WHITE PAPER

# Substation-wide disturbance, fault, and event recording for distribution networks with a centralized protection and control solution

# Centralized protection solution to ease fault analysis and improve distribution grid reliability

Power distribution systems are one of the most complex infrastructures found worldwide and they are expected to operate with high quality and reliability. More than ever, utilities and industries around the globe are facing an increasing number of challenges related to maintaining the reliability of their power distribution grids. To improve the overall reliability of the system, it is also necessary to have the right tools to reliably investigate disturbances in the power distribution network and take corrective measures to minimize such occurrences in the future.

All modern protection and control relays contain their own disturbance, fault, and event recording functionality, ensuring that no event is lost. Despite that these modern protection and control relays have the capability to store complete and reliable information about disturbances, fault investigation often takes more time, since substation-wide information is often missing. Only bay-specific information, which is collected by the respective relay from the connected current and voltage transformers and binary signals are captured in these disturbance records. Also, it is bit challenging to collect these disturbance recordings from each bay in the substation, as these are generally stored locally within the protection relays deployed in respective bays. This traditional approach still relies on various data analysis tools to generate substation-wide information, which makes the overall fault investigation process a bit time-consuming.

Centralized Protection and Control (CPC) is a promising new concept for distribution substations, and it has several benefits in comparison to the conventional relay-per-bay based approach. Consolidating multiple relays into one device reduces system complexity and offers effective ways to manage protection and control functions in the network. In addition to the benefits related to protection and control functionality, there is also the possibility to get other advantages such as a Centralized Fault Monitoring System (CFMS) for the complete substation for easy and efficient fault analysis. As the centralized unit has access to all substation measurements simultaneously, the same data can also be used for substation-wide disturbance, fault, and event recording purposes that can be post-analyzed in the same or in a separate system.

This paper aims to describe the benefits of a centralized protection and control system from substation-wide disturbance, fault, and event recording point of view for ease in fault analysis and improving overall power distribution grid reliability. There are many ways in which a CPC architecture can be deployed in power distribution networks, e.g., with a stand-alone Merging Unit (MU) in each bay connected to a CPC device commonly known as Centralized Protection and Control Scheme (CPCS) or with protection and control relays supporting IEC 61850-9-2LE (de-facto standard from EPRI as a 'light version' of IEC 61850-9-2) publishing and acting as an Intelligent Merging Unit (IMU), which is connected to a CPC device, commonly known as a Hybrid Protection and Control Scheme (HPCS). To explore improved utilization of technologies for substation-wide disturbance, fault and event recordings this paper describes (i) considerations for use of disturbance recorders and types of disturbances, (ii) challenges with traditional disturbance recorders in protection and control relays, (iii) CFMS-based on various CPC architectures for centralized disturbance, fault, and event recordings, and (iv) added value with a CPC architecture compared to traditional disturbance recording functionality available in protection and control relays, and dedicated fault management systems.

# Introduction

The electricity grid is an incredibly important system, and also one of the most complex networks ever created. The electricity grid has grown and changed immensely since its inception in the 19$^{th}$ century, when energy systems were small and localized. Originally devised to provide electricity to small regions, these grids have expanded and today they interconnect across continents. The electricity grid is a dynamic system. It has changed and evolved rapidly over the last century to accommodate new technologies, increases in electricity demand, and the growing need for reliable, diverse sources of electricity. Even on an hourly basis, the grid is changing, with different sources of electricity being manipulated to satisfy demand at the least cost.

The reliability of the electricity grid underpins virtually every sector of modern economy. The reliability of the grid is a growing and essential component of national security. Reliability can be defined as the ability of the electricity grid to deliver electricity to all points of consumption, in the quantity, and with the quality required by the consumer. Reliability is often measured by the outage indices defined in one international standard called Institute of Electrical and Electronics Engineers (IEEE) guide for electric power distribution reliability indices standard 1366. These outage indices are based on the duration of each power supply interruption, and the frequency of the interruption. All three major functional components of the electricity grid – generation, transmission and distribution contribute to reliability. As far as the consumer is concerned, transmission and distribution outages are of prime importance. In fact, many surveys show that 80%...90% of the outages experienced by consumers are caused by distribution system outages. Hence, this paper is more focusing on distribution networks instead of on other parts of the electricity grids. However, the concept of CPC can be applied not only for distribution networks, but also for power generation and transmission networks.

