time interactions using the protection system automation;
- precise online measurements that meet the requirements both in terms of protection and revenue metering.

Adaptability of the substation system automation would increase and it would finally be transformed to the transmission of dispersed power network system automation. For example, the global load shedding automation based on frequency will be switched partially off as the substation medium voltage feeders of non-primary consumers in the substation where the system automation is installed, as also the medium voltage feeders in another substation where the other part of global system automation sets the condition to perform the required operation from remote end. Communication between the parts of system automation in different substations is maintained using the reliable time-critical LAN communication that meets the international standard for communication. These parts of system automation are continuously interchanging the operation conditions, necessary power network measurements and also the healthy status that will limit the flexibility of global system automation in the power network.

The next example will be the fully automated regulation of wind parks from the Estonian transmission system prospective. The traditional realization to control and monitor the wind park from the remote control centre of the transmission system operator is the direct communication to the control and monitoring device in the wind park. The dispatch centre will be responsible for receiving the maximum generated energy to the transmission grid. In case of an emergency situation the power generation from the wind park might be limited from the remote control centre of the transmission system operator to ensure the stability in the transmission grid. If there are more wind parks and distributed energy resources connected to the

transmission grid, there are various operation activities are required from the manned dispatch centre.

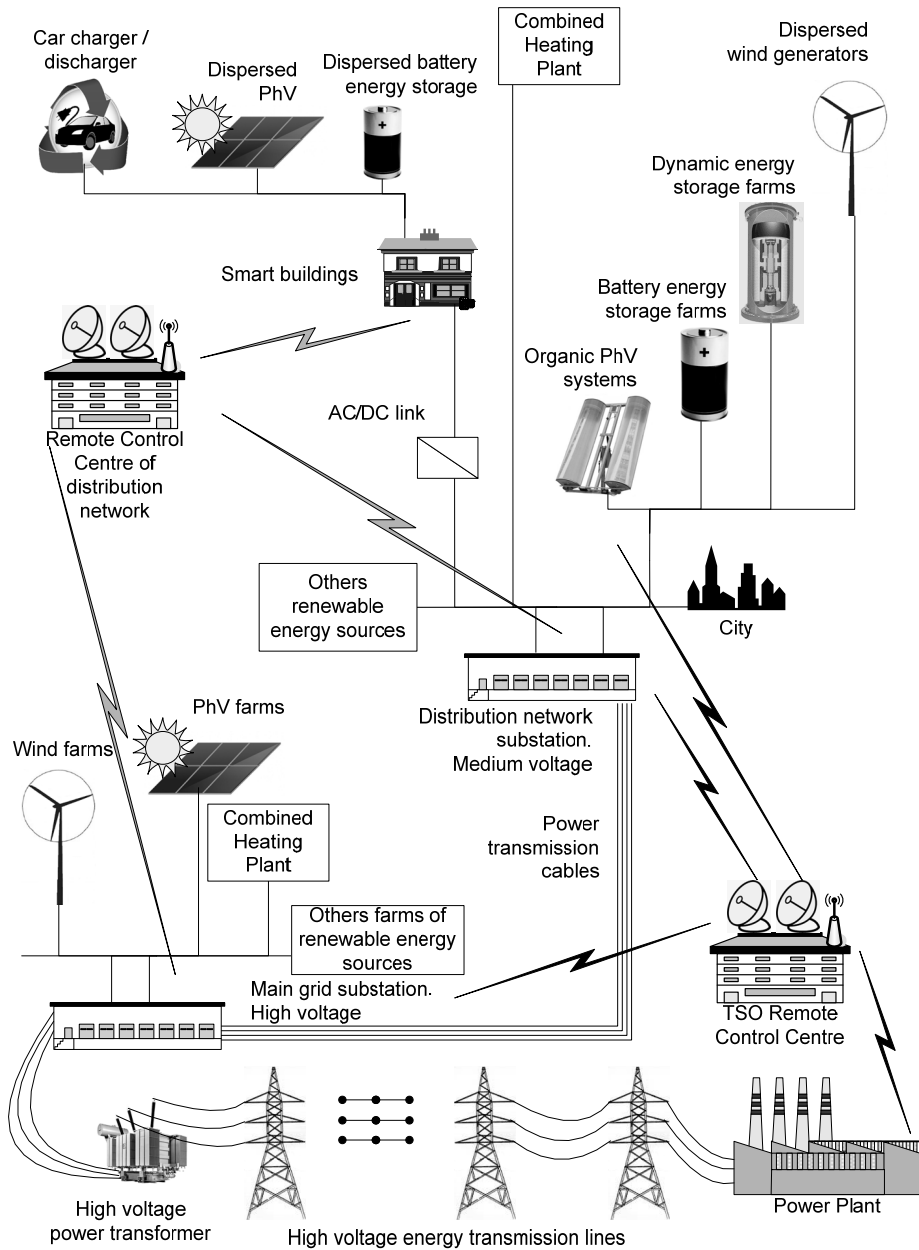


Figure 1.1 General view of the components in the energy system [23]

The fully automated interaction activities between the substations, the power station, the distributed energy resource units and consumers are only possible if important preconditions are fulfilled in terms of technology. Some of the preconditions are the following:

- digitalization of the protection process and local/remote supervision;
- qualitative and quantitative digitalization of all analog values (from the source) or quick quality lossless analog / digital signal transformation for minimum time duration;

- using of local digital network within every substation;
- ability to use the secured and reliable digital telecommunication network;
- standardized approach to be implemented in the control and protection of the primary switching device, by instrument measurements, relay protection, telematics equipment, control and protection of secondary device parameterization and documentation;
- secondary devices have to meet international standards to be interoperable and extendable.

Figure 1.1 shows the interconnections of the participants in the power energy network where the protection, control, monitoring and system automation functions are automated and supervised using the digital network and digital technics. Naturally, the common household will definitely be included in the aforementioned automation function, such as online metering, smart switching operations, 24h/7d management of household regarding the consumption of electricity, time-dependent charging of vehicles. These are only a few additional household functions that allow utilization of electricity in a more efficient way.

Nowadays the expansion of remote monitoring and control deeply into the household brings out the benefit for efficient analysis of possibilities in the energy saving. I.e. the annual consumption of energy in the building will be thoroughly inspected to find the way how to perform the building renovation to reduce the operating expenses and to save the power energy. In this case the buildings should be equipped with the metering system connected to the remote supervision centre to achieve the most effective power energy consumption. Such metering system will include many smart meters exchanging the measuring and control data to make possible the setting up the power energy consumption depending on time schedule in every household [11].

2 REVIEW OF THE ESTONIAN TRANSMISSION SYSTEM

The Estonian energy transmission network (Elering AS) is the public company that is 100% owned and governed by the Ministry of Economic Affairs and Communications. The Estonian energy transmission system is connecting the power plants, DER, RES, the transmission and distribution system operators and electricity consumers located in Estonia. As the sub-component, the Estonian transmission network belongs to the international synchronous zone BRELL. In the past the Estonian transmission network was part of the BALTSO cooperation organization of Estonian, Latvian and Lithuanian Transmission System Operators, but it merged to the European Network of Transmission System Operators for Electricity. Nowadays the former BALTSO functions as the Regional Group Baltic [3].

According to the agreements made in BRELL, Estonian overhead power lines are to ensure the optimal quantity of bi-directionally transmitted power energy using the local interconnections between Belorussia, Russia, Estonia, Latvia, and Lithuania (see *Figure 1.2*).

The high voltage DC link ensures the transmission of power energy between Estonia and Finland since 2006 at the rated capacity of 350 MW. In spite of the Elering AS control function of Estlink, it is not the asset of Estonian system operator, but the owner is Eesti Energia Group, which is a large enterprise that unites power generation, distribution and other companies.

The Estlink2 is also the high voltage DC link with higher rated capacity of 650 MW under construction in cooperation with Finnish and Estonian transmission system operators. The expected energizing of Estlink2 is the year of 2014.

The Estonian transmission system operator is erecting the emergency reserved power plant with the capacity of 250 MW. Hereby the ERPP will support the main grid stability and start to energize the Estonian electricity system from scratch (in case of black-out).

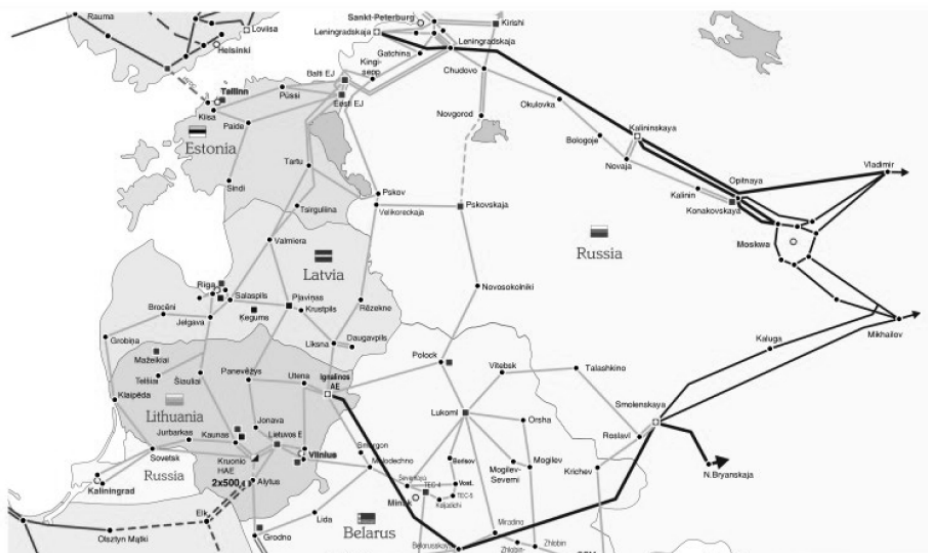


Figure 1.2 General view of the BRELL transmission network

The Estonian transmission system operator is responsible for the following assets:

- 5223 kilometres of high voltage overhead and cable lines (330 kV, 110 kV, 220 kV, 35 kV);
- 146 substations.

The Estonian transmission system operator is the independent TSO running the national grid under the Electricity Market Act guaranteeing the functioning of the whole electrical system and ensuring the quality of electricity supply. Elering AS is also responsible for the steady balance of the power system [2].

The maximum possible capacity of the main grid varies from the export/import demand, present operational network and future conditions. All the conditions of the transmission network are under thorough supervision and analysis of the Estonian transmission system operator, taking into account that Elering AS is the participant of Nord Pool Spot – the leading power market in Europe.

3 HYPOTHESES AND OBJECTIVES

The non-conventional instrument measuring technology at high voltage implementation is a prospective research or prototype direction; it is a consistence towards saving the world, towards producing pollution free technologies, and reducing the asset management costs.

The main achievement in the implementation of non-conventional instrument measuring technology is to have the entire standardized technical solution that is suitable for any kind of existing, renovated and new high voltage electrical installation (substation, overhead and cable lines).

Below the objectives of non-conventional instrument measuring technologies are listed:

- to analyze State-of-the-Art and NCIT technology comparison;
- to analyze preconditions to implement the NCIT technology;
- to compose requirements for NCIT implementation;
- to distinguish all NCIT possible benefits and drawbacks.

The new modern substation must contain all possible achievements in the fully digitalized relay protection, computing networking, measurement A/D conversion and remote end substation data interchange. This research estimates possible technical solutions to avoid the first implementation circumstances of innovative solutions. Specific requirements were set to avoid the lack of technical interoperability and life cycle time of equipment regarding the future service and extensions. During the analysis specific issues (e.g. measurement accuracy, interoperability, and proprietary technics) were found out that would influence thoroughly the non-conventional instrument measuring technologies. For example, the utility requirement to use the internationally standardized equipment is the guarantee for ensuring the equipment interoperability and opportunity to extend the substation in the future.

In spite of the above considerations, proprietary manufacturer-oriented electronics (e.g. in analog/digital conversion) is available that could be provided to the utility at higher prices and it will definitely eliminate the solutions not supported by other vendors or system integrators. Hence the NCIT system must meet rigid behavior requirements for input and output of some proprietary components in the NCIT system – such as “black box”.

4 CONTRIBUTION

The current thesis demonstrates the efficiency and power of the implementation of non-conventional instrument measuring technologies in the high voltage transmission network and the trends of future development. The present thesis analyzes the essential issues by the implementation of the measuring technology based on novel principles from a utility prospective.

Peculiarities of the study. NCIT is not an instrument transformer, but a complex system of analog sensors, analog/digital converters, special optical medium, temperature optical compensators etc. It is impossible to have this system partially. The output of such an NCIT system is analog and/or digital, whereby both types of outputs must be standardized. If the analog outputs are intended for existing “old-fashioned” extensions in substations, then digital output must match the inputs of protection relays, so the implementation of the digital standardized process bus (e.g. sample values, primary equipment protection, control and monitoring) is highly required. In addition, there are few possibilities to compose the implementation of NCIT digital standardized station bus (protection functions, logical functions, time synchronization, remote control and monitoring, parameterizing and mapping rules etc.), therefore the precondition of using the station bus should be foreseen to gain all the advantages from the implementation of the innovative technical solution of NCIT.

According to the EU directives^{2 3} the transmission system operators in the European Union should become public-owned companies, hence they will be open and transparent to all qualified bidders in the case of public procurement. Such practice has been implemented in Elering AS. So the qualified competitors have equal opportunities to win the tender. Thus, in the case of non-conventional instrument measuring technologies, every TSO requires system transparency and interoperability when applied with different vendor solutions. The standardized solutions would help to exclude the costly proprietary realizations in the high voltage substations and would ensure the efficiency by substation extension and renovation.

Pertinence of the study. Digitalization of different services in our world has not left the power energy generation, transmission and distribution fields untouched. But only after the standard IEC 61850 was composed, the protection relay devices (IEDs) could become fully digital devices and serve other IEDs using the substation LAN. The thesis is relevant towards the future vision of Estonian electricity system where the power energy transmission becomes the fully automated unit in each part of the substation, routing the power energy flows according to the operational situation of the transmission network and protecting the Estonian electricity system from transmission network conditions of probable black-out. In the future the protection and load shedding functions in power generation, transmission, distribution and electricity consumption would be tightly intertwined to guarantee the uninterrupted quality energy supply to customers and to force the energy market to act more efficiently.

² Directive 2009/72/EC of the European Parliament and of the Council

³ Directive 2009/73/EC of the European Parliament and of the Council

5 TRADITIONAL SUBSTATION TELEMATICS

5.1 History

Telematics plays a major role in today's power energy systems. Simon Nora and Alain Minc introduced the term of telematics in their report in 1978 titled as *L'Informatisation de la société*. In their report they compare the expectations of telematics with electricity: "...Today, any consumer of electricity can instantly obtain the electric power he needs without worrying about where it comes from or how much it costs. There is every reason to believe that the same will be true in the future of telematics...".

Unfortunately, derivation of the term telematics is still arguable, but the definition of the term by academician Dennis Foy became widespread: Latin *tele-* (far off) and Greek *-matos* (machinery).

After 34 years, when the report was published, some of the perspectives of telematics mentioned in the document have become an inalienable reality today. Actually the different telematics systems are inculcated in almost all areas of human activity: military, public, society, education, medicine, electricity production and consumption etc.

There is no information about the first telematics system. But the most efficacious telematics systems were in use by military forces and they were completely confidential, thus held in secret. After starting to use telematics for civil purposes, the interconnection of large power grids in the Midwestern and Southern U.S. (1962) could be handled as the largest first synchronized system in the world using the telematics conception.

5.2 Tasks in substation

The main components of remote control and supervision for power grid are the SCADA system, RTU, IED devices and communication between each other. The abbreviation SCADA usually refers to centralized and highly computerized systems, which monitor and control the substation equipment in online mode and analyze events in report or data base mode. The SCADA is the system spread out over large power network areas. All remote control actions, status supervision, gathering of measurements, some kind of analysis tasks are performed via locally placed RTUs and IEDs.

On the one hand, the substation RTU is dedicated for proper reaction to information objects (control, status, measurement messages), receiving them from side remotely connected to the SCADA system. On the other hand, RTU ensures the exact transmission of a message to the executing device (IED) receiving the commands from and sending the response back to the SCADA system. The RTU is located in the substations for exchanging the data (control, state, alarm, indication, measurement information) between the substation and the Remote Control Centre.

The reliability of the substation RTU is guaranteed by right parameterization, failure loss operation and long lifecycle. The aforementioned RTU functionality is specified as follows:

- RTU operational area (functions, data transmission, time base, technical data, Electromagnetic and Environmental Compatibility etc.);
- RTU hardware (modular topology, processor, I/O-, power supply modules etc.);
- control and monitoring (control, state, measurement, event, alarms, indication);

- time synchronizing;
- compatibility and interoperability with the SCADA;
- type of communication interface.
- The primary equipment of a substation should be connected to the IED device
- the tasks of which are:
- local control and monitoring function;
- protection function;
- provision of remote control and monitoring.

Figure 1.3 shows the typical primary equipment of a substation (marked with pink color) and the secondary equipment (marked with blue color).

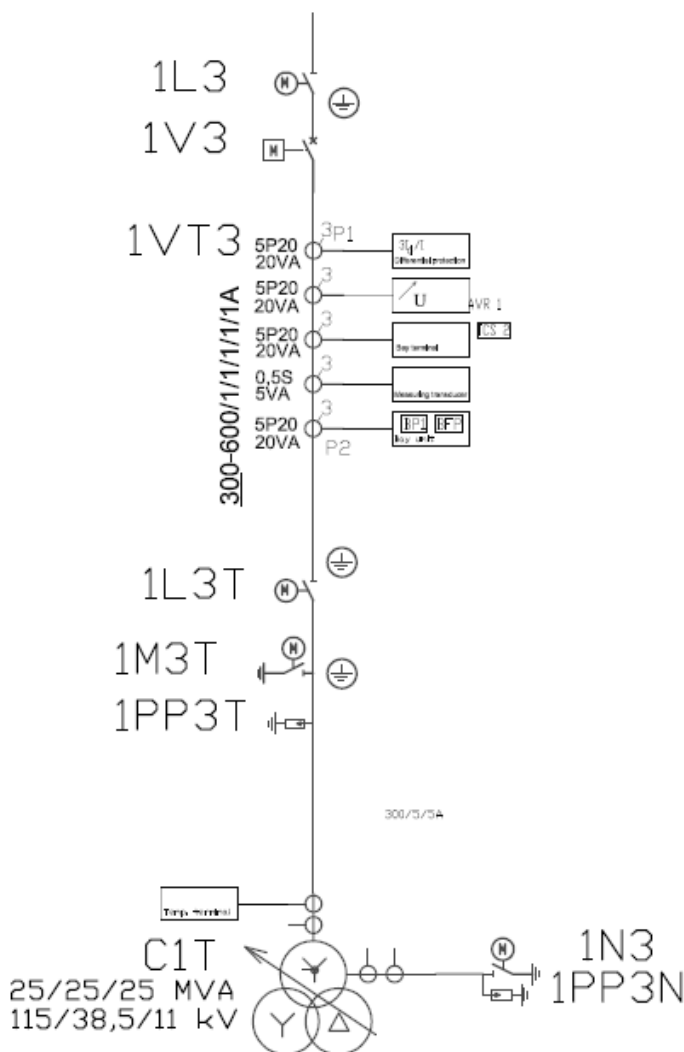


Figure 1.3 Fragment of 110 kV substation SLD [22]

The classical design of remote control and monitoring for primary equipment in a substation is performed by using several IEDs that ensure direct actions to primary equipment due to copper wired connections, e.g. control circuits, trip circuits, signal and monitoring circuits.

IEDs might be differently equipped with communication interfaces regarding the RTU; so the appropriated communications between IED and RTU could be both fibre optic to avoid the electromagnetic interferences or copper wired connections. Copper connections are used either for data transmission (e.g via RS485) or for binary information exchange (e.g. binary input/output).

Furthermore, IEDs should be connected to the RTU, which provides remote control operations and monitoring functions for the SCADA system of RCC and substation local PC workstation. All telematics devices and related communication systems (e.g. SCADA↔RTU↔IED) must be quite reliable to send and receive data information without any restrictions, time constraints or errors whenever needed. The telematics devices should execute all specified actions without any malfunction or disturbance. Because of remote communications between RCC and substation RTU, the relevance of telecommunication quality and redundancy is highly required from the utility point of view. Nowadays the telecommunication services could be provided from the utility (owner and service provider) or from third-party telecommunication.

Generally, there are three parts of telematics networks, which are divided depending on the network location:

- substation network (e.g. between RTU and IED);
- telecommunication service provider network (e.g. optic fibers of power transmission lines);
- Remote Control Centre network (SCADA).

Figure 1.4 shows a general overview of the typical realizing for telematics communications.

The substation RTU is something between the gateway device and the industrial controller, which usually has the:

- digital input / output modules;
- analog input / output modules;
- optical modules;
- processor module;
- power supply module;
- licences for external communication protocol;
- external communication ports to the SCADA;
- external communication ports to IEDs;
- external communication ports for time synchronization.

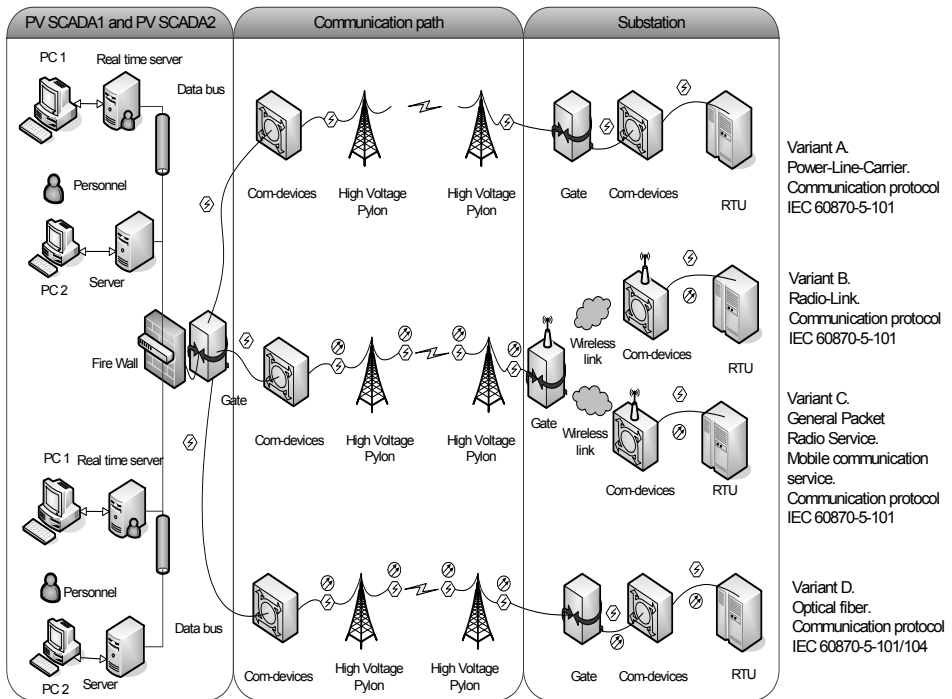


Figure 1.4 General communication schemes between RCC and SS [21]

Operational measurements are important for the RCC to control the power network in real time. The measurement visualization should be performed both locally and remotely for the management of the substation locally and the transmission network remotely. The measurement transducer is the device that converts one form of a signal to another, allowing its measurement to be displayed and data transmitted. This device is able to provide voltage and current based measurements to RTU. Measurement transducer uses the external DC power supply to operate. The measurement transducer must meet the specific accuracy requirements, which are harder for direct measurement than for calculated values (e.g. active and reactive power).

The substation measurement systems are divided into two fully independent groups like operational and revenue metering systems. The first one is provided to establish the control of emergency, technological and service activities (e.g. to check the voltage and current of the switched off power line). With appropriate use of operational measurements, the substation equipment is adequately estimated (e.g. needs for activation of backup power supply to customer). The second group is important for revenue AMR, which is not a part of telematics.

Because RTU is the only binding knot of the data exchange from and to the substation, the proper RTU working should be established without any mistake in the RTU internal data transformation in every data flow direction (see *Figure 1.5*).

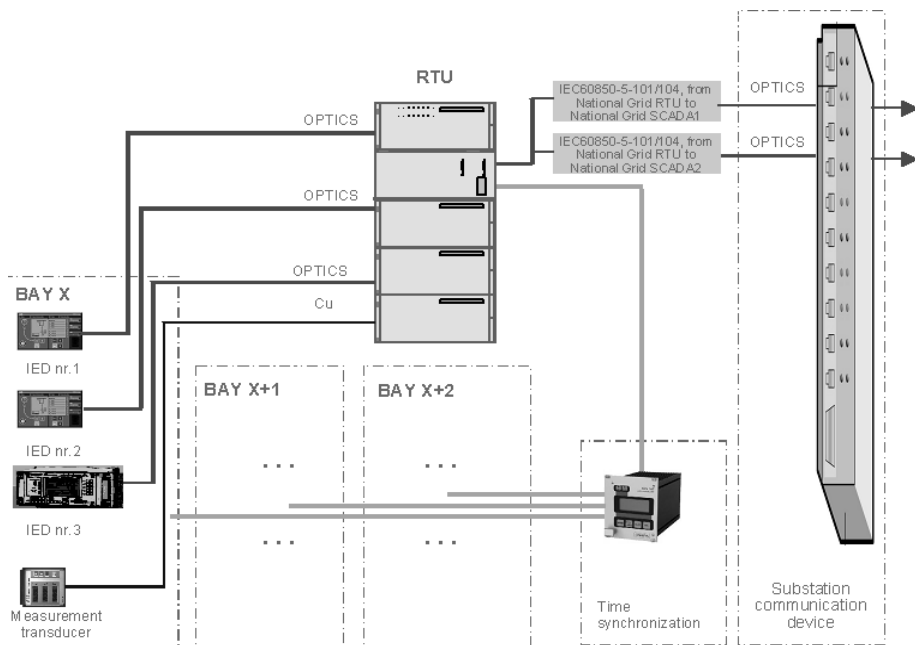


Figure 1.5 Simplified view of the substation bay telematics

One of the important requirements is the time synchronization of RTU and other IED devices in the substation. The purpose of the substation GPS reference clock and the time synchronizer (GPS device) is to ensure correct real local time and date run in IEDs (incl. RTU). Due to the operation of the GPS system, the transmitted signals from the substation in the SCADA system have always correct and synchronized time stamp. Previously the time synchronizing was performed by the SCADA, when using e.g. serial communication protocol according to the standard IEC 60870-5-101. Nowadays the local GPS system could be used in the substations for all required purposes [19].

Thus, all the components of substation telematics are responsible for faultless working, while RTU can only receive and transmit those signals, which are accessible for interoperation and are parameterized in RTU accordingly. Before the system is maintained and commissioned, the telecommunication network should be planned taking into consideration some aspects, which definitely influence telematics technical solution. The first step for telematics set up is to define the network type and the features of all telecommunication network components, which should physically and logically reckon and match:

- topology network (star, ring, fully reserved, tree, partial connections or mesh, bus) [35];
- identical physical communication ability (voltage level, optical wave length, optical cable plug etc.) for communicative devices;
- logical interoperability of device communication interface (standardized data transmission protocol like IEC 60870-5-103);
- all of telematics “participant” devices should match each other from hardware and software side like:
- copper wiring, current/voltage rate compatible;
- optical fibers, the same wavelength inside the optical cabling, suitable type of plugs etc.;

- use of the same open communication “language” (e.g. IEC 60870-5).

Sometimes hindrance may occur when the above-mentioned items have to connect all telematics system devices together. In case of the mismatched interface, the technical solution problem may be solved by using of additional converter-devices, which reduce the reliability of the whole telematics system.

Every protection device and RTU should be time synchronized with required accuracy, but the way how to perform that is the responsibility of the device manufacturer. There are typical time synchronization standards for output like IRIG-B, DCF77, GPS, time strings, 1 ppm, IEC 60870–5-101/103, IEEE1588. The time synchronization device should be adapted to all IEDs and RTUs in the substation and it is most important to follow identical time synchronizing mode excluding the individual solutions.

The IEDs need also interface for remote service communication.

The work which defines the quality of device operation is the parameterization of IEDs and RTUs. The parameterization of IED (protection relay) includes several parameterization levels:

- protection function (the essential purpose of the protection relay);
- logic (the additional non/standard logic in the protection relay);
- telemetry (the definition of information objects for RTU/SCADA).

The last item is directly bound with telematics, whereby the defined information objects for the RCC should be linked from previous parameterization levels. The main idea is to precisely define all the addresses of information objects. In case of using IEC 60870-5-103 there is the type identification and information number. The same numbers should be inserted into the configuration of the source and receiver devices (IED and RTU) to transmit the exact amount of information objects to the SCADA correctly.

5.3 Parameterizing of telematics device

The trivial tele-control and -monitoring in the substation might be established using different methods and practices depending on which level the telecommunication is required; as a rule the hardwired binary inputs/outputs and analog modules would execute the necessary tasks. But creation of telecommunication based on the telecommunication protocol is something different.

In telecommunication the basic difference is between logic how to create the IED telecommunication (e.g. meets the communication standard IEC 60870-5-103) and gateway (RTU) telecommunication to the RCC (e.g. meets the communication standard IEC 60870-5-104), but in general, the principal sequence remains the same. The thesis presents the telematics parameterization, configuration and its typical obstacles based on RTU device handling, the activities of which are compared later to alternative system automation and telecommunication based on newer standards.

The RTU is the device that is foreseen to serve the RCC and substation equipment to intercommunicate remotely. The intercommunication scope includes different types of information, i.e. commands, statuses, positions, indications, measurements. The main parts of the RTU usually are:

- hardware (rack, power supply module, processor module, I/O-modules, communication modules etc.);

- firmware (small program to control internally different components of hardware module);
- parameterization;
- communication links for external telematics consumers (different networks, cables, communication devices for data exchange with the SCADA system, IEDs, measurement transducers, GPS time synchronization system etc.).

RTU hardware components should be selected according to technical requirements stated in the requirements of the client. The RTU software affords all parameterization features that enable performance of all needed RTU extensions, tunings, adjustments etc. Basically the parameterization features of RTU configuration software are divided into four groups:

- hardware;
- communication interfaces with external telematics devices;
- logic function;
- information objects exchange with telematics system participants.

The RTU hardware should be correctly defined by the RTU software. The reason is that, in addition to the location of different RTU extension modules for their proper use in couple with external telematics devices, internal communication between RTU modules is ensured via system bus. The communication interfaces of RTU support all possible RTU connections with the SCADA system, IEDs, measurement transducers and GPS time synchronization system. The logic realization requires also use of the standard logical elements like AND, OR, NOR and/or some extended block-elements, e.g. measurement converter in RTU. The grouping of some sub-signals with the following composing of the independent group-signal in RTU for the SCADA system belongs to logic function too. The most obstructive part of the RTU parameterization is the definition of signals (information objects) transmitted and received by the RTU. The reason is the adjustment of various number of information object parameters. To keep the RTU parameterization under control and to avoid the human mistakes, the main steps by handling the RTU parameterization should be kept in mind (shown in *Figure 1.6*).

The most important document that describes the scope of the telematics system in the substation is the client's requirements. This document is mostly concentrated on the specification of the RTU requirements, but also depends on some requirements stated for another telematics devices (e.g. for measurement transducer). The valid RTU requirements are obvious, expressed in:

- RTU compatibility to the existing RCC equipment [20];
- RTU compatibility to the new and/or existing substation equipment [20];
- the transparency of the telematics system with RTU for supervision and future modification;
- standardized solutions of the telematics system equipped with RTU, i.e. use of international standards by constructing and commissioning of the telematics system;
- easy detection of the possible failure in the RTU;
- easy replacement of failed RTU modules;
- repairing of the failed RTU modules intact the others.

There is another inseparable part of supply documents that helps to specify the features and functions of the RTU as compared to common requirements. It is the scope of the supply document that illustrates more or less the actual demands for a

specified substation RTU. Hence, the contractor must obey the requirements stated in both documents.

The RTU is parameterized by an RTU specialist using a usual human-machine interface (keyboard, mouse, display) of the PC. Commonly each manufacturer uses proprietary RTU software for RTU parameterization.

