U.P.B. Sci. Bull., Series C, Vol. 83, Iss. 3, 2021 ISSN 2286-3540

MIGRATION TO MODERN DISTRIBUTED CONTROL SYSTEMS IN ELECTRIC POWER SUBSTATIONS: INTEGRATION VS. REPLACEMENT

Danut Adrian POSTOVEI[1], Constantin BULAC[2]

This article discusses two migration strategies to modern Distribution Control Systems, one approach is to save as much as possible the past investment by integrating and upgrading the old automation equipment and the software, and the other is to deliver a completely new solution with up-to-date technology. The purpose of this paper is to illustrate the gain and the drawback when choosing one strategy or the other. Other goal is to illustrate the needs of migration to fully IEC 61850 standard as path for transition towards digital substations.

Keywords: DCS, SCADA, BCU, IED, RTU, IEC61850, migration.

Abbreviations

DCS	Distributed Control System
SCADA	Supervisory Control and Data Acquisition
IED	Intelligent Electronic Device
GOOSE	Generic Object-Oriented Substation Events
TCP/IP	Transmission Control Protocol/Internet Protocol
BCU	Bay Controller Unit
RTU	Remote Terminal Unit
HMI	Human Machine Interface
PRP	Parallel Redundancy Protocol
RSTP	Rapid Spanning Tree Protocol
NCC	National Control Center
LAN	Local Area Network
FE	Front End (SCADA Master Unit)
EWS	Engineering Working Station
I/O	Input / Output

1. Introduction

The modern DCSs evolved into a flexible and scalable automation solutions which make them mandatory in the actual competitive energy business

[1] PhD student, Dept. of Power Engineering Systems, University POLITEHNICA of Bucharest, Romania, e-mail: postovei@yahoo.com.
[2] Prof., Dept. of Power Engineering Systems, University POLITEHNICA of Bucharest, Romania, e-mail: cbulac@yahoo.com.

environment. Comparing to PLCs and traditional DCSs, the modern DCSs are designed to provide automation solution in a safe, reliable, and cost-effectively manner.

The innovations of Information and Communication Technology applied for DCS and SCADA systems overcome the geographical barriers and made the remote monitoring and control an easy task [1].

Although modern DCSs continue to provide basic functions, just as traditional ones, namely monitoring and controlling of a large volume of inputs / outputs, they have evolved and designed to interconnect all monitoring and control equipment, ensuring full visibility of all data at the central level, usually in the power plant / substation control room [2]. Over the years, the hardware, software, and networks have become increasingly sophisticated but with few exceptions, control is still done in the field controller (IED).

A successful modern DCS migration depends on having a detailed, complete, and accurate picture of the process facility to provide all technical means for accurate monitoring and process control, reliable protection system and optimal dataflow to the National Control Center. The system design becomes the most important part of the project which can make or break it.

Nowadays, a lot of electric power transmission and distribution substations are managed by DCSs, implemented intensively especially over the past 15 years. Unfortunately, since the DCSs were not implemented simultaneously, the utilities operators are facing the issues of operating with different technologies, many of them being already obsolete and need upgrade or replacement even if their life cycle is not over.

Considering the tradeoff between investments and benefits, the mix of different technologies provides a balance while a completely new system offers the ground for interoperability and easy moving to the next migration milestone, the digital substations. As the substation communication architecture is based on hybrid LANs [3] with several communication protocols, the advantages and disadvantages of the implemented architecture should be the main objective which in fact represent the biggest challenge when migrating to a modern DCS.

The main goal of this article is to present an optimal design and functional solutions for both integration or replacement of the old system, considering the customer requirements, international and customer applicable norms, budget constraint, hardware and software limitations, cybersecurity, and the impact of the monitored and controlled process for extension and future growth.

2. Methods and Materials

2.1. DCS vs. SCADA

The best automation solution to monitor and control a process, specifically an electrical power substation is a DCS. The evolution and complexity of DCSs has greatly diminished the difference from a SCADA system. However, some features differentiate them, as shown in the Table 1.

Table 1

Comparison between DCS and SCADA systems

DCS	SCADA
Manage operations in a single location, plant, or substation.	Manage applications that are spread across a wide geographical location.
Advanced monitoring and control capabilities of the single location, plant, or substation.	Interconnects multiple RTUs, DCSs or simple PLC controllers.
It is a process state driven, oriented towards the technological process, receive, and send data to the distributed process controllers.	It is an event driven system, oriented towards data collection, and its central station usually "stands" over simple RTUs or complex DCS.
Uses a network to interconnect sensors, controllers, and actuators.	Cannot perform advanced process control techniques by its own. Supervision of the process. mainly of changing primary equipment position and set points of automations.
It is more integrated in the process and can perform high-end automation tasks.	It is bigger than a DCS and more flexible.