Recording events before, during and after a disturbance is often the only way to find out what has happened in the power distribution network and allows us to reliably investigate a disturbance or event afterwards in order to be able to make improvements towards overall reliability. Understanding the state of the electricity grid and its components before and after the fault is of utmost importance to power engineers to be able to take corrective measures. For decades, utilities and industries have been monitoring

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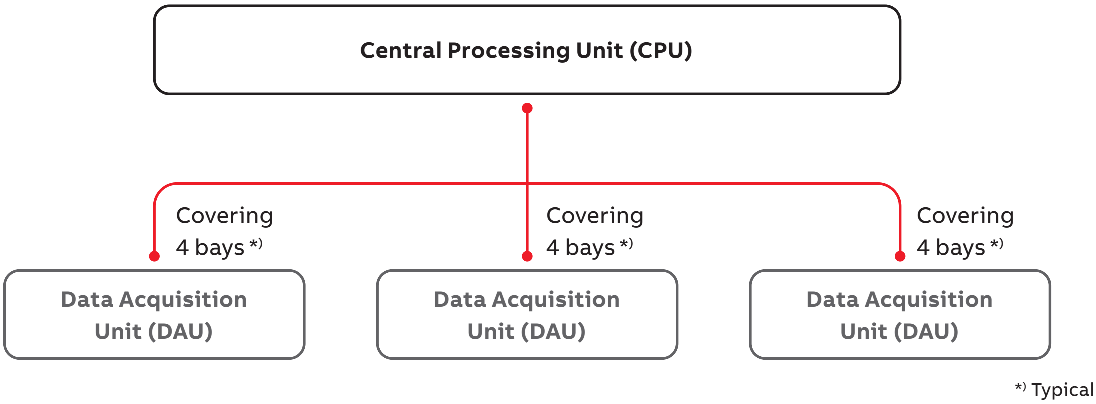


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**Figure 1. Typical fault monitoring system with centralized CPU and DAU architecture**

their grids for disturbances, anomalies, and faults. It was quite common to use chart recorders – an electromechanical device that records an electrical or mechanical input trend onto a piece of paper (the chart); these represent the first-generation deployment of fault monitoring systems.

At the generation and transmission level, we easily find the dedicated devices deployed as fault monitoring systems, however, fault monitoring is not quite as popular in distribution networks. The lack of a robust fault monitoring system increases downtime for consumers and loss of revenue for utilities or industries. Traditionally, a transmission substation relies on a FMS (Fault Monitoring System) wherein Data Acquisition Units (DAU) deployed at the bay/s level to acquire process level data, which is then processed by the central CPU unit. Such typical FMS architecture is shown below in figure 1.

The evolution of protection relays from electromechanical relays to static relays to modern numerical protection relays with communication capabilities have improved the operation and control of power systems, however, as far as disturbance, faults and event recordings are concerned the approach is still bay-wise and often a substation-wide fault monitoring system is deployed with some other dedicated devices or system. Maybe due to cost concerns, it is not so common to have a dedicated substation-wide fault monitoring system for distribution substations and only bay-wise information available from numerical protection relays is utilized to investigate a disturbance in the power distribution network.

The concept of CPC is not new, but only the advancements in computing technology and international standards have made it a feasible alternative for modern substations. Traditionally the protection has been distributed in multiple different numerical protection relays ('Decentralized') but in a CPC architecture all the safety critical intelligence is in one device ('Centralized'). Apart from the other benefits about centralization of protection and control, a CPC architecture can also be utilized to achieve a substation-wide disturbance, fault, and event recordings platform, which can replace traditional fault monitoring systems.

# Considerations for use of disturbance recorders and type of disturbances

There are several considerations when installing disturbance recording and monitoring equipment. The first step is to identify the type of event to be monitored e.g. recording of power system faults to verify protection system performance or recording of power swings on the system. The second step is to consider the appropriate sampling frequency, type of event triggers, record length, and analog and binary inputs that are to be monitored to choose the best disturbance recording device. The third step is to consider the limitations and errors in the disturbance recording device that may be introduced into the records due to the characteristics of the sensing equipment.

There are typically four types of disturbance or event records which will be important for protection engineers [1] i.e., transient, short term, long term, and steady state.