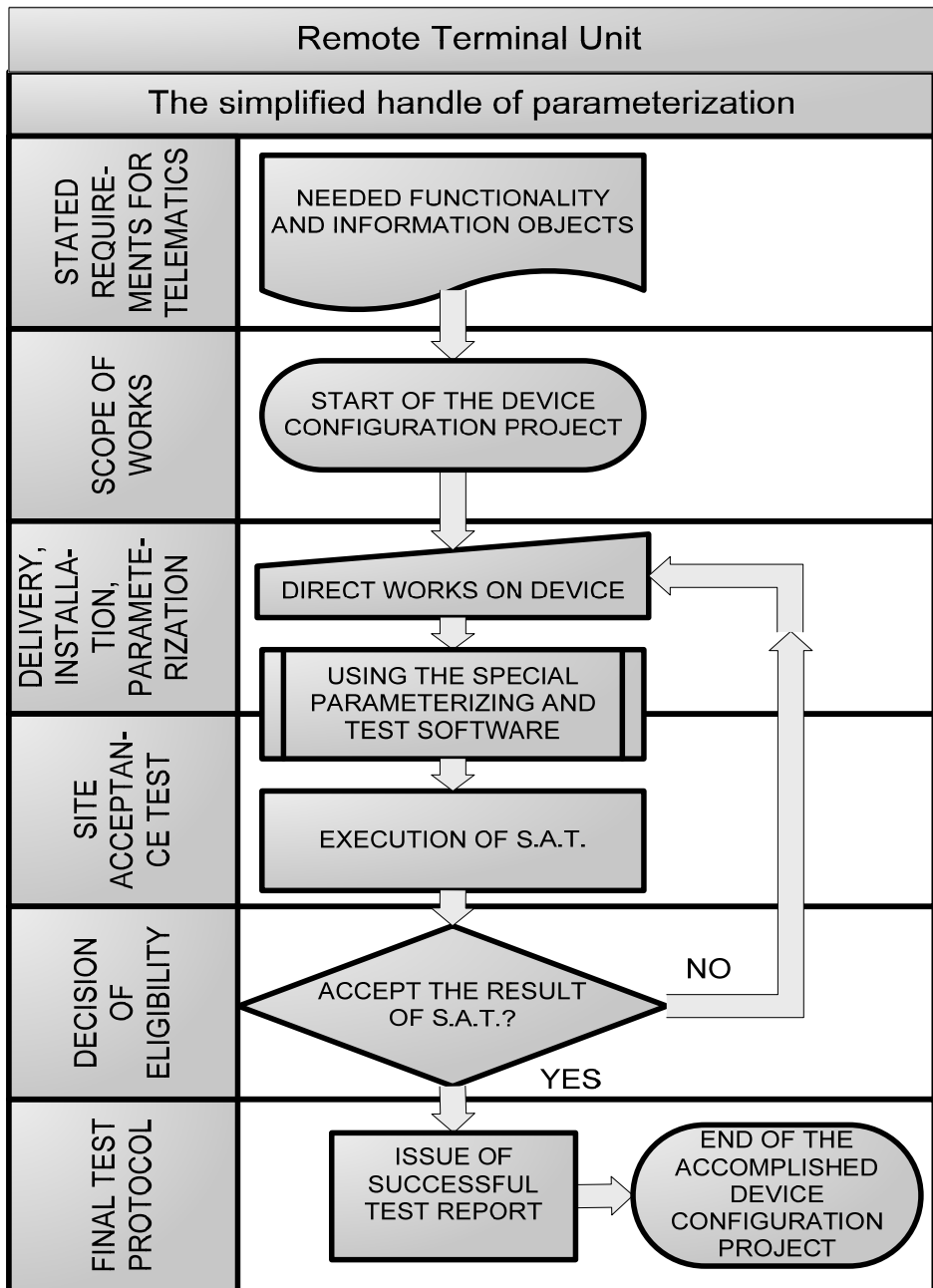


Figure 1.6 RTU parameterization handling [20]

Numerous RTU software tools are available that are equipped with specific features of human-machine interface (HMI). As a result, there are many possibilities to present the image of the RTU internal structure in configuration software. To make the RTU software easy to understand for the client personnel, it

should meet the requirements of IEC standard compatibility, e.g. the international standard IEC 61131 for programmable logic controllers (e.g. part 3 programming languages: ladder diagram, sequential function charts, function block diagram, structured text, instruction list). Thus, the data types, objects, function blocks, logic etc. defined by the RTU software do not confuse the client personnel though the software manufacturer does.

If the whole or part (substation extension) of RTU parameterization is ready for implementation, the preliminary test of RTU parameterization will be established to detect the possible RTU internal mistake or conflict. It will be performed using several testing software programs. There are two solutions for that:

- to activate the functions of RTU parameterization software check (e.g. “compile” or “consistency check”);
- to conduct the external test for RTU configuration (e.g. IEC 60870-5-104 data transmission protocol test system).

Naturally, the first method is more preferable and less expensive to test the ready RTU configuration. The second method involves third-part testing software like RTU parameterization software. The testing process is followed by the site acceptance test of the RTU configuration required. The SAT is one of the routine tests for the telematics systems that might be:

- design test (manufacture’s test);
- site acceptance test (SAT and pre-SAT; on-site device test before the final commissioning);
- specific test (according to the client demand).

The functional target of RTU should be checked by the execution of the SAT. As a rule, there are more than one telematics devices connected to the RTU that should react adequately to the RTU behavior. Hence, in the case of precursory RTU parameterization, the telematics system participants like IEDs (e.g. protection relays) should be also parameterized correctly. Care should be taken to ensure that single modification of some parameters in the telematics participant device will not cause a failure because of non-up-to-date RTU parameterization. In the best case it will end with failure of some remote control functions for the SCADA system. The worst case will cause the human accident like remote high voltage energizing operation of power overhead line servicing by maintenance personnel.

The best solution of SAT execution is not only to test all the parameterized information objects defined in RTU, like their test from “lower” level (IEDs binary inputs, RTU binary/analog inputs etc.) up to the SCADA system, including the testing of all remote commands execution from RCC. Thus, *Figure 1.7* explains the RTU configuration process including more steps concerning the other telematics devices.

There should be not any mitigation to reduce the testing amount of information objects even concerning logic grouping of information objects composed in RTU or IED. All sub-information objects belong to separate SAT performance.

The above described handling process scenario of the RTU parameterization should be valid not only by new RTU placement and its parameterization works, but also in the case of any extension of the substation telematics system.

As compared to the RTU, the IED has a few slight differences concerning the telecommunication performance that require the IED protection functions activation and definition. All the other telecommunication parameterization possibilities remain in general the same.

Nowadays there are various types of IEDs on the market that could include even some functionality of RTU/gateway. Thus, the IED of some manufacturer could establish telecommunication directly to the RCC. Hence, the IED telecommunication parameterization is not under observation because of principal similarity to the RTU configuration.

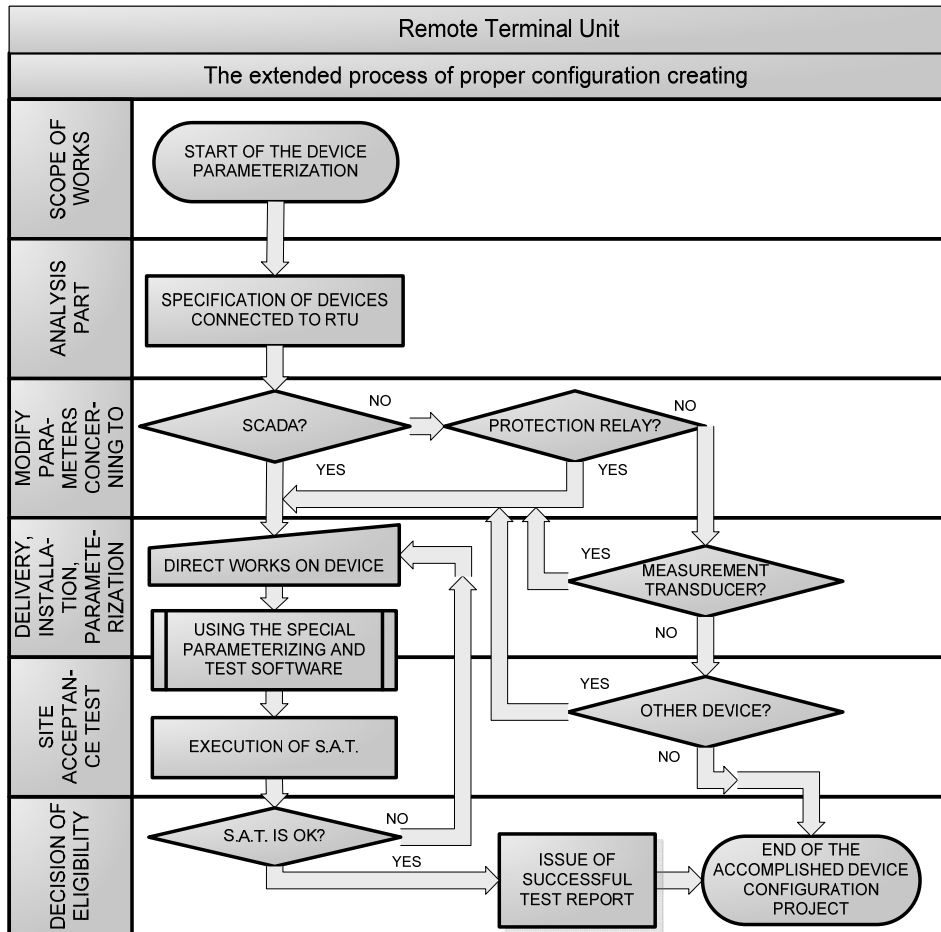


Figure 1.7 RTU sequence of configuration [20]

5.4 Traditional measuring devices

The traditional current and voltage transformer is widespread in every electricity system from low voltage to extremely high voltage levels. Those primary devices ensure the accurate and online measurement streams for appropriated protection function actions in relay protection, for visualization of the power energy exchanging process in the transmission/distribution network, for the analyzing of the power energy quality and for keeping the revenue metering records. The instrument transformers reduce the primary measuring value to the secondary value according to clear value ratio to handle it in secondary SS devices. The working principle is based on the Maxwell-Faraday equation of electromagnetic induction for inductive CT, VT and for capacitive VT with capacitive voltage divider.

The current instrument transformer may be placed in the control room (gas insulated substation) or directly to the switchyard (air insulated substation). The CT will need a space in both types of insulation.

As a rule, several bays in the substation are equipped with CT:

- power (auto)transformer high voltage bay;
- power (auto)transformer middle and low voltage bay;
- bus-bar coupler bay of different voltage levels;
- reactor bay;
- capacitor bay;
- overhead and cable line bay;
- auxiliary transformer bay.

The CT contains a cap, bellow, primary rod with terminals, cores, casting, internal (oil-paper) and external (porcelain or composite) insulation, filling oil and a box (see *Figure 1.8*). The CT may have a few cores according to the request. Usually it is used for transmitting the measurements to the different protection relays (main and back-up relays). The idea of multiplicity of cores is based on CT redundancy. Hence the “*N-1*” criterion could be fulfilled if one core among the others will rupture its proper work, i.e. other cores of CT will remain in normal operation unimpaired.



Figure 1.8 Example of instrument CT

The instrument voltage transformer is the primary device that makes voltage measuring opportunities available for relay protection and monitoring purposes. Like the CT, the voltage instrument transformer may be also placed in the control room (gas insulated substation) or directly to the switchyard (air insulated substation). The VT needs a space in both types of insulation.

As a rule, the following bays are equipped with VT:

- power overhead and/or cable line bay;
- power (auto)transformer all bays;
- each section bay of bus-bar;
- by-pass bus-bar bay;
- reactor bay;
- auxiliary transformer bay.

The cap, bellow, bushing, casting, external (porcelain or composite) insulation, windings, iron core and terminal box of the VT are shown in *Figure 1.9*. The VT could be used in different types of performance:

- capacitive VT (single phase);
- inductive VT (three phase).

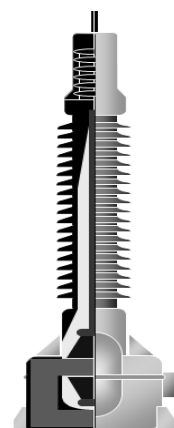


Figure 1.9 Example of instrument VT

The first variant of VT could be roughly named as a capacitor divider the main advantage of which is that it is cheaper than the inductive VT. The performance of the inductive VT represents usually two different secondary windings. One is the open-delta winding (single phase earth-fault distinguishing) and the other is the star-winding.

Nowadays the instrument transformer commonly used is a combined instrument transformer that includes in one primary device case the current and the voltage

instrument transformers. The main advantage of that is space saving in the the switchyard and low price of the device.

The MTs are commonly equipped with a visualization display, but it is also possible to order without that. The MTs could be connected into the loop or radially (star topology). The RTU and measurement transducer use the industrial telecommunication protocols like Modbus or Profibus and internationally standardized communication protocol IEC 60870-5-102/103 and IEC 61850. By the maintenance of the MT the input connection scheme must be taken into consideration (n-wires balanced load, n-wires unbalanced load). The conventional technical solution for telematics connections is represented in *Figure 1.5*. It is the telematics structure based on star topology. The key device in such a telematics system is the RTU that manages data exchange between IEDs and Remote Control Centre. The communication protocol of IEC 60870-5-103 will be used in the direction of IEDs. The communication protocol of IEC 60870-5-104 is used in the direction of RCC. The RTU is connected to the substation switch that provides the necessary communication links of RTU for the RCC. In both directions from the RTU optical cables should be installed, maintained between appropriated devices to ensure optical insulation of different telematics devices. The measuring transducers are commonly hardwired to the RTU directly or via electrical/optical decoupling device. The telematics system is equipped with a local time synchronization system (based on GPS) that is connected either to the RTU that distributes the time synchronization signal from a GPS receiver to the IEDs or to each IED and RTU separately via signal cabling or optics.

The classical function of a measuring transducer (MT) is to convert analog signals received from the instrument transformer to the lower level analog signals and to digitalize those. The MT input side is usually hardwired to the secondary circuits of the instrument transformers and output side is connected to the analog inputs or communication interface of the Remote Terminal Unit (RTU).

The main features of a MT are listed below. They should be checked by the selection of the MT:

- input current (1 A or 5 A);
- external power supply (mostly used the DC);
- zero-output (preferable 4–20 mA);
- measuring accuracy class (e.g. 0.5);
- sample value (analog/digital transducer);
- programmable scaling and over-value;
- communication interface (analog/digital transducer).

Typical technical data of the MT are; input voltage, current, frequency, the overcurrent and overvoltage for a certain time period (continuous overcurrent or instantaneous), analog input impedance, measurement accuracy, and sampling rate.

The input values are commonly set with some reserved range (e.g. 120%), but the values above the nominal measuring range could not be given with declared MT accuracy class. The analog current input impedance would be kept as low as possible and voltage input impedance / vice versa; it will help to reduce the error due to differences of impedance values.

Measurement accuracy will be declared only in the nominal range of measurements and it is commonly 0.5 for the MT. An important quality is the sampling rate and measurement resolution ratio; the first shows the splitting up of the incoming analog signal per second and the resolution rate defines how precisely

the analog signal would be converted to digital value. Usually MT has the resolution rate 12 bit (0.0244% from total analog value) and sampling rate of 3 kHz (3000 times per second). It is quite accurate digitalization in MT, but is not enough for visualization of all needed harmonics. Higher sampling and resolution rates are implemented in a power quality analyzer intended to record power energy quality.

The digital MTs equipped with a visualization display are widely used. The MTs could be connected into the loop or radially (star topology). The MT uses the industrial protocols like Modbus or Profibus and the internationally standardized communication protocol IEC 60870-5-102/103 and IEC 61850 for data delivery to the substation telematics devices.

The financial side of the traditional measurement technology is constituted mostly by the following:

- purchase price;
- installation, commissioning and first operation costs;
- maintenance expenses;
- repairing costs;
- utilization costs.

The componential part of purchase for new secondary measuring devices like measurement transducers, the RTU device, the digital or A/D modules in RTU and accessories (please note that the power quality analyzer is not under discussion) is so fractionary regarding the costs of new primary devices that there is no special issue at all considering the total formation of investment calculations. The new primary devices are of course the margin investment part.

In a fact, the purchase prices are the sensitive issue. Thus, they are represented on a comparison diagram in *Figure 1.10*.

The diagram shows the large difference between the price of capacitive and inductive VT in 330 kV regarding the 110 kV VTs. The reason is that the constructive specialty of 330 kV VT level sets the ratio of used material (e.g. copper wiring, amount of oil content, external dimensions) to the voltage level. Essentially, the price for the capacitive VT is equivalent or lower than that of the inductive VT, but the amount of ordered VTs, the transportation costs, the VT factory location might influence the end price of the VT, as shown in *Figure 1.10*, 110 kV voltage level VTs.

The price variation of traditional instrument transformers

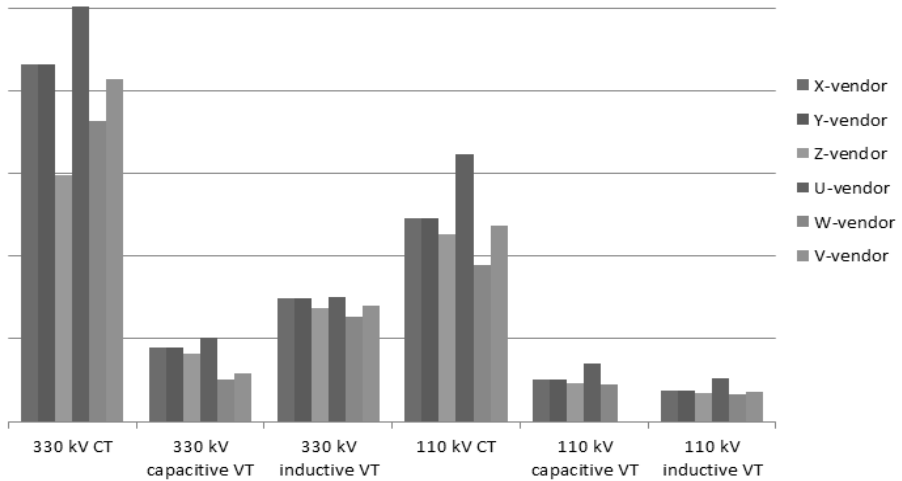


Figure 1.10 Comparison of purchase prices. 330 kV and 110 kV CTs and VTs

Figure 1.11 presents a more classical situation with some deviations on the Estonian market regarding the purchase price for 110 kV VTs.

The price variation of 110 kV traditional voltage transformers

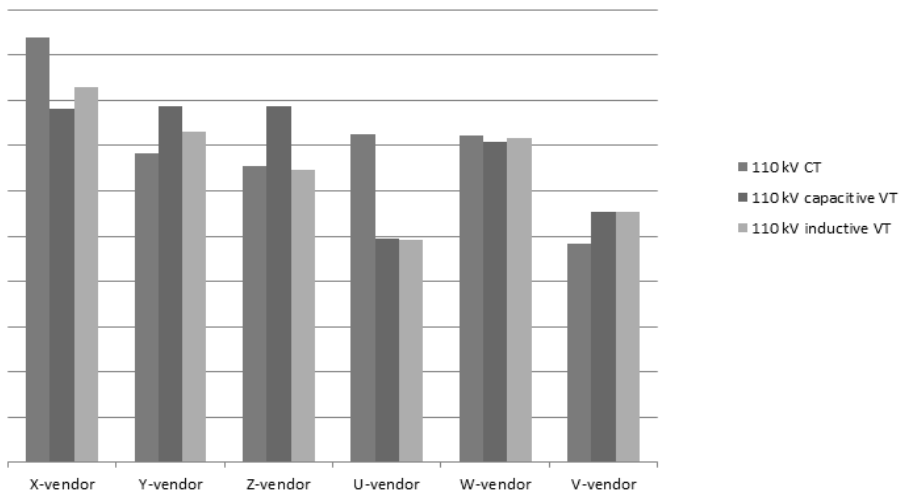


Figure 1.11 Comparison of purchase prices. 110 kV VT

The installation, commissioning and first operation costs are constant values and those depend on the amount of ordered CTs and VTs, the distance between the control room and the switchgear (the length of copper wiring) and charge for inspection services.

The asset management costs for modern traditional CTs and VTs should be infinitesimal, but the periodical visual check is still required (e.g. to check the instrument transformer oil level or to repair the oil leakage). Based on practical experiences in the Estonian transmission system operator, the asset management costs could be 0.01 - 0.05% from instrument transformer purchase price under normal conditions. The repairing works and the utilization costs at the end of the instrument transformer life cycle vary depending on the CT/VT type, size and voltage level.

6 TRADITIONAL INSTRUMENT TRANSFORMERS

6.1 General overview

The typical drawbacks of the traditional instrument transformer are basically caused by the design of the instrument transformer.

Magnetic core of the current transformer. The saturation in the magnetic core disturbs the presenting of an adequate value in the secondary winding, so the IEDs and other devices will not receive the measurement data to act properly. To solve such a saturation effect on relay protection functions, the IEDs are equipped with fast microprocessor technics that pick up and make the decision to send the command already during a couple of fault current periods before the instrument transformer saturation begins. *Figure 1.12* shows the fault characteristics of the overhead line that might have in phase current asymmetrical component that needs time to end the decay process exponentially.

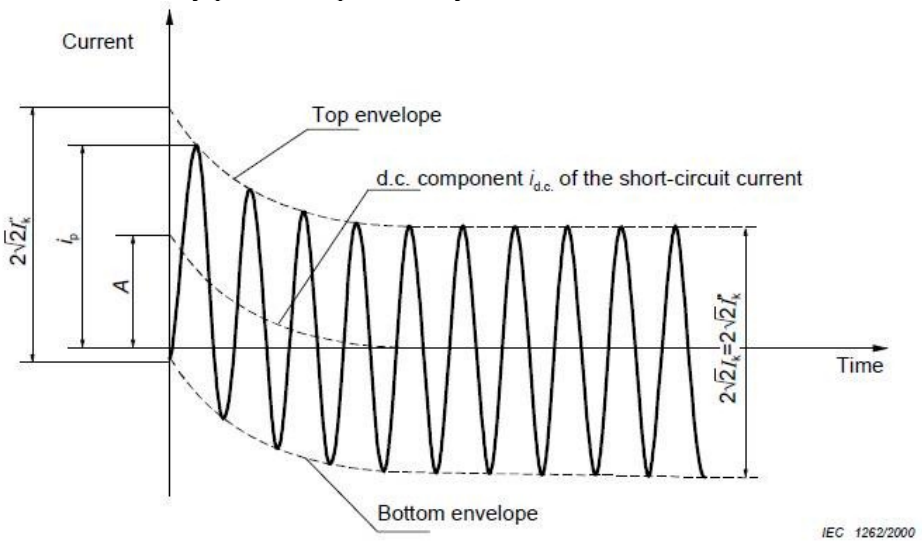


Figure 1.12. Short-circuit on the primary terminals of CT [IEC 60909-0]

The DC component causes the saturation of an instrument transformer in a certain ratio to sum current AC and DC components in input circuits. The distortion of magnetic core saturation influences secondary windings in the current transformer, as presented in *Figure 1.13*.

The traditional instrument transformer is usually characterized by following key features that give better overview about limitations within operation.

Insulation breakdown of an instrument transformer. The reason of that could be the over-voltage because of lightning or for example at the end of the current transformer life cycle. It is usually internal ground fault that excites a lot of heating energy for a short time period.

The content of oil or sulphur hexafluoride. The damage of an instrument transformer would cause environmental pollution. Furthermore, by the production of instrument transformer oil or SF₆, the industry causes also contamination.

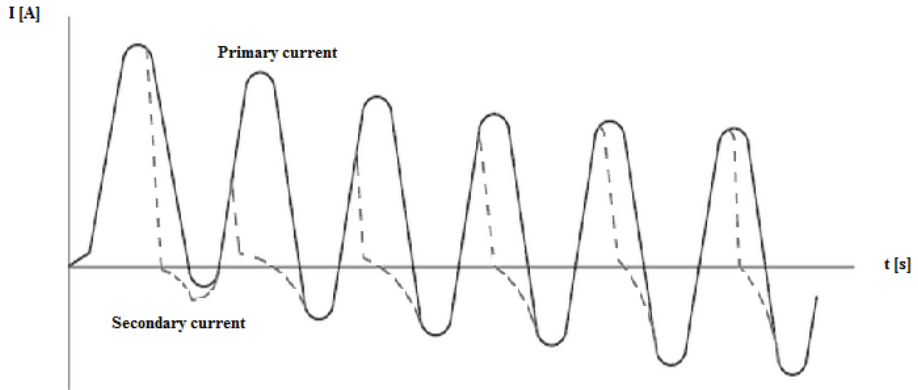


Figure 1.13. Saturation at CT secondary terminals [IEC 60909-0]

The ferro-resonance of an instrument transformer. The relation between non-linear inductance and non-linear capacitance might cause the ferro-resonance in the inductive voltage transformer. The hazard to thermal damage of a voltage transformer is conditioned with a jump of current value by slow increasing/decreasing of input voltage that is changing its inductive or capacitive character. Naturally the appropriated values of magnetic core flux (saturation) and network frequency imply the conditions for the appearance of ferro-resonance [36]. The phenomenon could occur by parallel connections of capacitance and inductance (e.g. earth connection, parallel overhead lines on the same pylon) and also by sequent mode connection. The main hazard is the magnet core saturation of instrument current transformer that causes the overheating of the primary winding due to the ferro-resonance phenomenon [12].

Non-linearity of measurement accuracy. In general, the accuracy class of an instrument transformer defines the range of error in respect of transformation ratio and phase shift. In other words “the accuracy class characterizes a current or voltage transformer in which the error, under specified application conditions, remains within the stipulated limits⁴”. Regarding the voltage transformers, the phase shift should be mentioned that is the error between the phases of the input and output voltages, voltage error and rated voltage factor that defines the maximum voltage values in multiplied mode meeting the declared measurement accuracy, operating and cooling conditions. Voltage transformers for measurements and protection are available, necessary to operate the relay protection under abnormal conditions (e.g. fault), when the voltage measurements could be very low. The voltage transformers for billing purposes have higher accuracy class that should be ensured within 80 to 100% of rated voltage, but with less voltage and phase displacement errors than the voltage transformers for relay protections.

The current transformers have also the same enlarged accuracy class intended for relay protection purposes. There are fixed values of the current under rated current conditions not to be exceeded in certain accuracy class of the current

⁴ Technical dictionary instrument transformers, Ritz Instrument Transformers GmbH, 2nd edition, 2011

transformer. *Figure 1.14* shows the limits for current error values depending on different accuracy classes.

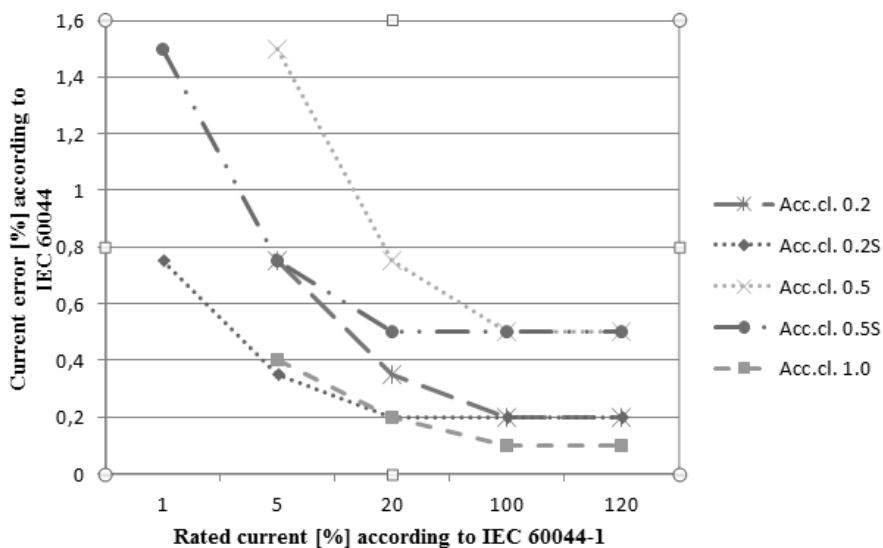


Figure 1.14. Standardized limits of CT current error

The difference in phase between primary and secondary currents should be also preserved in limits to meet the declared accuracy class of measurements in the current transformer. The allowed phase displacement is shown in *Figure 1.15*; those values are standardized limits for phase difference, which has positive sign of the angle, when the secondary values ahead the primary values [1].

As a rule, the current transformers should be tested after manufacturing during the factory acceptance test, which could include different types of routine and extended tests. The routine tests are the mandatory part of product quality verification before sending the product from the factory to the end customer. All the testing data would be fixed in the specific testing reports. The data of routine test describe the instrument transformer insulation, rated output and corresponding accuracy class, intern-turn overvoltage, composite error and security factor, power frequency withstand, ferro-resonance, partial discharges, $\tan \delta$ (dielectric loss ratio factor) and capacitance measurement at power frequency, impulse withstand etc.

The current value error and phase displacement are visualized in non-linear mode, which it is caused by the form of magnetization current of the current transformer. From the theory it is known that the secondary current should be the same as the primary current, i.e. magnetization current and inductance are zero. The real magnetic core is not the ideal CT, therefore the other components must be taken into account by calculating of the secondary current.

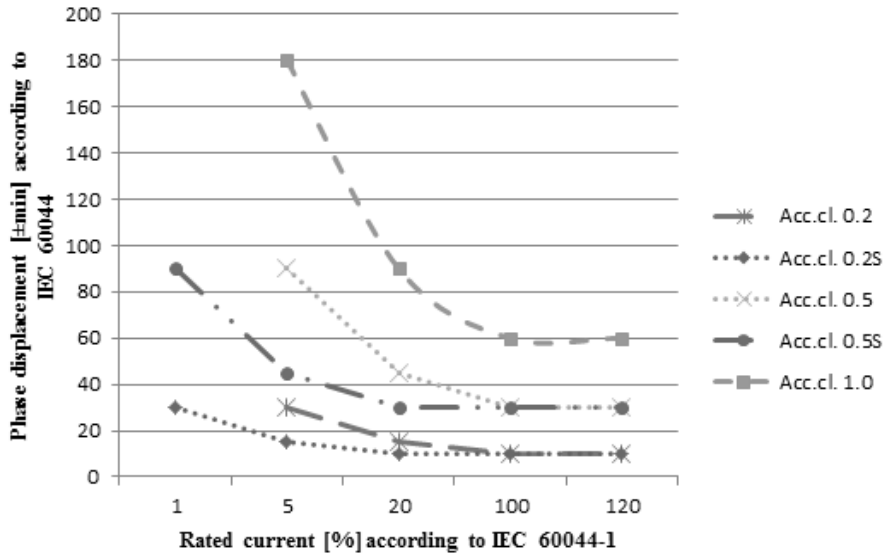


Figure 1.15. Standardised limits of CT phase displacement

The metering and protection CT cores differ from each other because of their function tasks. The CT metering core may not damage the metering devices connected in secondary circuits, therefore the metering CT is saturated faster by close to limits primary current values (e.g. at 120% of rated current). The protection cores of CT shall have extended linearized magnetizing curve to cover partially the overcurrent area.

Nowadays the linearized magnetic (e.g. with air gaps) cores are widely used to extend the overcurrent factor of CT (see *Figure 1.16*).

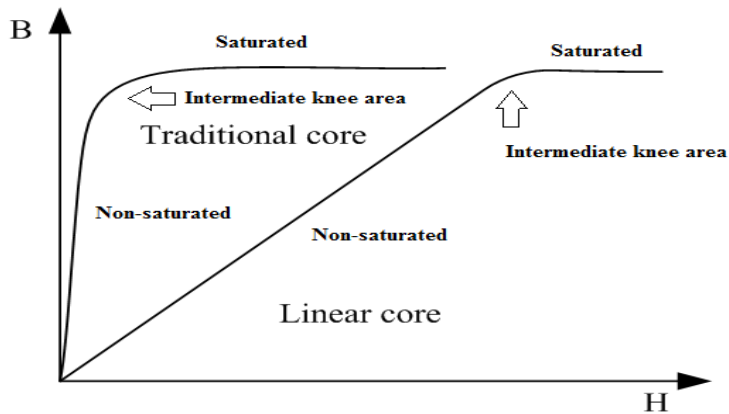


Figure 1.16. Comparison between different types of CT cores [1]

The real high voltage CT accuracy of measuring is better than required in the international standard. *Figure 1.17* shows the phase displacement within ± 8 angular minutes, that is a good result.

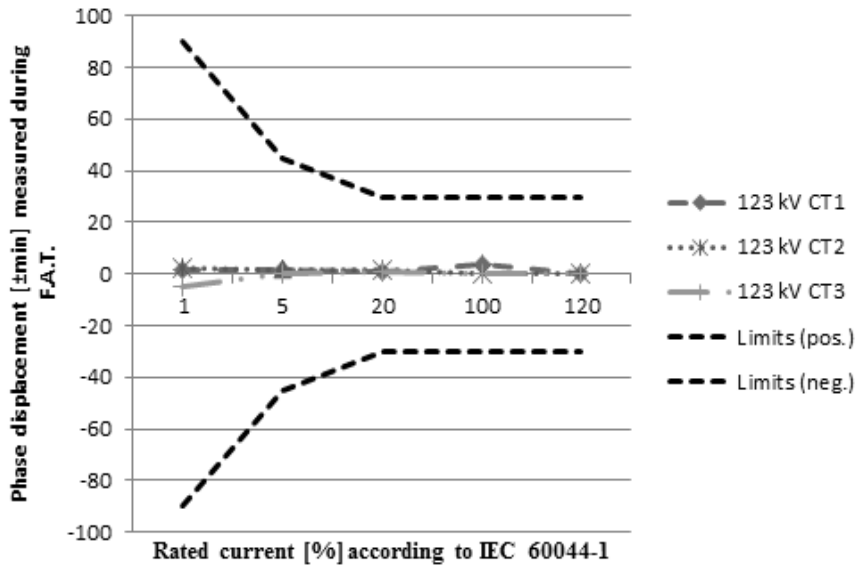


Figure 1.17. Phase displacement of 0.5S CT measuring core

Figure 1.18 presents the current error deviations between the measuring cores of different CTs.