Currently, according to the ANRE report for 2019, the monitoring and control at the SCADA central level of the electrical power substations in the portfolio of the transmission and distribution operators, Transelectrica SA and the Electrica SA, are presented in Table 2.

Table 2

Current substations integration in SCADA systems (Romania) [4]

Items	Transmission Operator (Transelctrica)	Distribution Operator (Electrica)
Total substations / cells (feeders)	81 / 630	6.500 / 35.000
Total SCADA datapoints	> 35.500	> 122.000
SCADA platform	e-Terra (AREVA France)	SCATEX (Efacec Portugal)
37 x Substations 400 kV	98%	---
40 x Substations 220 kV	95%	---
66/99 x Substation 110 kV	95%	80%
590 x PA/PT (transformer points)	---	6%
Remote Reclosers /Disconnectors	---	530 / 1.070
Primary high voltage equipment	6.500	4.600
Loads (direct consumers)	9	13.954
Switches	4.410	62.022
Shunt reactors / Capacitor banks	17	106

Power transformers	149	106
Generators and network equivalents	1.854	273
Digital Inputs	17.040	76.560
Digital Outputs	9.940	21.800
Analogues	8.520	24.000

2.2. The Distributed Control System concept

A Distributed Control System, with a typical architecture presented in Fig. 1, means a monitoring and control system for an industrial process, in which the monitoring and control elements are distributed throughout the plant [5]. Although the hardware part of the DCS, due to specific characteristics of each controller, is perceived as a multitude of autonomous entities, the software platform that manages them makes the whole process to be perceived as a single and coherent system. The architecture is opposed to a non-distributed control system that uses a single controller located in the system central location of the serviced installation.

Practically, the DCS software platform is designed to centralize all the network devices that are distributed throughout the entire plant, allowing central control, monitoring, and reporting of each individual component and process. The above-mentioned characteristics along with redundancy capability make the DCS a high availability and reliability system, able to control complex facilities and technological processes such thermal, nuclear, hydro, oil refinery and electric power substations as well.

A DCS is oriented towards the technological process, being able to receive and send data to the controllers distributed in the controlled installation, while SCADA is oriented towards data collection, and its central station usually "stands" over simple RTUs or over the remote DCSs.

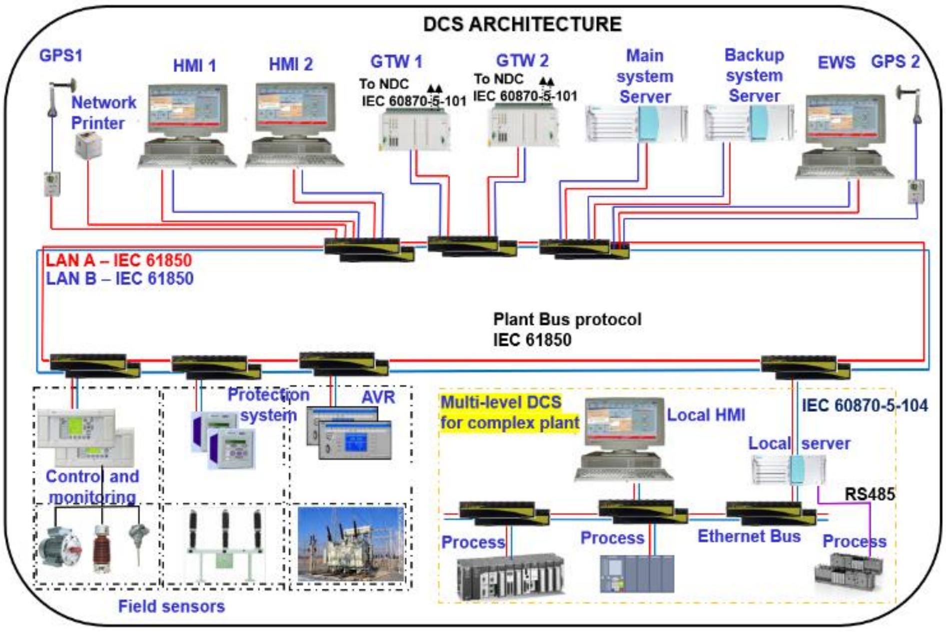

Fig. 1.Distributed Control System Architecture (adapted from [5])

As presented in Fig. 1, a DCS consists mainly in three basic components: Main/Backup Server with the role of a supervisory computers to collect and centralized the process data and provide the HMI interface, field controllers (IEDs) with the associated field sensors and control elements and a communications network.

The modern DCS concept improves system reliability and decreases installation costs by placing the control functions near the field process but keeping centralized remote monitoring and supervision features. Taking into consideration the other characteristics such flexibility and scalability, a modern DCS can handle various automation processes from a small to a very large one. In the case of substations retrofitting an optimal solution is represented by an implementation of a multi-level DCS architecture.