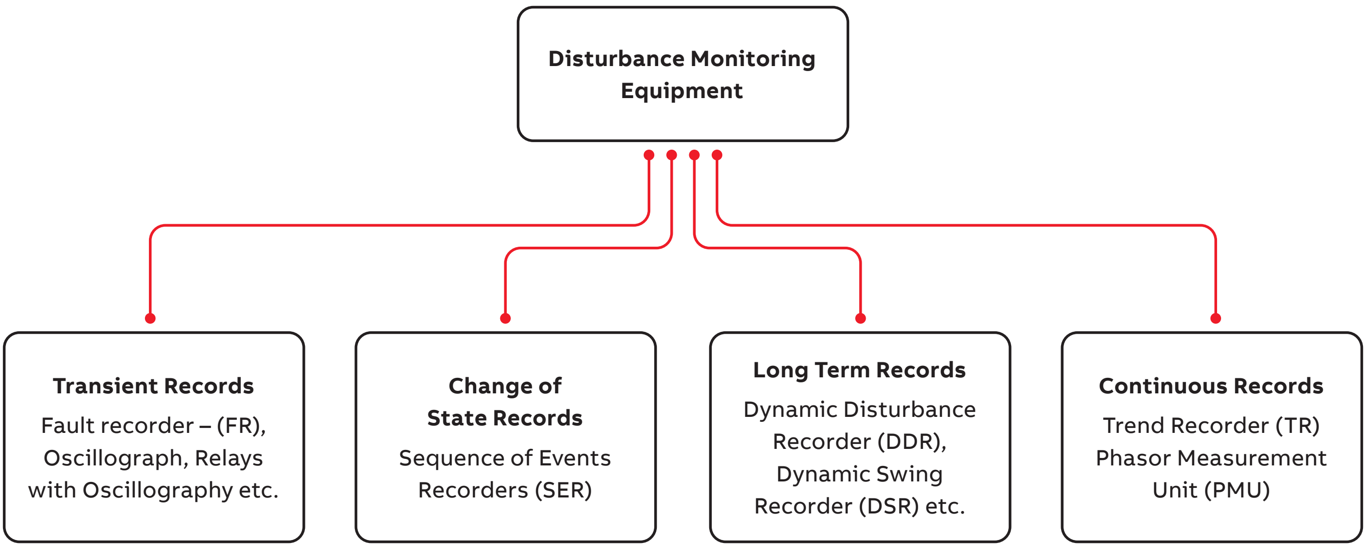


Figure 2. Four types of disturbance or event records

**Transient records** are an example of high-speed recordings wherein the recording device is used to capture the individual samples of the currents and voltages. These are measured by the device at a sufficient sampling frequency. These types of records enable analysis of power system faults and makes transient analysis easy. Generally, transient events are short in duration and typically the recording length is set to a few seconds. The important point for transient records is sampling frequency. If a protection engineer is interested in detecting a re-striking circuit breaker, then a high sampling frequency is needed. Typically, a Digital Fault Recorder (DFR) uses a sampling rate of 64 – 128 samples/cycle or even higher. However, protection relays as digital fault recorders use a sampling rate of 4 – 32 samples/cycle or even higher. A higher sampling frequency is not necessary for the protection functions, but it can be beneficial for transient records.

The PRC-002-2 standard by the North American Electric Reliability Corporation (NERC) specifies disturbance monitoring and reporting requirements; it states that its purpose is "to have adequate data availability to facilitate analysis of Bulk Electric Systems (BES) disturbances". It guides utilities on exactly what to monitor, where, and how long to keep data logs. Though PRC-002-2 is not directly applicable for distribution systems, it defines that the requirement for fault records must be a minimum of 0.5 seconds long and a minimum sampling rate of 960 samples per second, which is approximately 20 samples/cycle for a 50 Hz system and 16 samples/cycle for a 60 Hz system [2]. This should be the minimum consideration when deciding the sampling rate for transient records. This data should be stored in IEEE C37.111 COMTRADE format for easy analysis.

**Sequence of Events (SoE)** is time-synchronized indications of circuit breaker and switch positions which is very useful for fault and disturbance analysis. This data is where root-cause analysis/forensics usually starts and eventually leads to fault recordings which have more richness of data compared to transient records. SoE data is typically stored in Comma Separated Value (CSV) format.

**Long term records** go above and beyond DFRs and provides the richest data about an electrical disturbance. It requires monitoring of several more analogs than DFR, including real power (watts), reactive power (vars), and frequency (Hz). The data captured is phasor or RMS data, not sampled data. Recording length is typically in the range of a few tens to hundreds of seconds but can be hour/s too.

**Continuous records** are often referred to as trend recordings. They capture average analog quantities such as maximum and minimum values and are usually stored in a file with several days of data. Phasor Measurement Units (PMU) are considered steady-state recording devices, which collects the system state information over a wide area.