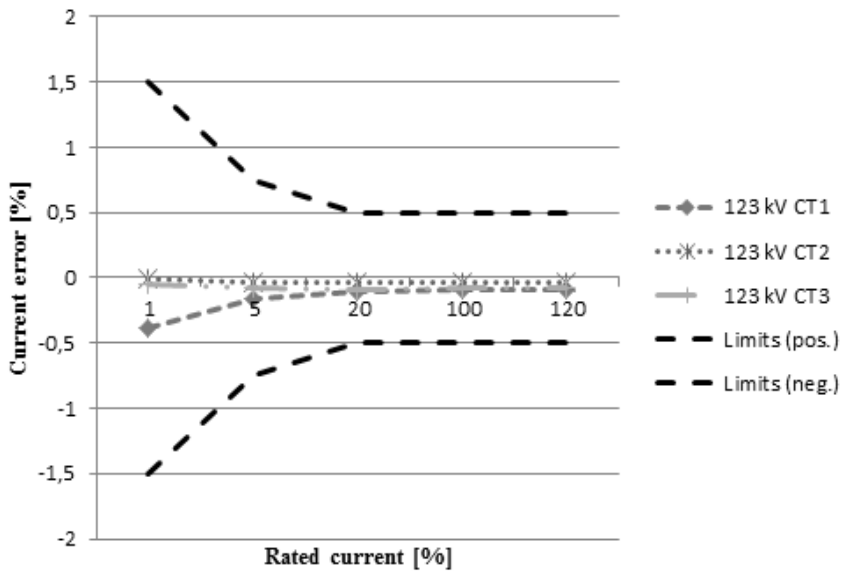


Figure 1.18. Current error of 0.5S CT measuring core

The routine test results of the core of the 3rd CT shows the common clearly expressed relation between current error and measured values at the beginning of rated current measurement range. The voltage transformers are divided to two groups regarding the working principle:

- inductive VT;
- capacitive VT.

The inductive VT is like the power transformer that does not have the load. Thus all standard elements (e.g. ferro-magnetic core, primary and secondary windings) are presented in VT. The influence of saturation and ferro-resonance should be under observation to avoid them. The easiest example is the de-energizing of 110 kV OHL being on the same pylon with 220 kV OHL. The resonance circuit will be formed by 110 kV OHL VT and the capacitance to the 220 kV OHL. Hence, when the voltage on switched off 110 kV OHL is decaying (at frequency 16.6 Hz), the magnetic flux is increasing in 110 kV VT and the saturation conditions would be fulfilled. The capacitive energy of 220 kV OHL will supply the oscillation and the ferro-resonance process will not stop.

The capacitive VT is based on the voltage divider principle, where the set of capacitances is used. The inductive VT includes the voltage transformer, but it is at much lower power and includes the damper into the secondary circuit. The capacitive VT might have the protection gap in the primary part to arc discharge the overvoltage.

The VTs are intended for measuring and protection purposes based on voltage. The VTs must meet the international requirements based on the international standards (e.g. IEC 60044-2).

Voltage factor. Among other important characteristics of VT (accuracy class, voltage error, phase displacement etc.), the rated voltage factor shows the multiplication of the rated voltage that VT could handle, ensuring the required measuring accuracy.

Power accuracy. It is the apparent power to be supplied from CT/VT, the secondary equipment with rated secondary current/voltage meeting the required accuracy.

6.2 State-of-the-art in measuring

In spite of the international standard IEC 60044, many parts of IEC 60044 were replaced with the extended standard IEC 61869 in July 2013, including the major content of standard IEC 60044 that was used in the current research work.

The qualitative and quantitative measurements from high voltage primary equipment to the RCC are usually sent by reducing the current and voltage levels. The devices commonly used for this purpose are traditional electromagnetic current and voltage instrument transformers and measurement transducers that are receiving the secondary values from instrument transformers and distributing them to the RTU in any required mode (analog signal – e.g. 4..20 mA, communication protocol – e.g. Modbus RTU, IEC 60870-5-103).

Because the traditional measurement technology is using low level voltage and current values, the opportunity to sample them and transmit the sampling to the IEDs presents the real advantages and benefits in today's high voltage substations as NCIT. The structure and rules how to act are stated in the standard IEC 61850 part 9-1 and part 9-2. The process bus of the substation is responsible for streaming the measurement information to the different IED (e.g. differential protection, distance protection), specific indication information regarding the measurement system and for the control and monitoring of primary equipment (e.g. circuit breaker, isolator, earthing switch). The control and monitoring of primary equipment in the transmission network is not yet widespread, thus the basic implementation of nowadays process bus is focused on the digital sample values sending to the relay protection devices. The standard IEC 61850 allows the data flow to be used according to the ISO/IEC 8802-3 (unicast – one-to-one between

client and server; multicast - broadcast) and to the standard IEC 60044-8 (specified in IEC 61850-9-1 for many subscribers). The use of stand-alone merging unit is not mandatory if this functionality is implemented in an electronic instrument transformer. The first important issue by sample values transmission is the adjustable sample value rate from 80 samples per cycle (protection functions) to 256 samples (power quality analyzer, splitting system etc.). The second important issue is to send the sampled values being time synchronized; therefore the precise oscillator must be integrated in MU or electronic instrument transformer or the precise time synchronization pulse per second. The primary part of non-conventional instrument technology could be described by a sensor, optical or copper medium, merging unit or integrated electronics, which all must resist the different ambient temperature, thus the ambient temperature compensator is required. Unlike the traditional instrument transformer, the installation of non/metallic sensing element of the non-conventional instrument technology might be classical or combined with a circuit breaker or a high voltage bus-bar.

7 THE ROLE OF STANDARDIZATION

Telecommunication in a substation is an inseparable part of power engineering. Electrical power transmission and distribution could ensure the uninterrupted and reliable operation of an electricity system with efficient telecommunication only. Nowadays the supervision for energy production, transmission and distribution is made by use of appropriated telematics. The telematics was different in the energy sector and was not enough interoperable; hence telematics systems were manufacture oriented systems. There were a lot of drawbacks regarding the interoperability issues because of complex integrity of different telematics devices and telecommunication protocols (e.g., the proprietary communication protocols that cause heavy dependency on one manufacturer).

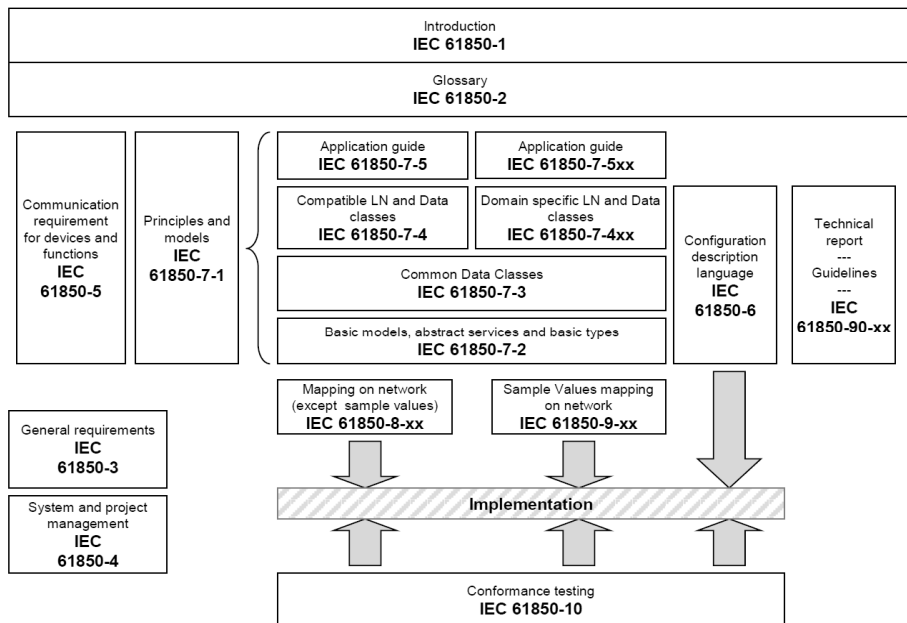
The standardization is a proper way to have a telecommunication system in the energy sector under control. Therefore, the internationally standardized telematics solutions should be used in telemetry setting the main requirement for a substation as *“acceptable price with high quality and sustainability”*. It means the construction process to build, modify and extend the telematics system despite the system vendor/integrator/manufacturer. What kind of international standard for telematics systems in the energy sector could satisfy all the needs regarding telematics?

The answer is the international standard of IEC 61850. This standard was specially designed for use in the energy sector like transmission and distribution. The IEC 61850 defines equipment control and monitoring, measuring and alarming, reliability check of information stream and automation behavior in faulty cases, protection functions etc. The clear advantage of implementing this standard is covering TSO and DSO and also the applications of renewable energy solutions, smart measuring, energy storage etc.

The IEC 61850 standards were published from the International Electrotechnical Commission in the period of 2002 – 2004 and were caused an immediate dispute around the world. The huge amount of publications about IEC 61850 in newspapers, scientific journals, books, surveys etc. shows the tremendous growth of interest towards its implementation. And several years later the personnel of transmission, distribution utilities and power generation companies started to realize the real technical solutions based on the standard IEC 61850. Step by step the understanding of project composing principles took a shape in the substation automation system using the standard IEC 61850. While the standard IEC 61850 seems firstly to be too trivial, the target customer should see beyond the standard the innovative solution through sophisticated data transmission via substation local area network. Today many IEC 61850 capabilities could be useful not only in limits of substation functional dimensions (e.g. substation automation, HMI, SCADA, bay and bus-bar automation), but also in relation to the communication between the different substations, different utilities and power generation companies, the different consumers and even different countries. The key benefit will be the possibility to construct the digital network to serve the so-called station bus and process bus, where the physical devices could form different virtual devices, the measurement data flow ensures the protection operation, the system automation could be distributed within the different substation bays, the measurements distributed from switchyard could be digital and accurate enough without the implementation of a traditional instrument transformer etc.

The process bus does not set the implementation limits with current and voltage sensors using the distribution of sampled values according to the standard for the

demand of relay protection and revenue metering, it also predefines the possibilities to erect the substation on the new level of substation smartness, smartness of primary equipment. Unfortunately only few manufacturers on the market offer the above-mentioned process bus solutions, but it is all because the customers are looking for complete station bus and process bus solutions to integrate them in one substation and to benefit from all kind of feasible advantages offered by the standard IEC 61850. The standard IEC 61850 is not debatable as a stand-alone standard, but it is standing “shoulder-to-shoulder” with other works of IEC Technical Committees (other IEC standards), national standards, European standards and international standards.



IEC 1402/11

Figure 1.19 Parts of the standard IEC 61850

The standard IEC 61850 is divided to several parts make easier access to different aspects of the standard shown in *Figure 1.19*.

8 MEASURING AND DATA COMMUNICATION

8.1 Preparing the data communication

The transmission of measurements as part of the process of bus implementation requires the preparedness of substation for digital technology compliance and digitalization of data exchange via communication paths.

What is the reason for use of the high-level computing and digital network technology in the substation? The new concept of substation automation, control and monitoring system presumes the existence of substation LAN, which should have the opportunity to extend it. The substation LAN could be constructed for remote event reading, remote service, time synchronization etc. If the steps to follow the logic of “linked” capabilities devices (IEC 61850) are injected to the ideological principles of substation construction, commissioning and operation, then the modern substation will reach all benefits and advantages that offer higher horizons of efficiency regarding the different implementation and saving opportunities. In general, the implementation of a digital station bus is relevant due to the advantages of the financial and configuration process:

- standardized technical solution;
- standardized devices that ensure the functional and communication interoperability;
- backward and forward compatibility for parameterizing and service software tools;
- reduced man/hours within system design;
- reduced commissioning costs;
- station bus device interoperability;
- typical modeling of substation;
- encapsulated services in Ethernet;
- object orientation;
- substation sample modeling with SCL up to the all data needed IED;
- reduced use of copper wiring.

The start point to gain the aforementioned advantages is to meet the appropriated international standards that are valid in the European Union. This research took into account the IEC 61850, which is intended for such novel substations construction principles. The station bus is the TCP/IP based LAN that serves the substation automation and control functionality according to the standardized Ethernet technology. The innovative substation automation system needs more information objects to make the SAS more transparent and reliable, but as a result, the applications working with those various information objects are more complex. The information object amount is steadily increasing thanks to the advancing semiconductor technology. The standard IEC 61850 ensures the capability of handling the online information concerning all the users. The standard IEC 61850 offers the key advantage of standardized information modeling. The addressing is running without attaching the device code (e.g. replace the distance protection relay with overcurrent terminal relay), and furthermore, the addressing to information objects is implemented by pre-defined and user defined object naming. This could help to avoid the use of vendor specific configuration files in the device. The automatic process of configuration is another benefit of the standard IEC 61850. The IEC 61850 is not another telecommunication protocol, it is the conglomerate of

encapsulated services and applications to obtain the maximum supervision and control result in the high voltage substation SAS and supervision.

In brief, the key characteristics of the IEC 61850 station bus are:

- modeling (physical device, logical device, logical node, data object, attribute);
- model and service mapping (e.g. LN data to MMS; MMS service read/write; object mapping to OPC);
- standardized object names (e.g. *ER.E1.Q1/XCBRI.ST.Pos*);
- unified configuration language (SCL – XML based representation of modeled data and communication services);
- manufacturing message specification (structure of message for IED and the control system);
- Client/Server (the server communicates with many clients via TCP/IP, client driven connection; the model is seen);
- Publisher/Subscriber (broadcast/multicast without feedback; the model is hidden);
- freely extendable logical nodes [32].

Figure 1.20 provides a better understanding of what is changing and where the difference between the configuration of telematics in previous time and the configuration of telematics as part of SAS configuration according to the IEC 61850 station bus is.

As it was mentioned before, the advantages of the internationally standardized technical solutions and devices are the benefit key to have the independence of the device manufacturers, clear vision how to extend the existing technology and to have an opportunity to reduce the investments. Thus, the international standard to be used is IEC 61850. The appropriated files written by SCL are intended to configure the IED communication. The following files are to be generated for the aforementioned tasks:

- CID-file is the IED configuration;
- ICD-file is the functional capability template to be configured in the IED configuration tool;
- IID-file is the pre-configured instance of the specific IED (2nd edition of IEC 61850);
- SCD-file is the substation configuration that includes instances and communications;
- SED-file is the configuration of interfaces to be used for data exchange between the projects (2nd edition of IEC 61850);
- SSD-file is the configuration of substation equipment in the switchyard.

Figure 1.20 shows the management of the software pieces needed for proper configuration of substation secondary devices. Nowadays each IEC 61850 brand-new IED comes to the market with ICD-file. The IED capability description file specifies the IED functionality on the relay protection data communication level. If the utility knows already what the primary structure is in the substation, then he could prepare the SSD-file for the whole substation by himself and using the system configuration tool he could create the SCD-file. The vendor configuration tool is usually needed to parameterize the IED directly using the appropriated data from the substation SCD-file. The CID-file is necessary, when the IED utility parameterizes the IED preparing all the individual communication descriptions.

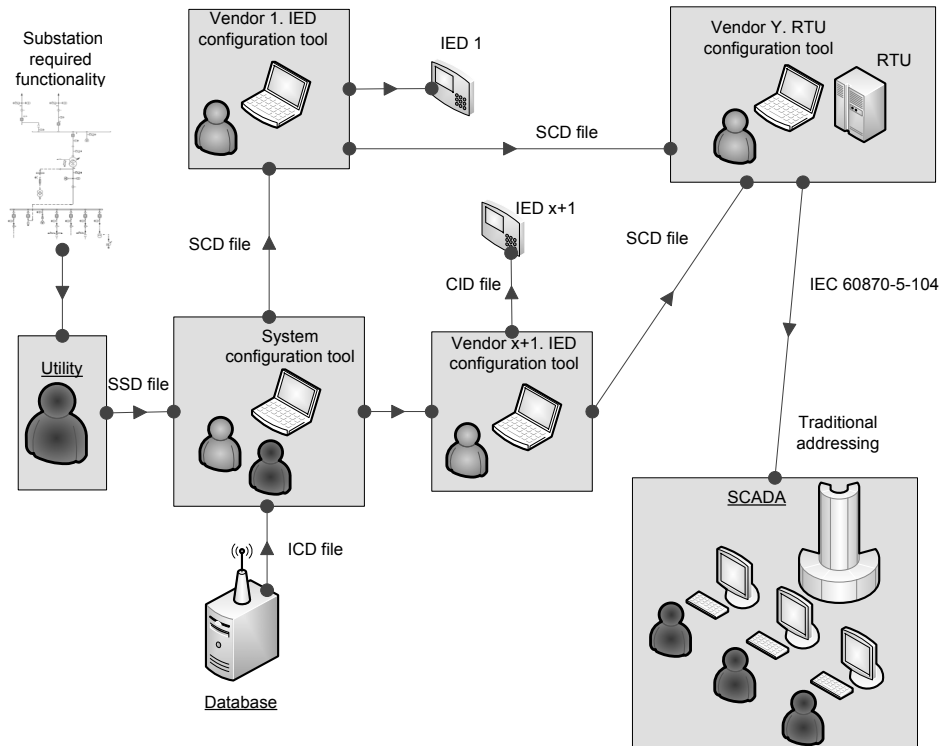


Figure 1.20 Configuration overview of the station bus

The database is intended to compose the independent IED-file storage from different manufacturers of IEDs. The IED capability description is necessary to observe the functionality of IED. To define the single line diagram and the communication structure and protection functions the system specification description is needed (output of system configuration tool). The configured IED description file is the part of substation configuration description file for only one IED. The SCD-file describes the whole configuration of the substation. There is one interesting file of instantiated IED descriptions that is defined in the 2nd generation of the IEC 61850. The idea is to create the instances of IEDs as the instance of IED data model without configuration. The IID presents the information of data modeling, communication part, and functions for only one IED.

8.2 Designing the data communication

From the utility point of view, the IEC 61850 station bus has the lowest price with all the required capabilities. To verify the compliance to the standard IEC 61850 the utility will check the specific IED documentation. The first determination of suitable IEC 61850 IEDs could begin from the following IED documentation:

- the IED manufacturer gives the record statement about the IED accordance to the standard IEC 61850;
- the IED will obtain the IEC 61850 conformance test report from the independent test lab [26];
- PICS Protocol Implementation Conformance Statement (the communication capabilities of the system or device that are foreseen to be tested);

- MICS Model Implementation Conformance Statement (describes the data object model elements supported by the system or device);
- TICS Tissue Conformance Statement (device supported technical issues owned and defined by UCA user group);
- PIXIT Protocol Extra Information for Testing (contains system or device specific information regarding the communication capabilities of the system or the device to be tested. PIXIT does not belong to the standard and could not be standardized).

If the existing IED documentation is not enough or includes informational gaps, then the real IED testing procedure could be performed or the IED could be disqualified for the project.

Some basic technical requirements that help to verify the IED to be in the telecommunication system of the substation secondary part are as follows:

- Ethernet based LAN,
- fewer communication devices;
- communication cabling – optical fibres;
- redundant communication regarding the LAN devices;
- openness for substation extension;
- physical segregation for main and backup protection relay;
- use of LAN encapsulated services;
- standardized substation devices;
- long life-cycle of a communication device.

The examples of minimum reliability, environment and topological requirements for the IEC 61850 station bus to be fulfilled in the substation are as follows:

- requirements to computing network devices - switches:
 - MTBF at least 30 years;
 - meeting the international standards:
 - standard meeting declaration and conformance test reports for IEC 61850-3;
 - IEC 60255-21-1, ..-2 or e.g. MIL-STD-167 and -810 (vibration, extreme operation temperature range, humidity, etc.);
 - IEC 60255-21-2 or e.g. MIL-S 901D (shock test);
 - IEC 61000-4 parts 2, 16, 29 (electromagnetic compatibility);
 - automatic seamless LAN reconfiguration capability;
 - VLAN priority handling;
 - doubled active standby power supply modules;
 - main, backup, auxiliary and remote handling switches are from the same manufacturer, type and version number;
 - data exchange speed at least 100 Mbps [30];
 - support different types of fibre connectors (e.g. LC, ST);
- requirements to cabling:
 - optical non-plastic fibres;
 - optical halogen free cable;
 - optical metallic free cable;
 - single-mode or multi-mode according to the distance between communicative devices;
 - the wave length will match the IED station bus interface specification;
- telematics requirements to IEDs:

- meeting the standard IEC 61850;
- the loop communication for IEDs connections is allowed if the IED is equipped with a non-manageable integrated switch;
- interface to support several Ethernet services.

8.3 Substation computing network topology

The secondary devices connected to each other in the substation LAN should be defined before beginning to compose the local area network in substation. The traditional substation of TSO has protection relays, measuring devices and different ancillary devices that ensure the control, monitoring and protection functions of substation primary equipment. Despite the IEC 61850 possibilities to allocate the protection functions independent of the physical device, the protection devices are grouped based on physical device principles:

- main protection devices (differential protection, bus-bar differential protection, line differential protection, line distance protection relays);
- backup protection devices (current protection functions in bay terminal protection relays, voltage protection functions in bus-bar protection relays);
- ancillary devices (automatic voltage regulator, power transformer ARS terminal, annunciator, time synchronization system);
- measuring devices (measuring transducer, power quality analyzer, disturbance recorder);
- telematics devices (RTU, GW, local workstation, LAN switch);
- devices for revenue metering of power energy.

All the above-mentioned devices will be placed at the substation LAN topology to fulfil the following requirements:

- RTU lower communications shall be redundant;
- to build up the IED communications the following variants will be implemented:
 - ring for switches, star for IEDs (see Figure 1.21); the amount of switches connected in ring is defined by voltage level and functionality of IEDs. The basic communication organization principles of IEDs connections per one switch are the following:
 - 330/220/110/35/15/10/6 kV main protection relays;
 - 330 kV backup protection relays;
 - 330/220/110/35/15/10/6 kV backup protection relays and system automation devices;
 - ancillary protections and functions (e.g. annunciator, power transformer ARS);
 - *ring for switches, loop for IEDs* (see the Figure 1.22); the maximum number in serial connected IEDs is limited by main and backup protection functions and feasibility defined by the utility. The partition principles of IEDs connections are (in one stroke):
 - main protection switch: 330/220/110/35/15/10/6 kV main protection relays;
 - 1st backup protection switch: 330/220/110/35/15/10/6 kV backup protection relays,
 - 2nd backup protection switch: 330/220/110/35/15/10/6 kV bus-bar VT protection relays, BFP, CBFP and SAS protection relays;

- ancillary switch: all voltage level automatic voltage regulator, auxiliary and ancillary protection relays and devices (e.g. annunciator, IED of power transformer automatic reserve switching);

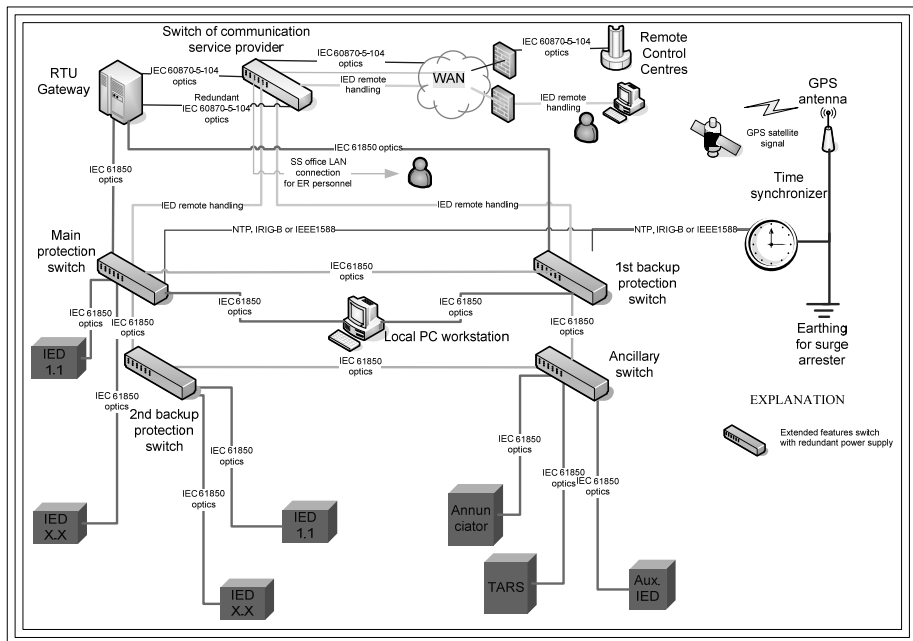


Figure 1.21 LAN topology no.1 of the IEC 61850 station bus [18]

- ring for switches, star for IEDs per bay (see Figure 1.23); the amount of switches connected in ring is defined by cable/overhead lines, power transformer and others bay protection relays and devices:
 - cable/OHL bay;
 - power transformer bays;
 - all bays serving with SA;
 - ancillary SS services;
- station bus functionality requirements:
 - all the other automation functions will be realized without copper wiring on the secondary part:
 - circuit breaker automated reclosing;
 - circuit breaker failure protection;
 - any transmission network parameter load shedding,
 - islanding;
 - the substation physical LAN with the following encapsulated services:
 - time synchronization;
 - remote handling;
 - MMS data exchange;
 - GOOSE data exchange;
 - LAN automatic reconfiguration for less than 5-10 ms;
- IED communication capability requirements:
 - SS control interlocking (not the relay protection blocking) shall be realized for complete SS interlocking system by GOOSE messages (copper connections with interlocking coils shall remain in use);

- all GOOSE messages shall be under supervision from appropriated protection relays connected with GOOSE message receiving. Hence the fast retransmit on data change and continuous the periodic slow retransmit of GOOSE without data change (watch dog with configurable retransmission time in ms) are required. The function logic of GOOSE message supervision shall be agreed with the Client;
- the using of VLAN handling, priority tagging is mandatory;
- the interlocking logic process using the supervised GOOSE shall be blocked after any failed GOOSE message (e.g. gap in GOOSE message continuous sending) and shall cause the continuous blocking for interlocking logic (i.e. also for IED control logic of primary equipment) until de-blocking command will be initiated centrally from RCC. The exact blocking logic of interlocking logic shall be agreed with the client;
- GOOSE messages are not allowed for use for trip command, starting and blocking (except interlocking logic) signals, SAS and/or protection functions and for annunciator (local alarm centre);
- all new GGIOs shall be agreed with utility;
- requirements to the time GPS synchronization system:
 - the IEDs, RTU and local PC workstation shall be time synchronized with local time (i.e. protection relays, RTU shall log the events and send the information within IEC 61850 and IEC 60870-5-104 with the time stamp of local time);
 - the using of network time protocol is allowed;
 - the system shall be equipped with highly precise oscillator that should automatically overtake the keeping the time accuracy even the GPS signal is lost.

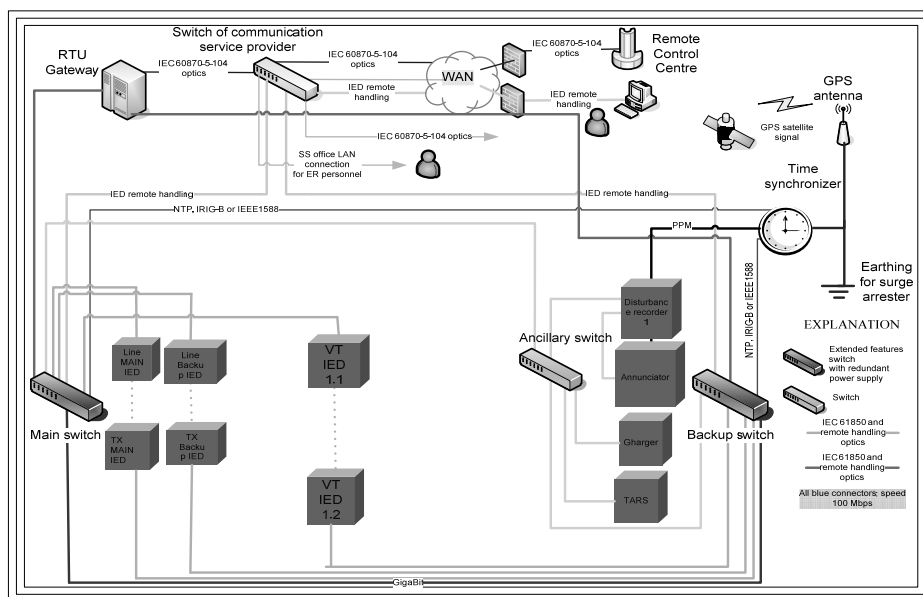


Figure 1.22 LAN topology no.2 of the IEC 61850 station bus

The different schemes of the substation LAN topology are not only the schemes, the complicity of the LAN topology depends on the IED amount, the task importance and reliability criteria. All the presented schemes have their own

benefits and drawbacks the discussion of which is out of scope of this thesis research.

As a result of the above-mentioned requirements the targets of the pre-planned substation LAN should clearly face up the financial efficiency, provide technical applicability and guarantee the maximum uninterrupted functionality of substation secondary devices.

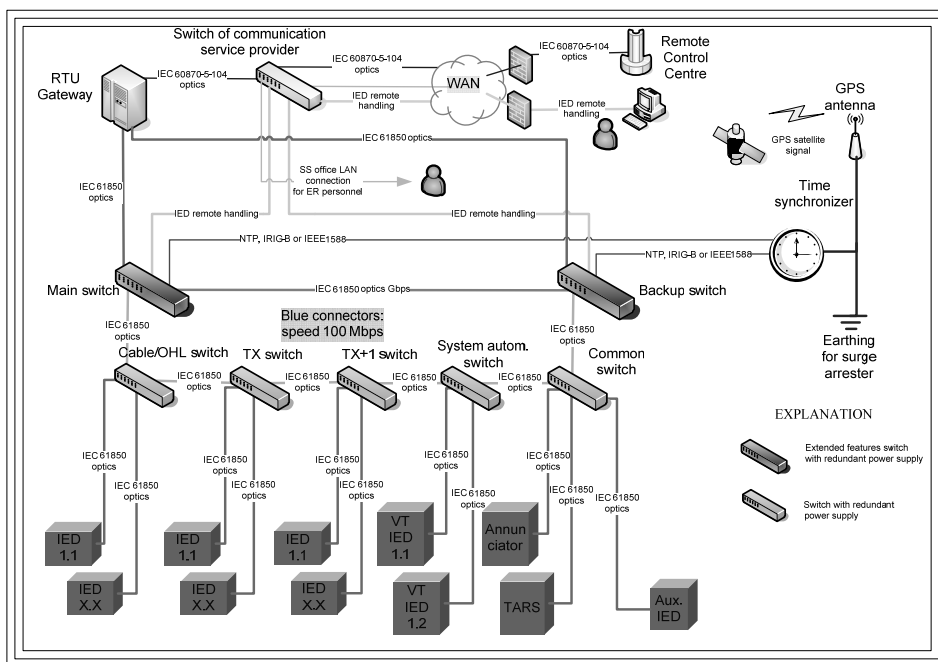


Figure 1.23 LAN topology no.3 of the IEC 61850 station bus

To clarify the task of the station bus, it should be mentioned that the substation TCP/IP network is intended to link together the control, monitoring, and protection functions between physically separated secondary devices. Thus the independent data interchange between them from the connection to secondary circuits up to the substation primary devices would be established.

By the determination of the efficient substation LAN topology, the designer will take into account not only the amount of LAN components, but also the different factors of MTTF, MTBF and working availability and probability to fail.

The abovementioned factors characterize the life cycle of the certain device. The life cycle is divided to three time phases: running-in, continuous operation and operational resource finishing. During those phases the possibility of a device to fail is higher at the beginning of exploitation and at the end of life time.

Mean Time To Failure is a factor that determines the reliability rate. The MTTF is applicable to the systems and to the device as the system. The MTTF is used to characterize the systems or devices that have no possibility to be recovered, but for example could be only hot-swapped.

Mean Time Between Failure is a factor to determine the amount of failures per time period. The MTBF is the key factor in compiling a new system from appropriated devices in spite of the underestimation of the device MTBF from the end users [37]. Hence the pre-planning persons, system integrators and end user should have this information as well as price information about the device.

