UNIVERSITY OF VAASA

SCHOOL OF TECHNOLOGY AND INNOVATIONS

ELECTRICAL ENGINEERING

Samu Haapoja

STUDY AND DESIGN OF INTER-RANGE INSTRUMENTATION GROUP TIME CODE B SYNCHRONIZATION OF IEC 61850 SAMPLED VALUES

Master's thesis in Technology for the degree of Master of Science in Technology submitted for inspection, Vaasa, 11th of January, 2018

Supervisor	Kimmo Kauhaniemi
Instructor	Juhani Koivupuro
Evaluator	Petri Välisuo

FOREWORD

The idea for this master's thesis came from the R&D department of ABB MVP and it covers the system level analysis of a bay-level device using IRIG-B as a synchronization source with PTP.

This has been a very interesting work utilizing many different disciplines and fields of sciences. I have learned a lot during this work. Thanks to the entire R&D department of ABB MVP and especially to my instructor, Juhani. It has been very interesting, challenging, rewarding and teaching journey to have worked with you all these past few years.

I would like to give thanks to my beautiful and wonderful wife Anne for the support she has given me during this hectic year while battling with her own thesis. Also, thanks to my studying comrades Heija, Jaakko, Ilkka and Sami. Studying in the group is always more effective than alone.

This thesis is dedicated to my late grandmother who stubbornly always stated that she wouldn't see the day of my graduation. Sadly, she was right as she passed away in the spring of this year. Wish you were here.

Vaasa 20.12.2017

Samu Haapoja

TABLE OF CONTENTS

SYMBOLS AND ABREVIATIONS

Symbols

A	Availability
$MTTF$	mean time to failure [a]
$R(t)$	reliability exponential distribution function
t	time [s]
t_1	Sync-message sent timestamp
t_2	Sync-message received timestamp
t_3	Delay_Req-message sent timestamp
t_4	Delay_Req-message received timestamp
λ	rate of failure [s]

Abbreviations

1PPS	1 pulse per second
9-2LE	Implementation Guideline for Digital Interface to Instrument Transformers using IEC 61850-9-2
ABB	ASEA Brown Boweri
ADC	analog-to-digital converter
APDU	application layer protocol data unit
ASDU	application layer service data unit
BC	boundary clock
BCD	binary coded decimal
BMC	best master clock
CF	control flag

CERN	European Organization for Nuclear Research
CT	current transformer
DA	distribution automation
DCS	disconnector switch
DC	direct current
E2E	end to end
ESW	earthing switch
GIS	gas insulated switchgear
GPS	global positioning system
HSR	High-availability Seamless Redundancy
IEC	International Electrotechnical Commission
IED	intelligent electronic device
IEEE	Institute of Electrical and Electronics Engineers
IO	input/output
IP	Internet Protocol
IRIG	Inter-Range Instrumentation Time Group
IRIG-B	Inter-Range Instrumentation Time Group – timecode B
IT	instrument transformer
LAN	local area network
LCD	liquid crystal display
LHMI	local human-machine interface
LPIT	low-power instrument transformer
MTTF	mean time to failure
MTTR	mean time to repair
MU	merging unit

NERC	American Electric Reliability Corporation
OC	ordinary clock
OLTC	on-load tap changer
OSI	Open Systems Interconnection
P2P	peer to peer
PC	personal computer
PHY	physical layer
PLC	programmable logic controller
PPS	pulses per second
PRP	Parallel Redundancy Protocol
PTP	precision time protocol
RBD	reliability block diagram
RCC	Range Commanders Council
RedBox	redundancy box
RTC	real-time clock
SA	substation automation
SAMU	stand-alone merging unit
SAS	substation automation system
SBS	straight binary seconds
SCADA	supervisory control and data acquisition
SLD	single line diagram
SNTP	simple network time protocol
SPOF	single point of failure
SV	sampled values
SYNC	synchronization

SyncE	Synchronous Ethernet
TAI	atomic time
TC	technical committee
TC	transparent clock
UDP	User Datagram Protocol
UTC	co-ordinated universal time
VT	voltage transformer
WG	working group
WHMI	web human-machine interface
XO	crystal oscillator

UNIVERSITY OF VAASA	
School of Technology and Innovations	
Author:	Samu Haapoja
Topic of the Thesis:	Study and Design of Inter-Range Instrumentation Group Time Code B Synchronization of IEC 61850 Sampled Values
Supervisor:	Professor Kimmo Kauhaniemi
Instructor:	M.Sc Juhani Koivupuro
Evaluator:	Assistant Professor Petri Välisuo
Degree:	Master of Science in Technology
Degree Programme:	Degree Programme in Electrical and Energy Engineering
Major:	Electrical Engineering
Year of Entering the University:	2011
Year of Completing the Thesis:	2018 **Pages:** 78

ABSTRACT

Distribution substations are an important part of a chain which delivers energy from power production to customers. They transform the voltage level from transmission levels, usually 35kV and up, to distribution levels ranging between 600 and 35000 V. Recent developments in the instrument transformer field have been toward low-power solutions which use digital measurement values called sampled values in place of analog voltages and currents in substations.

The IEC 61850-9-2 standard and its implementation guideline 9-2 LE by the UCA international users group define an interface for sampled values. This interface is used between an IED and LPIT. The main requirement of using sampled values is accurate time synchronization in order to prevent phase misalignment resulting in unnecessary protection function tripping. 9-2 LE defines two methods for synchronization: 1PPS and PTP. Today, PTP is widely used in the western markets, but due to costs associated with PTP-capable GPS clocks and Ethernet switches as well as vendor inoperability problems, some markets are hesitant to take into use. The purpose of this thesis is to propose a solution to this problem: use IRIG-B as a synchronization method in a PTP grandmaster.

This paper discusses the differences between these two time synchronization topologies, associated costs, disturbance handling, accuracy and it also discusses the design of IRIG-B to PTP conversion done in a bay-level device. The device acts as a PTP grandmaster but the source comes from an IRIG-B clock instead of a GPS PTP grandmaster clock. The results shown in this thesis demonstrate that using IRIG-B as a main or redundant source in synchronization of sampled values is a more cost-effective option, especially if the station is to be retrofitted with sampled values configuration. The proposed bay level device also maintains the desired accuracy levels of ±1 μs set by IEC 61850-5.

KEYWORDS: **Time synchronization, Precision Time Protocol, Inter-Range Instrumentation Group, Sampled values**

VAASAN YLIOPISTO
Tekniikan ja innovaatiojohtamisen yksikkö

Tekijä:	Samu Haapoja
Diplomityön nimi:	IEC 61850 -näytteistettyjen arvojen synkronoinnin tutkiminen ja suunnittelu käyttäen Inter-Range Instrumentation Group aikakoodi B:tä
Valvoja:	Professori Kimmo Kauhaniemi
Ohjaaja:	Diplomi-insinööri Juhani Koivupuro
Tarkastaja:	Tutkijatohtori Petri Välisuo
Tutkinto:	Diplomi-insinööri (DI)
Koulutusohjelma:	Sähkö- ja energiatekniikan koulutusohjelma
Suunta:	Sähkötekniikka
Opintojen aloitusvuosi:	2011
Diplomityön valmistumisvuosi:	2018 **Sivut:** 78

TIIVISTELMÄ

Sähkönjakeluala-asemat ovat tärkeä osa sähkönsiirtoketjua, joka siirtää energiaa tuotantoalueilta loppukäyttäjille. Ne muuntavat jännitetason siirtotasosta, joka on aina 35kV ylöspäin, jakelutasolle, joka vaihtelee 600:n ja 35 kV välillä. Viimeisin kehitys mittamuuntajien alalla on ollut kohti digitaalisia vähätehoisia ratkaisuja, jotka käyttävät digitaalista mittadataa analogisten arvojen sijasta. Tätä mittadataa kutsutaan näytteistetyiksi arvoiksi.