# Challenges with traditional disturbance recorders in protection and control relays

Protection in power systems has been subject to several technological advancements. From electromechanical relays to the microprocessor-based intelligent electronic device (IED), relaying has been an essential aspect to the continuing development of more flexible, interconnected, and smart power distribution networks.

Modern numerical protection relays are not just providing integrated protection, control, measurements, and monitoring functions, but it has the capability to provide disturbance, fault, and event recordings for the bay where it is deployed. Modern numerical protection relays can record all four different types of disturbances discussed in the previous section.

Despite that modern protection relays can act as disturbance, fault, and event recorders, they have some drawbacks as listed below:

- Using relays as recording devices means having the data distributed in many devices instead of combined into one device. This makes it difficult to get a substation-wide view and obtain data for fault analysis.
- All such disturbance, fault, and event records through numerical relays are limited to the "zone of protection" associated with the relay. Also, analog signals will be limited to the available CT/VT inputs to the protection relay.
- Combining data e.g., SoE, DFR, trends from these individual sources in the substation is a manual activity and there may be additional hardware and/or software.
- There are likely also differences in the triggering method, sampling rate, and record length to consider among various numerical protection relays in a substation.
- Time synchronization challenges. Old numerical relays may have time synchronization with serial protocols, whereas modern numerical protection relays have time synchronization through Simple Network Time Protocol (SNTP) or Precision Time Protocol (PTP).
- Data retrieval is possible with either a one-to-one connection between the protection relay and the laptop through the front port of the relay, which is a very simple connection. However, it becomes cumbersome, because the engineer needs to walk to each relay to download the disturbance data for the whole substation. Remote communication-based data upload is recommended, however, that will impact the available network bandwidth for other important substation traffic like MMS (Manufacturing Message Specification), GOOSE (Generic Object Oriented Substation Events), Sample Analog Values (SAV) or time synchronization traffic in an IEC 61850-based substation.
- Protection relays may have a slow sampling rate compared to dedicated DFR, limited response to high frequency, DC filtering, and software filters, depending on the method used by the relay.

NB: It is always recommended to review the relay specifications before using it as disturbance, fault, and event recorder for a substation.

# A CFMS based on various CPC architecture for centralized disturbance, fault, and event recordings

The IEEE PES PSRC WG K15 working group on Centralized Substation Protection and Control defines CPC as a system comprised of a high-performance computing platform capable of providing protection, control, monitoring, communication, and asset management functions by collecting the data those functions require using high-speed, time synchronized measurements.

As mentioned in IEEE PES PSRC WG K15 working group report [3], CPC architecture for secondary systems is not a new concept and it dates back almost to the beginning of wide adoption of computers for business use. The first proposal was published in 1969, and a first installation as a field proof concept was done in 1971.
CPC architecture can also be utilized as a substation-wide disturbance, fault, and event recorders solution which provides a more standardized approach to having a fault monitoring system in substations.

The basic building block of a CPC architecture is the IEC 61850 communication protocol.
The IEC 61850 protocol is nowadays widely used in substations, thanks to its future-proof IT architecture and a common language for all the components of a substation. Since industries and utilities already widely accept IEC 61850 for the automation of transmission and distribution substations, the same technology can also be applied for a CFMS with CPCS architecture or HPCS architecture.

The fundamental difference between CPCS architecture and HPCS architecture lies in the principle of distribution of partial or full duplication of protection and control functions between bays, substation levels or even concentrating all functions at the substation level [4]. Both of these architectures are utilizing IEC 61850-8-1 part, which allows the elimination of copper wires between bay devices on the horizontal level, i.e., relay-to-relay communications – substation bus and IEC 61850-9-2LE, which allows the sharing of digitized information from instrument transformers or sensors in a standardized way to other bay units and/or CPC unit – process bus [6]. Thanks to IEC 61850 it is now possible to share bay level instrument transformer or sensor information between different bays and/or CPC unit at the substation level. This is the core foundation of the CPC architecture as a CFMS.