Of course, there is no perfect scenario regarding the integration of an existing DCS into a new one or to operate separately the two systems. Depending on the technological differences between the two systems, each situation must be analyzed separately.

2.3. DCS communication architecture

A DCS availability or network redundancy is directly associated with overall plant or controlled technological minimal interruption, as an essential requirement for the continuous monitoring and safe control.

Currently, the most common communication architectures for DCSs used in electric power substations are represented by a mixed combination of “Link Aggregate" and RSTP, or "Link Aggregate" and PRP [6].

The term "Link Aggregate" refers to how to connect multiple network links in parallel, to increase the transfer capacity or, more importantly, to see a DCS ensuring redundancy in case of one communication link failure.

The RSTP protocol prevents the problem of loops in the communications network by forming a logical tree network that includes all the switches in the network, thus ensuring that certain network connections are put in a standby state, so that there is no traffic data through that connection, thus breaking any physical loop in the network.

The PRP protocol offers uninterrupted communication redundancy, with an error failure time of 0ms required for high-speed critical functions. The “sender” uses two independent network interfaces that transmit the same data simultaneously, and the “receiver” uses the first data packet and rejects the second one. If only one data packet has been received, the receiver interprets that a fault has appeared on the other communication channel.

In case of limited budget implementation, RSTP is the right choice being a protocol supported by most industrial devices. RSTP is not recommended for very complex DCS architectures and interoperability with proprietary protocols, or in the situation where the recovery time of communication failure is essential, due to the network high latency.

PRP can run on two independent networks and therefore can perform hot swap switching of network devices, regardless of network topology: star, ring or mixed, performing communication recovery in 0ms (bump less), a function achieved by continuous monitoring of network devices. This aspect is achieved by doubling the network interfaces and the copper or fiber optic cable connections, which leads to a high cost with the implementation of the DCS network.

Devices with only one Ethernet interface (printers, laptops, GPS) can be connected just to one of the PRP LAN. In PRP architecture the switches must handle Jumbo-Ethernet frames and the linkage of the two networks could leads to breakdown of the communication.

The use of the combination of the two standards ensures an N-1 redundancy, having the network return time within a range of seconds.

2.4. Intelligent Electronic Device

The generation, transmission, and distribution of power needs 24/7 monitoring and control to maintain the grid reliable and uninterrupted power supply. In this respect, the flexibility in integration and interoperability of IEDs over RTUs lead to a migration from the classic RTUs to IEDs in all new DCS implementations.

IEDs (Intelligent Electronic Device) are microprocessor-based equipment with continuous self-supervision, used in the electric power system for monitoring, controlling and protection functions. There are many types of IEDs used in a substation network, such as BCU (Bay Control Units) to monitor and control of disconnectors and circuit breakers, protection relays to detect faults, switch off and isolate selectively the protected equipment from the power grid so that the consequences of the defect are limited as much as possible [7], AVR (Automatic Voltage Regulator), metering units (MU), power transformer monitoring (Qualitrol), ATS (Automatic Switch Transfer), etc.

2.5. IEC 61850 communication protocol

Since its first release in 2003, IEC61850 was widely adopted by all the DCS manufacturers and nowadays all the architectures rely on this standard. It is a protocol based on Ethernet networking and designed to perform protection functions, monitoring, control, and metering functions. The IEC61850 standard provides four types of communication services that allow data exchange between devices connected to the same network, such as:

- Client–Server based on TCP/IP MMS (Manufacturing Messaging Specification), connection-oriented protocol. DCS/SCADA systems use MMS Client/Server communication to perform the monitoring and control functions. Applications from DCS servers to IEDs, like protection relay or BCU using the Client/Server services are not time critical. The acceptable latency of Client/Server communication is in the range of 100-200ms, with the maximum delivery time of 800ms and a maximum recovery time of 400ms [8]. TCP/IP mechanisms also care for repeating lost frames and the right ordering in the receive buffers.

- GOOSE (Generic Object-Oriented Substation Event) protocol, directly on Layer 2, multicast, repetition mechanism, for the fast transmission of data over the network. Even if the GOOSE messages have no destination address, by design they are restricted to stay within a LAN and do pass not pass-through routers to other LAN [9].

Applications between IEDs like interlocking signals and trip messages use the GOOSE service based on a connectionless one to many – the multicast service. Goose service has a maximum delivery time of 8ms and a maximum recovery time of 4 milliseconds. IEC 61850 standard distinguishes between two types of reporting: buffered reporting and unbuffered reports. in the first case the reports are buffered by the server in case a connection to the client is interrupted and in the second case the Server just "throws" the report to the communications network without knowing if the message get to the required Clients, and if the communication is down the message will be lost.