IEC 61850-9-2 standardi ja sen UCA:n julkaisema sovellusohje 9-2 LE määrittelevät rajapinnan näytteistetyille arvoille. Tätä rajapintaa käytetään myös IED:n ja LPIT:n välillä. Päävaatimus näytteistettyjen arvojen käyttämiselle on tarkka aikasynkronointi, jotta voidaan välttyä vaihevirheiltä sekä väärältä suojausfunktioiden laukeamiselta. 9-2LE määrittelee kaksi synkronointimetodia: 1PPS ja PTP. Nykypäivänä PTP:tä käytetään lähinnä länsimaisilla markkinoilla, mutta siitä aiheutuvien kustannuksien, etenkin aikalähteidein ja Ethernet-kytkinten osalta, sekä eri valmistajien yhteensopivuusongelmien takia jotkut markkinat ovat epäileväisiä PTP:n käyttöönoton suhteen. Tämän diplomityön tarkoituksena on ehdottaa edellä mainittuun ongelmaan ratkaisu: IRIG-B:n käyttö synkronointimetodina PTP masterikellossa.

Tässä työssä käydään läpi eroja kolmen eri synkronointitopologian välillä: investointikustannukset, häiriönkesto, aika-tarkkuus sekä luotettavuus ja käytettävyyslaskennat. Työssä suunnitellaan myös yleinen asematason laite, joka pystyy toimimaan PTP aikamestarina IRIG-B syötteellä. Tässä työssä esitellyt tulokset osoittavat, että IRIG-B:n käyttö pääasiallisena tai redundanttina aikasynkronointimetodina on enemmän edullisempi sekä luotettavampi vaihtoehto näytteistettyjen arvojen synkronoimiseen, varsinkin jos asemalla on jo vanhastaan IRIG-B aikalähde. Käsitelty laite täyttää myös IEC 61850-5:n asettaman yhden mikrosekunnin tarkkuusvaatimuksen.

AVAINSANAT: Aikasynkronointi, Precision Time Protocol, Inter-Range Instrumentation Group, näytteistetyt arvot

1 INTRODUCTION

As timekeeping technology developed, life became more planned and structured based on the time of date. Today, the western world revolves around the clock. The need for precise time synchronization for power networks was recognized early as modern microprocessor-based devices became more commonplace. Time stamps for events happening in the power grid had to be somewhat accurate and synchronized between different intelligent electronic devices (IEDs) scattered around the grid. Otherwise, power network operators could not manage fault situations, especially if there was communication, analog or digital, between the different devices.

Digitalization of substation automation (SA) devices brought up new challenges. In the past, different manufacturers used a variety of different standards and guidelines making interoperability very difficult. International Electrotechnical Commission (IEC) together with the power and utility industry sought out to change this. Technical Committee 57 of IEC was responsible for gathering proposals and requirements for the set of standards that were set out to become the IEC 61850 –standard. In 2003 the first edition of IEC 61850 was published, and it became the de facto standard for SA devices by truly enabling vendor interoperability (IEC 61850-1 2013: 7). Most parts of the standard have received a second edition.

Digitalization, with the help of IEC 61850-standard, has brought new ways of transmitting measurement data between devices. Analog measurement values can now be transformed to the digital playing field and transmitted over large distance via fiber optic cables. This is known as sampled values (SV) over process bus communication and it is part of IEC 61850-standard. The main requirement for transmitting accurate measurement values over digital networks is that the devices are synchronized to an accurate synchronization source. With the advent GPS (Global Positioning System) based atomic clock sources, time synchronization accuracy has gone through major improvements.

Today, a wide variety of time synchronization standards are used. These include, but are not limited to, Inter-Range Instrumentation Time Group-B (IRIG-B) and Ethernet-based solutions such as Network Time Protocol (NTP) and IEEE1588 Precision Time Protocol (PTP). These methods have one thing in common. They are all synchronized via some source to a GPS reference clock and provide different devices with the coordinated universal time (UTC) so that they can calculate the required offset to correct their internal clocks. American Electric Reliability Corporation (NERC) requires that all internal clocks in disturbance and monitoring equipment used in power transmission and generation are synchronized to within ±2 ms of UTC (NERC 2006). This covers IEDs as well. The IEC 61850-5 standard recommends that devices are synchronized via the same communication network they communicate by (IEC 61850-5 2013: 61). This basically limits the synchronization methods to Ethernet-based solutions, such as NTP or PTP.

Accuracies differ between those mentioned methods. NTP can obtain accuracy of ±10ms, while IRIG-B format 000 can provide accuracies better than ±500 ns (Peer et. al. 2011: 4). Most accurate of these is PTP. Using PTP with a master that is synchronized with a GPS antenna, sub 100 ns accuracies within the UTC can be obtained (Liu et. al. 2016). The IEC 61850-5 standard also categorizes different accuracy requirements based on different performance classes and this is shown in Table 1. From this table, it can be seen that the most critical process bus and synchrophasor applications require time synchronization accuracy of ±1 µs to the UTC.

Table 1. Synchronization performance classes in IEC 61850-5 (IEC 61850-5 2013: 68).

Performance Class	**Accuracy**	**Application**
T5	±1 µs	Critical process bus and synchrophasor applications
T4	±4 µs	Process bus, synchrophasor
T3	±25 µs	Miscellaneous
T2	±100 µs	Point-on-wave switching, zero crossing, synchronism check
T1	±1 ms	Event time tags (1ms)
T0	±10 ms	Event time tags (10ms)

The problem that comes from this requirement for the highest performance class T5 is that it basically mandates the use of either IRIG-B or PTP. The IEC standard for Sampled Values (SVs) over process bus communication IEC 61850-9-2 Ed. 2 recommends the use of 1 Pulse Per Second (1PPS) or PTP (IEC 61850-9-2), as opposed to only 1PPS of edition 1. 1PPS is a timing pulse requiring a dedicated bus, copper or light conductor, in the same way as IRIG-B does. PTP is a relatively new standard and technology. Thus, stations that want to retrofit an accurate time synchronization scheme over the Ethernet will have to invest into PTP Grandmaster clocks that are synchronized to GPS signal. This investment is then increased even more when redundant topologies are taken into consideration. Thus, a requirement for a solution that fulfils these specifications and can utilize already existing equipment, such as IRIG-B masters, arises. Hence, the market requirement is this: a bay-level device that can act as a PTP grandmaster over the station LAN (Local Area Network) while being synchronized to an IRIG-B source. The aim of this thesis is to study the capabilities of IRIG-B synchronization when used with PTP as a redundant and stand-alone solution and if it fulfils the requirements set by IEC 61850-5 and IEC 61850-9-2 standards.