Similar to any other substation automation system, a CPC architecture needs reliable time synchronization. The MUs, IMUs and CPC unit either in a CPCS or HPCS arrangement are all connected to the substation's Ethernet bus and therefore they need to handle publishing of and subscription to IEC 61850-9-2LE SAV communication profile. Therefore, they require highly available, high precision, low cost, and simple maintenance time synchronization.
PTP is a future-proof standard Ethernet protocol described in the standard's IEEE 1588 and IEC 61588 Ed 2. PTP ensures high accuracy time synchronization of 1 µsec and a time stamp resolution of not more than 4 µsec. Hence, PTP is one of the preferred time synchronization methods for this kind of time-sensitive network. [5]

With multi-core processing capability and advancements in industrial computing, CPC hardware makes it possible to receive and process multiple streams of data, stitch them together to generate a substation-wide disturbance recorder which may have up to 20 data streams from various bays with 4 Current Transformer (CT) signals and 4 Potential Transformer (PT) signals in each data stream coming from each bay. This way it will be possible to record up to 160 analog values in the disturbance record along with other digital information, such as circuit breaker status, protection start/trip information, and other external signals. This is the first step towards transient recordings. Similarly, all the events available at the individual bay level from MUs or IMUs can be concentrated at the CPC hardware level to generate substation wide SoE records. Long term records such as power, energy, frequency response can be derived from the data stream received from MUs or IMUs and dedicated functions can be run in the CPC unit to generate long term records. Trend recordings are also possible with CPC or HPCS architectures, wherein the data stream received from each bay is processed in the CPC unit to turn data into useful information. Typically, such CPC hardware has a built-in web-based Human Machine Interface (Web HMI), which contributes towards a better user interface (UI) and user experience (UX) for protection engineers working in the substation.

As shown in below Figure 3, a basic CPC architecture is utilized for a substation-wide protection, control, and fault monitoring system, where a MU is deployed at each bay level to provide digitized information to the CPC unit based on IEC 61850-9-2LE, which defines a sampling rate of 80 samples/cycle (which means a sampling frequency of 4 kHz in 50 Hz networks and 4.8 kHz in 60 Hz networks) [5]. A sampling rate of 80 samples/cycle meets or even exceeds requirements to provide better coverage for transient records compared to a sampling rate of 20 samples/cycles as defined in NERC-PRC-002-2 [2]. Raw measurement values sent to a subscriber – CPC unit is the exact emulation of the signals from instrument transformers or sensors.
The CPC unit is then able to run substation-wide disturbance, fault, and event recorders, as well as protection and measurement functions, without having to make any adaptions. Apart from acting as a digital interface unit between the primary equipment and the CPC, the MU can also host I/Os (input/output) to handle feeder-based digital signals. It can communicate digital status of primary equipment such as the circuit breaker, isolator, and earth switches to the CPC unit.
The MU becomes the most important part of the CPC architecture since it acts as a bridge between the primary equipment's process data and the computing platform. We can also use process units along with the MU which then provides additional I/Os to communicate additional process-related signals to the CPC unit or CFMS.