- Sampled Values (SV) protocol, directly on Layer 2, multicast, data stream, for the fast transmission of analogue values over the network. SV has a maximum delivery time of 2ms and a zero-recovery time (bump less redundancy).
- Basic services like NTP, SNMP, HTML are not time critical. Those services have a maximum delivery time of 500ms and a recovery time of 300ms.

The GOOSE and SV protocols are used for critical high-speed functions such as station interlocking, protection tripping and blocking schemes and other station-related protection devices and control functions [8]. Protection devices are required to safeguard the expensive power equipment and transmission lines against overloads and damages [10].

In the analyzed study case presented in Fig. 2, the common language between IEDs, system servers and Gateways and RTU is represented by IEC61850 protocol [11].

2.6. IEC 60870–5–104 communication protocol

It is a Master-Slave protocol, which provides a communication profile for monitoring and control between two automation systems.

The IEC 60870–5–104 specification combines the application layer of IEC 60870-5-101 [12] and the transport functions provided by a TCP/IP (Transmission Control Protocol/Internet Protocol) [13].

In the architecture presented in Fig. 2, IEC 60870–5–104 protocol is used to exchange data between Gateway and NCC, where the NCC is the Master/Controlling station and HV-DCS is the Slave/Controlled station.

Being a multilevel architecture, the HV-DCS Gateway acts as a Master and MV-DCS RTU as a Slave. It is observed that the Gateway play both role, Master and Slave. In Fig. 2, HV-DCS under IEC 60870–5–104 is either a controlling station or a controlled station.

2.7. Ethernet protocol

It is defined by IEEE 802.3. standard and is still the most popular set of protocols for the Physical and Data Link layers. Ethernet protocol is preferred in electric power substations for its data transfer quality, high speed, security, and reliability. Even if Ethernet operate at different speeds and use different types of media, all the versions are compatible with each other being able to communicate in the same network through interconnection devices such as bridges, hubs, and switches.

2.8. Dual Homing (Dual Link)

It is a network redundancy protocol with recovery time, having two active links, one is sending and the other one is in hot stand-by, sending link changes if one link is down. The switch over time is < 5ms. This type of redundancy is applicable for all industrial computers, such System servers, Gateways, EWS, HMI and RTU in case of 20 kV network.

This solution also comes with some limitations such supervision of only directly linked connections and broken connections in the upper or lower network will be not detected by the device.

3. Key experiments

The present work intends to present some migration aspects, advantages, disadvantages, and recommendations related to different DCS migration scenarios for two similar substations, with the same scope of better visibility of the running process and more connectivity of the substations in the power grid network.

The two migration approaches in this paper are:

a) **Integration**: is a stepwise migration of the existing DCS into the new one, even having the possibility of operating in parallel the old and the new systems.

b) **Replacement:** remove the existing automation system and replace it with a completely new DCS.

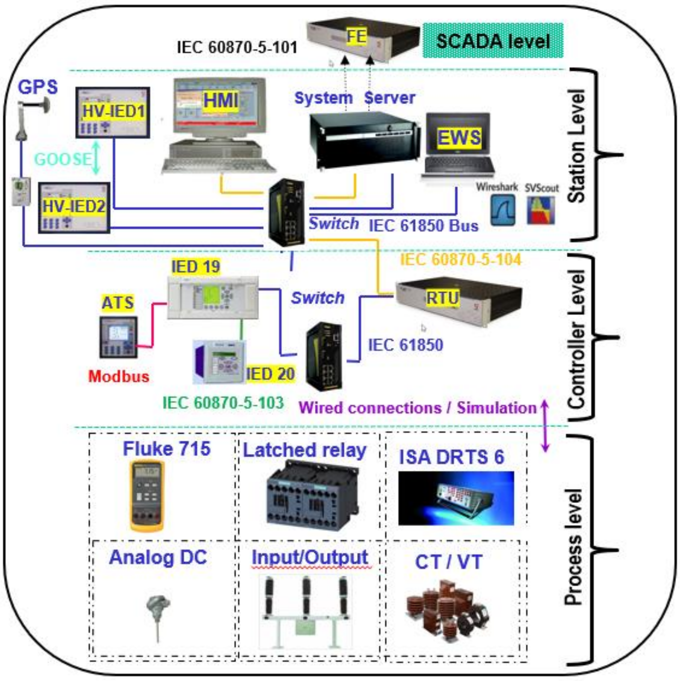

Fig. 1 Study case laboratory framework

As presented in Fig. 2, for both scenarios, the real architectures implemented in the substations were simplified and reproduced by the authors in the SCADA Laboratory at University POLITEHNICA of Bucharest / Faculty of Power Engineering / Power Engineering Systems Department, covering all the intended experiments such, hybrid LANs, data exchanged between DCS levels, GOOSE messages, IEC61850 and legacy protocols communication interoperability, HMI, monitoring, control and data acquisition, protocols conversions and telecontrol from upper SCADA level.