1.1 ABB Medium Voltage Products

The subject for this thesis was proposed by ABB Medium Voltage Products business unit (BU) in Finland. This work couldn’t have been done without the support from the company and in particularly from the research and development department of the BU. ABB Medium Voltage Products has its roots in the foundation laid by Gottfrid Strömberg and the Strömberg Company which produced its first protective relays in the 60s and first microprocessor based relay was produced in 1982. In the year 1983 Kymi Oy and Strömberg Oy fused together to form Kymi-Strömberg. The Strömberg part of the company was then sold to Swedish ASEA which then formed ABB together with Brown Boweri of Switzerland.

Today, Medium Voltage Products BU in Vaasa, Finland carries the protection legacy of Strömberg delivering around 1500 devices weekly. Every device is manufactured made to order. The BU has a global responsibility for development, marketing, sales and production of Protection and control relays for medium voltage networks including relevant software tools, secondary distribution automation (DA) also known as grid automation solutions. Also, the BU has the responsibility for global operations, customer support and training for the distribution automation business. The research and development department in Vaasa is the global leader for new products and platforms within distribution and substation automation products with close co-operation with other ABB technology centers worldwide. The extensive research and development activities in the Vaasa technology center revolve around hardware, embedded and PC software, communication protocols, protection application, and algorithms. (ABB 2017a.)

1.2 Objectives and scope of the thesis

The objective of this thesis is to examine the advantages of using IRIG-B with PTP as a synchronization method in sampled value applications as opposed to pure PTP systems and if using it is indeed more cost-effective option to increase time synchronization system reliability and availability. Rest of the objectives are to present the necessary theoretical background to the subjects and to introduce a general design of a bay level device capable of acting as a PTP grandmaster while being synchronized with IRIG-B input.

The scope of this work includes the examination of three redundant time synchronization topologies. The examination is done with reliability and availability calculations, cost calculations as well as disturbance handling and accuracy concerns. These are covered in chapter 5. A basic design of a bay level device capable of PTP synchronization with IRIG-B time signal is discussed in chapter 6. Chapter 7 brings everything together and a conclusion is drawn. Everything is then summarized in chapter 8. Chapters 2, 3 and 4 introduce the relevant theoretical background regarding the subject: substation automation systems, time synchronization, reliability and availability calculations.

2 SUBSTATION AUTOMATION

Even though the electrical grid is going to undergo a radical change from ladder type structure to a structure that resembles a web once it gets more complicated, one thing will still be common: electric substations. Substations can be categorized into four different categories: switchyard, customer, system station and distribution substation (Burke et. al. 2007: 1-2). These can then be divided by the equipment used in the substation. These are air-insulated, gas-insulated, outdoor and indoor apparatuses. Those four categories have different responsibilities, but the equipment used within them are similar in nature (Burke et. al. 2007: 2). Digitalization of the electric grid has modernized the substations by switching from mostly mechanically operated and protected substations to automated substations. Different devices participating in the automation of substation functions are called substation automation (SA) devices. SA can be defined as a deployment of substation and feeder operating functions and applications in order to optimize the management of capital assets and enhance operation and maintenance efficiencies with minimal human intervention (McDonald 2007: 2). Different SA devices can then create systems which are called substation automation systems (SAS) respectively.

This chapter describes the most common electric substation type, the distribution substation, the devices within the said station and some protocols used in SA devices. Next topic discussed in the chapter are redundant Ethernet topologies which play a vital role in the reliability of communication within SA architectures.

2.1 Distribution substation

The most common electric substation encountered by the customer is the distribution substation, as they are located close to the load centers. They provide distribution circuits that supply most customers (Burke et. al. 2007: 2). As part of this, the main task of a distribution station is to lower the voltage levels from transmission levels, high voltage, to distribution levels or medium voltage. These levels vary between different countries as the levels are governed by the legislation. In Finland, the voltage levels of the distribution network vary between 110-0.4 kV (Fingrid 2017). A distribution substation can also drop the voltage in increments i.e. from 400 kV down to 110 kV and from 110 kV to 20 kV. This kind of a station attends also in the transmission of electrical power as the 110 kV is transmitted via transmission circuit to different substations.

A distribution substation can be divided into two sides: primary and secondary side. The division is done according to the main transformer which acts as a galvanic separation of the different voltage levels. Transmission level voltage is first measured by a voltage transformer (VT). Then the main station circuit needs to be able to separate from the rest of the network. This is done by using disconnector switches (DCS) and circuit breakers (CB). Current is also measured before the main transformer with current transformers (CT). These devices are controlled by a protection relay. It takes the measurement data from the instrument transformers (IT) and acts according to set parameters. This means that if there is a main transmission level fault in the station, the distribution station can be isolated from the rest of the transmission or the area network. Then the primary voltage level is dropped to secondary level by the main transformer. Some stations have more than one transformer. The feeding capacity of a substation is increased by adding a second transformer. The secondary of the transformer can then be isolated from station busbar by another set of disconnectors and breakers and instrument transformers. These can be controlled by the same transformer protection relay. (Harris & Childress 2007; Momoh 2008)

The secondary of the main transformer is connected to busses or bus bars. Busses are metallic bars that interconnect different distribution bays to the secondary voltage level. Each bay is protected by protection relay measuring the said bay and controlling disconnectors and breakers connected to the bay. Busbars also usually have a dedicated bus bar protection relay, especially if a redundant double busbar arrangement is used. There are 6 common arrangements used: single bus, double bus-double breaker, main and transfer bus, ring bus and breaker-and-a-half arrangement. Detailing the difference between these arrangements is out of scope for this thesis, but an example of a double bus-double breaker in SLD (single line diagram) format is shown in Figure 1. Any particular bay can also be grounded by an earthing switch (ESW) when servicing the bay.

This can be done with a three-position switch acting as a normal DCS as well as an ESW. Different bays then connect to different load centers via distribution lines and cables. Substations form a critical part of separating faults from the electric grid. With SA devices, this separation is done automatically, and the status of the network is monitored via SCADA (Supervisory Control and Data Acquisition) programs. (Bio 2007; Momoh 2008.)