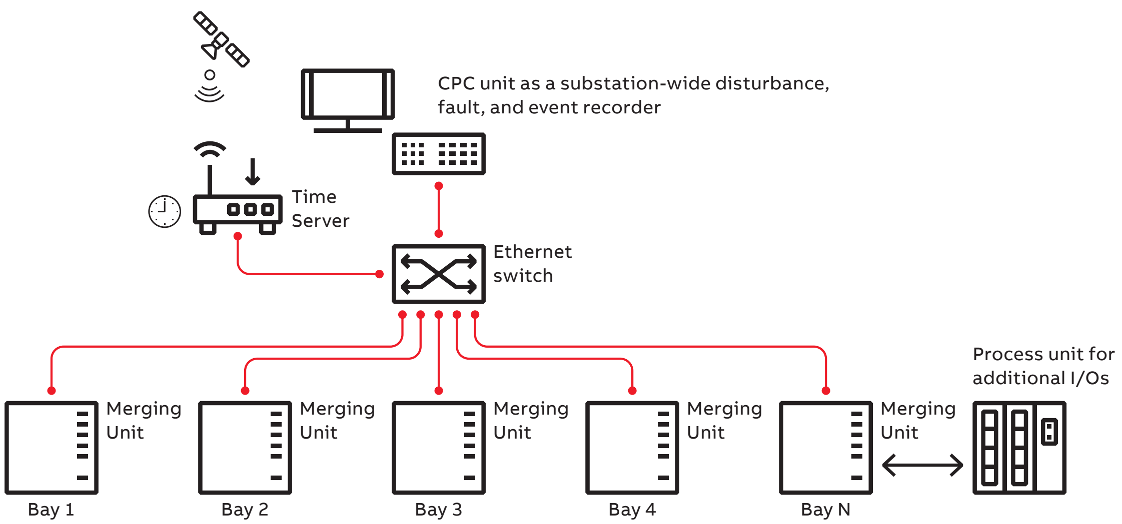


**Figure 3. Basic CPCS-based architecture for a CFMS**

The HPCS architecture is very similar to the CPCS architecture. The difference is that protection relays with MU capabilities, also known as Intelligent Merging Units (IMU), are utilized to build the architecture instead of MUs. The IMU combines the standard functionality of a merging unit, acting in accordance with IEC 61850-9-2LE, where basic protection, control, and supervision functions are in accordance with IEC 61850-8-1. The IMU can also run all the available protection, control, and monitoring functions for the bay where it is deployed, or it can act as back-up to the CPC device which is running the protection, control, and monitoring functions. IMUs can also run their own disturbance, fault, and event recorders, just like modern numerical protection relays. Naturally, IMUs can only provide bay-specific information, as they lack substation-wide disturbance, fault, and event recording capability. This is where an HPCS architecture can offer the best of both approach. Since decades, we have been using numerical protection relays in substations and many protection engineers are more familiar with a de-centralized approach for protection and control. Fortunately, we can retain this preference for a de-centralized approach and add the benefit of a CPC approach for substation-wide disturbance, fault, and event recorders – in a CFMS, as shown in Figure 4 below.

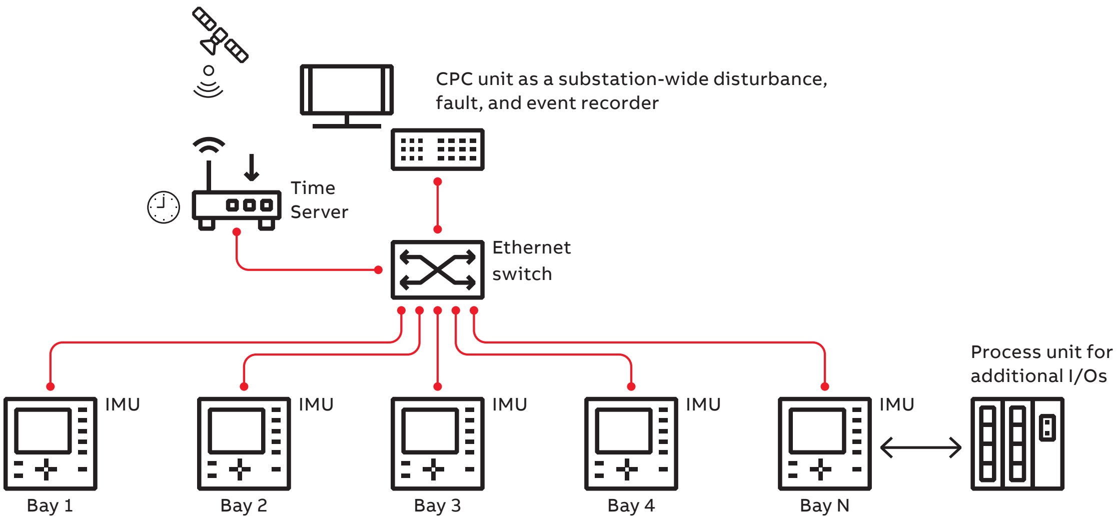


**Figure 4. Basic HPCS based architecture for a CFMS**

Based on the substation strategy, the protection engineer can decide to deploy either a CPCS architecture as shown in Figure 3 or a HPCS architecture as shown in Figure 4 for a CFMS for substation-wide disturbance, fault, and event records.

The advantage of a CPC architecture is complete independence from the protection and control architecture. This enables easy deployment for brownfield applications. In the next section, the added value of CPCS/HPCS architecture is discussed from the point of view of a protection and control (P&C) system, and further details of CPCS/HPCS acting as main or back-up protection for substations are given. Introducing a CPCS/HPCS architecture is an added benefit for brownfield applications, if the protection engineer is looking for both functional and physical redundancy to an existing P&C system.

HPCS architecture brings the best of both the traditional de-centralized approach and the centralized approach. Greenfield applications can be planned with IMUs for the P&C system at each bay level while the CPC unit would be placed at the central level to act as the CFMS device. Also, it is possible to have partial or full duplication of the P&C system in the CPC unit to achieve the functional redundancy of the P&C system in the substation.