Unfortunately the MTBF is not stated on the specification sheet and it is not easily found. The end user will have to be very careful when accepting the devices without necessary data that might badly influence the complete system installation in critical situations.

Mean Time To Repair is a factor that determines the time for the device to be repaired. As a rule, the MTTR is applicable to device components that could be replaced to recover the device functionality. Usually the MTTR does not describe the programmable logic, functions and routine, i.e. the software is not specified in this factor. The issue that has great influence on MTTR is the time to be out-of-operation of the device. To reduce this factor the end user is trying to purchase some spare parts at the same place of device installation or close by the built object.

The non-conventional measurement technology suits perfectly for the provision of AC current and voltage measurements from the high voltage switchyards. The non-conventional measurement technology is based traditionally on the not-in-use physical phenomenon. Because that measurement technology and the phenomenon are not widespread and well known, the term *non-conventional* would be used in this research to characterize the innovative approach. In some years, when the non-conventional measuring technology steps into the market of high voltage measurement forcing out the habitual instrument transformers and measuring transducers, *non-conventional* will become conventional enough.

There are not many patented solutions for NCIT and the main objective is the NCIT technology is not only the sensing element. There are four different sensing technologies to reach the target:

- current measurements of the NCIT technology based on the *optical sensing element* (Faraday's effect), i.e. the magnetic field influences the polarization angle of the light beam flux. The important light elements in this solution are the double refraction crystal and the polarizers (see *Figure 1.24, A*); The following equation shows the calculation of angle [28] between plane-polarised light:

$$\Delta\phi=V*B*d. \quad (9.1)$$

- current measurements of the NCIT technology based on the *shunt resistor* in the secondary winding (the output voltage on the shunt resistor is directly proportional to the primary current and ratio between the primary and the secondary winding numbers of turns) [13];
- current measurements of the NCIT technology based on *air gap coil* (Rogowski coil that is wound on the air core), thus the voltage in the secondary winding output is proportional to the derived primary current [13]. The output signal is not anyhow realistic and it should be treated to receive the real primary current;
- voltage measurements of the NCIT technology based on the classical *RC-divider* (chosen because of non-sensitiveness to frequency deviations);
- voltage measurements of the NCIT technology based on piezoelectric effect. The applied pressure (tension/compression) causes the difference of electrical potential in the crystal. The sensor comprises the piezo-electric sensor element and the fiber optics wound around the sensor [27] [31];

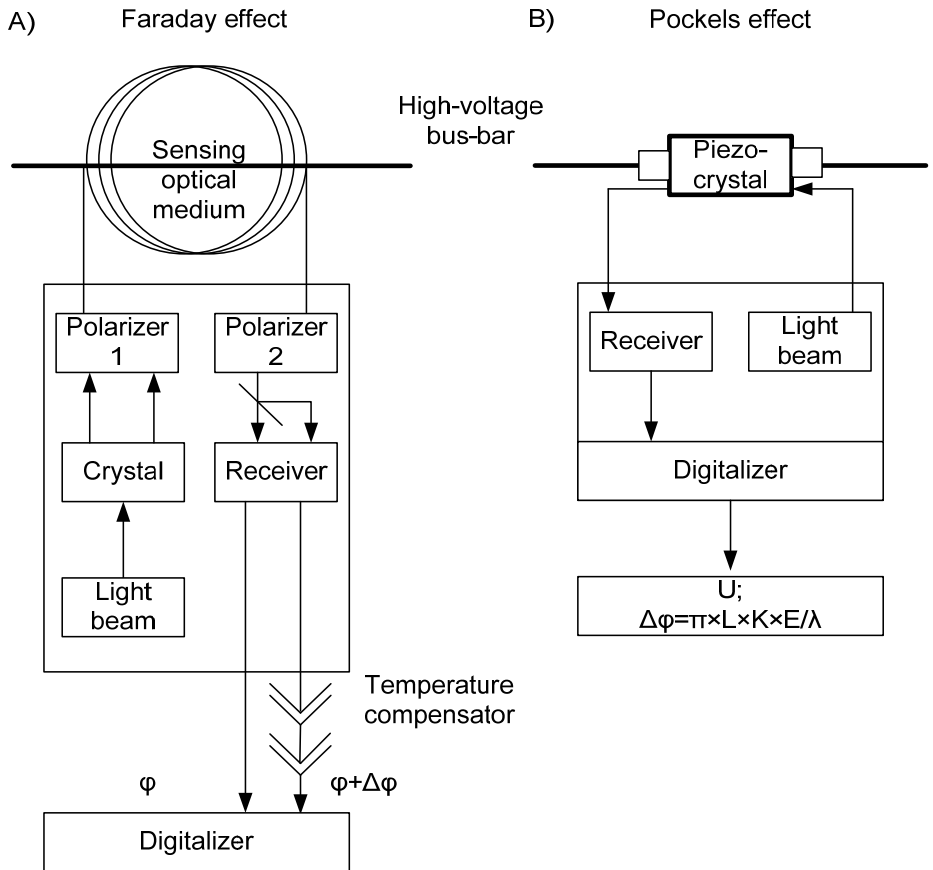


Figure 1.24 Examples of current and voltage NCIT

- voltage measurements of the NCIT technology are based on the *linear electro-optic effect* when electric field-induced linear birefringence occurs inside the refractive index (how the light propagates through the optical medium), i.e. electrical field influences the light polarization angle (Pockels effect) [24]. Thus the birefringence in the piezocrystal is caused due to the AC electrical field (see in *Figure 1.24, B*). The angle [38] between two polarised light signals could be expressed by:

$$\Delta\varphi = \pi \times L \times K \times E / \lambda. \quad (9.2)$$

The all afore-mentioned are the NCIT details regarding the sensing element, but the utility is interested in additional values that he would get from implementation of NCIT technology. Thus the utility starts to ask how:

- to reduce the substation renovation or construction costs;
- to make redundant the system of NCIT;
- to use the NCIT for protection relays, for revenue metering system and for the power quality analyzer;
- to increase and keep the measurement accuracy;
- to minimize the vibration affect;

- to record the aperiodic component of current during the fault;
- to compensate the temperature dependence [29];
- to extend the measuring range without additional charges.

The NCIT technology might work properly if the whole system sensing element, optical medium, output module including the analog / digital converter is functioning perfectly. Hence, the electronic device should be discovered and familiarized. The international standards IEC 61850-9 and IEC 61869-9 are related to the merging unit, the device is responsible for the digitalization of current and voltage measurements in both directions. On the one hand, the MU is just the device to sample the analog values to the digital mode IEC 61850-9-2 (like MT with e.g. Modbus RTU interface), but on the other hand, the MU is a fully automated device that is able to take into account many physical parameters by the transmission of the digitalized values to the secondary devices. Actually the MU is the device that enables the sampling performance of current and voltage values obtaining them from CT and VT, to publish the current and voltage measurements to the related subscribers, i.e. substation secondary devices (monitoring, protection, power quality) as the sample values (multicast values mapping over Ethernet) [9], to time-link the current and voltage values, to avoid connections mostly of copper, and last but not least to exclude the requirement for the galvanically insulated current and voltage inputs of protection relays and disturbance recorders. Because of patented NCIT technology, the end user does not know very much about the analog values that are sent to the MU directly from the primary conductor. The important details should be presented in the MU specification regarding the process bus interface. The substation process bus is the part of substation LAN that is responsible for process tasks. In fact, the utility as an end user should not know much about the NCIT current and voltage sensors, whereas the process bus interface would be carefully described in the utility requirements.

9.1 Sample value

The device that broadcasts the sample values to the protection relays and power analyzers is the Merging Unit. The MU is the analog-to-digital converter whereby the analog signal could be electrical or optical. The MU is receiving continuously the analog current and voltage measurements, is sampling them and publishes the digital values to the relay protection LAN. The basis of the sample value is the sampling process that means the splitting of the steady analog signal to the different level discrete signal at a regular time period. The regular time period should be defined by the sample rate, i.e. by sample frequency. The higher the sample frequency is, the more samples are in the output of the analog value digitalizer and the representation of the analog signal is more exact. The regular time period between samples should be very precise to change all the possible analog signals to the discrete signals. The digitalized signals or measurements would be sent to the measuring instrument. Nowadays the most widely implemented solutions of IEC 61850 measurements transmission are based on Light Edition (LE) of the standard IEC 61850-9-2. The general differences of LE as compared to the original standard are:

- 80 samples per cycle for protection and metering (from analog values);
- 256 samples per cycle for power quality (from analog values);
- optical time synchronization pulse per second (1PPS);

- LD names and LNs are defined for MU;
- three-phase voltage and neutral voltage (dataset);
- three-phase current and neutral current (dataset);
- trip signals are not supported in MU.

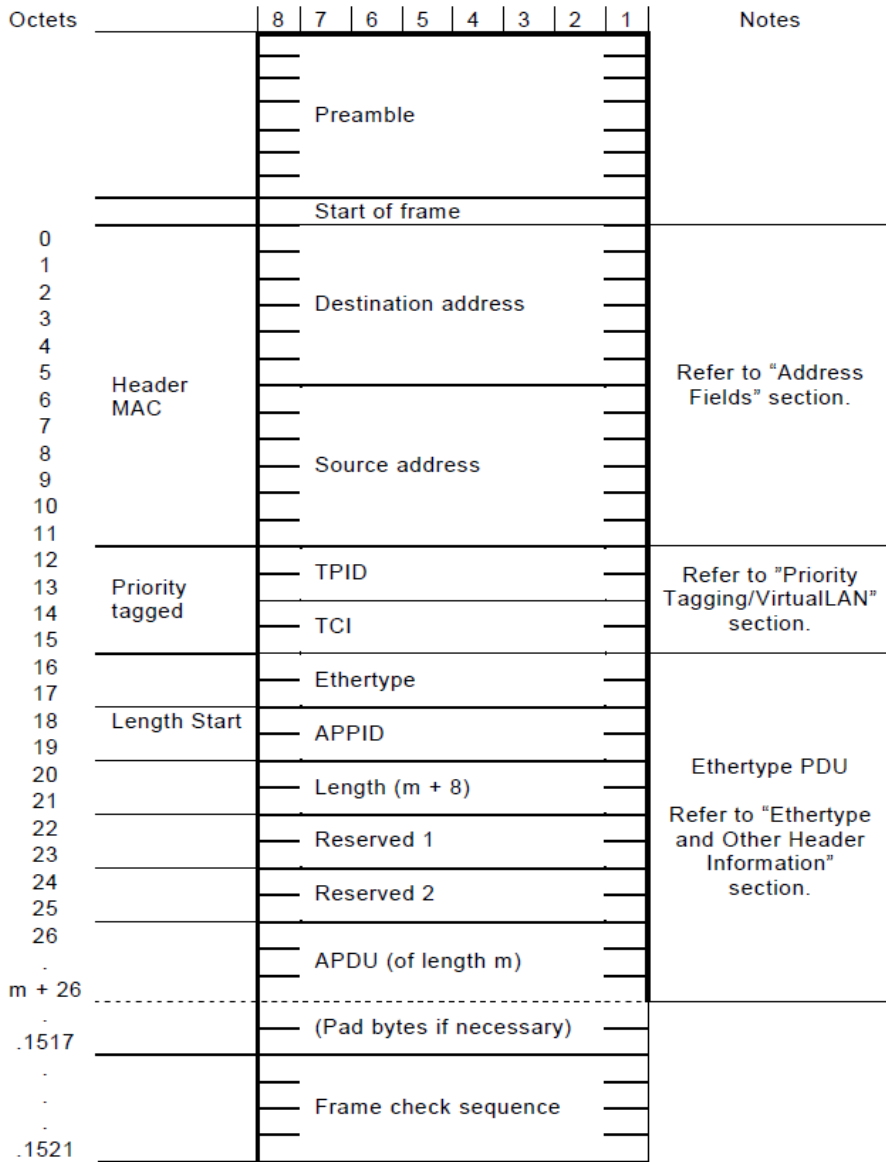
For better understanding of the sampling process according to the international standards, the standardized frame format (see *Figure 1.25*) will be discussed. This frame format is based on the well-known standard ISO/IEC 8802-3 that describes the data information exchange principles between systems in LAN and WAN. The standard third part sets rules for using of the physical layer and media access control.

By the implementation of the afore-mentioned frame format, the utility shall keep in mind that the sample values could be used now in most cases according to the Light Edition of IEC 61850- 9-2 [9] and to the implementation guide of UCA International User Group that is “not-for-profit corporation focused on assisting users and vendors in the deployment of standards for real-time applications for several industries with related requirements”⁵.

Below the frame will be briefly reviewed. The preamble is used for the synchronization of Ethernet frames in substation LAN. The destination MAC address might be needed, e.g. as multicast address to follow the messages to the certain ports of the switch [33]. The source MAC address is the publisher MAC address. The priority tagging will set the priority class to send the appropriated messages in the first turn. The VLAN is intended to sectionalize the LAN for more efficient substation LAN implementation and for splitting the network burden [30]. The MAC address shall be based on VLAN, therefore the MAC address will be assigned to the particular VLAN. The Ethertype defines the type of application services that might be used (e.g. GOOSE, SV, GSE); the SV service type is 0x88BA [10]. The application identifier has a freely configurable number and it is recommended to set it unique for each specific destination source. The application data protocol unit contains the SV information. Each frame contains several samples in the dataset, so for the protection relay (80 samples/cycle) the total sample number is 32 000 pcs.

The planning of the LAN for measurement transmission in LAN should take into consideration the amount of IEDs that receive the measurements from the MU. The more IEDs there are in the same LAN, the less measurements are possible to transmit from the MU without obstacles, because each IED needs some part of measurement data traffic (e.g. 10 Mbit/s).

⁵ UCA, <http://www.ucaiug.org>



IEC 099/04

Figure 1.25 ISO/IEC 8802-3 frame format. IEC 61850-9-2

9.2 Merging unit and particular application

The merging unit is the device that:

- digitalizes the analog value from the primary equipment to the digital value for further transmission of the value via substation LAN using the sampling methods;
- converts and inverts the analog signal from the primary equipment to the standardized analog value for traditional protection relay with classical analog inputs (current and voltage) using the value sampling and interpolation methods.

The digitalization of the analog value is similar to the MT, but as a rule the MU has higher sample frequency and the communication principles between MU and the secondary devices (e.g. relay protection) meet the international standards and are reliable to distribute the necessary measurements under every condition to the substation secondary devices.

Digitalization of the analog values and to interpolation of them back to the analog value on the lower power level is necessary because of the transition period from electro-mechanical and semi-digital protection relays to the fully digital protection relays, where there are many “old-fashioned”, but completely in order and properly functioning substations with no influence of digital technics onto protection relays. Thus the possibility to connect the traditional electro-mechanical or semi-digital protection relay to the MU is indispensable in such substations.

The interpolation is a sophisticated process of guessing the value at any time and between the taken samples. Thus, the interpolation is the inverted sampling process. The MU could use a specific method of interpolation to provide a better possibility to reconstruct the analog signal, whereby the simplest interpolation types like linear interpolation would not be used.

Because the MU could be treated as a *Black-box*, the MU should meet the typical basic requirements stated to the MU functional behavior of software, hardware specification and interoperability:

- high energy analog output signal for revenue metering 1A or 5A;
- low energy analog output signal for protection 200 mV [17];
- bandwidth 10-6000 Hz (up to the 100th harmonic);
- CT accuracy class for revenue metering 0.2S;
- CT accuracy class for protection 0.5;
- VT accuracy class metering and protection 0.2;
- IEC 61850-9-2LE interface, CT accuracy class for revenue metering 0.2S;
- IEC 61850-9-2LE interface, CT accuracy class for revenue metering 0.5;
- time synchronization 1 pulse per second;
- VT circuit inputs;
- CT circuit inputs.

There is the vital functionality of the measuring sensors that would be required from the transmission system operators - i.e. the redundancy of the NCIT sensors and MUs. It would be performed in different ways – integration of several NCIT sensors in one sensor block and the duplication of MUs. Those solutions ensure the “N-1” reliability criterion for distribution of the sample values segregating the main and back-up relay protection functions and the revenue metering [15].

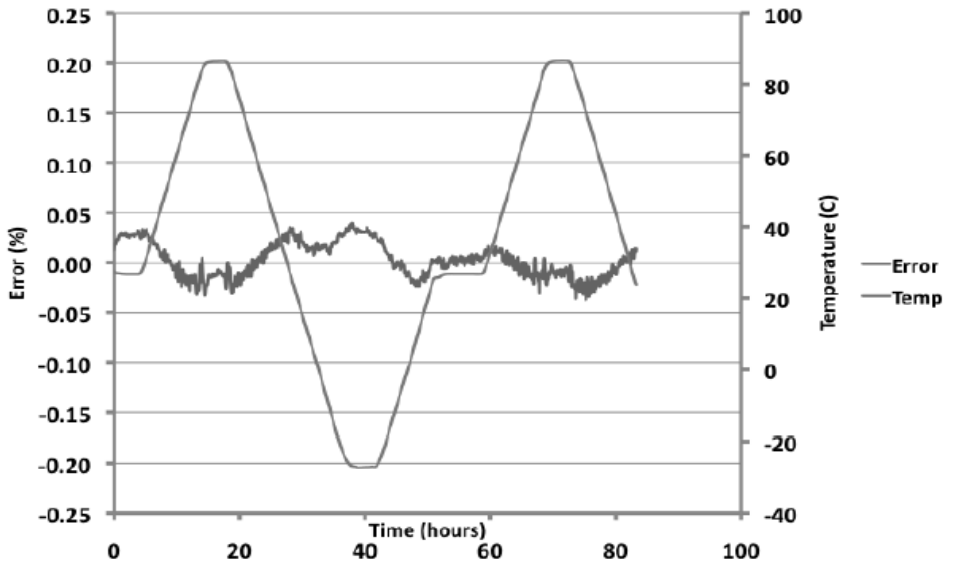


Figure 1.26 Example of temperature dependent measuring error [8]

Because of today's lack of non-conventional voltage instrument transformers the use of the complete NCIT technology is impossible, thus connection to the MU can be established by the traditional VT. The ambient temperature fluctuations cause changes in the current measurements; hence the MU will have temperature compensation for current sensors (see *Figures 1.26* and *1.27*).

The accuracy class in the *Figure 1.26* remains in the accuracy class.

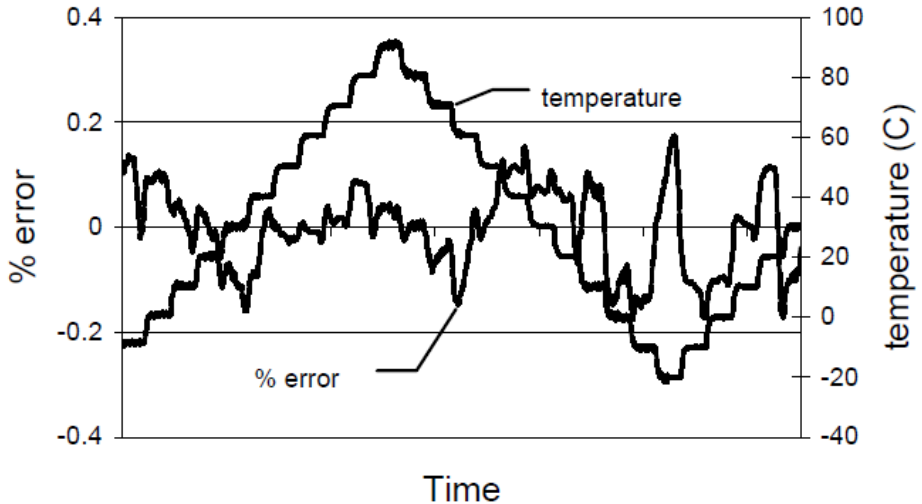


Figure 1.27 Example of temperature dependent measuring error [14]

The *Figure 1.27* shows the signalling logic compensating the linear dependence of bow-tie HiBi (high birefringence) spun fibre on the ambient temperature. The sensitivity of HiBi sensor is linearly dependent on temperature (temperature dependence of the spun Verdet constant). This dependence is avoidable by continuous temperature monitoring of the sensing element and the correction of the signal forming [6] [29].

The measuring sensors connected to the MU might use the different analog-to-analog or analog-to-digital conversion technologies beginning from the using of Rogowski coil and ending with voltage drop conversion on the resistive shunt. The output of such sensors (physical connections) for converted data transmission could be mostly optical, but the copper wired connections are also well-known by some specific NCIT solution implementations.

The error rate of NCIT current sensors could achieve 0.2% by 0.1% of rated current and remain into the accuracy class by 1000% and even more of rated current [34].

The MU should have the analog outputs that are suitable for implementation of the traditional analog-digital protection relays and the metering applications. But the circumstance is they may not be the universal analog outputs because of burden class (energy extracting). I.e. the common metering applications require low energy consumption 1 A/5 A with rating factor two, however the protection applications need for 40 A theoretically with three phase currents. This tremendous amount of energy is not realistic in analog outputs of the MU. Hence the LEA outputs (200 mV) were developed and standardized for the above-mentioned demand. The LEA format has limitations because of electro-magnetic interference that sets the distance limitation within analog secondary circuits [7] [14]. And the only solution remains the sample values implementation on substation LAN.

9.3 Measurement transmission using the LAN

The transmission of measurements within substation LAN requires the following composition principles for NCIT applications:

- NCIT primary sensing elements (CT and VT) with a merging unit;
- NCIT CT primary sensing elements and traditional VT with a merging unit;
- traditional CTs and VTs with a merging unit.

The requirement to transmit the measurements within substation LAN is only applicable to substation already equipped with LAN that intended for operational data exchange between protection relays. The *Figure 1.28* shows the basic principles to form the station bus and process bus independently; e.g. the protection relays shall have separated data communication interfaces meeting the standard IEC 61850-8-1 and the standard IEC 61850-9-2 (sample values). The reality slightly differs from the basic overview in *Figure 1.28*. The main reason is the modern LAN device technology that helps to avoid the using of many physical LAN networks with implementing of virtual LAN. The VLAN is the ability to make the data link segregation between differently mapped workstations in the same physical LAN according to the different rules. In another word the one group of one broadcast domain (or network allocation) is not able to “see” the data of another domain placed in the same physical network. The VLANs could be used on the substation LAN to make separate the data communication between RTU and SCADA and between IEDs [4].

The station bus is responsible for data traffic between IEDs, RTUs, local workstations, HMI and sometimes exceptionally remote SCADA. As a rule the substation automation data transmission is divided regarding the data type would be sent out to the substation switch; operational messages (e.g. MMS) and GOOSE messages. The amount of VLAN communications increases accordingly, if the station bus has the third party consumer (like the DSO).

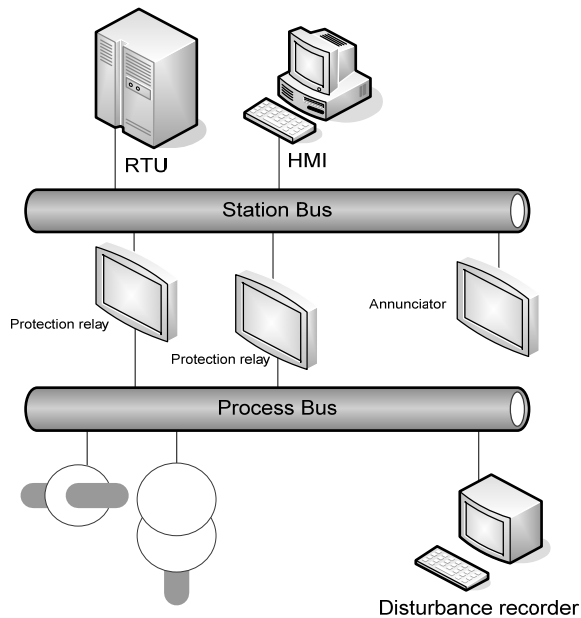


Figure 1.28 Structure of IEC 61850 substation implementation

The process bus could fulfil the versatile tasks like the measurement sampling, transmission of measurements to the disturbance recorder or power quality analyser, management of primary switching equipment etc. The process bus could be part of the one substation LAN or physically separated in critical applications. The most important issue is the speed and reliability of data transmission in process bus realisation. The sample values are time critical, because they are using the application layer mapped directly to the data link layer. The outliving of transport and network layers increased the performance of digital measurement data exchange [5].

9.4 Overview of NCIT topologies

The topology conglomerate of LAN and NCIT connections depends on the use variations of NCIT components. There are only three basic ideas how to implement the NCIT at the substation today:

- semi-NCIT;
- NCIT with traditional instrument transformers;
- “pure” NCIT.

Figure 1.29 shows the one of nowadays obstacle i.e. the lack of the NCIT voltage sensors, thus the MU might be in connection as with current sensors as also with traditional voltage instrument transformer. The drawbacks of such topology remains based on construction ideology of traditional voltage instrument transformer. The MU should compensate or correct the all physical effects up to the appropriated level digitally before the value goes to MU output (analog or discrete). Another case when the influence of some conditions or properties would be unavoidable in MU. Therefore the additional devices could be used with MU to eliminate the unwanted influence.

There are redundant MUs are shown on the *Figure 1.29*, which ensure the operation of protection functions in case of MU outage in overhead line bay or bus-

bar MU. The communication of the MUs to the substation LAN is shown as the VLAN connections among the station bus LAN.

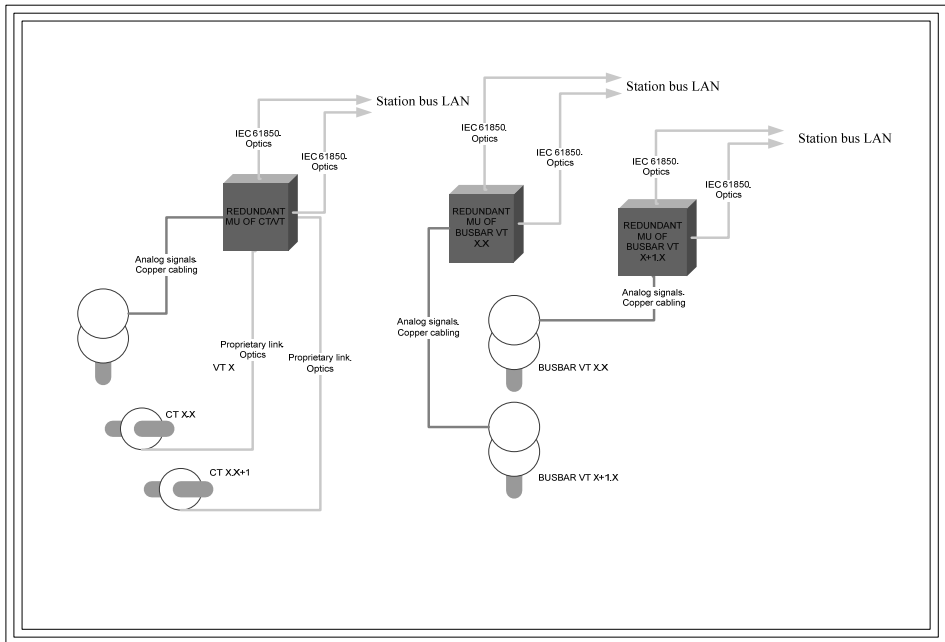


Figure 1.29 Topology of the semi-NCIT

Figure 1.30 presents the NCIT technology in the substation as the two separated systems to back up each other. The key benefit of such solution is to ensure the protection functionality in substation type with 110 kV sections in case of breakdown of one MU.

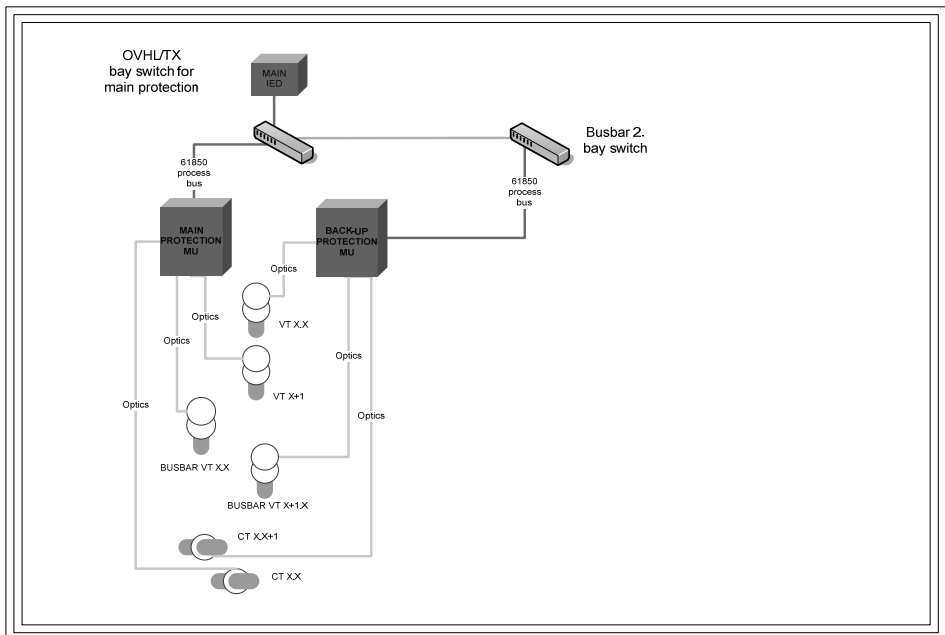


Figure 1.30 NCIT topology

Figure 1.31 presents the NCIT technology with the redundant sensors (integrated by manufacturer) that are serving by different MUs to increase the availability of the NCIT system.

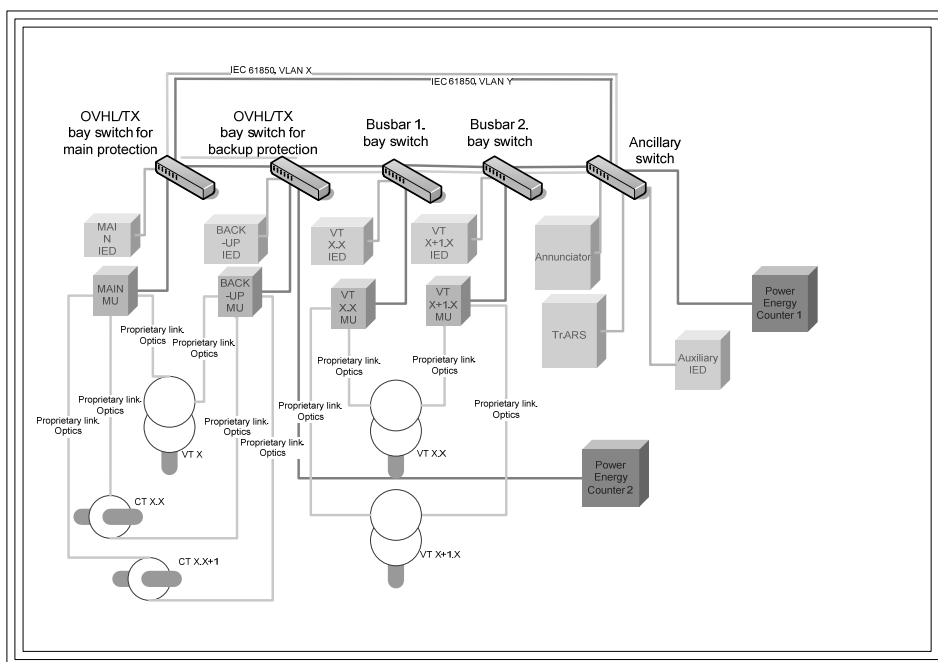


Figure 1.31 NCIT topology with redundant sensors

The brief sum of the issues should be taken into consideration is following:

- avoid noise by measuring;
- ensure standardized dynamic behaviour of MU (IEC 61850-9-2);
- do the records from disturbance recorders;
- perform the remote handling of MU;
- ensure resistance to thermal current;
- chose right MU installation place (could be installed in switchyard or in control room);
- define original or mixed NCIT solutions with traditional CTs and VTs;
- think about life cycle working stability (not only sensors, but also MU);
- require the programmable measuring range in MU without changing the sensors;
- technics shall meet the IEC standards (e.g. 61869);
- provide from MU 80 – 256 sam/c;
- state the accuracy for revenue metering – 0.2S;
- working temperature should be -40..+60C°;
- require the independence on phase shift from frequency in high voltage part.