3.1. Case study 1 – Integration of an existing DCS

Despite of intensive automation and monitoring of substations, the medium voltage part still has a marginal role comparing to high voltage ones.

In this context exists the first scenario which analyzes the integration aspects of a an already running DCS for a 20 kV substation, and its integration, when migrating the entire substation which include 220 kV and 110 kV voltage levels, to a modern DCS.

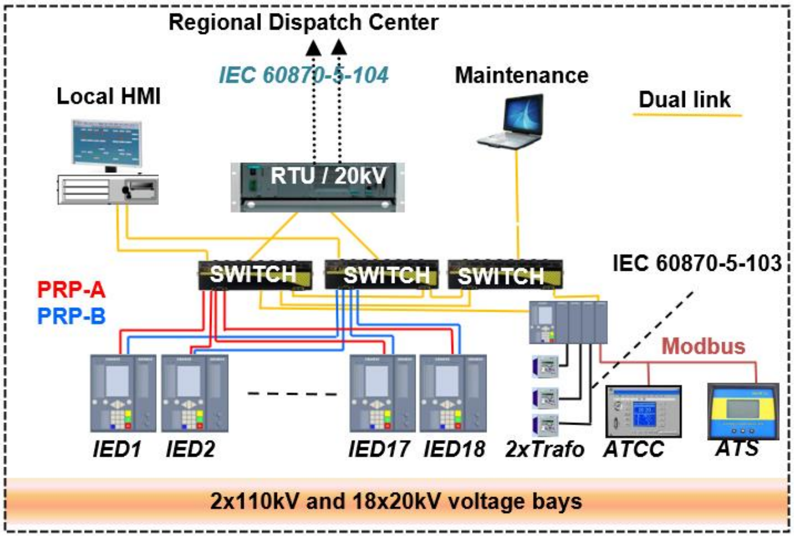

Fig. 3. Turnu 20 kV substation-Existing DCS (simplified communication architecture)

As presented in Fig. 3, the study case starts from an existing situation, respectively a running DCS in Turnu 20 kV substation.

The existing system consists of:

- A proprietary DCS software platform.
- 18 x IEC61850 compatible IEDs, mounted inside 20kV panels;
- 6 x IEC 60870-103 legacy protection relays, mounted in 110kV transformer bay cabinets;

- 2 x Modbus devices for each 110/20 kV transformer bay, dedicated for automation functions such ATCC (Automatic Tap Changer Control) and ATS (Automatic Transfer Switch);
- One RTU which collect all the data from the process;
- A local HMI and the maintenance laptop.
- Communication infrastructure composed of communication switches optical fiber, Ethernet copper cable and serial RS485 cables.

The scope of this first study case is to present an optimal architecture design, data models compatibility, overall system limitations, advantages, and disadvantages of this migration strategy. When starting from an existing system as shown in Fig. 2 and need to fulfill the customer demands to integrate the existing system into the new one and keep both systems running in parallel, to reduce the present investment and save it the past one, the optimal solution is to design a multilevel DCS, as presented in Fig. 4.

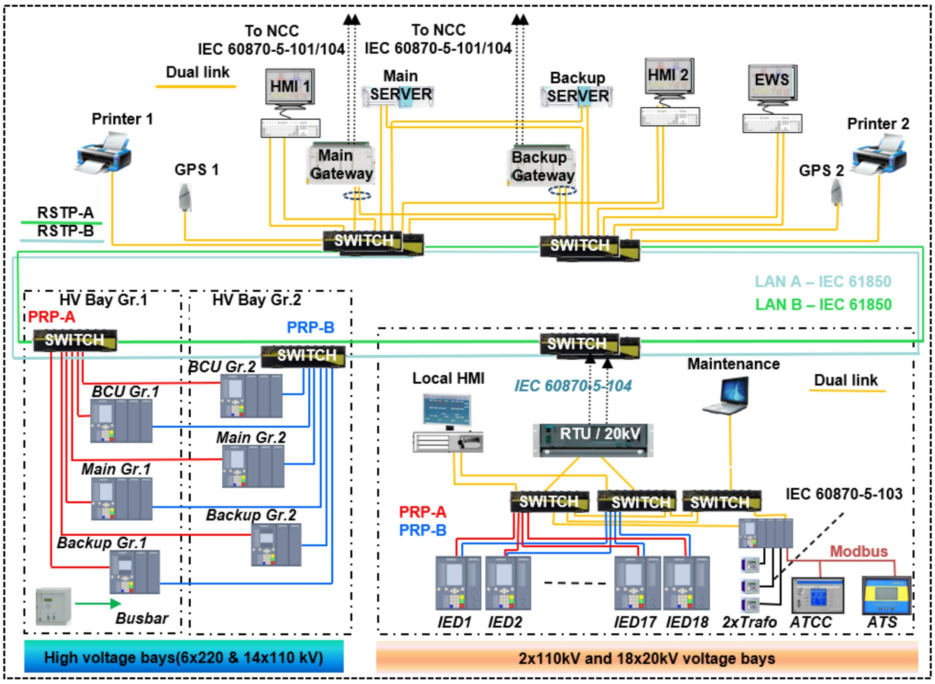

Fig. 4. Turnu 220/110/20 kV substation (simplified architecture after the migration)