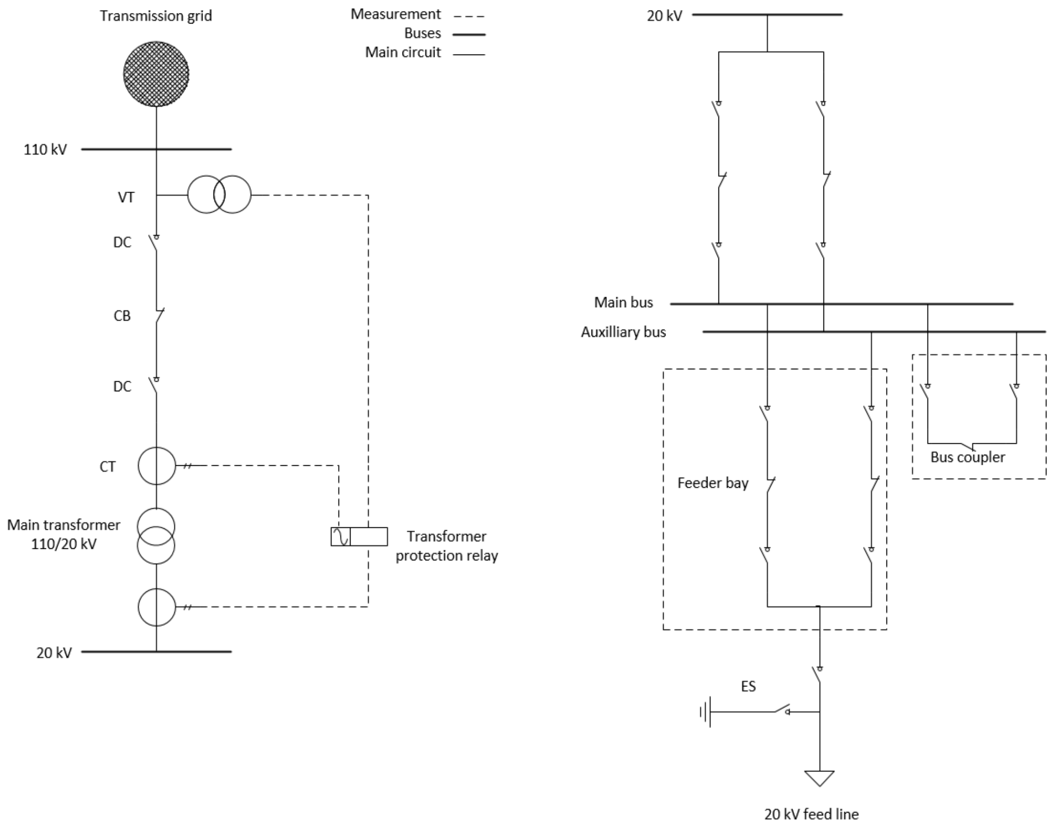

Figure 1. Example SLD of a 110/20kV distribution station section with double bus-double breaker configuration. Control IEDs and ITs from the secondary side are omitted for simplicity.

The future of electrical substations is going to be increasingly digital. Measurement data is being digitalized with the advent of low-power instrument transformers (LPIT) that can be integrated into gas insulated switchgear (GIS). These systems provide more robust solutions as the sensors and transducers used in LPITs do not interface with the main circuit directly, but they measure the voltage and current by other means instead. Thus, in case of a measurement transformer fault, the whole circuit is not subject to the fault circuit. With traditional galvanic transformers, the circuit needs to be cut and a transformer with a winding is inserted into the circuit. GIS with integrated LPITs is shown in Figure 2.

Figure 2. GIS with LPITs. (ABB 2012: 3.)

2.2 Intelligent Electronic Devices

Intelligent electronic devices are a group of devices which control different parts of the substation. These can be protective relays, On Load Tap Changer (OLTC) controllers, Circuit Breaker (CB) controllers, capacitor bank controllers and so on. One thing in common with these devices is that they are microcontroller devices which are user configurable via a setting file and usually they have communication ports, such as Ethernet or serial communication ports. Digital protective relays are the primary IED inside a medium voltage substation. The Institute of Electrical and Electronics Engineers

(IEEE) (IEEE 100 2000: 1336) defines an IED as: “Any device incorporating one or more processors with the capability to receive or send data/control from or to an external source (e.g., electronic multifunction meters, digital relays, controllers).”

2.2.1 Protection relays

One of the IEDs in a SAS is as protection relay or protective relay. They are, as the name suggests, responsible for the protection of the various equipment found in the electrical grid as well as controlling circuit breakers, switches and de-couplers. They operate by detecting abnormal power system conditions resulting in the initiation of appropriate power system changes (Sleva 2009: 34). In the example-SLD shown in Figure 1, a transformer protection relay is responsible for measuring values on both sides of the transformer and controlling the breakers and disconnectors connected to it. It acts as a sort of differential relay by measuring the difference between the terminals. Transformer turn ratio is taken into consideration. If the secondary current and voltage levels do not match the primary side, a fault can then be deduced. The protection relay trips the control equipment, thus separating the faulty transformer from the rest of the circuit.

Previously, protection relays were mechanical, but nowadays they have been replaced with intelligent microcontroller based relays in most substatinons. Communication also plays a big part in the systems. Today’s IEDs can either communicate via binary inputs and outputs indicating various interlocking schemes or they can communicate via a dedicated communication bus: serial or station-wide local area network (LAN). In order to separate a faulty part of the station from the rest of the network and to prevent non-faulty parts from needlessly separating, an interlocking scheme can be deployed using a communication protocol such as GOOSE (generic object-oriented substation event). For example, if a feeder protection relay notices a fault, it can use interlocking by sending a GOOSE message to block other feeder protection relays’ capability of tripping their breaker controllers for a set time. GOOSE is included in the IEC 61850 standard which is explained later.

Protection relays need to be user configurable and settable, so at least a local human-machine interface (LHMI) is needed. Most IED manufactures provide PC (personal computer) based software for configuration as well since most of the protection relays are essentially programmable logic controllers (PLC). Figure 3 shows an ABB RET620 protection relay. The front panel acts as an LHMI, but the IED also has a WHMI (web human-machine interface). LHMI also includes a liquid crystal display (LCD), otherwise setting the relay via LHMI would be difficult. A simplified SLD can also be shown in the LCD and various control functions can also be performed by selecting them from the LCD via the buttons. ABB protection relays can be configured via Protection and Control IED Manager PCM600. A screenshot of PCM600 with a REF615 relay is shown in Figure 4.

Figure 3. RET620 transformer protection relay (ABB 2017b).

PCM600 represents the station layout in the plant structure which is very useful with big projects containing a multitude of relays. Application configuration is also done with programmable logic blocks.

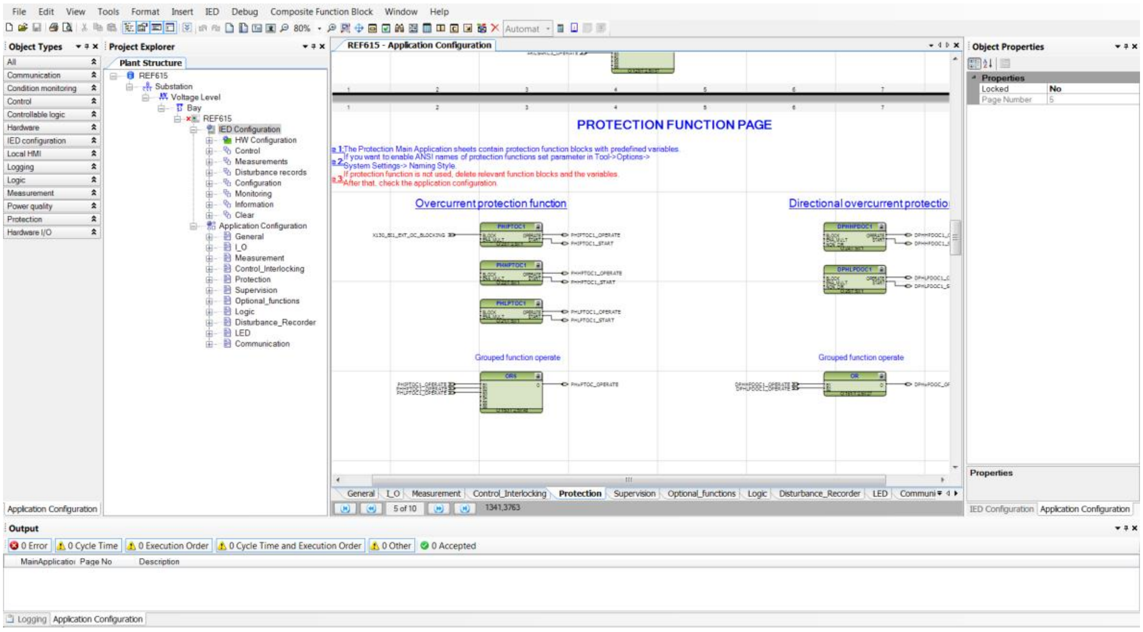

Figure 4. Visualization of the programmable logic blocks in PCM600, as seen in the user interface of PCM600 configuration application.