10 SPECIMEN TO THE MERGING UNIT REQUIREMENTS

There is example of some typical requirements the MU shall meet:

- IEC standardized high voltage measuring system shall include:
 - current sensors (available as mass product on the nowadays market)
 - with accuracy class 0.2S;
 - redundant/doubled sensing element;
 - extreme ambient temperature operation range (-40°..+50°);
 - voltage sensors with accuracy class 5P (not available as mass product on the market);
 - working frequency 10-6000 Hz;
 - redundant (processor and power supply) merging unit:
 - digital interfaces IEC 61850-9-2 (SV: 80-256 samples/cycle). One group of separate interfaces is intended for relay protection and the other group – for revenue metering;
 - adjustable analog current input rated burden 10 VA(20VA), current 1 A(5 A);
 - maximum withstand current;
 - adjustable analog current output; e.g. consumption 1 VA, current 1 A. Indoor installation. The variable number of independent current outputs;
 - voltage input, e.g. rated burden per ph. 1 VA, voltage 110-500V. The variable number of independent voltage inputs;
 - multirange voltage output, e.g. rated burden at least 1 VA, voltage 100-240V. The variable number of independent voltage outputs;
 - adjustable measurement range (e.g. x2.5) with the same current sensors;
 - time synchronization input (e.g. PTP, 1PPS);
 - LAN interface for remote handling;
 - one multipurpose software tool (parameterizing, analyzing, remote handling etc.).

11 IMPLEMENTATION MILESTONES FOR NON-CONVENTIONAL MEASURING

From the utility prospective the implementation of the NCIT will impact the utility activity. Therefore the following milestones shall be taken into consideration.

The *first milestone* refers to the personnel of utility. The acquiring the NCIT additional knowledge, considering the NCIT educational costs and hands-on training for pre-planning personnel and asset-managers are highly required for innovative technical solutions. The expectations of utility for well-versed utility personnel in novel measuring technology are ahead of the time and are not realistic, especially by first implementation of such solutions. Anyway the utility possessing of thorough *know-how* about the NCIT conversion of analog values to the digital is not necessary and even possible, because the patented NCIT technology does not foresee the deep customer penetration into the NCIT details due to business confidence, fabrication secrets and warranty limitation. Hence the *black-box* approach should be applicable to the NCIT technology from customer point of view. In other words it has no sense to know how, for example, the high voltage primary values become the discrete value or what kind of interpolation is used for the analog signals forming in the HEA interface. The behaviour of output signal depending on measurements in the primary part is considerably more important.

The technical requirements for the NCIT equipment shall extract the specific preliminary document to simplify the estimation of NCIT equipment. The form of that document could be different, but the most useful form is the questionnaire. The fulfilled questionnaire will help the utility to pre-examine the NCIT equipment to be sure the offered devices are meeting the general technical requirements stated by utility (see Appendix).

The *second relevant milestone* is the need of utility to have knowledge about F.A.T and S.A.T. content and procedures to be carried out in the substation with the target to check e.g. the proper functioning of MU input/output interfaces in different grid operational situations. Thus, the composing of the testing activities is a vital and necessary requirement for the end customer. It could be useful to avoid the composing the test procedure starting from scratch, because the similar testing content and sequence could be already established by some international non-profit organization. The end customer has to possess the enough knowledge for efficient analysis of the offered NCIT system that technical data are stated in the product specifications, of the independent test lab confirming test reports, of the interoperability testing reports and the references.

The *third milestone* is the NCIT long-term service agreement with the manufacturer or the system integrator. This is relevant to the financial part rather than to the technical issues, whereby the technical support, the regular service, the delivery of the spare parts etc. should be stated in the service agreement documents.

Today's NCIT technology is matured enough for simple implementation to serve the relay protection. The power analysis, disturbance recording and the revenue metering could be also realized using the NCIT, but there are some limitations to the interoperability issues and the higher sample frequency. Such specific implementations as the integration and co-operation of the traditional instrument measurements and non-conventional instrument measurements located in different places need to be clearer from the experience point of view.

There is another important requirement (*fourth milestone*) by the implementation of the NCIT, due to the backward compatibility of the devices declared as the IEC 61850 process bus devices shall be ensured whenever the standard IEC 61850 is being extended.

The NCIT implementations in the busbar differential protection or using the intercommunications between substations remain temporarily out of the research scope, because of lack of or insufficient implementation knowledge and case studies. The pilot projects were started already in the 90s, but those substation NCIT installations do not help enough to convince the potential customer to overcome to the newer measurement technology with financial benefit. And the NCIT device manufacturers do not speed up the producing of the technology that does not offer good demand and sale volume [25].

There is a necessity to use the revenue metering and power quality analysing in NCIT implementation because of functional advantages of novel measuring technology. But there are no regular use cases available in Estonia for revenue meters with the NCIT technology because there are no appropriated type approval, lack of test procedure and hence no possibility to register into the metering system database from the State authority. Hence the continual analyzing of use case studies is the *fifth milestone* should be mandatory to keep the NCIT technical requirements of utility on the top of meeting the reliability and availability criteria.

12 FUTURE TRENDS AND RESEARCH

The future sets the challenges for generation, transmission, distribution and consuming of electrical energy, whereby the data exchange has the major role to route the energy streams, to activate and deactivate the generating units depending on consuming demand, to carry out the scheduled electricity consumption, to storage the energy as for short-term as also for long-term period, to ensure the grid stability based on measuring information around the total electrical network and many more.

The perspective smart grid concept is exciting many power energy professionals from different walks of life to set the unified idea how the smart grid should function. Partially the smart grid functions are not very new (e.g. load shedding automation), but they have a new vision how to gain savings on energy consumption and to make this energy consumption homogeneous within the day period. Another goal is to make the energy consumption and generation predictable all the time. It might help to reorganize the ratio between renewable energy and fossil fuel based generated energy flexible without any impact on supply reliability. Nowadays there are some pilot projects based on such vision, but this system will be propagated worldwide.

The functions of real smart grid are impossible to be established without active intercommunications between all participants on the electricity market (production, transmission, distribution, consumption). Only after that it is reasonable to start thinking about a self-healing electricity grid. If the electricity network has the measurement system with an integrated transmission function in every node, then by collecting such measurements online it is possible to create a global automation system for monitoring and fully automated action, for example, to the primary switching devices to energize/de-energize the power network segments according to the logic ensuring the power energy supply to the customers.

Finally, the revenue metering of electrical energy would be integrated in the appropriated service application that would collect the data about consumed power energy from, e.g., database storages. The revenue metering values could be sent, for example, to the data storage via the MU or similar devices with less capability if needed (e.g. farm household).

Therefore the aforementioned trends and opportunities should be studied to be implemented in electricity networks.

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14 **ABSTRACT**

This research determines the sequence of how to implement the transmission of measurements in a substation using the non-conventional instrument technology. This approach is needed for versatile apprehension of the essential key benefits in digital substation. Hence the use of substation LAN for different purposes and tasks like protection communication, time synchronization, remote handling etc. is the beginning and the prerequisite for a further step to be made into the digital form for transmission of measuring data between various parts of substation primary and secondary equipment.

The study gives an overview of how to proceed from the determination of the suitable technical solution realized by the NCIT technology, how to make NCIT technology transparent, how to handle the technical obstacle that might occur during different project phases and what kind of the end targets should be followed from the utility point of view regarding the novel technology benefits and drawbacks.

The study covers the issues that help to comprehend the roles of the manufacturer based on non-conventional instrument transformers, the system integrators and the utility by preplanning tasks, by the project establishing and by the asset managing. The utility should minimize the risks with multi-vendor solutions, which will ensure the future benefits in the case of substation extensions, secondary equipment repair and retrofit.

15 CONCLUSION

The present research work “Measurement and Data Communication Technology for the Implementation in Estonian Transmission Network” is composed arising from the instantly changing measuring and data exchange technology, the formation of open energy market and the necessity to upgrade the substation in the high voltage transmission network as the end result.

The following tasks are solved according to the set up target of the research work:

- the study includes the research, the analysis and the comparison of the different novel NCIT technologies that are applicable in the high voltage transmission networks. The study gives the proposals for NCIT implementation. Herewith the technical solutions for implementation of NCIT technology are invented regarding the Estonian transmission network;
- the study includes the research, the analysis of the data communication technology and its implementation specialties within the process in high voltage transmission networks;
- the study includes the research of the distinctive features in Estonian transmission network regarding the implementation of novel NCIT measuring and data communication technologies. The specific requirements are worked out for the implementation of the innovative technology. The specific requirements content the special Quotation Questionnaire that helps the utility personnel to evaluate the equipment of NCIT already in the stage of offering.

The results of the research work will facilitate the technology development and the selection for the best technological solutions in Estonian TSO Elering.

16 KOKKUVÕTE

Käesolev doktoritöö „Mõõte- ja andmesidetehnoloogia uurimine ja rakendamine Eesti kõrgepinge ülekandevõrgus“ on koostatud seoses kiiresti uueneva mõõte- ja andmeside tehnoloogiaga, avatud elektrituru tekkimisega ning sellest tuleneva vajadusega moderniseerida Eesti kõrgepingevõrkude alajaamad.

Vastavalt töö eesmärgile on lahendatud järgmised püstitatud ülesanded:

- töös on uuritud, analüüsitud ja võrreldud erinevaid kõrgepingevõrkudes rakendatavaid nüüdisaegseid mõõtetehnoloogiaid ning antud soovitused nende rakendamiseks. Seejuures on välmitud tehnilised lahendused mittetavapärase mõõtetehnoloogia rakendamiseks Eesti kõrgepingevõrkudes;
- töös on uuritud ja analüüsitud protsessiiniil põhinevat andmesidetehnoloogiat ning selle rakendamise iseärasusi kõrgepingevõrkudes;
- töös on uuritud Eesti kõrgepinge ülekandevõrgu iseärasusi võimaliku uue mõõte- ja andmesidetehnoloogia rakendamise seisukohalt ning välja töötatud tingimused uue tehnoloogia rakendamiseks. Väljatöötatud tingimused hõlmavad ka eriküsimustikku, mille alusel hinnatakse mitte-konventsionaalse tehnoloogia seadmestikku veel pakkumuse esitamise faasis.

Doktoritöö tulemused võimaldavad Eesti süsteemioperaatoril Elering kavandada oma edasist tehnoloogilist arengut ning valida selleks parimad tehnilised lahendused.

ELULOOKIRJELDUS

1. Isikuandmed

Ees- ja perekonnanimi	Igor Mets
Sünniaeg ja -koht	9. oktoober 1977, Tallinn, Eesti
Kodakondsus	Eesti
E-posti aadress	igor.mets.private@gmail.com

2. Hariduskäik

Õppeasutus (nimetus lõpetamise ajal)	Lõpetamise aeg	Haridus (eriala/kraad)
Tallinna Tehnikaülikool, Elektriamite ja jõuelektronika instituut	2007	elektriamid ja jõuelektronika / bakalaureus
Tallinna Polütehnikum	1997	tööstus- ja soojus- automaatika süsteemid

3. Keelteoskus (alg-, kesk- või kõrgtase)

Keel	Tase
vene	emakeel
eesti	kõrgtase
inglise	kesktase
saksa	algtase

4. Täiendusõpe

Õppimise aeg	Täiendusõppe korraldaja nimetus
august 2013	Sicam RTUs Workshop – Configuration IEC 61850 Interface, <i>Siemens</i>
veebruari 2013	Power Plant (Gas) Electrification at site course, <i>Wärtsilä</i>
jaanuar 2013	Power Plant W34DF Operation and Maintenance at site course, <i>Wärtsilä</i>

5. Teenistuskäik

Töötamise aeg	Tööandja nimetus	Ametikoht
juunist 2007	Elering AS	alajaamade juhtimis-süsteemide spetsialist, Arendus
veebruar – juuni 2007	Fortum Termest AS	automaatika-spetsialist, Arendus
veebruar 2006 – veebruar 2007	Fortum Termest AS	juhtiv automaatika-spetsialist mehitamata katlamajades, Käit

CURRICULUM VITAE

1. Personal data

Name	Igor Mets
Date and place of birth	9 th October 1977, Tallinn, Estonia
Citizenship	Estonian
E-mail address	igor.mets.private@gmail.com

2. Education

Graduation year	Educational institution	Education (field of study/degree)
June 2007	<i>Tallinn University of Technology</i> . Department of Electrical Drives and Power Electronics	Electrical Drives and Power Electronics / Bachelor
June 1997	Polytechnic School of Tallinn	Systems of Industrial and Heating Automation

3. Language competence/skills (fluent, average, basic skills)

Language	Level
Russian	native
Estonian	fluent
English	average
German	basic

4. Special courses

Period	Educational or other organization
August 2013	Sicam RTUs Workshop – Configuration IEC 61850 Interface, <i>Siemens</i>
February 2013	Power Plant (Gas) Electrification at site course, <i>Wärtsilä</i>
January 2013	Power Plant W34DF Operation and Maintenance at site course, <i>Wärtsilä</i>

5. Professional employment

Period	Organization	Position
June 2007 – present	Elering AS	Specialist of substation remote terminal unit systems, R&D
Feb. 2007 – June 2007	Fortum Termest AS	Automation specialist, R&D
Feb. 2006 – Feb. 2007	Fortum Termest AS	Leading automation specialist of unmanned remotely manageable heating plants, Asset Management

APPENDIX

[PAPER-I] Dmitrenko, I. (2011). IEC 61850 and Measurements. *Electronics and Electrical Engineering*, 6 (112), pp. 106 – 110.

IEC 61850 and Measurements

I. Dmitrenko

*Department of Electrical Drives and Power Electronics, Tallinn University of Technology,
Ehitajate str. 5, 19086, Tallinn, Estonia,
Technology Department, Elering OÜ,
Kadaka str. 42, 12915 Tallinn, Estonia, phone: +372 5331 2049, e-mail: igor.dmitrenko@elering.ee*

Introduction

The aim of current work is to face up the important aspects of the implementation the standard of International Electro-technical Commission IEC 61850 for control, monitoring and protection automation in the new Elering OÜ substation.

Overview of conventional measuring technology

The secondary equipment of transmission network substation is constructed from different devices that modify the semi-closed system of substation automation, control and monitoring. The definition of semi-closed system means:

- Communication topology (star) for internal data exchange within telematics system;
- Open remote handling connections of protection relays mainly for external data exchange.

The instrument current transformer is the primary device that makes current measuring opportunities available for relay protection and monitoring purposes.

The several substation bays shall be equipped current instrument transformer with CIT like HV power (auto)transformer bay, MV power (auto)transformer, HV/MV busbar coupler bay, HV power overhead and/or cable line bay etc.

The general content of the CIT is cap, bellow, primary rod with terminals, cores, casting, internal (oil-paper) and external (porcelain or composite) insulation, filling oil and body. The CIT may have few cores according to the request. Usually it is used for transmitting the measurements to the different protection relays (main and back-up relays). Hence the “*N-1*” criterion will be fulfilled if one core will rupture its proper work, i.e. other cores of CIT will remain in normal operation unharmed.

The instrument voltage transformer (VIT) is the primary device that makes voltage measuring opportunities available for relay protection and monitoring purposes. The several bays shall be equipped with VIT like power HV

overhead/cable line bay, power (auto)transformer MV voltage bay etc.

The cap, bellow, bushing, casting, external (porcelain or composite) insulation, windings, iron core and terminal box are general parts of VIT. The VIT could be used in different type of performance:

- Capacitive VIT (single phase, more than 35 kV);
- Inductive VIT (three phase up to the 36 kV).

Nowadays the often used instrument transformer is combined instrument transformer that includes in one primary device case the current and the voltage instrument transformers. The main advantage of that is space saving in the switchyard and device cheapness.

The task of measuring transducer (MT) is the convert analog signals to the other level analog signals or digital signals. The MT input side is usually hardwired to the secondary circuits of the instrument transformers and output side is connected to the analog inputs or communication interface of Remote Terminal Unit (RTU).

The MTs could be connected into the loop or radially (star topology). The RTU and MT are using as well the industrial protocols and as communication protocol IEC 60870-5-102/103 [9] and IEC 61850.

The conventional telematics technical solution is the telematics structure based on star topology. E.g. the serial communication protocol of IEC 60870-5-103 will be used in direction of Intelligent Electronic Devices (IEDs) and the TCP/IP communication protocol of IEC 60870-5-104 – in direction of Remote Control Centre (RCC). The MTs are commonly hardwired (loop) to the RTU directly or via electrical/optical decoupling device. The telematics system shall be time synchronized (GPS) with appropriated time accuracy [10].

IEC 61850 station bus and process bus

There are several debating themes concerning to IEC 61850 implementation:

- Cost-efficient design by primary equipment;
- Cost-efficient solution (same network for different tasks);

- Device parameterizing transparency;
- Cost efficient device parameterizing work;
- Several services via same local area network (LAN);

- Large testing availability in IEC 61850 LAN;
- IEC 61850 interoperability of different vendors.

The Utility shall firstly read carefully through all parts of standard IEC 61850 and “pluck out” the key opportunities, needed for Utility. The tight consulting shall take a part between Utility and Manufacturer for better understanding of IEC 61850 benefits. Usually there are several basic questions that Utility should answer:

- How deeply to allow the IEC 61850 into the station bus, that get the maximum of the benefits;
- How deeply to allow the IEC 61850 into the process bus, that get the maximum of the benefits;
- Education and training steps for Utility specialists.

The process bus is distinctive by direct IEC 61850 implementation in the switchyard, e.g. measuring system and control of circuit breaker (is not under discussion).

There are the proposal requirements according to IEC 61850 for the SS telematics:

- The optical connections (e.g. optical LAN) should be used between substation IEDs, RTUs and workstations;
- The maximum of substation equipment functions like power transformer automatic reserve switching, load shedding automation, circuit breaker automatic reclose equipment, circuit breaker failure protection, current blocking logics, shall be realized using the standard IEC 61850;

- The communication protocol between IEDs, RTUs and workstations shall fully meet the standard IEC 61850;

- The substation (SS) shall have one physical LAN for telematics, automation, time synchronization, remote handling and interlocking logics all together;

- The one LAN interface is able to provide few services from different IP-addresses (e.g. IEC 61850 services, remote handling, time synchronization);

- The SS shall have one physical LAN for telematics, time synchronization and remote handling purposes. The maximum number of sequent connected RTU and IED devices shall be defined;

- The amount of switches connected in LAN is defined by voltage level and functionality of IEDs. E.g. one switch is per HV I. main relay protection, HV II. main relay protection, HV backup relay protection, together HV backup and MV relay protection and ancillary protection and functions (e.g. annunciator, power transformer ARS);

- The device certification of meeting the standard IEC 61850 (independent test-lab) **[Error! Reference source not found.]**, e.g. IEC 61850-3 for switches;

- The IEDs, RTUs and workstations shall be time synchronized with accuracy of equal or less than ± 1 ms within IEC 61850 LAN;

- The system switching devices shall use the VLAN handling. The priority tagging, Rapid Spanning Tree Protocol or dual Self-Healing technology are mandatory for use;

- The system switching devices shall ensure “N-1” criterion for IEDs, RTUs and workstations;

- The recovering time (only by RSTP) of system switching devices is defined by amount of switches and the

exact value of recovering time shall be calculated and agreed with Utility;

- The SS control interlocking (NOT the relay protection blocking) shall be realized for complete SS interlocking system by Generic Object Oriented System Event (GOOSE) messages (copper connections with interlocking coils shall remain in use). The GOOSE messages are part of Generic Substation Event (GSE) that contains also the Generic Substation State Event (GSSE). The main difference between GOOSE messages and GSSE messages is unique re-transmitting system of data set in GOOSE, but the status will be only transmitted within the change in GSSE message;

- The starting and blocking signals of automation, protection functions and trip signals shall not be realized by GOOSE messages;

- GOOSE messages shall be under supervision from protection relays. Hence the fast re-transmit on data change and the periodic slow re-transmit of GOOSE without data change (configurable retransmission time in ms) are required;

- Factory Acceptance Test for each IEC 61850 device and built system at factory;

- The all appropriated software, licences, tools (e.g. IEC 61850 substation configurator tool) and accessories concerning to the IEC 61850 shall belong to delivery;

- The using of Merging Unit (MU) is requested for measurement transmission tasks to the station bus from process bus;

- The measurement accuracy of instrument transformers shall be 0,2S for non-conventional (0,2S and also 0,5 for conventional types) [8];

- The sampling value of sampled measurement value for relay protection and measurement visualizers shall be at least 80 times per period and 256 for quality analyzer;

- The MUs shall be time synchronized with accuracy of ± 1 μ s and simultaneously use same time;

- The IEDs, RTUs and workstations shall have certification of conformance test for IEC 61850 from independent test-lab;

- The parameterizing of SS according the IEC 61850; e.g. all new logical nodes shall be agreed with Utility, the creating or deleting of the device data set online is not allowed, because of modified data loss after device reboot;

- The appropriated ICD (IED Capability Description), SCD (Substation Configuration Description), SSD (Substation System Specification Description) etc. files for shall be delivered to the Utility after SS final commissioning. The Utility shall take into consideration that some parameterizing tasks (e.g. creation of Configured IED Description, Instantiated IED Description, System Exchange Description) will be done by Vendor software automatically without any influence and the necessity of handle them by human;

- The redundancy conditions (the RTU, LAN etc.);

- The industrial local PC workstation with full functionality of conventional RTU could be used instead of conventional RTU device installation.

Probable station bus solutions

The IEC 61850 is dedicated for internal using in SS

station bus and process bus.

Since the measurements transmission could be

ensured by IEC 61850, no MTs are more needed for appropriated tasks.

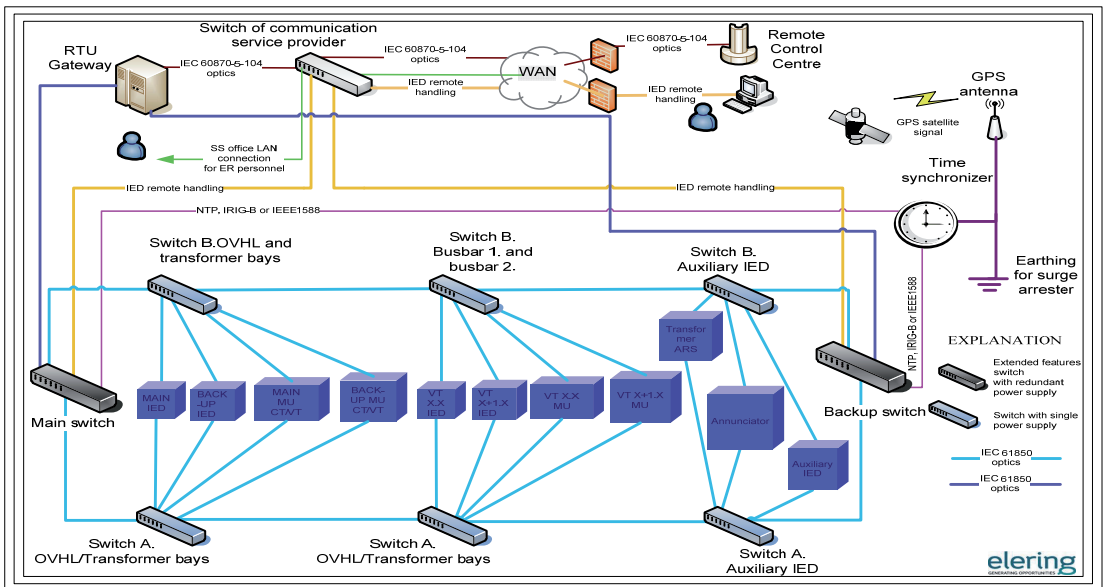


Fig. 1. Structure of IEC 61850 LAN (variant A)

The “Contra” technical key-attributes [Fig. 1]:

- A lot of switching devices (costly solution);
- Long period for recovery time. Probable data losses during the switch recovery time. This solution can be improved by reducing of the switch amount by integration the main and back-up switches into some bay switches. Or two IEDs shall be connected in sequence same switches;

- IED vendors could not always offer an IED with doubled IEC 61850 interfaces.

The “Pro” technical key-attributes [Fig. 1]:

- The “N-1” criterion is fulfilled for every switching device;
- The one malfunctioned IED does not influence other IEDs, RTU (or local PC workstation).

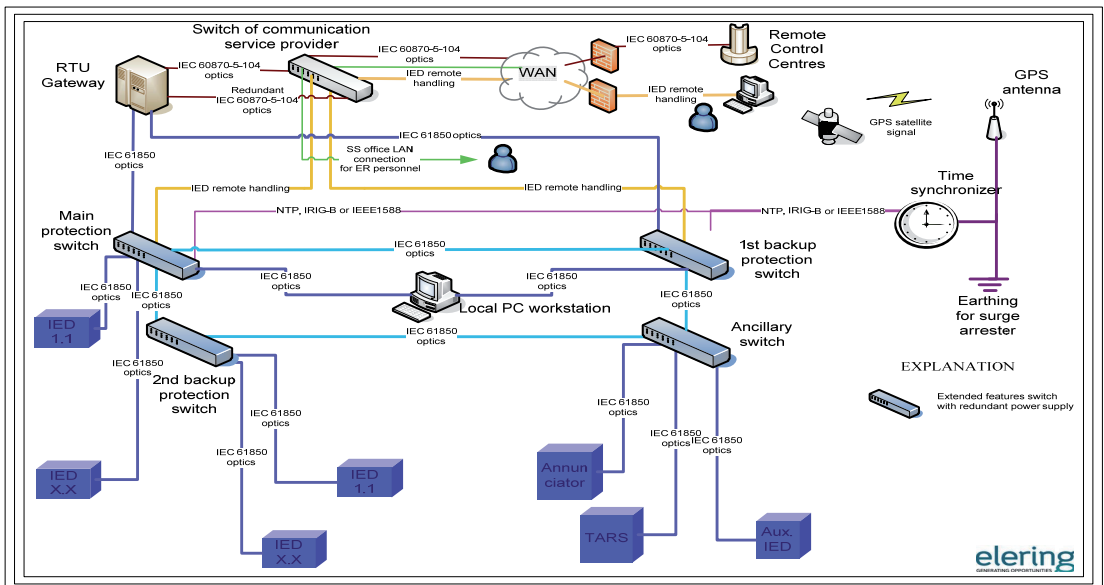


Fig. 2. Structure of IEC 61850 LAN (variant B)

The “Contra” technical key-attributes [Fig. 2]:

- Switches are not redundant.

The “Pro” technical key-attributes [Fig. 2]:

- The segregation of one malfunctioned IED;
- Cost-effective solution;
- One malfunctioned IED does not influence other IEDs, RTU (or probable workstation).

Probable process bus solutions

The non-conventional instrument transformers are built up using the physical effects of materials [4]. As a rule those are optic materials. The NCVITs and NCCITs shall meet the international standards (IEC 60044 - 7 and IEC 60044 - 8 correspondingly). The NCVIT is based on the electro-optic Pockels effect that produces birefringence in an optical medium induced by a constant or varying electric field. The birefringence is proportional to the electric field. The Pockels effect occurs only in crystals that lack inversion symmetry (e.g. lithium niobate LiNbO_3). The NCCIT is based on Faraday effect that is between light and a magnetic field. The rotation of the plane of polarization is proportional to the intensity of the component of the magnetic field in the direction of the beam of light.

The common benefits of NCCIT/NCVIT are lack of copper cabling, filling oil and SF_6 , easy maintenance, light weight, easiness to monitor the measurements online and e.g. AIS NCCIT can be placed without a separate basement.

The drawbacks of NCCIT/NCVIT are mostly redundancy requirement (e.g. two separate current sensors or two separate NCCITs, redundant MU, two optical cables in the different cable duct), special water resistant and penetration protection for optical fibres.

The NCVIT and NCCIT have MUs that send the light signals to the appropriated light polarizers. After that MUs receive the signals back and convert them according to the IEC 61850. The sampling of SMV is adjustable between 80 and 256 samples per period. The common MU shall be equipped with redundant DC power supply module, redundant processor module, IEC 61850 redundant optical communication interfaces.

Some devices do not have united IEC 61850 interface for station bus and process bus; hence sometimes the separate IEC 61850 LAN may be used for that tasks (IEC 61850-9-2).

Conclusions

The implementing of measuring system based on the standard IEC 61850 involves the re-organizing of whole relay protection, substation automation, control and monitoring.

This essential aim of this work is the transforming the doubts and fears to the grasp the first implementation of IEC 61850 in the substation. The current work is based on secondary research type that offers different technical solution collations, models of new IEC 61850 implementing solutions and sets up the ground for Smart Grid future coming [11]. The better understanding of IEC 61850 issues, economic effect and ensuring the “N-I” criterion in designed bus topologies offers the innovative

approach by planning of IEC 61850 substations. The article also shows that the implementation of IEC 61850 as simple communication protocol is the irrelevancy and misunderstanding of IEC standard in power energy sector. The primary achievement of work is implementing of many above treated proposal requirements of station bus in official procurement document of Estonian TSO.

The remote handling procedure sets also strict cyber security requirements to the build-up the connection. All security methods like VPN, passwords, encryption, firewalls, IP-control and management technologies, shall be applied for substation LAN. The Utility should get the overview of some public security standard [6] and maybe to use an outsourced consulting service concerning to cyber security topic.

Acknowledgments

I would like to thank the Elering OÜ Company for the basic data and materials ([1], [2]) that were kindly given for using them in the current article and to accentuate the Tallinn University of Technology for financial support.

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I. Dmitrenko. IEC 61850 and Measurements // Electronics and Electrical Engineering. – Kaunas: Technologija, 2011. – No. 6(112). – P. 106–110.

The technical solutions based on the standard of International Electrotechnical Commission (TC57) 61850 are changing the traditional imagination of principles for relay protection, local and remote supervision, measuring system, ancillary services etc. in substation. The complexity of managing the IEC 61850 substation building project forces to move forward by further specifying the requirements concerning to primary and secondary substation equipment. The implementing of IEC 61850 (e.g. measurements) requires the knowledge, avoiding the misunderstandings, confusions and even opportunism against the new technology within different level of Utility personnel (planning, asset managing etc.). Ill. 2, bibl. 11 (in English; abstracts in English and Lithuanian).

I. Dmitrenko. Standarto IEC 61850 pagrindimas // Elektronika ir elektrotechnika. – Kaunas: Technologija, 2011. – Nr. 6(112). – P. 106–110.

Tarptautinė elektrotechnikos komisija keičia relinės apsaugos, vietinės ir nuotolinės sistemų priežiūros ir kt. techninius sprendimus. Atlikta standarto IEC 61850 apžvalga, pateiktos pagrindinės problemos, susijusios su atnaujintu standartu. Standartui IEC 61850 tobulinti reikia žinių, kurios padėtų išvengti nesusipratimų, painiavos. Il. 2, bibl. 11 (anglų kalba; santraukos anglų ir lietuvių k.).

[PAPER-II] Dmitrenko, I.; Laugis, J. (2010). Obstacles of Substation Telematics System. 14th International Conference of Power Electronics and Motion Control Conference (EPE/PEMC), 2010. IEEE, pp. 48 – 53.

Obstacles of Substation Telematics System

Igor Dmitrenko*, Prof. Juhan Laugis†

* Elering OÜ, Tallinn, Estonia, e-mail: igor.dmitrenko@elering.ee

† Tallinn University of Technology / Department of Electrical Drives and Power Electronics, Tallinn, Estonia, e-mail: laugis@cc.ttu.ee

Abstract—the remote control and supervision of electrical power transmission system ensure balanced electricity generating and consuming, taking under control the interruption of power supply for consuming, operating substation circuit devices remotely, precluding Blackout etc. The device to realize above-mentioned functions is the Remote Control Unit, the device, which is the inseparable part of the substation.

Keywords—data transmission, measurement, power transmission, standard, transducer.

I. INTRODUCTION

The aim of work is to locate the main problems, unstable places and critical circumstances concerning to telematics of substation and also to make a proposal how to establish the quality control on maintained ready-to-use telematics before its commissioning.

Gentlemen Simon Nora and Alain Minc began the history of telematics term (*la télématique*) with the report 1978 titled as *Rapport sur l'Informatisation de la société*.

In spite of the arguable derivation for above mentioned term, the term determination, made by academic Dennis Foy in English, became widespread over the world and it is explained like compound of the Latin *tele-* (far off) and Greek *-matos* (machinery).

The article deals with substation telematics system (telematics), based on experiences of the company Elering OÜ.

Elering OÜ (National Grid, Main Grid) is the Estonian transmission system operator (TSO). Using 110–330 kV high-voltage power lines, it unites Estonia's biggest power stations, distribution networks and corporate consumers in an integral energy system (see "Fig. 1").

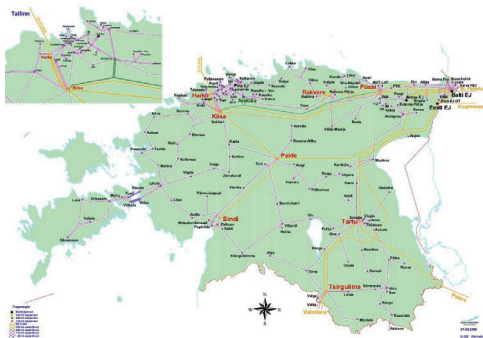


Fig. 1. Mapping of power transmission system in Estonia

The main functions of Elering OÜ are listed below:

1. ensuring the energy market existence according to European Union regulations;
2. transmitting electricity at voltages of 6–330 kV to distribution networks and power consumers;
3. ensuring the reliability of Estonia's electrical power system in conjunction with the power systems of the neighboring countries;
4. maintaining the capacity balance of the electrical power transmission system and managing the power system across Estonia in real time;
5. ensuring the Estonian energy balance and operating the balance settlement for the balance providers.