Under those circumstance the design of DCS architecture represents the big challenge, to reach a reliable communication network while keeping in operation legacy devices and communication protocols. Practically, a hybrid communication system, adopting different technologies at the same time [14] was implemented by the authors, able to connect the upper SCADA level with the new

220 kV, 110 kV and the existing 20 kV substations. The result of the migration is a multilevel DCS architecture, as presented in Fig. 4.

If at the main level the common language between the network equipment is IEC61850, the exchanged information with the existing system is done through the IEC 60870-5-104 protocol. Being a Master-Slave protocol, the exchanged data between two systems must pass through the 20 kV RTU. Since there is only one RTU, any communication failure of it will separate completely the two systems.

Even if some elements of the existing system network have IEC61850 capabilities and referring to GOOSE messages, they cannot be used by the main level elements due to the fact that the multilevel system is composed of two distinct networks, which prevents the exchange of GOOSE messages. To exchange the needed data between the IEDs from the two networks, the binary and analog signals must be wired.

Although at first glance the operation of two separate DCSs may suggest some advantages and cost savings for the owner, following this implementation the impact of operating with different technologies are highlighted here below:

Advantages: Saving the past investment, familiarity, and continuity with the old system.

Disadvantages: data accessibility issue from legacy devices, difficulty to accommodate different technology in the same architecture; serial devices receive and process only messages sent directly to them, frequent failures; maintenance and costly protocol convertors, use a separate network to get disturbance recordings from protection relays; unsupported hardware and software; Cybersecurity issues when using outdated software such Windows XP/7; limited the benefits of the newest technology like using the GOOSE which means a bigger quantity of wired copper cables to ensure the interoperability with the modern DCS; the integration of the old systems required costly protocol converters, meaning additional communication delay / latency in the network.

Even though a legacy control system may still work well after 30 years or even longer doesn’t mean that it is operating efficiently, reliably, safely, or cost-effectively.

Recommendations: replace the old RTU by a modern System Server to better carry on the new role of the gateway between the two systems, after the migration. In case of extreme budget constraint, the RTU can be virtualized (virtual machine) inside the System Server of the new system; segmentation of the 20 kV communication network in two parts, one dedicated for IEDs 1-18 which exchange only IEC61850 messages and the second one for the two transformer bay controllers which convert Modbus and IEC 60870–5–103 legacy protocols to IEC 61850. For redundancy purpose, the old system must have four Ethernet switches instead of existing three; connect the IEDs 1-18 to the new system network, to benefit of GOOSE messages features and reduce the copper wiring connection to the new system.

3.2. Case study 2 – Remove and Replace the existing DCS

The context of choosing this approach is represented by a recent real upgrade of three electric power transmission substations, respectively Raureni, Arefu and Hasdat 220/110 kV, owned by Transelectrica SA, Romanian Transmission and System Operator (TSO). Going back in 2008, the initial supplier was Areva T&D France. After 10 years, in 2018 the owner decided to upgrade all the above-mentioned substations, but this time the contract was awarded to a different supplier, respectively Siemens AG Germany. In this context, Siemens decided to migrate the entire DCS to its own brand and to the up-to-date technology, instead of upgrading the existing ones. For this study case Arefu 220/110/20 kV substation implementation was analyzed, like Turnu 220/11/20 kV substation, but the migration strategy was to remove the existing system and replaced it with IEC61850 devices [15].

The substation DCS architecture was designed based on Ethernet network, with three levels: Level 0 = Process, Level 1 = Direct Control and Level 3 = Plant Supervisory. Arefu substation architecture has one main communication ring in redundant ring topology and several bay LAN segments, where all the IEDs are connected. IEDs are designed with PRP for the redundancy purpose and high system availability. This segmentation keeps the traffic to a minimum and improve the network cybersecurity.

The main LAN-A/B can carry mixed traffic such binary status, metering, IED settings, GOOSE messages. To not overload the network, all the bay controllers are installed in the switchyard, closed to the monitored and controlled field equipment. This is done by extending the station bus into the switchyard near the source, to digitalize the voltages, currents, and I/O directly to Ethernet packet stream, to use as much as possible the GOOSE and Sampled Values service, aspects that contributes to an important copper wiring reduction by replacing them with digital messages on data networks. Also, in the same way the 110/20 kV transformers bay cabinets were removed from the 20 kV building and placed in containers near the power transformers, thus saving a big amount of copper cable.