The choice of CPC architecture, either CPCS or HPCS, depends on many other aspects and it can be decided on a case-by-case basis only. Also, the typical architecture discussed in figure 3 and figure 4 is without a communication redundancy set-up, however, such an architecture generally supports a standardized redundancy strategy such as PRP or HSR. Such communication redundancy architecture is out of scope for this paper.

# Added value of a CFMS over conventional FMS approaches

An CFMS approach with either CPCS or HPCS architecture also offers some more possibilities to run a number of more applications for the substation. These architectures give full flexibility with “N” number of possibilities for protection and control functions allocations across process, bay, and substation level.

These architectures make it possible to add advanced or missing protection and/or control functionalities very easily compared to the deployment of additional new numerical relay/s at bay level, which might be a costlier approach along with sacrificing system availability due to the necessity of taking the feeder out of service to do the upgrade. The flexibility to adapt to different project requirements is handled inside the software functions and with communication engineering; thus, these architectures are hardware-independent. It is quite common in critical substations to have functional redundancy in terms of a main and a back-up relay, if a CFMS is deployed in the substation then the same architecture can also be utilized to either act as the main or the back-up protection system for the substation. It is even possible to add missing functionalities in the substation with either CPC or HPCS architecture, e.g., bay 3 relay does not have 79 – auto reclose function. When it is envisaged to improve the reliability of the distribution network then the same can be simply enabled in the CPCS's or HPCS's central unit. Likewise, it is possible to introduce substation-wide protection functions such as low impedance-based busbar differential in these kinds of architectures without any separate wiring, instrument transformers and hardware. Figure – 5 is showing one such example, where the CPC unit is not just acting as the CFMS, but it is also hosting all the substation-wide protection function instances for each bay as the main protection device for the substation and the bay level IMUs are acting as the back-up devices for each bay.

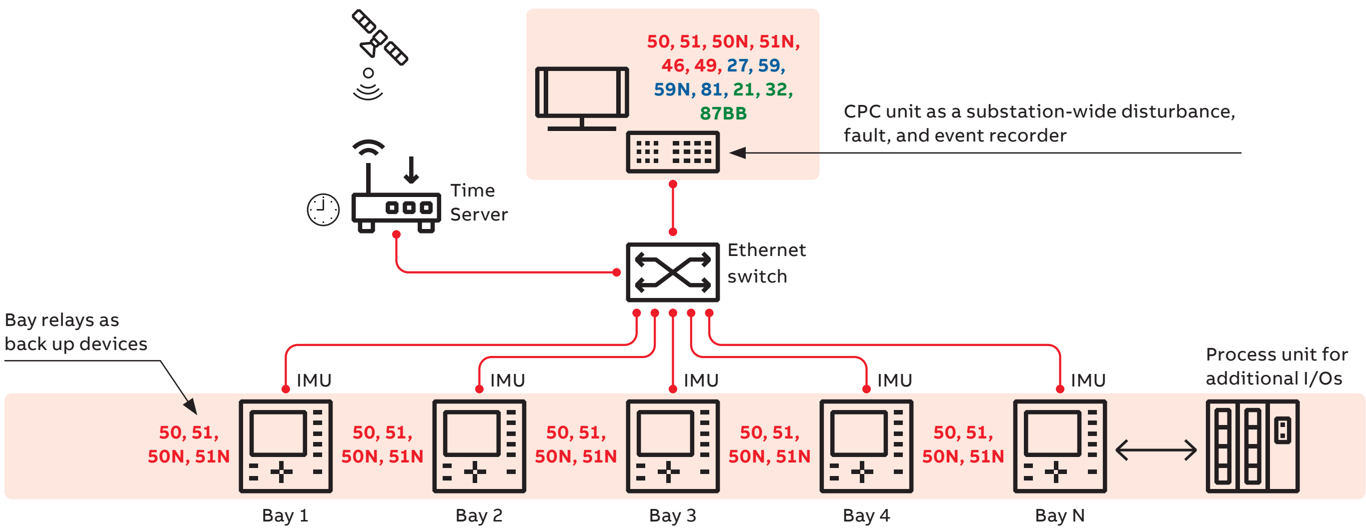


**Figure 5. CPC unit as the CFMS and main protection device for the substation**

This architecture addresses the main concern of utilities and industries wherein they are still not fully confident to utilize CPC architecture for time critical protection applications, mainly due to concerns related to communication redundancy or physical redundancy of CPC hardware. Moreover, it will take some time to build up more confidence within the community that the protection and control system can be modular and fully flexible just like in IT industries where applications are software-driven and there is no dependency on specific hardware.