2.2.2 IEC 61850 – Communication networks and systems in substations

All the functions presented in previous sections would be difficult to accomplish without international and widely accepted industry standards. Previously, IEDs were governed by many different standards and various manufacturers used different practices. This caused interoperability problems. An IEC working group (WG) from the technical committee (TC) 57 has been gathering since the year 1994 to gather ideas for a substation automation network standard. These ideas were then proposed to national IEC committees and they were accepted as the new set of standards found in the IEC 61850 standard. (IEC 61850-1 2003: 11). The scope of the standard was then extended in the second edition published in 2013. The extended application scope of the standard now includes power quality domain, historical data, distributed generation monitoring and automation, feeder automation, substation to substation communication and monitoring functions according to IEC 62271 (IEC 61850-1 2013: 4-5). Other significant technological changes to the previous edition are smart grid considerations (IEC 61850-1 2013: 5).

IEC 61850 –standard has widely accepted as the common industry standard for protection relays. It governs the way relays are configured enabling customers to configure third-party devices with other third-party configuration programs. As the communication interface and data model is also defined, interoperability is achieved in that front as well. As the standard is being expanded to cover the future needs of smart grid solutions, more and more applications are providing built-in support for the standard. IEC 61850 can be seen more as a multi-purpose standard and not just a standard for relay manufacturers.

2.2.3 Merging Units and Sampled Values

One aspect that has been covered in the recent development around the IEC 61850 standard is the digital measurement values, otherwise known as sampled values (SV). These values are measured by ITs and they are converted by a merging unit (MU) which acts as an analog-to-digital converter (ADC) providing the end devices with digital measurement information. A merging unit can either be inside an LPIT, or as an outside device which takes either digital SV streams and combines them into one stream, or by taking phase measurement values from analog ITs. This kind of device is called a stand-alone merging unit (SAMU). SV streams consist of phase measurement data and stream identification data contained in Ethernet frames in application-layer service data units (ASDU). This data is then decoded in the end device and used in monitoring, measurement and even protection schemes. Figure 5 depicts an Ethernet frame containing an SV. Application-layer protocol data unit (APDU) can contain multiple ASDUs.

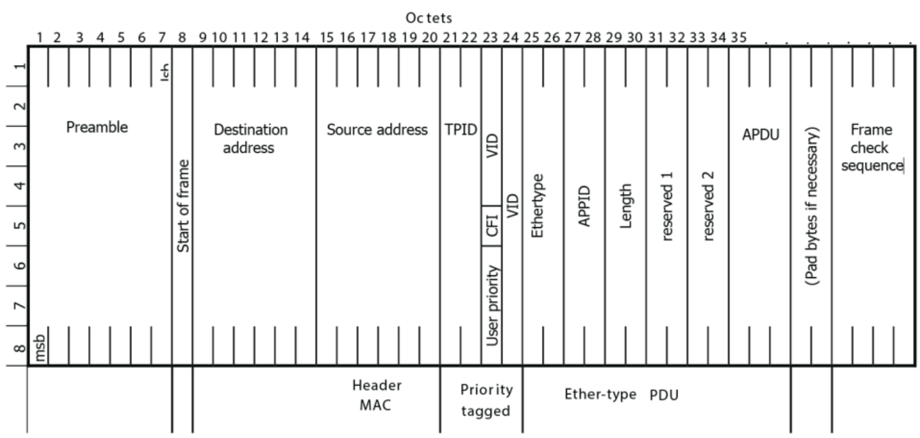

Figure 5. Contents of an SV-Ethernet frame (Derived: UCA International Users Group 2004: 14.)

The SV streams are specified in the IEC 61850-9-2 standard which was later defined more accurately in the UCA published *Implementation Guideline for Digital Interface to Instrument transformers using IEC 61850-9-2*, more commonly referred to as 9-2LE, as the IEC 61850-9-2 only provided details for the data model. UCA international users group is a not-for-profit organization consisting of members of companies in the power utility industry. With 9-2LE, vendor interoperability could be achieved with one vendor providing ITs, other the merging unit, and third the IEDs using those measurement values. A study made in 2011 (Yang et. al. 2011) showed that protection schemes implemented with 9-2LE showed comparable results to traditional schemes. Another study (Yang et. al. 2013) found that despite interoperability being improved with 9-2LE, there are still some difficulties in achieving full vendor interoperability as some vendor combination didn’t work as expected.

9-2LE was expanded and incorporated into the IT family standard series in 2016. It is now defined in the IEC standard for the digital interface for instrument transformers IEC 61869-9. It provides backward compatibility to 9-2LE as well as defining more sampling rates. Preferred sampling rates are 4800 Hz regardless of power system frequency and 2 samples per frame, effectively halving the output publishing rate (IEC 61869-9 2016: 20). There are some MUs on the market already supporting the IEC 61869-9 such as *Siemens SIPROTEC 6MU805* MU (Siemens 2016). However, it hasn’t seen wide use yet as it is as of publication of this paper a very new standard.

2.3 Redundant communication topologies

Since more and more functionalities have been and are being moved to the Ethernet network, ever-increasing attention needs to be placed on the communication network security and reliability. Redundancy as a concept is not a new one. Redundant communication means that in case of main communication bus failure, a backup bus is used instead. Redundant communication tolerates a single failure, thus, increasing the availability of the whole system. This is important especially when time synchronization for the system is provided via the same communication link. There are two common redundant topologies used in SAS: Parallel Redundancy Protocol (PRP) and High-availability Seamless Redundancy (HSR) protocol. These are standardized by the IEC 62439-3 –standard. Both share the same concept of zero switchover, i.e. they do not reconfigure or cut off the communication, redundant communication topology, but they differ in execution. With PRP it is easier to incorporate non-redundant equipment into the network, but it is also more expensive as every network switching component is duplicated, whereas HSR is more cost effective by implementing redundant rings in the network (ABB 2010: 60, Taikina-aho 2011: 67).

2.3.1 Parallel Redundancy Protocol

PRP is covered in clause 4 of the IEC 62439-3 –standard. As the name would suggest, the main concept of PRP is to provide a parallel network path for every device. This means, that every supporting node in the network is connected to another with dual connections. This can be achieved with two Ethernet switches, each switch acting as a redundant network hub. Illustration of PRP is shown in Figure 6. Different redundant networks are separated by colour. PRP operates by replicating each frame on the sending node to the two independent networks. The receiving node processes the first arriving frame and then discards the copy. Responsibility for the hiding of the two networks from the upper levels and replicating and discarding is in the hands of the PRP layer. (Weibel 2008.)

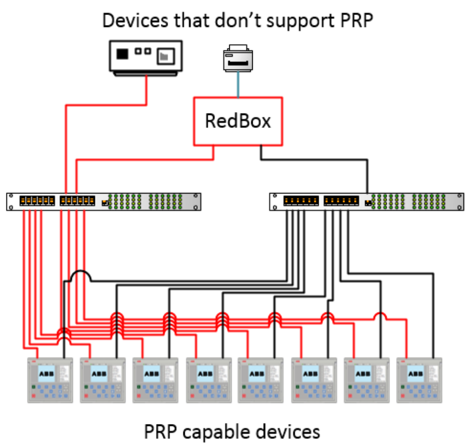

Figure 6. Example of a PRP topology with a RedBox and a singly attached node.