Finally, with the designed architecture presented in Fig. 5, the migration strategy achieved a fully IEC 61850 objective, thus enabling fundamental improvements in the monitoring and control the substation that is not possible with the design chosen in the previous strategy due limitations of the legacy staff.

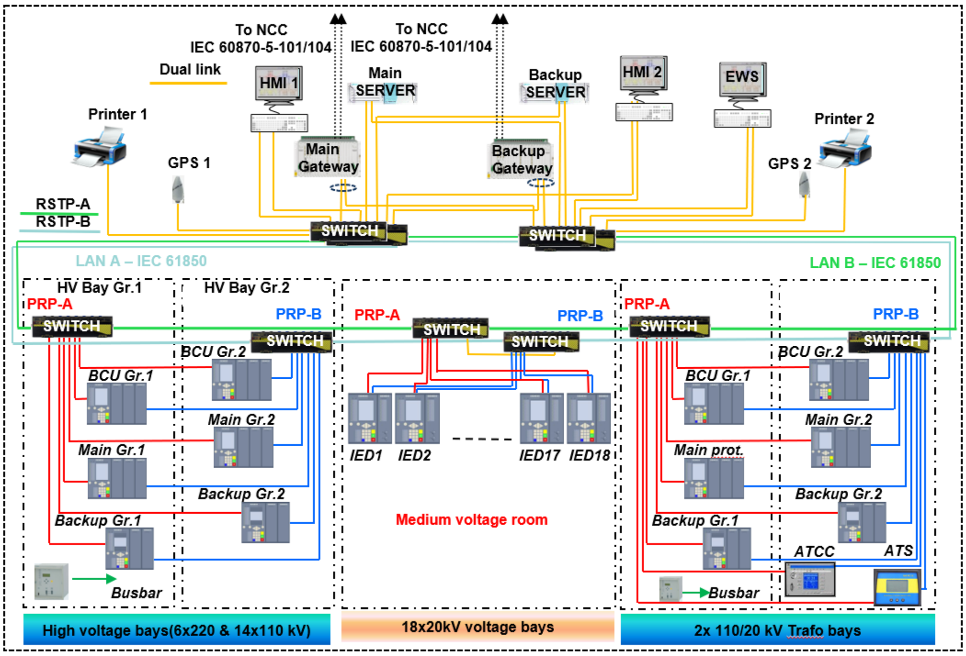

Fig. 5. Arefu 220/110/20 kV substation (simplified architecture after the migration)

Comparing to the mixed solution adopted in the first study case, a fully IEC 61850 approach accommodates the needs of the larger system, scalability, and interoperability with other similar systems, following this implementation the impact of using only IEC 61850 protocol:

Advantages: all the substation field devices can be modeled in a hierarchized and tri-dimensional data model instead of plane-linear in case of legacy data, that is closer to human thinking than the way computers work; exchange data between IEDs through substation network, thus eliminate a big amount of copper wiring between IEDs; interoperability between different vendors; user friendly names for all data, instead of index/numbers; vertical and horizontal communication and self-monitored messages; low engineering cost for installation or future migration; companies that migrate to a newer, more effective control system gain a key advantage over competitors that wait for assets to reach end of life.

Disadvantages: the benefit of fully IEC61850 DCS must be economically justified; complex system with a very abrupt learning curve; dependency on the supplier expertise; request a high speed and reliable network; it is limited to the substation ‘’wall’’; depending on the vendor, the number of IEC 61850 devices in the same network are limited (Ex: 256 IEDs for some vendors).

Recommendations: IEC 60870-5-104 is a much better version of IEC 60870-5-101 as communication protocol to SCADA EMS, having the support for TCP / IP which result in a betted bandwidth; allocate dedicated communication switches for substation Servers and Gateways to not mix them with the auxiliary equipment such GPS, printers and maintenance computers; for the same IEDs, start the parametrization by extracting the ICD (IED Capability Description) file from a device and use it as a template for all the similar ones, thus avoiding configuration errors; the use of generic logic nodes (GGIO) type to be considered only in the punctual situation in which there is no correspondent in the standard logical nodes, or it is not available from the manufacturer; understand the IEDs capabilities to be sure that is performing the necessary functions on the LAN; for the exact functions of an IED, the time saving parametrization is a simply copy-paste of the CID (configured IED description) file, followed by changing the IP address of the physical device and the name of the logical device; mapping the data between IEC61850 and IEC 60870-5-101 has to be done, and tested later, data by data to avoid inconsistencies with SCADA database; in case of hot-swap implementation, a carefully planned migration is mandatory to avoid unnecessary outages.