II. OVERVIEW OF TELEMATICS FOR ELECTRICAL POWER TRANSMISSION SYSTEM

The substation is tight conglomerate of primary and secondary equipment. The primary equipment deals with direct contact of high voltage electricity (e.g. power transformer, circuit breaker, isolator, earthing switch). The secondary equipment of substation does not have any direct access to the high-voltage electricity, except some external telemetry communication paths, which could be build up, using high-voltage lines (e.g. power-line-carrier technology communication, realized by over-head-lines of power transmission). The telematics of substation is always secondary equipment.

The main parts of control and supervisory for power grid telematics are Remote Control Centre (RCC), substation Remote Terminal Units (RTU), Intelligent Electronic Devices (IED) and different local communication paths.

The RTU is dedicated for adequate reaction on information objects (control, status, measurement, alarm), exchanging them between the substation and remotely to the supervisory control and data acquisition (SCADA) system of the RCC. On the other side, the RTU shall be connected to the executing device, which should react on control action from the RCC. Sometimes the RTU is named as SCADA gateway, while it serves the link between the substation and the RCC, i.e. between the local network and the external network outside the substation. The good example of RTU definition presents also in [4].

As a rule, the reliability for the RTU during its whole lifecycle can be ensured by certain requirements of the Client. Hence, these requirements characterize the functionality of the RTU hardware and software, needed for uninterruptible proper run of device, proceeded from RCC demand.

For example, one of the RTU requirements may be the modular hardware topology of the RTU [2]. Due to fulfillment of above mentioned requirement, the malfunction of one RTU I/O module does not affect the proper run of another I/O module of same RTU.

With purpose of remote control and monitoring, the primary equipment of substation should be connected to the substation IEDs. The IED is secondary device, which tasks are local control and monitoring function, protection function and the providing of remote control and monitoring opportunities. Commonly the IED is a protection relay. Unlike the some different explanations of substation IED meaning [4], the current article deals with the abbreviation IED as protection relay only.

On the "Fig. 2" the primary equipment of substation is marked by pink colour and the secondary equipment is marked by blue colour.

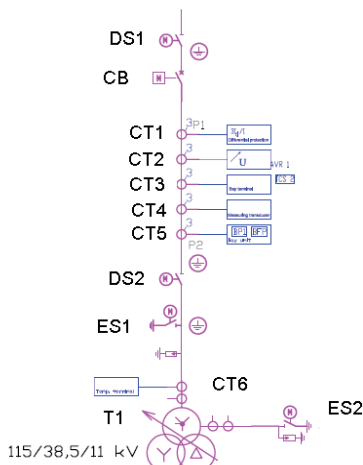


Fig. 2 Fragment of main electrical schema. 110 kV transformer bay

The IED should be connected to the RTU, which provides remote control operations and monitoring functions for RCC system. There are three working principles of protection relay, and they are closely bound with opportunity of communication mode to the RTU:

1. electromechanical protection relay (as a rule, this relay does not have an external communication interface for data exchange, which is based on some transmission protocol standard for the informative interface of protection equipment. So the external communication could be made by binary or analog copper connections only);
2. analog-digital protection relay (this relay has an external optical or electrical communication interface for data exchange based on some transmission protocol standard for the informative interface of protection equipment. As the option the conventional binary and analog copper connections are also possible in the device);
3. numerical protection relay (this relay has an external optical or electrical communication interface

for data exchange based on some transmission protocol standard for the informative interface of protection equipment.).

Nowadays the most used interface of protection relay for information transmission to the RTU is optical and transmission protocol based.

Usually the data transmission protocol IEC 60870-5-101/104 and IEC 60870-5-103 are commonly used for connecting RCC and IEDs to the RTU correspondingly. As additional opportunity, the IEC 60870-5-101/104 could be also applied directly for communication between RCC or RTU and some types of IEDs.

The different transmission protocol could be utilized for the data distribution from measurement transducer to the RTU. Usually the communication protocol of world prevalent usage (e.g. Modbus, Profibus) in communications with measurement transducers.

The measurement transducer is the device, which sends the operational measurement data to the RCC using the RTU. The measurement transducer converts analog values, received from secondary circuits of instrument transformers (voltage and current transformers), to the protocol based digital data for the RTU.

The measurement transducer shall meet the specific accuracy requirements, which are more rigorous for direct measurement distribution, than for distribution of calculated values (e.g. active and reactive power) [2].

The one of the important requirements is the time synchronizing of RTU and other IEDs in substation, which is shown on "Fig. 3".

The purpose of substation GPS reference clock and time synchronizer, including all communications to target-devices (GPS system) is dedicated for correct real local time and date run in IED-s (incl. RTU) and for correct time stamp of signal, which is sent to the RCC.

Previously the time synchronizing was performed by RCC (only IEC 60870-5-101). Nowadays the GPS system shall be used in a substation for time synchronizing of all IEDs and the RTU.

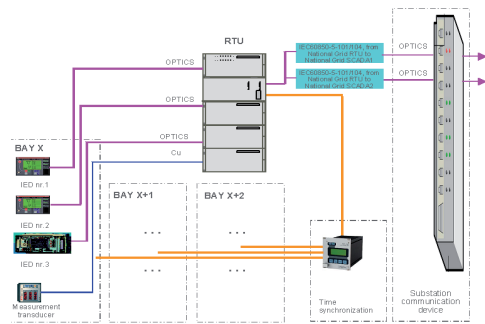


Fig. 3 Simplified structure of bay telematics

The RTU is only the device, which sets up communication between the telematics upper and lower paths - substation and the RCC.

The substation telematics could also be equipped with local PC workstation or simple local Human-Machine-Interface-monitor (e.g. touch-screen panel). The both

variants could support the standard opportunities like the event storing, local control and monitoring, visualization of substation main electrical schema etc. The good to mention premise for installation of above-written systems, is:

1. to have a back-up opportunity of local control and monitoring in the substation for emergency case (e.g. the unmanned substation loses the connection with the RCC, hence the appropriated specialist could be directed to the substation for that reason);
2. traditional substation telematics structure will be replaced with another cost-effective technical solution (e.g. without RTU as separately standing device).

Because of large amount of information concerning to the local PC workstation and other HMI-systems, the current article does not cover any aspects regarding to them.

III. COMMON KEYNOTES OF THE TELEMATICS

The first steps of design engineering for telematics is to define the network type and appropriated features of all telecommunication network components in the substation, such as:

1. topology of network (e.g. star, ring, fully reserved, tree, mesh, bus structure);
2. the physical connectivity of communication interface for every communicative devices (e.g. in voltage level, optical wave length, optical cable plug);
3. the compliance with standard and interoperability for communication interface of every communicative device (e.g. the optical interface of the RTU, marked as compliant with standard IEC 60870-5-103 of data transmission protocol within certain RTU product range of one manufacturer);
4. the functional interoperability of every communicative device (e.g. protection relay, which conforms to standard IEC 60870-5-103 of data transmission protocol).

Hence all components of telematics shall match to the one integrated system, independent from particular performance of single device, with target of whole telematics proper running.

If the rigorous requirement of communication between two telematics devices with incompatible communication interfaces, belongs to fulfill, then the technical solution could be the using of additional inter-converter, which, of course, reduces the reliability of substation telematics in this part. But this solution is tied with opportunities of regular inter-converter production, which, unfortunately, cannot not cover all possible conversion variants of telematics inter-communication.

In the late nineties, the power engineering run into notion of being addicted to one manufacturer of substation telematics and automation devices, because of private manufacturer-specific data transmission protocol. Hence once new substation was built, it wasn't possible to extend existing substation telematics equipment without costly relationship with previous Contractor (i.e. IED, RTU etc

manufacturer). It caused the preferable using of open-standard data transmission protocol in the substation. This data protocol is defined as international standard for data transmission for the informative interface of protection equipment.

A. Communication compatibility

A few years ago the device ability of different manufacturer to telecommunicate using the international standardized protocol was anything else as successfully realized. Even now some of the IEDs and RTUs could not telecommunicate in "plug-n-play" mode between different devices of different manufacture in spite of their label "IEC 60870-5-103 compliance", because of using private area, defined by protocol standard. The most adequate control of telecommunication suitability is to check the compliance with the international testing companies, which publicize compliance reports of devices from manufacturers of power energy area.

B. Time synchronization

Every protection device and RTU should be time synchronized with required time accuracy, but the way how to perform that is responsibility of device manufacturer:

1. physical interface - D-Sub 9 pins, 2-pole plug, optical interface etc;
2. time synchronizing protocol – Irig-B, DCF77, GPS, time strings, 1 ppm (pulse per minute), IEC 60870-5-101/103, IEEE 1588 (Precise Time Protocol) etc.

C. Remote terminal unit and protection relay

The parameterizing of IED (protection relay) includes several levels:

1. protection function (the essential purpose of protection relay);
2. logic (the additional non/standard logic in protection relay);
3. telemetric (the definition of information objects for RTU/ RCC).

The main idea of establishing the telematics communication is to precisely define all addresses of information objects. In case of using IEC 60870-5-103 there are type identification and information number.

The RTU parameterizing is to define the information objects of data transmission protocol (address, type etc.) exchanging them with RCC (the international data transmission protocol standards IEC 60870-5-101/104 are often used for that). The figure "Fig. 4" shows the example of double command, double point, single command, single point and floating point measurement.

IEC Specific		Point Specific
Type	IEC addr	PointName
C_DC_NA	1	C1T 10kV VL 10155
C_DC_NA	2	C2T 10kV VL 10185
M_DP_TA	2001	C1T 10kV VL 10155
M_DP_TA	2002	C2T 10kV VL 10185
M_SP_TA	3001	Avarii 110kV
M_SP_TA	3002	Korratus 110kV
M_ME_NA	1001	C1T 10kV P
M_ME_NA	1002	C1T 10kV Q

Fig. 4 Properties of some IEC 60870-5-101 information objects

D. Measurement transducer

The most widely spread mode of communication between RTU and measurement transducer is the using as well the industrial protocols like Modbus or Profibus, as IEC 60870-5-103. If in third solution the star topology is appropriated, then Modbus and Profibus need for loop-connection. Thus, there are only possible to make a mistake with configuration during definition of information object address, dead band, threshold and also over-measured rate, which should be calculated according to certain rule.

IV. THE TESTS OF TELEMATICS AND THE RELATED ASPECTS

The main Client idea how to find the suitable and compatible device for the telematics is to check each telematics unit for the appropriated approval tests (documents), like acceptance, sampling, commissioning, conformance etc tests. The main groups of such tests are adduced below:

1. type test (test to confirm that current device belongs to the certain range of devices according to appropriated inter- and national standards);
2. conformance test (test to approve, that the current device is constructed according to rules/standards);
3. routine test (test to check, prove, demonstrate produced each separate device features, that meet the appropriated quality requirements with and without witness of Client).

It is quite important to check appropriated test protocol to be sure, that all of telematics devices have statement about succeeded type test and conformance test, e.g. the [5] is one information source for that need. The above-mentioned protocols are formal documents, hence they should be checked from device pertinence point of view.

The routine tests are applicable on the factory and in the substation correspondingly. The routine tests are mostly attached to the project execution, but it is also possible to enhance the test process according to demand of the Client. It can intensify the quality control of product. The routine tests for telematics usually are:

1. design test (factory internal test of interface, connections, cases etc.);
2. pre-FAT test (factory internal test of device availability for ready-to-use);
3. factory acceptance test (FAT is a project phase where the manufacturer shows that the device or

system design with performing meets all of Client's requirements, stated in contract);

4. pre-SAT test (factory internal test of device availability for ready-to-use in appropriated system);
5. site acceptance test (SAT is a project phase where the manufacturer approves in on-site mode, that complete telematics, which goes into operation, is fully functional according to Client requirements);
6. special test (according to the necessity).

While the type test is strictly controlled and managed by manufacturer, then routine tests should be performed according to the requirements of manufacturer. But the FAT and the SAT should be organized taking into consideration the requirements of the Client for test scope and probable request for witness of Client during the testing process.

Traditionally the FAT follows the conformance test, whereat the last one ensures the meeting the international standards and principle applicability of device to the substation equipment. The next step is to perform the SAT after succeeded FAT [3].

The FAT scope may content some parts of the SAT scope and vice versa. It became especially feasible in case of using the new substation automation protocol IEC 61850. Hence it is possible to assemble full substation telematics at the factory, and there is no need to perform same time-consuming check in the substation. For example, if the interlocking logic is tested during the FAT, there is no need to fully check it again during the SAT. But unfortunately, the well-practice experiences of vendors do not always ensure and cover all aspects of customer requirements, that's why the good co-operation between Contractor and Client is the best way to agree the exact scope of the FAT and the SAT. The Client proposals to add different test methods could mainly influence the SAT, but the FAT remains relatively inflexible.

The basic functionality of substation telematics system is commonly concentrated in two types of device groups like relay protection and remote control and supervision. While the RTU is a binding unit between RCC and substation secondary equipment, then the basic indicator of proper work of substation telematics system is the RTU itself. The above-mentioned device groups are differentiated not only by core functions of certain device, but also by assembling topology on physical level. Unlike the protection relay, the RTU has modular hardware composition, which usually causes inconveniences to perform the FAT for whole RTU. Hence the SAT of the RTU belongs to mandatory check program of substation commissioning.

The one of main aspects in proper work of substation telematics is faultless definition of the information objects between the RTU and the RCC.

While the amount of information object list varies from 200 to 2200 pieces per substation, the mistake, done within modifying the information object (add, remove, change) could occur. The modification of information object maybe different, e.g. the implementation of wrong point address, wrong name, wrong point type area wrong grouping. Thus, the continuous check of substation information object list evolution (correct approximated information object list in the beginning, modifying during

the technical project and final variant) and check for the RCC interoperability list are strictly necessary check activities.

The finalized information object list is commonly end-documented for start to parameterize the RTU and the RCC. In spite of *métier* experiences in past, there is still a human factor during device or system parameterization. It needs to pay more attention on check results after completed parameterization works. There are more complicated cases, when increases the necessity to check the device parameterization, e.g. existing RTU extension or retrofit of that.

The most complex problem is the informational noise from the RTU, like continuous flicker indication of some state point. It can be wrong behaving of functions in the protection relay, malfunction of RTU communication module etc. The RCC has special feature, implemented in SCADA system, if the information object will change its status with frequency, which exceeds maximum frequency value, set for receiving it into the RCC SCADA system, then this signal will be ignored in RCC SCADA system for certain time.

Fore better understanding of occasion to mismatch the latest version parameterization software (configuration tool) for older RTU, the compatibility of RTU parameterization software within one range product of same manufacturer is important remark to be checked during and after commissioning works.

The mismatch of the firmware in RTU hardware part to the certain version of the RTU parameterization software could also embarrass the commissioning of the RTU.

Actually they are manufacturer dependent problems. But as a end-user, the Client shall locate the risks and consequences concerning to such peculiarity. If the Client relies fully on one vendor (total outsourcing), then it is not so easy to come to the agreement with the vendor (Contractor), because firstly, the Client usually does not have any information about that and secondly, the Client does not have influence on technical project in details, according to the outsourcing principle.

V. THE QUALITY CONTROL OF TELEMATICS BEFORE AND NOW

The main aim of telematics quality control is to proof the integrated functionality of all components together, which are elements of one assembled telematics system.

The information objects list helps a lot to parameterize the RTU correctly and to define the information amount in the RCC. But, additionally, it also gives the information, what kind of the data does belong to exchange and which devices are receiver and transmitter.

The basic methods of the RTU testing were commonly based on random way, according to Client requirements. Previously, the Contractor took responsibility for full SAT himself. But it gave a strong negative feedback during the warranty period and after that, especially, when came out the necessity to extend the substation.

The first step to harden the test process in the substation was the RTU “on-line” test with RCC for each appropriated information object, including even the measurements. The main advantage and disadvantage of this testing is opportunity to imitate all information objects for RCC alarms and indication signals from protection

relay or even from the RTU, not from signal source. It can be used because of operational stability of national grid, when, for example, operating of certain primary or secondary equipment is not allowed. If there are no possibilities to test information objects “live”, then they could be imitated from telematics system or by copper connections. The advantage maybe useful, because all information objects will be tested in spite of whatever national grid status. But the disadvantage is the remaining in non-tested status of the information objects sources. The next lack of above mentioned test is out-of-test staying information objects from previously commissioned energizing phase of project. If the existing RTU should be re-parameterized, adding some new information objects or logic for substation extension part, then all existing information objects shall remain in use. But the Client cannot be sure, that in result of RTU re-parameterizing, there will be no human-factor mistakes as in existing information object part, as also in new extension part of the substation.

With the target to simplify the check of information object list, the special point addressing is implemented, dividing information objects into several independent signal address ranges.

The less amount of information objects is achieved by the principal decision about grouping of alarm and indication signals in the substation telematics (see “Fig. 5”).

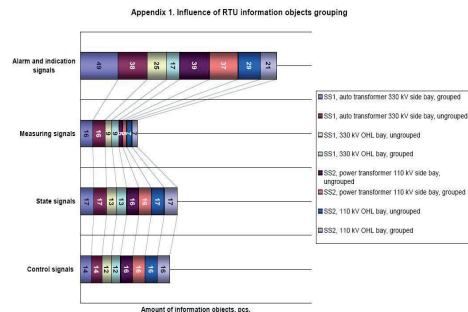


Fig. 5 Comparing of ungrouped signals to grouped

The drawback of the signal grouping principle could be located in misunderstanding of wrong forming of signal group.

As it is mentioned above, the protection against the information noise, which comes from substation RTU to the RCC, is solved by implementing of special filters on RCC side, which monitor the information object manner and blocks in case of its flicker, twitch or some another abnormal behavior.

VI. THE PROPOSAL OF INSTRUCTIONS FOR QUALITY CONTROL OF TELEMATICS

The best variant of the SAT solution should be the ability to perform information objects sequence test (“one-by-one”) with repetitive test part of partial information object scope for current energizing project phase from previous project phase. The test process should involve the RTU and the RCC with appropriated communication

paths between them, primary equipment and relay protection devices.

The idea of such testing is to follow the complete movement of alarm or indication signal from the beginning (signal source or as close as possible to signal source) to the end-target (RCC). This test shall also treat the each sub-group signal independently.

Unlike the Client, the Contractor prefers device oriented information object list, which shows all protection relays information objects sending to the RTU. It is good for maintain works, but insufficient for revision of Client, who needs for bay oriented list structure.

Nowadays many RTUs use the MS Excel standard sheet to collect and convert the data in to the RTU parameterization files. As a rule this sheet includes names, descriptions, delays, groups and types of information objects etc. At the end of substation project, the new MS Excel table list should be extracted from the RTU for Client check by RTU parameterization software, including all related features of the information objects, source device name, connection type, protocol types, communication protocol addresses and other specific data.

The large amount of information objects could be reduced by aggressive implementation of group information objects. They should be the alarm and the indication signals only. The time critical signal shall be clearly defined from non-critical, because the RTU logical function of grouping may influence grouped information object time tag with additional time delay.

After each modification of RTU the additional selectively SAT should be carried out according to the actual power transmission grid conditions concerning to substation equipment. The best variant to avoid the human mistakes or failures of RTU parameterizing during the RTU new extension, is to allow completely new RTU for each extension part of substation, i.e. do not allow the extension of the existing RTU. It is also reasonable step taking into account the ensuring of competitiveness between manufacturers in tender period.

The better solution for the information noise blocking is to differentiate the malfunctioned “noising” signal by logic of the RTU. Thus the information about failed protection relay signal will be sent to the RCC differently comparing to some RTU failed signal.

As it was told above, the problem of compatibility of new RTU and its previous versions of parameterization software is not the responsibility of Client, but of manufacturer. That’s why the correct information about device offers in telematics, needed for substation construction should be given from potential Contractors to the Client.

The more complicated problem is tied with RTU hardware firmware, because of continuous development of some RTU hardware or even software parts. The role of Client in this process is void, if the project execution is based on out-sourcing principle. In other cases, the Client shall put into his requirements the conditions of permission for appropriated device use. The Contractor shall use the telematics device, which meets all requirements of Client, has statement document with successful standard conformance test execution from accredited European international standard committee. If successful conformance test was already executed for appropriated telematics device, which had in statement

firmware, software etc versions, then the Contractor may use telematics device with only this firmware, software etc, which version numbers stated in document of successful conformance test execution.

The last notice is the warning from losing the RTU parameterization files (configuration), because mostly RTUs do not have opportunity to get parameterization files anymore by downloading them from the RTU, since they uploaded.

VII. CONCLUSION

The successful accomplishment of substation telematics building is possible according to well preplanned Client ideology of substation telematics, with ability to organize the scope of testing programs and with close co-operation between Client and Contractor. The Client’s expected Contractor best practice is to construct the substation telematics according to the Client requirements, to put Client attention on some probable improper decision with the aim of improving, to check executed works carrying out the FAT as well as the SAT in keeping with additional needs of the Client, defined for scope of acceptance tests.

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The Handle of Substation Remote Terminal Unit Configuration

Igor Dmitrenko, Tallinn University of Technology, Elering OÜ, Juhan Laugis, Tallinn University of Technology

Abstract. The remote control and supervision of electrical power transmission system is the balanced system between electricity generating and consuming, taking the responsibility for the stability of power supply consuming. The device to be responsible for above-mentioned tasks is a Remote Terminal Unit with faultless proper configuration.

Keywords: communication terminal, testing, SCADA systems, software.

I. INTRODUCTION

The goal of work is to differentiate the circumstances following the delivery, maintaining, parameterization and commissioning of Remote Terminal Unit (RTU) in the main grid substation. The solution how to hold the control on proper functionality of RTU during its whole life cycle taking into consideration possible modification of main grid substation telematics system.

The basic data and materials for current analysis are kindly given to represent by Estonian transmission system operator (TSO) company Elering OÜ.

Elering OÜ (National Grid, Main Grid) is Estonian transmission system operator (TSO). Using 110–330 kV high-voltage power lines, it unites Estonia's biggest power stations, distribution networks and corporate consumers in an integral energy system. Elering OÜ has international grid connections, hence the Estonian TSO is a member of several international organizations, engaged in power transmission (see "Fig. 1").



Fig. 1. Position of Estonian electrical power transmission system on map.

The main functions of Elering OÜ are listed below:

- ensuring the energy market existence according to European Union regulations;
- transmitting electricity at voltages of 6–330 kV to distribution networks and corporate consumers;
- ensuring the reliability of Estonia's electrical power system in conjunction with the power systems of the neighboring countries (see "Fig. 1");
- maintaining the capacity balance of the electrical power transmission system and managing the power system across Estonia in real time;
- ensuring the Estonian energy balance and operating the balance settlement for the balance providers.

II. OVERVIEW OF TELEMATICS IN POWER TRANSMISSION SUBSTATION

The main parts of telemechanical control and supervisory for power grid are Remote Control Centre (RCC), RTU, IEDs (Intelligent Electronic Devices), measurement transducers, local reference clock device and communications paths.

The substation RTU is device for immediate reaction on information objects (control, status, measurement messages), receiving them from side to remotely connected RCC - Supervisory Control and Data Acquisition system (SCADA system). On the local side the RTU shall be connected to the executing device, that reacts on control or parameter set action from SCADA system personnel.

The reliability of the substation RTU during its lifecycle and the parameterization for proper working according to SCADA system operating needs should be ensured by technical requirements and by continuous checking of ready-to-act substation apparatus.

Usually the primary equipment of substation should be connected to the IED, that tasks are local control and monitoring of primary circuit apparatus, protection function and the providing of remote control and monitoring opportunities. Very seldom in case of the IEDs are not requested, the only substation RTU has responsibility on all above-mentioned functions.

The measurement transducer is the device, that sends the operational measurement data to the SCADA system via the RTU.

Nowadays the most popular physical way to ensure the reliable data exchanging between protection relay and RTU is optical data transmission, i.e. using of optical cables.

As a rule the data transmission protocol IEC 60870-5-101 (serial) and/or IEC 60870-5-104 (TCP/IP) is the low and upper level of data transmission between substation equipment and the SCADA system. The data transmission protocol IEC 60870-5-103 (serial) is used for connecting different independent devices (e.g. IEDs) or their groups to the RTU. The mostly used data transmission protocol standards like Modbus, Profibus are well-known solutions for communication between measurement transducers and the RTU. The one of the important SCADA system requirements is the time synchronizing of whole substation telematics. The principle structure of is shown on "Fig. 2".

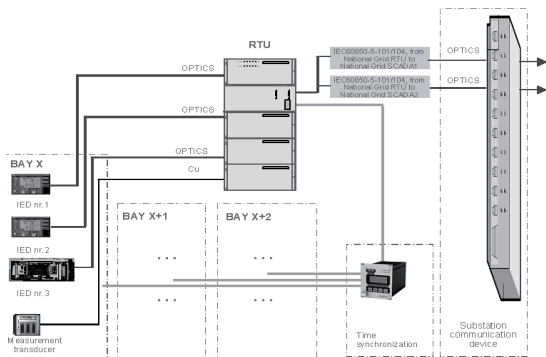


Fig. 2. Simplified structure of bay telematics.

The purpose of substation reference clock with appropriated input signal (e.g. Global Position System signal) or and time synchronizer is dedicated for correct real local time and date run in IED-s (incl. RTU) and for correct time stamp of signal, that is sent to the SCADA system.

III. THE REALIZING OF THE TELEMATICS PART IN THE PROJECT

The construction of new substation telematic system presumes some steps made before. There are some of them:

- necessity to build the new telematics system in substation;
- budgetary possibilities for building of the new telematics system in substation;
- technical requirements for telematics system in scope of supply;
- the professional qualification of Contractor by Client;
- signed procurement with suitable Contractor for telematics works defined in scope of supply works;
- existence of Client's project workgroup with appropriated "know-how".

The realization method and management style for project accomplishment could be different, where a few of above-mentioned points would be skipped.

A. Contractual method, "turn-key"

This realization method of project is necessary in case of Client insufficient or lack of needed specialists, materials,

building techniques etc, that are irreplaceable for successful finalizing of preplanned project or project part. There should be well developed relationships between Client and Contractor during the tender. The both Client and Contractor set up his own workgroup with their own project managers.

Common benefits:

- more than one project could be managed by Client, while the Contractors may be different and independent;
- the responsibility for uncompleted project lies with Contractor;
- the Client accepts only finished building object, i.e. the substation.
- the Client accepts only finished building object, i.e. the substation.

Common drawback:

- continuous Client check the accordance of Contractor technical solutions to Client requirements.

B. "Self-made" method

This realization method of project is opposite to previous. The main idea of "self-made" method is to reduce the project costs using own personnel, knowledge, materials, mechanics etc.

Common benefits:

- cost reducing of the project;
- timesaving for some internal agreement during the project;
- flexibility for realizing the project.

Common drawbacks:

- the company should have capacities to cover all of activities concerning to realizing of the project. I.e. planning, drawing, working personnel qualification with valid licenses and certification, bulk sales contacts, machinery park;
- long-term duration of realizing the project.

C. Split to multitask method

As a rule the project consists from several work tasks. Some of them could be established internally by the workforce of the project initiator. But for some work tasks, to be accomplished by internal execution, it is not really purposeful, because the expense for company internal realizing compared to outsourcing is prevalent. Hence splitting the work to multitask could be very rational in such case.

Common benefit:

- reduce the price of the project by splitting the work to multitask scope.

Common drawback:

- the part of Client work scope and Contractor work scope shall be clearly specify during the project planning stage.

IV. THE PRINCIPLE OF RTU CONFIGURATION COMPOSING

The main parts of the RTU are:

- the hardware (rack, power supply module, processor module, I/O-modules, communication modules etc);
- the firmware (small program to control internally different components of hardware module);
- the parameterization;
- the communication links for external telematics consumers (different networks, cables, communication devices for data exchanging with SCADA system, IEDs, measurement transducers, GPS time synchronization system etc).

The select of RTU hardware components should be done according to technical requirements stated in quality documents of Client.

The RTU software affords all parameterization features, that enable to perform all needed RTU adjustments. As a rule the parameterization features of RTU configuration software are divided to four groups:

- hardware group;
- communication interfaces with external telematics devices;
- logic function group;
- group of information objects exchange with telematics system participants.

The RTU hardware should be correctly defined by RTU software. The reason of that, in addition to the location of different RTU extension modules for their proper using in couple with external telematics devices, is the ensuring of internal communication between RTU modules via system bus.

The communication interfaces of RTU support all possible RTU connections with SCADA system, IEDs, measurement transducers and GPS time synchronization system.

The logic realizing requires also using of the standard logical elements like AND, OR, NOR and/or some extended block-elements e.g. measurement converter in RTU. The grouping of some sub-signals with following composing the independent group-signal in RTU for SCADA system belongs to logic function too.

The most obstructive part of the RTU parameterization is the definition of signals (information objects) transmitted and received by the RTU. The ground of that is the adjustment of various number of information objects parameters.

The basic principles of RTU parameterizing handle is shown on figure "Fig. 3".

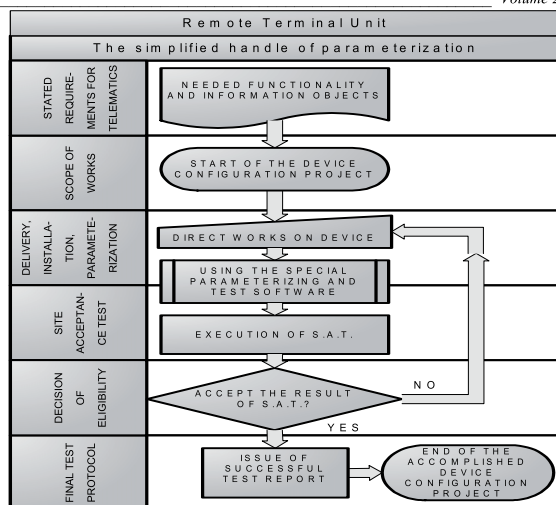


Fig. 3. Simplified handle structure of the RTU parameterization.

The most important document describes the needed telematics system is the Client's requirements statement. This document is mostly concentrated on specification of the RTU requirements, but also depends on some requirements stated for another telematics devices (e.g. for measurement transducer). The necessity of the valid RTU requirements becomes obvious in:

- the RTU compatibility to the existing RCC equipment;
- the RTU compatibility to the new and/or existing substation equipment;
- the transparency of the telematics system with RTU for supervision and future modification;
- standardized solutions of the telematics system equipped with RTU, i.e. use of international standards by constructing and commissioning of the telematics system;
- easy discover of the possible failure in the RTU;
- easy replacement of failed RTU modules;
- independent reparation of the possible failed RTU modules from others proper working;
- etc.

There is another inseparable part of supply documents that helps to make precise the features and functions of the RTU comparing to common requirements. Its name is the scope of supply document, that illustrates more or less the actual demands for specified substation RTU. Hence the Contractor shall obey requirements stated in both documents.

The parameterization of RTU is making by RTU specialist using a usual human-machine interface (keyboard, mouse, display) of the PC. Each manufacturer uses his own RTU software for his RTU parameterization. There are a lot of different RTU software tools that equipped with specific features of human-machine interface (HMI). In result of this, there are many possibilities to present the image of the RTU internal structure in configuration software. To make it the

RTU software easily to understand for the Client personnel it should meet requirements of IEC standard compatibility, e.g. the international standard IEC 61131 for programmable logic controllers (e.g. part 3. programming languages: ladder diagram, sequential function charts, function block diagram, structured text, instruction list). Thus the data types, objects, function blocks, logic etc defined by RTU software do not confuse Client personnel in spite of software manufacturer.

If whole or part (substation extension) of RTU parameterization is ready for implementation, the preliminary test of RTU parameterization will be established to detect the possible RTU internal mistake or conflict. It will be performed using several testing software programs. There are two solutions for that:

- use implemented in RTU parameterization software check functions (e.g. “compile” or “consistency check”);
- use external software to test end results of RTU configuration (e.g. IEC 60870-5-101 data transmission protocol test system).

Of course, the first method is more preferable and less cost method to test the made RTU configuration. The second method involves third-part testing software like RTU parameterization software.

After above mentioned testing processes the site acceptance test (SAT) of RTU configuration belongs to fulfill. The SAT is the one of routine tests for the telematics systems that are commonly:

- design test (manufacture’s test);
- site acceptance test (SAT and pre-SAT; on-site device test before it’s final commissioning);
- special test (according to the necessity for Client).

The functional target of RTU should be checked by the execution of the SAT. As a rule there are more than one telematics device connected to the RTU, that should react adequately to RTU behavior. Hence in case of precursory RTU parameterization, the telematics system participants like IEDs (e.g. protection relays) should be also parameterized correctly.