Devices that do not support PRP can be added to the network by using redundancy boxes commonly known as RedBoxes. They provide frame discarding and duplication functionalities for the devices downstream. Otherwise, uncritical nodes can be attached to only one of the networks as in Figure 6, making them singly attached nodes. These singly attached nodes must be attached to the same network. In the case of doubly attached nodes, or nodes attached to both networks, discarding of the duplicate message is handled in the application layer.

2.3.2 High-availability Seamless Redundancy

As opposed to PRP, HSR works by duplicating paths with redundant rings. Devices supporting HSR in the ring are connected to each other dually. Ring ends can then be connected to an HSR capable switch. Some devices have an interlink port or ports as well, where HSR incapable devices can connect to. Figure 7 shows an example HSR topology with message directions. The basic principle of message duplication is different from PRP. An HSR device sends the message to both directions, clock-wise and anti-clock-wise, simultaneously. Whichever message arrives first at the wanted destination is kept and the later received duplicate is discarded. This means that if one of the redundant links is broken, the message is received through the other way. In Figure 7, RedBox discards the later arrived duplicate and removes the HSR encapsulation for the HSR incapable device receiving the message. (Hirschmann 2014.)

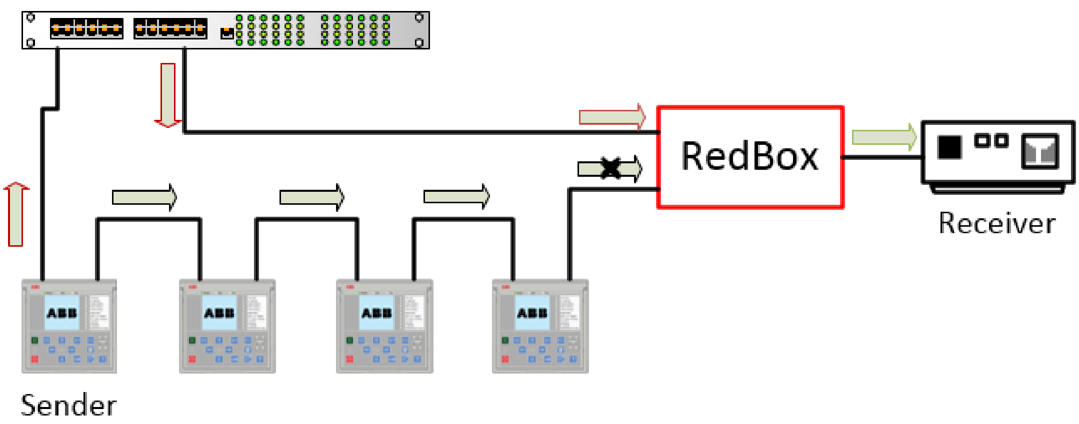

Figure 7. An example of an HSR topology with message direction.

Unlike PRP, HSR devices encapsulate Ethernet frames with an HSR header, and this means that duplicates are recognized as soon as the HSR header has been read (Hirschmann 2014). Drawbacks of using HSR over PRP is that incorporating devices without HSR support is much more difficult making HSR network more difficult to expand as RedBoxes are mandatory for every device that is not HSR capable. This is the case for the message receiver in Figure 7. Additional difficulties with HSR comes when using PTP synchronization in HSR networks. IEEE 1588/IEC61588 standard does not allow loops in the network. Therefore, IEC 62439-3 standard specifies how PTP works inside HSR rings (IEC 62439-3 2016: 103-113).

3 TIME SYNCHRONIZATION

As it was mentioned before the need for accurate time synchronization in the devices connected to the power grid was recognized very early. When talking about time-critical applications, such as process bus communication, time synchronization is one of the most important aspects. The IEC 61850-5 standard requires that the most critical process bus and synchrophasor applications have a time synchronization accuracy of ±1 μs (IEC 61850-5 2013: 68). This automatically eliminates some of the time synchronization methods available. The scope of this thesis contains two methods that fulfil the requirement: PTP and IRIG-B.

3.1 Precision Time Protocol

As the amount of transferable data via the Ethernet in ever shortening time grew, it enabled the possibility to use communication networks to transmit time synchronization information. Precision Time Protocol (PTP), or IEEE1588/IEC 61588 as the standard is known, is an IP multicast communication based standardized time synchronization protocol originally developed by Agilent for distributed instrumentation and control tasks (Industrial Networking 2006: 1). As Ethernet networks can vary in size, traffic and complexity, the only possibility to have accurate time information circulating between devices in the network, is to know the message delay between each node in the network. PTP works in this way.

PTP is an application layer protocol in the OSI (Open Systems Interconnection) model and it operates over IP (Internet Protocol) and UDP (User Datagram Protocol) protocols. The main idea of PTP is to synchronize each device in the network to the most precise clock. This clock is determined via best master clock (BMC) algorithm and it is explained more thoroughly later in section 3.2.6. It is basically a comparison algorithm. Now, one clock acts as the master and the rest are deemed as slaves to it. Clocks are categorized into three clock categories: ordinary clock (OC), boundary clock (BC) and transparent clock (TC). A clock, or device, with only one network port, is termed an OC. A clock with multiple network ports is deemed as a BC and clocks which do not themselves synchronize over PTP but do participate in transmitting information between devices is termed as a TC. These clock types are explained more thoroughly in section 3.1.4. (IEC 61588 2009, Industrial Networking 2006: 3.)

3.1.1 Synchronization

Slaves are synchronized to a master clock by exchanging messages with it. Synchronization is divided into two phases: offset calculation and delay measurement. Bidirectional multicast communication is used by the slaves to synchronize to the BMC. First, the offset between the slave and the master is calculated. This is done by cyclically transmitting a unique synchronization (SYNC) message to the relevant slaves. The SYNC message contains the timestamp of when the message was transmitted, or in the case of a two-step synchronization, the timestamp is transmitted in a follow-up message. Difference between single-step and two-step synchronization methods is explained more thoroughly in section 3.1.2. The slave then notes when the sync message was received. Now the slave knows two timestamps: t_1 and t_2. In the second phase, the slave then sends delay request message to the master and takes note of this sending timestamp t_3. The master now receives the delay request message and notes the reception time t_4 and conveys this timestamp to the slave by embedding it in the delay response message. The slave can now process these timestamps to compute the offset and the mean propagation time of messages between these two clocks. This message exchange is shown in Figure 8. (IEC 61588 2009: 34.)

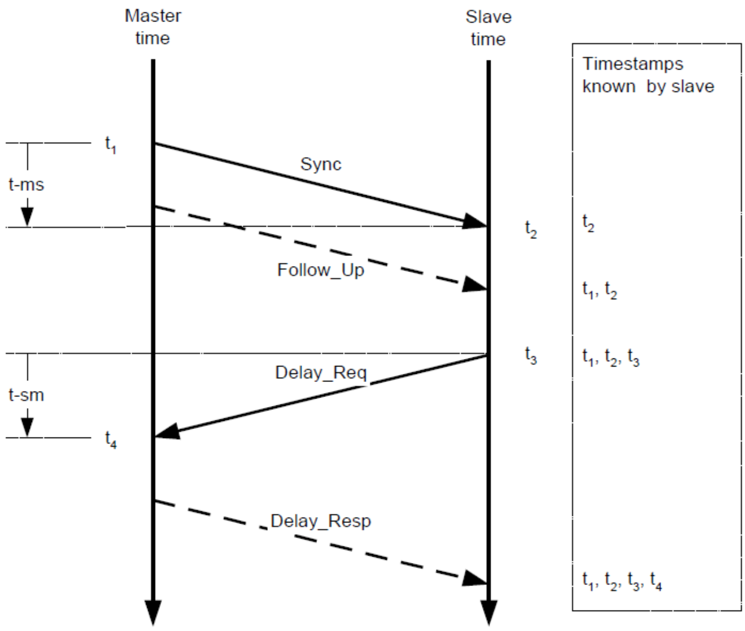

Figure 8. Basic synchronization message exchange. (IEC 61588 2009.)