# Conclusion

A CFMS based on either CPCS or HPCS architecture brings a lot of advantages compared to conventional FMS systems that have been used in substations for many years. The following table shows a quick comparison of a CFMS approach with either CPCS or HPCS architecture compared to conventional FMS or FMS through numerical relays.

| | **Fault monitoring through numerical relays** | **Traditional FMS as shown in Figure 1** | **CFMS with either CPC or HPCS architecture** |
|---|---|---|---|
| Sample rate | Varying (not standardized) | Varying (not standardized) | 80 samples/cycle as per IEC 61850-9-2LE |
| Analog/ Digital channels | Limited to relay's analog/digital input | Depends upon DAU's hardware capability | Typical dataset of 4I + 4U for each SAV data stream. Digital channels depend upon MU/IMU's hardware capability |
| Zone coverage | Limited to bay only | Centralized | Centralized |
| Substation wide visibility | No | Yes | Yes |
| Data recording memory size | Limited to few KBs (kilobytes) or MBs (megabytes) | Large up to hundreds of MBs or GBs (gigabytes) | Large up to hundreds of MBs or GBs (gigabytes) |
| Setting complexity | Low | Moderate | Moderate |
| Scalability/ Modification | No | Yes | Yes |
| | **FMS through numerical relays** | **Traditional FMS** | **CFMS with either CPC or HPCS architecture** |
| Deployment | Easy | Complex | Fairly easy |
| Additional functions | Not possible | Not possible | Possible e.g. Main/back-up scheme or substation wide functions such as low-impedance busbar differential |
| Standardization | Not standardized (varying samples frequency, channels etc.) | Not standardized (varying samples frequency, channels etc.) | More standardized approach (utilizing IEC 61850-9-2LE for samples with each data stream with 4 I + 4U) |

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**Table 1. Quick comparison of various FMS for substation**

A CFMS solution based on either CPC or HPCS architecture makes it possible to utilize the true potential of IEC 61850 not just for substation-wide disturbance, fault, and event recordings, but it is also helpful to gain functional, physical and communication redundancy for the protection and control scheme for the substation. This offers many benefits like increased flexibility and reliability, a standardized solution, better UI/UX, as well as the possibility to introduce advanced protection and control functionality. Optionally, also cloud connectivity for efficient analytics-based asset management solutions. There is no fixed architecture for the deployment of such a configuration since it depends on the substation's protection philosophy, criticality of the connected load, design specifications, etc.

In summary, a CFMS based on either CPCS or HPCS architecture brings significant added value to distribution substations compared to a conventional fault management system or fault monitoring functionality available through numerical relays.

## Abbreviations used

| | |
|---|---|
| BES | Bulk Electric Systems |
| CFMS | Centralized Fault Monitoring System |
| CPC | Centralized Protection and Control |
| CPCS | Centralized Protection and Control Scheme |
| CSV | Comma Separated Value |
| CT | Current Transformer |
| DAU | Data Acquisition Unit |
| DDR | Dynamic Disturbance Recorder |
| DFR | Digital Fault Recorder |
| DSR | Dynamic Swing Recorder |
| FMS | Fault Monitoring System |
| FR | Fault Recorder |
| GB | Gigabyte |
| GOOSE | Generic Object Oriented Substation Events |
| HMI | Human Machine Interface |
| HPCS | Hybrid Protection and Control Scheme |
| IED | Intelligent Electronic Device |
| IEEE | Institute of Electrical and Electronics Engineers |
| IEEE PES PSRC WG K15 | The Institute of Electrical and Electronics Engineers Power & Energy Society Power System Relaying Committee Working Group K15 |

| | |
|---|---|
| IMU | Intelligent Merging Unit |
| I/O | Input/Output |
| KB | Kilobyte |
| MB | Megabyte |
| MMS | Manufacturing Message Specification |
| MU | Merging Units |
| NERC | North American Electric Reliability Corporation |
| P&C | Protection and Control |
| PMU | Phasor Measurement Unit |
| PT | Potential Transformer |
| PTP | Precision Time Protocol |
| RMS | Root Mean Square |
| SAV | Sample Analog Values |
| SER | Sequence of Events Recorder |
| SNTP | Simple Network Time Protocol |
| SOE | Sequence of Events |
| TR | Trend Recorder |
| UI | User Interface |
| UX | User Experience |
| VT | Voltage Transformer |

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