It needs to be careful that single modification of some parameters in telematics participant device will cause a failure because of non-up-to-date RTU parameterization. In the best case it will end with failure of some remote control functions for SCADA system. The worst case will cause the human accident like remote high voltage energizing operation of power overhead line servicing by maintenance personnel.

The best solution of SAT execution is not only to test all the parameterized information objects defined in RTU, like their test from “lower” level (IEDs binary inputs, RTU binary/analog inputs etc) up to the SCADA system, including the testing of all remote commands execution from RCC. Thus the RTU configuration process includes more steps concerning the other telematics devices (figure “Fig. 4”).

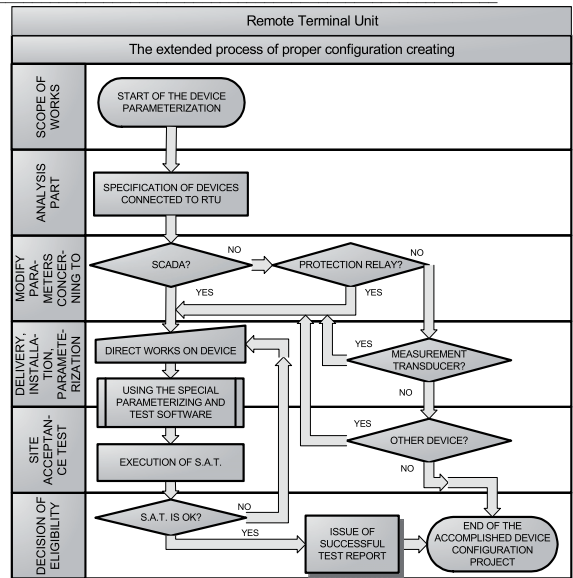


Fig. 4. The extended structure of RTU configuration process.

There should be no any mitigation to reduce the testing amount of information objects even concerning logic grouping of information objects composed in RTU or IED. All sub-information objects belong to separate SAT performance.

The above described handle process scenario of the RTU parameterization should be valid not only by new RTU placement and its parameterization works, but also in case of any extension of substation telematics system.

V. THE FINALIZATION OF THE RTU WORKS. HINDRANCES

When all above defined steps of the RTU configuration project are successfully performed and RTU is already put into continuous failure-free operation, the handover process of the project documentation, secondary device (telematics, protection, communication etc) parameterization files and configuration software should be started.

There are three possibilities of backup the RTU parameterization files with appropriated (used for making RTU parameterization) software:

- get the RTU parameterization files and RTU software to keep and use it by Client;
- get the RTU parameterization files and RTU software. To conclude a contract with external company, that will take the responsibility for keeping and handling over of the appropriated RTU parameterization files and RTU software;
- to conclude a contract with Contractor or manufacturer, that will ensure keeping and handling over of the appropriated RTU parameterization files and RTU software.

The first variant is mostly used by power transmission companies that are able to manage substation building project and construct the substation within own company. But it is

also common for companies, that intend to carry through the “turn-key” projects.

The second one is more suitable for companies that do not have technical personnel to service the secondary substation devices.

The last variant is rarely used because of needs to have a special relationship between the Contractor and Client with possible reciprocal company ownership.

There are some clearly distinguished parts of RTU software and needed accessories:

- RTU software ownership licences;
- RTU software installation package;
- PC/RTU communication adapter for parameterization, cable etc (optional).

There are three different types of licence for RTU software depending on manufacturer:

- paper based document (written whom is licenced, licence number, product code etc);
- data fail licence (needed for proper working of RTU software);
- external data storage unit (e.g. CD-ROM);
- external licence holding device (hardware lock, dongle; needed for starting and working of RTU software).

Some manufacturer of RTU software uses all types of above listed licences at once. But someone has also RTU hardware dongles (e.g. IEC 60870-5-101 communication dongle) despite already existing licences for RTU software. This kind of dongle should be attached to the RTU hardware for proper working of RTU communication.

When running status of the RTU will be fixed and assured then all of those materials will be delivered from Contractor to the Client. Thus the Client needs to be more careful and well informed about content of certain RTU delivery proposal.

The one reason should be noticed, that continuously developing technology of RTU in hardware part and in software could cause some “mismatches”. That’s why the some range of product is increasing rapidly “forgetting” the software support of older device models, that are still in use by Client or even under manufacturing.

Usually the developing of RTU software does not stop if product is ready. The software mistakes, bugs etc will be repaired by extracting of software updates, hot-fixes. Thus such components of RTU software like parameterization features, RTU operational system, RTU firmware etc could also be changed by Contractor during the substation building project. But at the end of project the Client will receive only new RTU software, probably without any additional update, hot-fix or similar. Commonly the newer RTU software enables more functional possibilities for RTU, contains some program corrections, updated firmware, faster processing etc, but it is useless while the lack of RTU support remains for those additional features by older RTU hardware type.

The next unexpected circumstance is possible non-compatibility of the RTU software older version with newer one or impossibility to have both versions of RTU software simultaneously, installed on same Client’s PC hard disk.

VI. THE PROPOSAL SOLUTION FOR KEEPING QUALITY CONTROL OF THE RTU

The localizing of the main key points in amount of needed materials, that belong to request from Contractor, guarantees the proper work of Client’s substation RTU:

- proper parameterization of entire RTU;
- flawless definition of information objects concerning to telematics “lower” level (e.g. IEDs);
- flawless definition of information objects concerning telematics “upper” level (RCC, local workstation, time synchronization system);
- flawless definition of logic tasks in the RTU;
- proper parameterization of the RTU related telematics devices;
- appropriated RTU software including all needed service packs, hot-fixes, update, upgrade etc;
- appropriated parameterization adapter needed between RTU and PC with installed RTU software;
- documentation (schemes, manuals, test protocols etc).

Even regardless of some modern methods for present of information object in RTU like MS Excel standard sheet im-/exporting, there are still possibility for human factor. Usually the MS Excel sheets with specified information objects belong to conformation by Client (different modification is possible) and after that, the agreed by Client information objects should be parameterized in RTU at once. Unfortunately the RTU parameterization upload to the RTU is not one-time action, but repetitive depending on phase of substation construction project, when partially commissioning of primary devices is necessary (e.g. case of large substation with several voltage level switchyards). Hence the parameterization of the RTU remains still in progress and is daily changing.

If after each modification of RTU parameterization the additional full SAT should be carried out then performing of “intermediate” SAT does not have any sense. The only last SAT on the end of substation construction project (RTU part) could be reliable for setting of RTU test protocol document.

In result of that, the best variant to avoid the human failures by any extension of substation RTU in the future is to demand new independent RTU for extension part of substation.

The important Client idea is to be sure in reliability of proper RTU parameterization files and delivered RTU software. When the all RTU parameterization files are ready for upload to the substation RTU, the Contractor shall declare the finished work and readiness for SAT execution before commissioning according to the method, that is represented on the figure “Fig. 5”. At the same time the all other telematics participants shall be ready for SAT too.

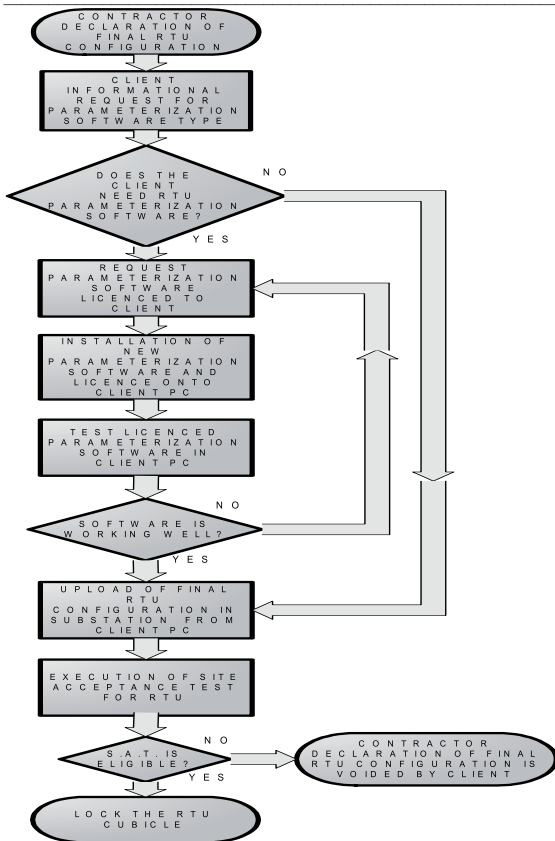


Fig. 5. The check process structure of the RTU.

The additional task for the Contractor is to prepare RTU software, RTU parameterization accessories in PC of the Client. The Contractor should check the version of RTU software with or without extra service packs, hot-fixes etc. In result of Client decision the Contractor shall deliver the full RTU software package with all needed additional updates and upgrades. If the Client needs for new RTU software, the Contractor should deliver it and help him to install it on the Client's PC. Sometimes the extra program licence should be installed for the flawless RTU software running.

After the check of RTU software correct working on Client's PC, the transfer of the RTU parameterization files would be performed from Contractor's PC to the Client's PC. By successful accomplishing of the appropriated RTU files transmission to the Client's PC, the upload of RTU parameterization files will start from Client's PC to the RTU by supervision of Contractor. If it is done, the SAT procedure should start for substation RTU.

Any other faulty case causes above described process repeating, up to the successful result of RTU software installation, RTU parameterization file uploading and appropriated SAT proceeding.

If such requirement is not realizable because of main grid conditions (e.g. energizing of primary equipment), the

alternative solution of substation telematics system constructing could be possible. The separate RTU should be placed for each primary equipment part (bay based). In this way the volume of RTU SAT for every energizing stage of the substation project may be performed independently.

CONCLUSION

The main message of current article is the challenge to generate the new approach in relationship between TSO company and Contractor (Partner) for improving *de facto* independence of TSO company from manufacturers, for increasing of quality by Client's defined SAT and for bringing the know-how to the TSO company in part of RTU systems. It needs to do the cooperation work with Partners more tightly to achieve the above mentioned end target.

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Igor Dmitrenko

Education.

1992-1997. Tallinn polytechnical school. Specialty of industrial and heating automation)
2000-2007. Tallinn University of Technology. Department of electrical drives and power electronics. Faculty of Power Engineering. Bachelor degree with documented master degree qualification
2007-present. Doctoral student of Tallinn University of Technology. Faculty of Power Engineering. Estonia

Work experiences.

2001. Practice in AMK GmbH & Co.KG. Production of industrial frequency converter. Germany
2003. Practice in SMN Elektrotechnik GmbH. Quality control of cable accessories production. Germany
1998-2006. Termest OÜ. Electrician, service specialist, service senior specialist. Supervision and service of unmanned water boiler and steam plants. SCADA system. Maintenance department. Tallinn. Estonia
2006-2007. Fortum Termest AS. Automation specialist. Unmanned water boiler and steam plants. Development department. Tallinn. Estonia
2007-present. Elering OÜ. Specialist of substation RTU systems. Technology department. Estonia

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The substation local PC workstation. Present and future

Igor Dmitrenko, Juhan Laugis
 Tallinn University of Technology
 Elering OÜ
igor.dmitrenko@elering.ee; laugis@cc.ttu.ee

Abstract

The substation local PC workstation is the control and supervision system for part of electrical power transmission system, i.e. substation. The article deals with concept of substation local PC workstation, lately realized projects and development trends for technical solutions.

Keywords

Substation, hardware, software, communication standards, power transmission control, workstation

Introduction

Elering OÜ (National Grid, Main Grid) is Estonian transmission system operator (TSO). Using 110–330 kV high-voltage power lines, it unites Estonia’s biggest power stations, distribution networks and corporate consumers in an integral energy system (see figure “Fig. 1”).

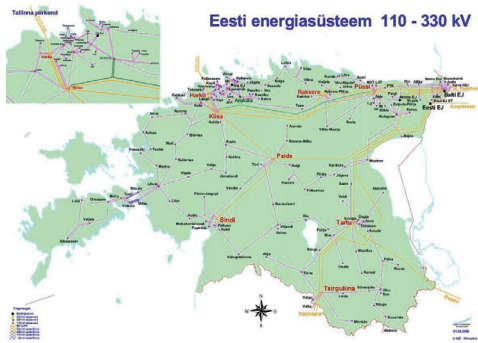


Fig. 1. Mapping of electrical power transmission system

The main functions of Elering OÜ are listed below:

- transmitting electricity at voltages of 6–330 kV to distribution networks and corporate consumers;
- developing and operating a 110–330 kV electrical power transmission network covering the whole of Estonia;
- ensuring the reliability of Estonia’s electrical power system in conjunction with the power systems of the neighboring countries;

- maintaining the capacity balance of the electrical power transmission system and managing the power system across Estonia in real time;
- ensuring the Estonian energy balance and operating the balance settlement for the balance providers.

The electrical power transmission system is a centrally controlled technical system including:

- power stations;
- consumers;
- the electricity supply network between power stations and consumers together with its respective management-, telecommunication- and protective systems (transmission network, distribution network).

1 Overview of substation telematics

The substation telematics is utility conglomerate of all different tele-control and –monitoring systems, mounted in substation, involving in those systems also remote communication paths between substation and Remote Control Centre of power transmission network (see figure “Fig. 2”).

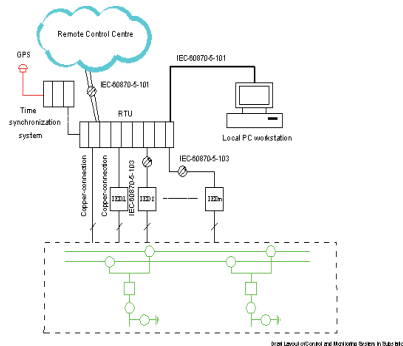


Fig. 2. Concept of substation telematics

As a rule, the participants of the substation telematics are Remote Terminal Unit, protection relays, communication devices, local PC workstation and measurement transducers. The Remote Control Centre, in turn, shall be able to communicate with substation telematics, i.e. it should have physical and logical links to the to the substation equipment.

1.1 Remote Control Centre

The Remote Control Centre (RCC) is the centralized or decentralized supervision centre for power transmission system, with ability to control and monitor the substation remotely. Usually it equipped with supervision control and monitoring acquisition (SCADA) system to collect and distribute all needed data to the target (e.g. remote command to switch off the appropriated circuit breaker in the substation).

The RCC has one energy management system (EMS) with several subsystems for different tasks performing in:

- dispatcher system (SCADA, operational activities);
- auxiliary informational systems (automatic meter reading, electrical load management operation, quality control etc);
- ancillary service system of power market (for system operators, suppliers, consumers, balance keeping etc).

1.2 Remote Terminal Unit

The substation Remote Terminal Unit (RTU) is dedicated for adequate handling of any information object (data telegrams of control, status, measurement), exchanging it between substation equipment and RCC. The RTU is located in the substations, communicating with others local devices of substation telematics and gathering the data over whole substation.

1.3 Intelligent Electronic Device

The primary equipments of substation should be connected to the device, which tasks are:

- local control and monitoring function;
- protection function;
- providing of remote control and monitoring.

There are protection relays, which ensure all above mentioned tasks in one device. Because of the highly advanced digital protection relays, their mostly used name is the Intelligent Electronic Device (IED). This device should be connected to RTU, which provides remote supervision opportunity of substation for the RCC.

The substation may have several IEDs and they should be connected to the RTU by optics to avoid electromagnetic interferences. In special cases the protocol based copper connections are also possible for data exchange.

1.4 Local communications of telematics

The one of the important keystones by the engineering of substation telematics, is to define communication paths, using them for data exchange of telematics in substation (e.g. transmission protocols in accordance to the standard for basic telecontrol tasks with or without network access and to the standard for the informative interface of protection equipment). Some communication protocols are specially designed for LAN-network and in case of using it, the network should be

designed by certain mode. There are a lot of different network configuration, like star, ring, fully reserved, tree, partial connections or mesh and bus network.

Another part of communications takes place on higher level of telematics, i.e. with the RCC. Nowadays the telematics engineer should take into consideration way of data exchanging (TCP/IP network based or serial communications).

1.5 Time synchronization system

Because the high responsibility for whole power transmission system, which consist of numerous substation units, every status information object shall be clearly distinguished by occurring time. While appropriated 60870-5-10x communication protocols developed by IEC Technical Committee 57, support the adding of time stamp for certain information object types, then the only thing to perform is to ensure the correct and adequate time with needed accuracy for telematics devices.

1.6 Measurement transducer

The substation measurement systems are divided into two fully independent groups like operational and commercial measurement systems. The operational measurements will be sent to the RCC via substation RTU. Hence first one is dedicated to establish control of emergency, technological and service activities (e.g. to check the voltage and current of the switched off power line). The commercial measuring shall be sent using the AMR system, which is fully independent from substation telematics.

1.7 Local PC workstation

The substation local supervisory capabilities is empowered by the local PC workstation (figure. "Fig. 3").

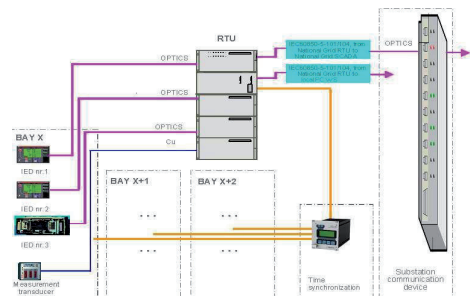


Fig. 3. Simplified structure of bay telematics

The substation local PC workstation (WS) is the independent Human-Machine (HMI) system from the RCC of electrical power transmission system. It ensures a back-up possibility for local emergency control and monitoring of substation and in case of communication failure with RCC, the substation RTU remains in use of WS anyway.

2 Local PC workstation

The WS is based on high-tech and -end device with advanced applications, comparing to conventional personal computer. The functional content of the WS is predetermined by target of its using, hence the WS shall meet the appropriated requirements, which are valid in the substation.

If the WS is connected to the RTU, then the RTU parameterizing is to define the information objects for data transmission protocol (address, type etc) exchanging them as with WS as also with RCC. But unlike the RCC, the information objects, defined in the WS, shall be more distinguished or even initial. That's why, the WS has usually more detailed information, comparing to the RCC.

The common requirements, applied for the WS, shall cover environmental and electrical conditions (dielectric strength, EMC, IP protection-class etc). Hence the placement of the WS shall be designed for substation high voltage equipment in any case.

2.1 Functionality

As a rule the WS has following functions:

- the exchange the data between WS and others substation telematics devices using the IEC standardized communication protocol;
- the performing of the control and monitoring on substation equipment (e.g. the same range of defined information objects for the WS, as they are for the RCC);
- the storage of all actions (events, performed by WS, locally or from RCC);
- Human-Machine Interface (HMI), including specific Graphical User Interface (e.g. GUI for main circuit diagram with operable switchgears);
- the event archive with capability to view, extract and transfer appropriated information objects into MS Excel format, using the portable storage device (e.g. USB 2.0 memory stick);
- the long term event history based on full time stamp, scrolling and filtering (e.g. by alarm event) of events;
- the time synchronization of WS;
- numerical trend and graphical curve set for multiple information objects;
- definition of WS information objects based on MS Excel standard spreadsheets;
- the updating of the WS capacity shall be flexible;
- in case of temporary power failure (both power supplies) of the WS, it shall start running automatically to normal operation condition when power supply is restored. After any interruption in power supply or communication all states, alarms and indications shall be automatically updated in all parts of the telematics;

- if the WS is out of operation, this alarm shall be sent to the RCC via RTU, and the RTU or other telematics devices shall buffer all events that have occurred during power interruption time for information lose prevention;
- the power supply of the PC workstation shall be fed by the DC/AC inverter supplied from the DC batteries;
- the interlocking system of primary equipment is running also in case of WS control;
- the malfunction, out-of-operation or other internal failure (IRF) of the WS shall be clearly distinguished in RCC.

2.2 Hardware

Usually there are no specific requirements to WS hardware. The WS should be constructed according to the best practice of WS Manufacturer.

However the WS shall ensure he functionality and meet some common requirements of the hardware:

- the WS shall not have any moving parts like fans, rotating HDD or similar. Whereby the appropriated cooling of WS shall be ensured for WS normal operation;
- the WS shall have HMI with obligatory GUI implementation;
- the WS shall have event buffer or event buffers for realization of fast intermediate memory;
- the communication between the telematics devices and WS shall be IEC 60870-5-101 or IEC 60870-5-104;
- the WS connection shall be optically insulated from others telematics devices;
- the flash-memory based HDD of WS shall be mirrored (RAID system, two HDD-s), i.e. one supposing malfunctioned HDD could be easily replaced with new blank one, which can be automatically mirrored after that;
- the WS shall have a CD/DVD writer/reader and at least three USB 2.0 ports for back-up needs;
- the power supply for WS shall be redundant and fed from substation DC-center.

2.3 Software

The WS software structure is usually represented by following parts:

- operating system and essential WS software;
- data acquisition;
- database;
- user interface;
- real-time and online support.

The engineering design of WS software depends on Manufacturer, which shall ensure the needed WS functionality and meet the common requirements:

- the compatible operation system for WS software shall be Microsoft Windows XP Professional;
- full compliance to the communication standard IEC 60870-5-101/104;
- the control of switchgears will be performed only by implementation of principle “Select-before-execute”;
- external time synchronization using standardized protocol of the time synchronizing telegrams;
- the information objects in WS shall be regularly updated (correct polling time and intervals for different data types);
- the parameterizing software licence and tools for WS workstation shall belong to delivery;
- the non-updated objects shall be clearly indicated in WS.

2.4 Commissioning

At first, the commissioning WS shall be malware and virus free.

After that all informational objects defined in WS shall be tested “online”, during substation Site Acceptance Test (SAT).

3 Future

The TCP/IP technology causes great developing in all field of human application. The power transmission is not a exclusion.

If the substation telematics equipped with the RTU and the WS separately, the costs of supply, mounting, parameterization, commissioning and others works, needed for accomplishment of above mentioned devices, are proportionally higher than to build a substation without WS. On the one hand, decentralized telematics devices are fundamental advantage, but only in case of absolute independence, but on the other hand, the WS communicates directly with substation RTU, hence malfunctioned RTU causes failed communications with WS and accordingly - non-operation of the WS.

So, there are two variants of technical solution (see figure “Fig. 4”):

- realize the substation RTU with additional touch screen panel, where the last one is equipped with flash-memory based HDD for event database;
- realize the substation WS with implemented features of gateway (RTU). This WS is equipped with touch screen panel (flash-memory based HDD).

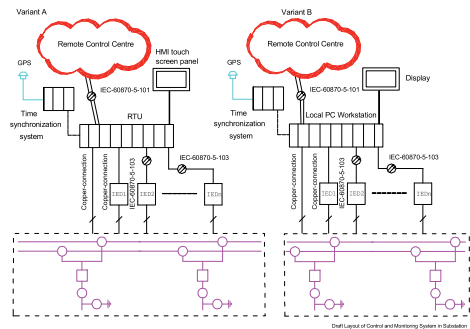


Fig. 4 Simplified structure of substation telematics with one unified RTU/WS device

4 Conclusions

The proposal solutions to integrate WS functionality into RTU or RTU functionality into WS are competitive and cost-effective solutions. There are no seen potent dangerous drawbacks. Concurrently the appropriated “combined” devices are already on the market for power engineering aim.

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Obstacles of substation telematics proper operation.

Igor Dmitrenko
Tallinn University of Technology
Elering OÜ
igor.dmitrenko@elering.ee

Abstract

The remote control and supervision of electrical power transmission system are the one of most efficient way how to ensure balanced electricity generating and consuming, how to take under control the interruption of power supply for consuming, how to prevent electrical hazard for people, how to operate all of substation circuit devices remotely, how to preclude Blackout etc. The local device, which gives such ability to realize all above-mentioned functions, is Remote Control Unit of substation. Now the Remote Control Unit is an inseparable substation part of remote control and supervision, as well as remote control centre or telecommunication path.

Keywords

Electrical power transmission system, Remote Control Unit (RTU), Supervisory Control And Data Acquisition (SCADA), Intelligent Electronic Device (IED), substation, telematics, relay protection, control, feedback, data transmission protocol (IEC 60870-5-101 Companion standard for basic telecontrol tasks, IEC 60870-5-103 Companion standard for the informative interface of protection equipment, IEC 60870-5-104 Network access for IEC 60870-5-101 using standard transport profiles).

1 Introduction

Elering OÜ (National Grid, Main Grid) is Estonian transmission system operator (TSO). Using 110–330 kV high-voltage power lines, it unites Estonia’s biggest power stations, distribution networks and corporate consumers in an integral energy system.

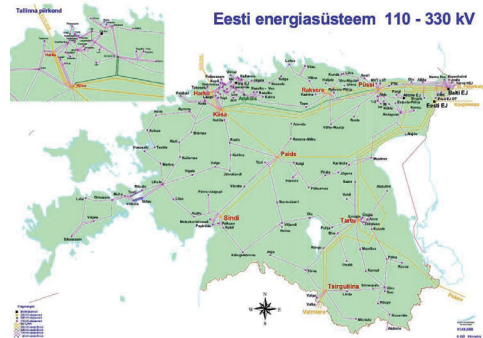


Fig. 1. Mapping of electrical power transmission system

The main functions of Elering OÜ are listed below:

1. transmitting electricity at voltages of 6–330 kV to distribution networks and corporate consumers;
2. developing and operating a 110–330 kV electrical power transmission network covering the whole of Estonia;
3. ensuring the reliability of Estonia’s electrical power system in conjunction with the power systems of the neighboring countries;
4. maintaining the capacity balance of the electrical power transmission system and managing the power system across Estonia in real time;
5. Ensuring the Estonian energy balance and operating the balance settlement for the balance providers.

The electrical power transmission system is a centrally controlled technical system including:

1. power stations;
2. consumers;
3. the electricity supply network between power stations and consumers together with its respective management-, telecommunication- and protective systems.

- a. transmission network;
- b. distribution network.

The physical processes of generating, transforming, transmitting, distributing and accumulating electricity take place and are managed in the electricity system. Estonian transmission system has a lot of different equipment, which could be divided into two sections:

1. different voltage level substation (one or more transformers, switching devices, protection relays, control devices, communication devices);
2. transmission lines (overhead lines, underground cables).

2 Overview of telematics for electrical power transmission system

The main parts of telemechanical control and supervisory for power grid are SCADA system, RTU, IED devices and communications paths.

The abbreviation SCADA (Control Centre) usually refers to centralized and highly IT-computerized systems, which monitor and control entire sites or some another, complicated systems spread out over large areas. All remote control actions, status supervision, getting measurements analyzing are performed via locally placed RTU-s.

The substation RTU is dedicated for adequate reaction on information objects (control, status, measurement messages), receiving them from side remotely connected to SCADA system. On the other side RTU shall be connected to the executing device, which should react on control action from SCADA system.

The Remote Terminal Unit (RTU) is located at the substations for collecting data (state information, alarms, measurements) from the substation to the Control Centre as well as for distribution of control commands from Control Centre to the substation.

Therefore to ensure reliability of substation RTU during its lifecycle and to parameterize it correctly according to SCADA operating needs, there are remote monitoring and control requirements for substation RTU. The above mentioned requirements specify substation RTU in following mode:

1. RTU operational area (functions, data transmission, time base, technical data, Electromagnetic and Environmental Compatibility etc.);
2. RTU hardware (modular topology, processor, I/O-, power supply modules etc.);
3. control and monitoring (control, state, measurement, event, alarms, indication);

4. time synchronizing;
5. compatibility and interoperability with SCADA
6. type of communication interface

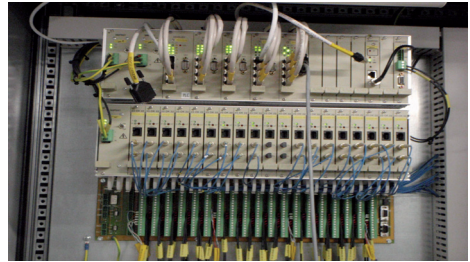


Fig. 1. The example of substation RTU

The primary equipments of substation should be connected to the IED device, which tasks are:

1. local control and monitoring function
2. protection function
3. providing of remote control and monitoring

On the next figure the primary equipment of substation is marked by pink and the secondary equipment is marked by blue colour.

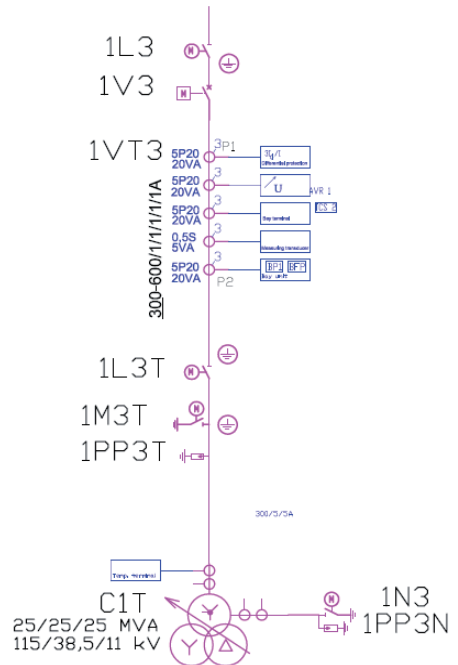


Fig. 2. Fragment of main electrical schema. 110 kV transformer bay

The IED device should be connected to RTU, which provides remote control operations and monitoring functions for SCADA system.

The substation has several of IED devices and they could be connected to the RTU by optics to avoid electromagnetic interferences, but copper connections are also possible.

All in the external telematics circuit defined devices and systems (SCADA-RTU-IED) shall be able to send and receive data information between each other without any restrictions or error at any time as it needs and executes all specified actions in correctly and in the right time.

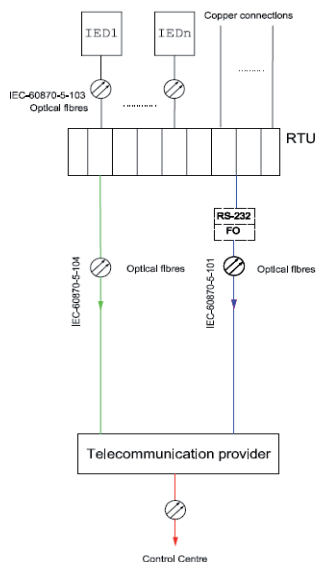


Fig. 3. Simplified structure of substation RTU communications

Mainly are three parts of telematics networks, which are divided depending on network location:

1. substation network (e.g. between RTU and IEDs)
2. telecommunication service provider network (e.g. power transmission lines)
3. Control Centre network (SCADA)

The general overview of type realizing for telematics communications is represented with following figure.

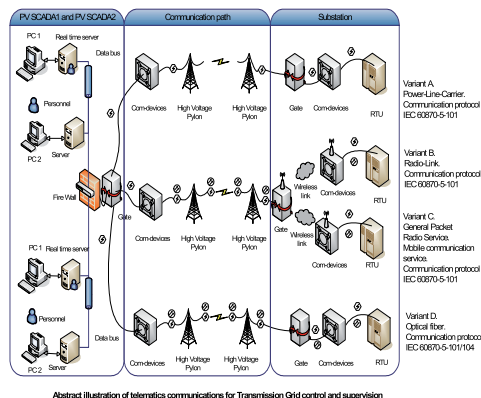


Fig. 4. Overview of data exchange communications in substation telematics

Actually the substation RTU is something similar as industrial controller, especially hardware, which may have:

1. digital input/output modules;
2. analog input/output modules;
3. optical modules;
4. processor module;
5. external communication ports.

As a matter of fact the last point brings the difference between RTU and controller, while RTU shall have communications with SCADA and IED devices using only internationally standardized data transmission protocols. Usually the controller producers realize the process communication working out vendor-oriented communication protocol.

Thus the only data transmission protocol IEC 60870-5-101/104 (SCADA network) and IEC 60870-5-103 (substation network) shall be used for connecting to the RTU, but for measurement transducers using some prevalent protocol (e.g. Modbus, Profibus) shall be chosen.

The operational measurements are also important for the Control Centre to control of primary equipment of power system. To have a full control on transmission network the measurement visualization should be locally and remotely performed.

The measurement transducer is the device that converts one form of signal to another, allowing its measurement or display to be made appropriate.

The measurement transducer is the device, which sends the measurement data to the SCADA using the RTU.

Those devices are able to provide voltage and current based measurements to RTU. Measurement

transducer uses the external DC power supply to operate.

The measurement transducer shall meet the specific accuracy requirements, which are harder for direct measurement than for calculated values (e.g. active and reactive power).

The substation measurement systems are divided into two fully independent groups like operational and commercial measurement systems.

So, first one is provided to establish control of emergency, technological and service activities (e.g. to check the voltage and current of the switched off power line). With appropriate use of operational measurements the substation equipment is adequately estimated (e.g. needs for activation of backup power supply to customer).

The second one, which is also enough important, is automatic commercial meter reading system (AMR), which is not a part of operative telematics.