3.1.2 One-step and two-step synchronization

In PTP, there are two ways to transmit timestamps used in the offset and delay calculations. It can be either contained in the SYNC-message or in a follow-up message which is sent after the original SYNC-message containing the transmitting timestamp of the SYNC-message. One-step synchronization uses the former and two-step the latter. IEC 61588-standard requires that all slaves work with either type. This is indicated by the twoStepFlag in the SYNC-message. If the flag is true, then it was sent from a two-step clock. (IEC 61588 2009.)

As slaves must support both methods, this is not an issue when building communication networks. This is only an issue for manufacturers as one-step timestamping can be considered harder to implement. To maintain high accuracy in one-step synchronization the timestamping must be done closest to the physical port and this usually requires a dedicated chip known as physical layer (PHY) chip. PHY timestamping has been shown to yield the most accurate synchronization solution (Weibel & Béchaz 2004: 3). One-step synchronization is more difficult in term of designing TCs such as Ethernet switches. One-step clocks require on-the-fly correction field updates, but two-step clocks require that the software remembers the dwell time of SYNC message matching it to the corresponding follow up message (Meinberg 2017a).

3.1.3 Peer to peer and end to end delay measurement mechanisms

In Section 3.1.1 a basic synchronization mechanism between two clocks was shown. When considering PTP time synchronization of a whole network the mechanism needs to be expanded. There are two options: peer to peer (P2P) or end to end (E2E) mechanism. The basic difference is that if the whole network, including switches, support at least TC level clocks then P2P should be used in order to achieve the highest accuracy. But if some intermediary devices, usually Ethernet switches, do not support PTP then E2E has to be used.

P2P delay measurement mechanism means that every node in the network knows the delay between it and every other physically connected, meaning straight connection and not through other nodes such as Ethernet switches, node. Instead of delay request messages, P2P devices send peer delay requests and responses periodically with other clocks in the network. Thus, the cumulative delay between two points in the network is more deterministic and accurate and the slave time can simply be calculated by adding network delay to the master time. E2E delay measurement mechanism only takes the delay between two end devices into consideration thus the slave timestamp is then calculated as a collection of timestamps from the devices between the slave and the master. Simplified difference between these two mechanisms is shown in Figure 9.

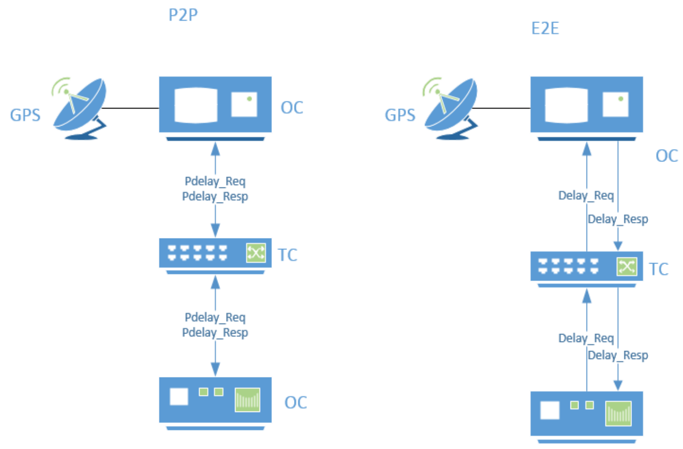

Figure 9. Difference between P2P and E2E delay measurement mechanism.

3.1.4 PTP clock types

As stated earlier, PTP clocks can be categorized into three categories: OC, BC, and TC. OCs can be categorized into three more categories: slave only, preferred grandmaster and master clock or slave clock. Slave only OCs will only be slaves to another OC in the network. Preferred grandmaster OCs will be just the opposite. Master or slave OCs will be slaves to another clock in the domain unless there are no better clocks available at which point they will become the grandmaster clock. Examples of OCs are GPS-grandmasters and IEDs. (IEC 61588 2009: 19-20, Meinberg 2017a.)

When tackling the issue of message queues, routers and switches are the main focus. The IEC 61588 -standard defines two clock types for switches and routers: BC and TC. Boundary clocks have one port which is in a slave state synchronized to a master and all other ports are in a master state distributing time to downstream devices. Basically, it takes the SYNC messages from one port, sets its own clock and generates new SYNC messages through the rest of the master ports. Transparent clocks correct the SYNC, or in the case of two-step synchronization the follow-up, message in the egress port. Ingress time stamp is measured once the message enters the device, preferably on the PHY layer, and when it leaves the device the timestamp is corrected with the residence time. This means that two-step TCs are easier to implement since they do not have to process timestamps on the fly, instead, the SYNC message prepares TC to modify the upcoming follow-up message. (IEC 61588 2009: 20-29.)

3.1.5 PTP clock datasets

Every PTP clock stores its features to datasets. Different types of clocks have different datasets that they need in order to participate in the BMC algorithm as well as communicate between other clocks. Appendix 1 represents the main clock datasets, which are presented in the IEC 61588-standard, in tables. Some of the datasets are shared with PTP messages and some are internal.

3.1.6 PTP message types

In order to participate in the BMC algorithm, synchronize other clocks and find out the delay between nodes in the network, periodical messages have to be sent. The IEC 61588 standard details these messages. Every message contains header information. It contains, for example, the domainNumber and the sourcePortIdentity information. Announce messages contain the most important fields when it comes to BMC algorithm and clock capability. The announce message according to IEC 61588 is shown in Table 2. In addition to these, announce messages contain stepsRemoved, currentUtcOffset dataset members and the message origin timestamp in originTimestamp. (IEC 61588 2009: 124-129.)

Table 2. Announce message fields. (IEC 61588 2009: 129).

Bits								**Octets**	**Offset**
7	6	5	4	3	2	1	0		
header								34	0
originTimestamp								10	34
currentUtcOffset								2	44
reserved								1	46
grandmasterPriority1								1	47
grandmasterClockQuality								4	48
grandmasterPriority2								1	52
grandmasterIdentity								8	53
stepsRemoved								2	61
timeSource								1	63

Sync- and Delay_Req-messages contain originTimetamp and Follow_Up-message contains the more precise preciseOriginTimestamp. If one-step synchronization is used, then the precise timestamp is included in the Sync- and Delay_Req-messages. Delay_Resp-messages contain the timestamp of previous Delay_Req-message once it was received and the identity of the requesting port in receiveTimestamp and requestingPortIdentity fields respectively. When P2P delay calculation mechanism is used then Delay_Req- and Delay_Resp-messages are swapped with Pdelay_Req- and Pdelay_Resp-messages. In order to eliminate asymmetry errors caused by messages with unequal lengths, Pdelay_Req messages are padded with 10 octets of reserved bits. Otherwise, the message is the same as Delay_Req message. On the other hand, Pdelay_Resp messages contain requestReceiptTimestamp as well as the requestingPortIdendity fields. Name of the receiving timestamp is different since the delay mechanisms use different calculation methods as detailed in section 3.1.3. If two-step synchronization is used, then with P2P Pdelay_Resp_Follow_Up messages are used to respond to Pdelay_Req. This message includes responseOriginTimestamp as well as the requestingPortIdentity fields. (IEC 61588 2009: 130-132.)