5. Conclusion

One important role of migration to modern DCSs is to move the controlled process toward a unique standard, respectively IEC 61850, to use the common automation technologies available for all the vendors for an easy, compatibility with modern IT facilities and business environment. The substations design must evolve towards a standardization of process architectures and HMI interface technology, to reduce end-user engineering and maintenance costs.

Maintaining several types of systems from different implementation periods represents an additional consumption of resources and limits the future development or expansion of the system. A major inconvenient of this approach presented in the first study case is represented by the segmentation of the substation in two area of automation, old and new system. Using the same technology for the entire substation reduces the design integration risk, avoid the very high engineering cost and prevents further delays in project implementation, handle protection system in a reliable manner without compromising the trip signals from protection relays. The marginal role of medium voltage substations must be reconsidered taking into consideration the growing presence of distributed generation on the medium voltage grid and the growing electrical charging vehicle network.

One of the IEC 61850 objectives is to reduce all the engineering process, including system specification, IEDs configuration, factory acceptance test and on-site installation. But another objective is to facilitate the maintenance of these systems. The degree of knowledge in IEC 61850 needed by each user depends on the IED capabilities and the IED configurators, that why to manage the standard requirements the appropriate training and software tools must be available.

A modern native IEC61850 DCS, represents technology for the future, higher system visibility, better interface with business and plant management staff and return the investment along with a low cost of ownership. In this paper, the authors presented two solutions of DCS migration strategy, pointing out the advantages, disadvantages, and recommendations. Future work will be about compatibility of data models, protocol conversions and transfer of additional data (metadata) specific to the old and new system, which is an ample subject, as legacy devices are still present in substations automation environment.

R E F E R E N C E S

[1]. K.S.Manoj,’’Industrial Automation with SCADA’ ’Notion Press 2019.

[2]. S. Chowdhury, S.P. Chowdhury and P. Crossley, “Microgrids and Active Distribution Networks”, The Institution of Engineering and Technology, 2009.

[3]. F. Salvadori, C.S. Gehrke, A.C. de Oliveira, M. de Campos, P.S. Sausen, "Smart Grid Infrastructure Using a Hybrid Network Architecture", IEEE Transactions on Smart Grid, vol.4, no.3, pp.1630,1639, Sept. 2013.

[4]. ANRE, „Autoritatea Națională de Reglementare în domeniul Energiei, “Raport Anual”, 2019.

[5]. Stuart A. Boyer - Scada_ Supervisory Control and Data Acquisition, ISA 2004.

[6]. T. Puzenberger, “Ethernet Network Redundancy in SCADA and realtime Automation Platforms”, Copa-Data GmbH, White paper 2016.

[7]. D. Costianu, N. Arghira, I. Făgărăşan Ioana, S. St. Iliescu, “Standards in Control and Protection Technology for Electric Power Systems’’ Proceedings of Journal ISOM No. 2 Vol. 2, page 416-427, 2008.

[8]. León, H.; Montez, C.; Valle, O.; Vasques, F. Real-Time Analysis of Time- Critical Messages in IEC 61850 Electrical Substation Communication Systems. Energies 2019, 12, 2272.

[9]. D. A. Poștovei, C. Bulac, I. Triștiu and B. Camachi, "Setting up a Distributed Control System Laboratory," 2020 11th International Conference and Exposition on ELectrical and Power Engineering (EPE), Iasi, Romania, 2020.

[10]. J. Wen, C. Hammond, A. Udren, ‘’ Wide-Area Ethernet Network Configuration for System Protection Messaging ‘’, Georgia Tech Protective Relay Conference, April 2012.

[11]. B. Camachi, O. Chenaru, L. Ichim, D. Popescu,’’A Practical Approach to IEC 61850 Standard for Automation, Protection and Control of Substations", ECAI 2017 - International Conference – 9th Edition Electronics, Computers and Artificial Intelligence, 29 June - 01 July, 2017, Targoviste, Romania.

[12]. 60870-5-101, First Edition, 1997-12, Telecontrol equipment and systems, Part 5-103, Interface of protection equipment.

[13]. Petr Matoušek, “Description and analysis of IEC 104 Protocol”, Technical Report no. FIT-TR-2017-12, Faculty of Information Technology Brno, Czech Republic December 2017.

[14]. F. Salvadori, C.S. Gehrke, A.C. de Oliveira, M. de Campos, P.S. Sausen, "Smart Grid Infrastructure Using a Hybrid Network Architecture", IEEE Transactions on Smart Grid, vol.4, no.3, pp.1630,1639, Sept. 2013.

[15]. Chen, X., Crossley, P.A., Guo, H., Design, construction and validation of a next generation protection and control system based on IEC61850 standards, DPSP 2014, 31 March-3 April 2014, Copenhagen, Denmark.