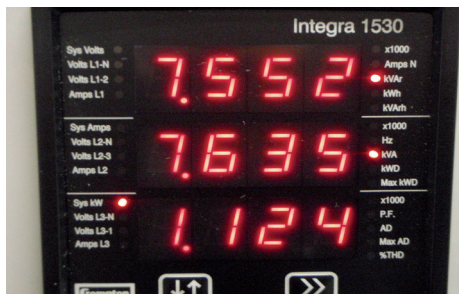


Fig. 5. Example of measurement transducer with 7-segment indication

Some examples of measurement transducer requirements:

1. the mentioned PC software, respective connection cable and possible RS-485/232 (or some other type) converter shall belong to delivery;
2. transducers for all bays shall have LCD display or 8-element indicator display equipped with background or direct illumination for local measurements. Transducers shall be placed into the relay cubicles so that measurements are visible without opening any door;
3. transducers shall be connected with three current phases directly to the measuring winding of the current transformer;
4. transducers shall be connected with three voltage phases directly to the measuring winding of the voltage transformer. The voltage circuits of the transducer shall be provided with their own MCB (miniature circuit breaker);
5. auxiliary supply for transducers shall be substation battery DC voltage. In one cubicle there shall be up to four transducers with one MCB of auxiliary supply.

The one of the important requirements is the time synchronizing of RTU and other IED devices in substation.

The purpose of substation GPS reference clock and time synchronizer (GPS device) is dedicated for correct real local time and date run in IED-s (incl. RTU). Due to operation of GPS system the transmitted signals from substation in SCADA system have always correct and synchronized time stamp.

Previously the time synchronizing was performed by SCADA remote control centre, in case of using only IEC 60870-5-101 between RTU and SCADA. Nowadays the GPS system shall be used in a substation for time synchronizing of all IED devices (incl. RTU).

So, the RTU is only one device, which sets up communication between the telematics upper and lower paths (substation and SCADA). So, it is the only local binding knot of the data exchanging from outside to inside and vice versa. Thus, the performance of RTU working should be without any mistake in RTU internal data transforming in both data shift direction.

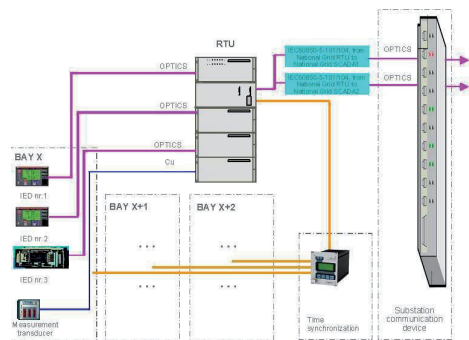


Fig. 6. Simplified structure of bay telematics

Thus, the all “participants” of telematics system are responsible for faultless working, while RTU can only receive and transmit those signals, which are accessible for interoperate and parameterized in RTU for its react. Additionally some logical functions shall be used in RTU like grouping of information objects.

3 Obstacles in telematics system

Before the system is maintained and commissioned, the telecommunication network should be planned taking into consideration some aspects, which definitively influences telematics technical solution.

The engineering is the first step for telematics set up to define the network type and the features of all telecommunication network components, which should physically and logically reckon and match to each other:

1. topology network (star, ring, fully reserved, tree, partial connections or mesh, bus)
2. the identical physical communication ability (voltage level, optical wave length,

optical cable plug etc.) for communicative devices

3. the logical interoperability of device communication interface (standardized data transmission protocol like IEC 60870-5-103)

So all of telematics “participant” devices should match to each other from hardware and software side like:

1. copper wiring, current/voltage rate compatible
2. optical fibres, same wave length inside the optical cabling, suitable type of plugs etc.
3. use of same open communication “language” (e.g. IEC 60870-5)

Concurrently three above mentioned points are sometimes the hindrance how to connect all telematics system devices together. In case of the mismatched interface the technical solution problem may be solved by using of additional converter-devices, which reduce the reliability of whole telematics system. The “open” communication languages are often used to ensure the transparency of telecommunication system, whereby the check for the problems and modification of existing telecommunication system could be easily carried out from independent (not from vendor side) specialists.

3.1 Communication compatibility

A few years ago the device ability of different manufacturer to telecommunicate using the international standardized protocol was anything else as successfully realized, because of unequal interpretation of the international communication protocol standard IEC 60870-5-103 by manufacturers. Thus a lot of the IEDs and RTUs could not telecommunicate between different vendor devices in spite of their label “IEC 60870-5-103 compliance”. Unfortunately the meeting the same situation is not a big infrequency even nowadays. The most adequate control of telecommunication suitability is to check the compliance from the international testing companies, which publicize compliance reports of devices from manufacturers of power energy area.

3.2 Time synchronization

The time synchronizing system does not stand out from similar inconveniences mentioned above. Every protection device and RTU should be time synchronized with required accuracy, but the way how to perform that is responsibility of device manufacturer. So, physical interface and time synchronizing mode varies vendor to vendor:

1. physical interface - D-Sub 9 pins, 2-pole plug, optical interface etc;
2. time synchronizing protocol – Irig-B, DCF77, GPS, time strings, 1 ppm, IEC

60870-5-101/103, IEEE1588 (Precise Time Protocol) etc.

The time synchronization device should be adapted to all IEDs and RTUs in the substation and most important is to follow identical time synchronizing mode excluding the individual solutions.

The IEDs need also interface for remote service communication, which is not a part of operative telematics.

The work, which defines the quality of device operation is the parameterizing of IEDs and RTUs. The parameterizing of IED (protection relay) includes several parameterize levels:

1. protection function (the essential purpose of protection relay);
2. logic (the additional non/standard logic in protection relay);
3. telemetric (the definition of information objects for RTU/SCADA).

The only point number three is directly bound with telematics. Whereby defined information objects for the Control Centre should be linked from previous parameterize levels. The main idea is to precisely define all addresses of information objects. In case of using IEC 60870-5-103 there are type identification and information number. Same numbers should be inserted into configuration of source and receiver devices (IED and RTU) to transmit the exact amount of information objects to the SCADA correctly.

3.3 RTU

The RTU parameterizing is to define the information objects of data transmission protocol (address, type etc.) exchanging them with SCADA system. One of the RTU tasks could be the ability to perform some logical time-uncritical functions. The RTU can be named as a repeater or converter for information sending from substation lower part (IEDs) to the Control Centre. As a rule the international data transmission protocol standards IEC 60870-5-101/104 are well known and often used in EU. Thus the almost all RTUs and SCADA systems manufactured in EU support above mentioned data transmission protocol standards. So, the protocol features and additional parameters should be set up in RTU for SCADA system. E.g. the standard IEC 60870-5-101 distinguishes information types like double command DC_NA, double point DP_TA/TB, single command SC_NA, single point SP_TA/TB etc. and their addresses. The information object address, type and data unit identifier elements should be defined correctly on both sides (RTU and SCADA system). Otherwise the collapse, malfunction or no-reaction situation may occur as a result of mismatched parameters of information object between RTU and SCADA system. The following figure shows double command, double point, single command, single point and floating point measurement, which are parameterized in RTU.

IEC Specific		Point Specific
Type	IEC addr	PointName
C_DC_NA	1	C1T 10kV VL 10155
C_DC_NA	2	C2T 10kV VL 10185
M_DP_TA	2001	C1T 10kV VL 10155
M_DP_TA	2002	C2T 10kV VL 10185
M_SP_TA	3001	Avarii 110kV
M_SP_TA	3002	Korratus 110kV
M_ME_NA	1001	C1T 10kV P
M_ME_NA	1002	C1T 10kV Q

Fig. 4. Properties of some IEC 60870-5-101 information objects

The configuration of telematics system is the most important, charge critical and herewith full of responsibility task of secondary equipment building work, which is vastly depending on co-operation between Client and Contractor (e.g. telematics device vendor). The main reason is having a continuous check of IED/RTU parameterize process and taking under control completed tasks by the on-site commissioning tests. Usually it is preliminary done in scope of supply firstly to avoid any incomprehensible. But there may be several modifications of offered telematics devices, therefore the final technical solution should be agreed again during the technical project phase.

3.4 Measurement transducer

The configuration of measurement transducer is not complicated, but the main difficulty is to define the right address and correct range of measurement in RTU. The most widely spread mode of communication between RTU and measurement transducer is the using as well the industrial protocols like Modbus or Profibus, as IEC 60870-5-103. If in third solution the star topology is appropriated, then Modbus and Profibus need for loop-connection. Thus, there are only possible to make a mistake with configuration during definition of information object address, dead band, threshold and also over measured rate, which should be calculated according to certain rule. But those errors are easy to discover and adjust. Sometimes it is time-consuming to match different vendor devices together (e.g. measurement transducer of X-manufacture and the RTU of Y-manufacture) despite the same communication protocol supporting.

3.5 Configuration of telematics device

The IEDs, RTUs and measurement transducers are digital devices, which have relevant parameterizing software. For the legal using of that software there is needed for the license code and sometimes for others accessories (e.g. digital license, hard lock). But if all software is delivered correctly, there is still no chance to keep calm for a long time. The reason of that is continuous development and improvement of substation telematics devices. The result is producing more and more as well free updates as upgrades for pay. If the configurations of telematics device are made by previous version of software, then it might not be more functional by newer one. The cause of such "surprise" can be older

operational system, weak main possessor or even the older hardware of device. Well the vendors try to avoid similar solution, which requires total modification of whole device from hardware and software, but there are still a lot of intricacies. Additionally the ability to download from telematics device is also enough important. Unfortunately not all of parameterizing fails could be downloaded from their "owners" (mostly concerning to RTUs). This drawback feature should be taken into consideration to ensure always the right backup parameterizing fails for the future.

After taking into operation of telematics, all of telematics device right documentation, manuals, current configuration/parameterization fails and them created software should be gather for Client archive. The holding of correct configuration/parameterization fails is especially important taking account of principle, that all telematics devices are system devices, thus modification of one telematics device configuration could influence on another devices, which could be also reparameterized to have a result effect. So, the Client should gather all of logically bound telematics device configuration/parameterization fails again after some possible improvement works in substation telecommunication system.

4 Conclusions

The planning, maintenance and commissioning of substation telematics are parts of complicated, full of reliability, needs for high technical competence work. The successful accomplishment is only possible with well preplanned Client ideology of substation telematics that means the Client should have telematics competent personnel (with "know-how" knowledge) and following the close co-operation between Client and Contractor. It is the reason, how the final target of project will meet the efficient technical solution avoiding a lot of misunderstandings. The Contractor best practice is to construct the telematics according to the Client requirements, to put Client attention on possible improper decision, to check done work carrying out as well the F.A.T as also S.A.T. with and without the Client. The main task of Client is to make relevant agreement of technical solution during the technical project level.

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Substation Telematics

Igor Dmitrenko
Tallinn University of Technology
OÜ Põhivõrk
igor.dmitrenko@pv.energia.ee

Abstract

The remote control and supervision of electrical power transmission system are the one of most efficient way how to ensure balanced electricity generating and consuming, how to take under control the interruption of power supply for consuming, how to prevent electrical hazard for people, how to operate all of substation circuit devices remotely, how to preclude Blackout etc. The local device, which gives such ability to realize all above-mentioned functions, is Remote Control Unit of substation. Now the Remote Control Unit is an inseparable substation part of remote control and supervision, as well as remote control centre or telecommunication path.

Keywords

Electrical power transmission system, Remote Control Unit (RTU), Supervisory Control And Data Acquisition (SCADA), Intelligent Electronic Device (IED), substation, telematics, relay protection, control, feedback, data transmission protocol (IEC 60870-5-101 Companion standard for basic telecontrol tasks, IEC 60870-5-103 Companion standard for the informative interface of protection equipment, IEC 60870-5-104 Network access for IEC 60870-5-101 using standard transport profiles).

1 Introduction

OÜ Põhivõrk (National Grid, Main Grid, Power Grid, electrical power transmission system) is Estonian transmission system operator (TSO). Using 110–330 kV high-voltage power lines, it unites Estonia’s biggest power stations, distribution networks and corporate consumers in an integral energy system [1].

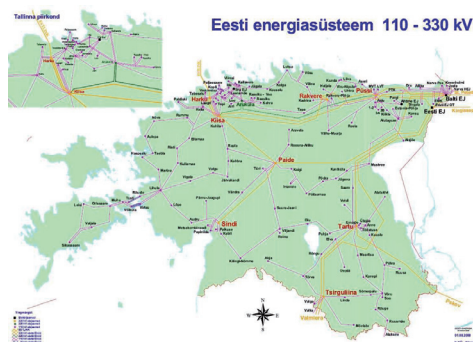


Fig. 1. Mapping of electrical power transmission system

The main functions of OÜ Põhivõrk are listed below:

1. transmitting electricity at voltages of 6–330 kV to distribution networks and corporate consumers;
2. developing and operating a 110–330 kV electrical power transmission network covering the whole of Estonia;
3. ensuring the reliability of Estonia’s electrical power system in conjunction with the power systems of the neighboring countries;
4. maintaining the capacity balance of the electrical power transmission system and managing the power system across Estonia in real time;
5. Ensuring the Estonian energy balance and operating the balance settlement for the balance providers.

The electrical power transmission system is a centrally controlled uniform technical system comprising:

1. power stations;
2. consumers;
3. the electricity supply network between power stations and consumers together with

its respective management-, telecommunication- and protective systems.

The physical processes of generating, transforming, transmitting, distributing and accumulating electricity take place and are managed in the electricity system. Estonian transmission system has a lot of different equipment, which could be divided into two sections:

1. different voltage level substation (one or more transformers, switching devices, protection relays, control devices, communication devices);
2. transmission lines (overhead lines, underground cables).

The amount in substations using equipment is shown below [2].

	2004/2005	2005/2006	2006/2007	2007/2008
Number of substations	142	144	144	144
110 kV substations	133	133	133	133
220 kV substations	1	1	1	1
330 kV substations	8	10	10	10
Length of lines, km	5,193	4,991	5,212	5,206
35 kV underground cables	54	54	53	53
35 kV overhead lines	8	8	7	7
110 kV underground cables	25	37	32	32
110 kV overhead lines	3,370	3,412	3,420	3,414
220 kV overhead lines	439	184	184	184
330 kV overhead lines	1,298	1,298	1,515	1,515

Fig. 2. Equipment of electrical power transmission system

OÜ Põhivõrk has brought in a process management system in order to run our work. Our main function is energy transmission and therefore we outsource support services (personnel management, legal services, real estate management, maintenance services and the switching in substations and power lines etc.) to other companies.

The OÜ Põhivõrk management system complies with the requirements of the ISO 9001:2000 quality management, ISO 14001:2004 environmental management and OHSAS 18001:2007 occupational health and safety management standards.

We use the balanced scorecard method to set new corporate goals, ascertain our critical success factors and establish the means for measuring success.

The OÜ Põhivõrk is one unit of Eesti Energia Company [3].

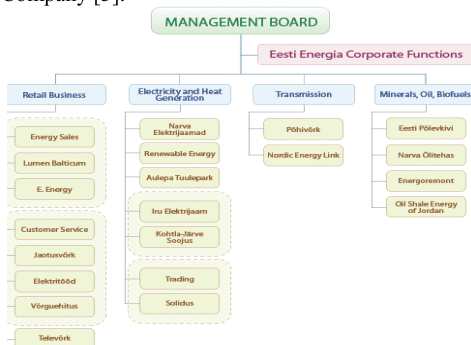


Fig. 3. Position of OÜ Põhivõrk in structure of Eesti Energia Company

In summer 2009 the electrical power transmission company OÜ Põhivõrk is performing changing of the Logo and Name. The new Re-brand Name will be ELERING (ELEctricity plus RING).

2 Overview of telematics for electrical power transmission system

The telematics plays the major role in nowadays power energy systems. Simon Nora and Alain Minc began the history of telematics term with the report 1978 titled as *L'Informatisation de la société*. In their report Simon Nora and Alain Minc compare the expectations of telematics with electricity: *“Today, any consumer of electricity can instantly obtain the electric power he needs without worrying about where it comes from or how much it costs. There is every reason to believe that the same will be true in the future of telematics”*.

Unfortunately the derivation of term telematics is still arguable, but the term determination made by academic Dennis Foy became widespread over the world and it is from the Latin tele- (far off) and Greek -matos (machinery).

After 29 years, when the report was published, some in the document mentioned perspectives of telematics were become today a inalienable reality. Actually the different telematics systems are inculcated in almost all area of human activity: military, public, society, education, medicine, electricity production and consumption etc.

There no information about the first telematics system, while the most efficacious telematics systems were in use by military forces and they were completely confidential, thus held in secret. After start to use telematics for civil purposes, the interconnection of large power grids in the Midwestern and the Southern U.S. (1962) could be handled as the largest first synchronized system in the world using the telematics conception.

The main parts of telemechanical control and supervisory for power grid are SCADA, RTU, IED devices and communications paths. What are they standing for?

The term SCADA usually refers to centralized and highly IT-computerized systems, which monitor and control entire sites or some another, complicated systems spread out over large areas. All remote control actions, status supervision, getting measurements analyzing are performed via locally placed RTU-s.

Generally there are three principle directions of process and using the SCADA systems:

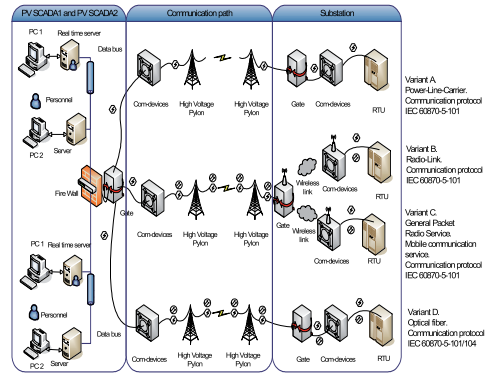
1. solid (private control network; closed system with no communication with extraneous foreign networks);
2. decentralized (LAN network; not standardized communication protocols; each alone standing unit could link with another one, being in one system together, but as a matter of fact, each unit is responsible for only its own particular task);
3. centralized (WAN, LAN networks; open standard).

The RTU is installed in a substation electronic device, which is responsible for adequate reaction on information objects (control, status, measurement messages), receiving them from side remotely connected to SCADA system. On the other side RTU shall be connected to the executing device, which could physically perform required action from SCADA system.

As a rule, the name of those devices, which are communicating directly with executing devices (circuit breaker, disconnector etc.), is Intelligent Electronic Devices (IED). For aim to exchange information between RTU and IED (also between IED and SCADA), the last one shall be connected to the RTU.

All in the external telematics circuit defined devices and systems (SCADA-RTU-IED) shall be able to send and receive information between each other without any restrictions or error at any time as it needs and execute all specified actions in correctly and in the right time. Taking into consideration already brought up conditions, the communication paths and links with special requirements shall be built up for that target.

There are three parts of telematics communications, which are divided depending on communication location (substation, electrical power transmission part, SCADA) data transport way (high-voltage overhead lines, high-voltage underground cables, optical cables, low-current cables, wireless communication or PLC-technology) and types of IEC 60870-5 data transmission protocols. The general division of type realizing for telematics communications is represented with following figure [1].



Abstract illustration of telematics communications for Transmission Grid control and supervision

Fig. 1. Overview of data exchange communications in substation telematics

Because of the RTU independent connections to IED devices and SCADA, the substation RTU is the only one device, which controls data flow between SCADA and IED devices. A substation has several of IED devices and they could be connected to the RTU principally by optics, but copper connections are also possible. How many IED devices should communicate directly with RTU?

The figure below illustrates it [2] (The IED devices marked in blue rectangle with catchword *terminal, protection, regulator, unit, and centre*. The measurement transducer marks with *transducer*. It is obligatory to connect them all to RTU for data exchanging between substation and the SCADA).

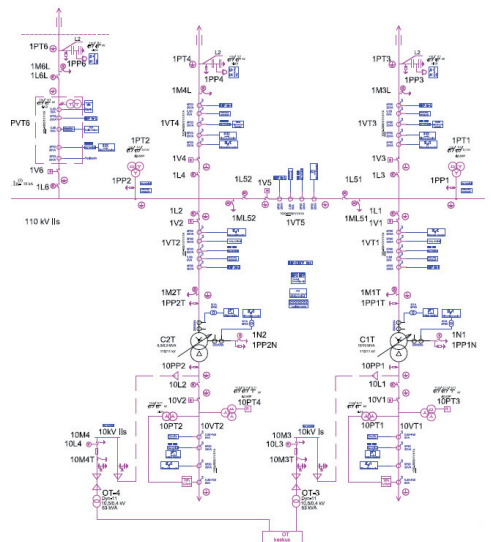


Fig. 2. Fragment of main electrical schema. 110 kV substation with protection relays

On the figure [3] is shown an example of only 110 kV transformer bay IED devices. There are some explanations of primary devices:

1. 1L1 disconnector;
2. 1V1 circuit breaker;
3. 1VT1 current transformers;
4. 1MIT earthing switch
5. 1N1 transformer neutral earthing switch
6. 1PP1T, 10PP1, 1PP1N surge arresters
7. CIT transformer

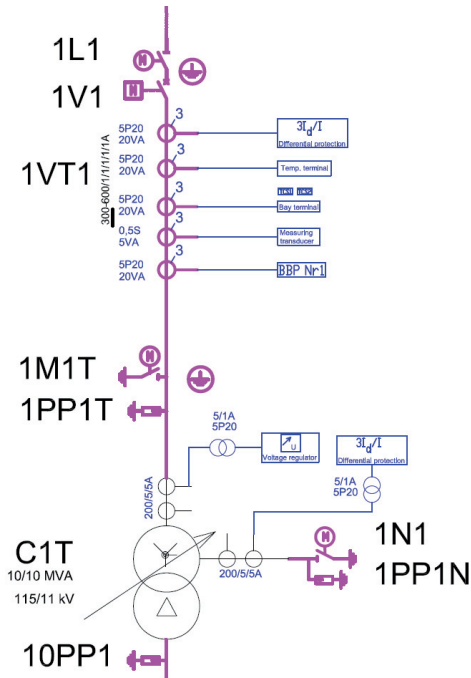


Fig. 3. Fragment of main electrical schema. 110 kV transformer bay

3 Requirements to substation RTU

Remote Terminal Units (RTU-s) are located at the substations for collecting data (state information, alarms, measurements) from the power system to the control centre as well as for controlling the process by forwarding remote commands to the power system.

Therefore to ensure maximum uninterrupted functionality of substation RTU during lifetime and to parameterize it correctly according to SCADA operating needs of Main Grid, there are remote monitoring and control requirements enforced by OÜ Põhivõrk for substation RTU. The above named requirements specify substation RTU in following mode:

1. RTU operational area (functions, data transmission, time base, technical data, Electromagnetic and Environmental Compatibility etc.);
2. RTU hardware (modular topology, processor, I/O-, power supply modules etc.);

3. control and monitoring (control, state, measurement, event, alarms, indication);
4. time synchronizing;
5. factory tests;
6. compatibility and interoperability with SCADA.

For example here are some features of RTU they should be:

1. The RTU must be capable of communicating with the master stations at all speeds between 1200 bps and 19200 bps.;
2. It shall be possible to connect IED-s of different manufacturers to the RTU using serial/optical interface (station communication bus) and EVS-EN 60870-5-103 (IEC 60870-5-103 based) communication protocol;
3. The EVS-EN 60870-5-101 addresses in RTU software shall be selectable with no limitations, e.g. it shall be possible to assign different object addresses for different master stations;
4. RTU real time clock, DC converter from the station batteries (220 V DC or 110 V DC) to logic voltages (for power supply), possible I/O modules and communication modules.

Actually the substation RTU is something similar as industrial controller, especially hardware, which may have:

1. digital input/output modules;
2. analog input/output modules;
3. optical modules;
4. processor module;
5. external communication ports.

In fact the last point brings the difference between RTU and controller, while RTU shall have communications with SCADA and IED devices using only internationally standardized data transmission protocols, whereas controller producers realize it working out some manufacturer oriented private communication protocol.

Thus the only data transmission protocol IEC 60870-5-101/104 (SCADA) and IEC 60870-5-103 (IED devices) shall be used for connecting to the RTU, but for measurement transducers some prevalent protocol (in use of different independent manufactures, e.g. Modbus RTU) shall be chosen.

The next figure [4] characterizes RTU connections.

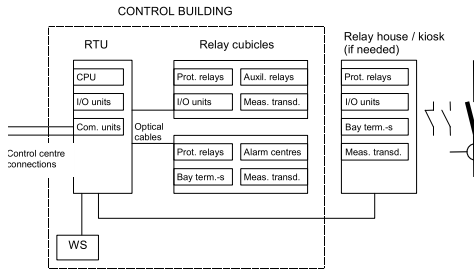


Fig. 4. Structure of communications between RTU and different devices

IEC 60870-5-101 is an international standard prepared by IEC TC57 (International Electrotechnical Commission Technical Committee for power systems management and associated information exchange). This uses standard asynchronous serial tele-control channel interface between data terminal equipment (converts user data into signals and vice versa) and data circuit-terminating equipment (signal coding, ready to transmit via Com-interface).

IEC 60870-5-104 protocol is an extension of IEC 60870-5-101 protocol with the changes in transport, network, link and physical layer services to use the network. The standard uses an open TCP/IP interface to network to have connections with the LAN and WAN.

IEC 60870-5-103 is a standard prepared by IEC TC57. It defines a standard that enables interoperability between protection equipment and devices of a control system in a substation. The device compatible with this standard can send the information using two methods for data transfer - either using the explicitly specified application service data units (ASDU) or using generic services for transmission of all the possible information. The standard supports some specific protection functions and provides the vendor a facility to incorporate its own protective functions on so called private data ranges.

The simplified principle of using IEC 60870-5 data transmission protocols in a substation presents in figure [5].

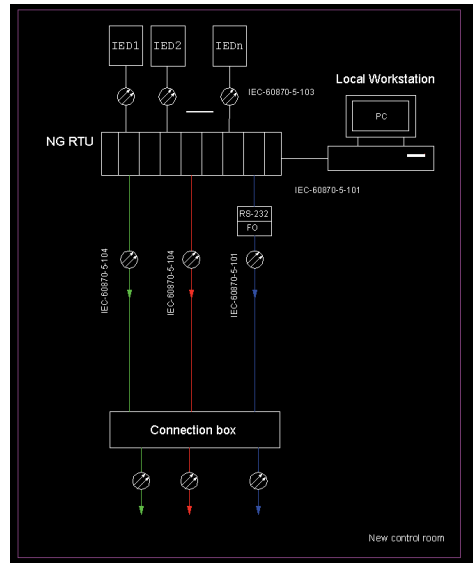


Fig. 5. Simplified structure of substation RTU communications

The most important activity by putting the RTU into operation is to define the information objects of data transmission protocol IEC 60870-5-101/104 (address, type etc.). It shall be always tested with SCADA remote control centre before commissioning of the substation RTU [6].

IEC Specific		Point Specific
Type	IEC addr	PointName
C_DC_NA	1	C1T 10kV VL 10155
C_DC_NA	2	C2T 10kV VL 10185
M_DP_TA	2001	C1T 10kV VL 10155
M_DP_TA	2002	C2T 10kV VL 10185
M_SP_TA	3001	Avarii 110kV
M_SP_TA	3002	KorratuS 110kV
M_ME_NA	1001	C1T 10kV P
M_ME_NA	1002	C1T 10kV Q

Fig. 6. Properties of some information objects

The one of the important requirements is the time synchronizing of RTU and other IED devices of substation.

The purpose of GPS reference clock and time synchronizer (GPS device) in the substation is time synchronization for correct real local simultaneous time and date run in IED-s (... all intelligent electronic devices, incl. RTU). Due to usability of GPS device the transmitted signals from slave IED-s to master IED (RTU) have correct and synchronized time stamp.

Previously the time synchronizing could be performed by SCADA remote control centre, in true only in case of using IEC 60870-5-101 between RTU and SCADA. Now the GPS local system shall be used in a substation for time synchronizing of all IED devices (incl. RTU).

4 Conclusions

Although the telematics offers a lot of possibilities regarding electrical power transmission control and supervision, the human factor remains by building up and adjustment of communications as between the RTU and SCADA remote control centre, as also between the RTU and IED devices. This so called *human factor* could cause mistakes with RTU parameterizing, IEC information object addressing etc. That's why the efficient inspection shall be always made within co-working of different level RTU and SCADA specialists.

Future. The data transmission protocols IEC 60870-5 are reliable and recommended to use them in field of power generation, distribution and consuming. But it needs more often to be able to establish communication between some IED devices just for exchanging information to solve their tasks. Regrettably the data transmission protocols IEC 60870-5 do not offer such ability as standard solution. Even more and more manufactures are thinking about costs reduction at the substation. For example there could be refused from traditional

copper cabling in switchyard replacing it with optical cables. How could primary devices communicate with IED devices, RTU and eventually with SCADA remote control centre? The answer is new protocol IEC 61850.

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[QUEST.] Mets,I. Example of Quotation Questionnaire to evaluate the equipment of non-conventional measuring.

Quotation Questionnaire for the non-conventional measuring equipment

Table 1.1 Example of Quotation Questionnaire for NCIT

GENERAL DATA FOR MERGING UNIT AND ACCESORIES		
Manufacturer		
Type designation		
Total number of merging units		
Accordance to the standards and standard certification, details	EVS-EN 60044-1	<input type="checkbox"/> Yes <input type="checkbox"/> No
	EVS-EN 60044-2	<input type="checkbox"/> Yes <input type="checkbox"/> No
	EVS-EN 60044-6	<input type="checkbox"/> Yes <input type="checkbox"/> No
	EVS-EN 60044-7	<input type="checkbox"/> Yes <input type="checkbox"/> No
	EVS-EN 60044-8	<input type="checkbox"/> Yes <input type="checkbox"/> No
	IEC 61869	<input type="checkbox"/> Yes <input type="checkbox"/> No
	IEC 61850-9-2LE	<input type="checkbox"/> Yes <input type="checkbox"/> No
	IEC 61850-9-1	<input type="checkbox"/> Yes <input type="checkbox"/> No
IEEE 1588	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Total number of digital inputs		
Functions of digital inputs		
Type and performance of digital input connections		
Total number of optical digital outputs (IEC 61850-9-2)		
Wave length of IEC 61850-9-2 optical interface		
Functions of digital outputs		
Type and performance of digital output connections		
Type and performance of digital input		
Total number of independent analog inputs		
Type and performance of primary sensing elements		
Maximum length of optical cabling to primary sensing element		
Type of temperature compensation		
Total number of independent (HEA - 1 A/5 A) high energy analog outputs		
Type and performance of independent (HEA -1 A or 5 A) high energy analog output		

Total number of independent (LEA – 200 mV) low energy analog outputs		
Total number of independent voltage analog output (100 or 220 V)		
Type and performance of independent (LEA – 200 mV) low energy analog output		
Output rated frequency		Hz
Output rated current I_N		A
Output rated voltage U_N		V
Rated burden of each analog output	<input type="checkbox"/>	VA
Rated burden of each analog output	<input type="checkbox"/>	VA
Input rated frequency		Hz
Input rated current I_N		A
Input rated voltage U_N		V
Rated burden of each analog input	<input type="checkbox"/>	VA
Rated burden of each analog input	<input type="checkbox"/>	VA
Auxiliary DC voltage		V
Type and performance of independent voltage analog output (100 or 220 V)	<input type="checkbox"/>	V
Hot-standby redundancy of power supply modules	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Hot-standby redundancy of processor modules	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Hot-standby redundancy of process bus outputs	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Number of measurement value samples for protection		
Number of measurement value samples for power quality		
Self-monitoring of digital inputs	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Self-monitoring of digital outputs	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Self-monitoring of analog inputs	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Self-monitoring of analog outputs	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Self-adjustment of laser power	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Type and performance of digital output (process bus) interface		
Separate TCP/IP port for PC connection	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Time accuracy of internal clock (oscillator) by external time		

synchronization		
Time synchronization of MU - pulse per second	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Time synchronization of MU – PTP (type)	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Ambient operating temperature range (°C)	<input type="checkbox"/>	
Maximum error of digital output (process bus) depending on ambient operating temperature		
Maximum error of 1 A/5 A analog output depending on ambient operating temperature		
Accuracy class 0,2S when secondary burden is any value from 0 % and 120 % of the rated burden	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Accuracy class 0,5 when secondary burden is any value from 0 % and 120 % of the rated burden	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Accuracy of current measuring		%
Accuracy of voltage measuring		%
Accuracy of active power measuring		%
Accuracy of reactive power measuring		%
Accuracy of frequency		%
Frequency bandwidth	-	Hz

**DISSERTATIONS DEFENDED AT
TALLINN UNIVERSITY OF TECHNOLOGY ON
*POWER ENGINEERING, ELECTRICAL ENGINEERING, MINING
ENGINEERING***

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