3.1.7 Best master clock algorithm

When deciding which OC is the best clock suitable to be the grandmaster clock for the whole network IEC 61588 -standard defines an algorithm which is used at the network layer in order to determine which clock is the best master clock. This takes the clock datasets into consideration and compares master capable clocks one by one. Figure 10 represents the algorithm. (IEC 61588 2009: 88.)

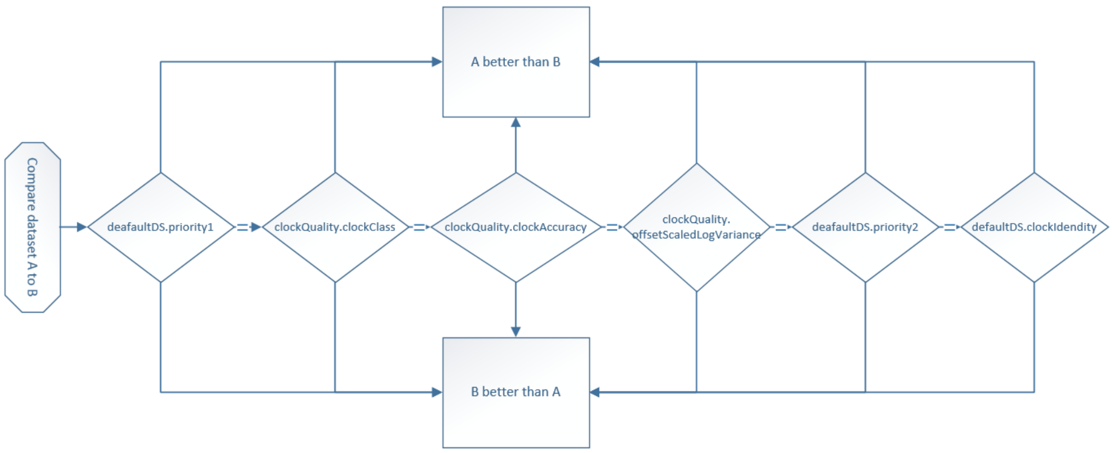

Figure 10. BMC comparison algorithm. (Modified from IEC 61588: 89.)

The BMC is determined based on information contained in Announce messages received and defaultDS dataset values of a given clock. Each clock computes only the states of its ports and does not take into consideration other clocks as such. First, every clock that can act as a master participate by sending announce messages containing the required information shown in Figure 10. During this listening period, which is four announce message interval long, every clock then compares announce messages to their own and decides if there is a better master clock in the network. This announce message comparison runs continuously at set intervals to see if the current master has dropped and a more capable master has emerged.

3.1.8 PTP profiles

The IEEE 1588/IEC 61588 standard also states that different profiles with selected features can be used with PTP for different applications. The standard only defines a specific set for the default PTP profile. Rest are left to different family standards to adopt. IEEE C37.238-2011 Power Profile is a widely used PTP profile in the power industry. In 2016, IEC/IEEE 61850-9-3 set the profile for power utility automation known as the Power Utility Profile and it is based on the IEEE C37.238-2011 Power Profile. And in 2017, IEEE revised the power profile with IEEE C37.238-2017 and it is, in turn, a modification of IEC/IEEE 61850-9-3.

3.1.9 Future of PTP

As of writing this thesis the next edition of PTP is under work, but it is stated to be *feature complete* and is slated to be released in the year 2018. Additions and improvements made to the standard are done in order to make the standard clearer, more flexible, more robust and more accurate (Meinberg 2017c). This, however, does not improve the actual validity of the BMC algorithm. It is touted as being the key part and key weakness of the PTP standard (FSMLabs 2017). Because of the nature of the algorithm, there is no actual checking done by the clients if the grandmaster is actually the *best master clock.* This results in faulty synchronization if the grandmaster sends out synchronization while claiming to be accurate. There should be a possibility to add intelligence to the client side. Some sort of majority voting system could be added to deem the actual best master clock. This would require additional research.

3.2 Inter-Range Instrumentation Group time codes

The need for accurate timestamping for data measured in different geographical locations arose in the missile and space industry. The early development of serial time codes was largely done by governmental space and military organizations. One of these organizations is the standards body of the Range Commanders Council (RCC) known as the Inter-Range Instrumentation Group (IRIG). IRIG proposed a series of time code formats that would be later known as NASA codes and based on these, the IRIG Standard Time Code Formats were proposed becoming the industry standard for serial time synchronization. (Endrun 2017.)

The latest version of the IRIG-standard IRIG standard 200-04 was published in 2004 by the RCC. It defines the characteristics of different time codes characterized alphabetically: A, B, D, E, G, and H. These differ mainly in their respective information publishing rates. Different time codes can then be categorized by a three-digit number signifying the modulation type, carrier frequency, and the coded expressions. In the scope of this thesis is the B time code as it is the most commonly used time code in the power utility industry. Rest are out of scope.

3.2.1 Time code B

IRIG-B is a time code containing binary coded decimal (BCD) formatted time-of-year information in days, hours and minutes, 17 bits of straight binary seconds (SBS) coded seconds-of-day, 9 bits for year information and lastly, 18 bits for control functions. This message is then published at a rate of 1 Hz and the signal consists of 100 pulses per second (PPS). The time frame of IRIG-B format is shown in Figure 11. (IRIG 200-04 2004.)

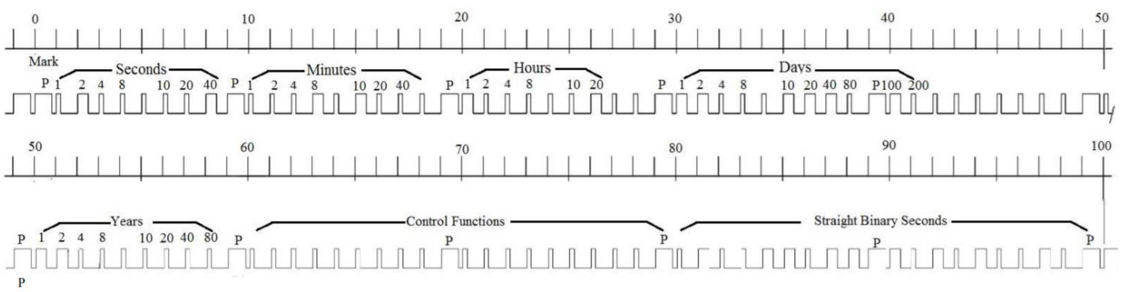

Figure 11. IRIG-B time codification of information. (Razo-Hernandez et. al. 2016: 3)

IRIG-B has three kinds of voltage level dwell time coded symbols: reference, IRIG zero and IRIG one. These are shown in Figure 12. Depending on the used output format, the signal is either modulated or bit-time coded. The most common serial time code is the unmodulated DC (direct current) format or B00x (Razo-Hernandez et. al. 2016: 3). This can be seen as the first signal in Figure 12.

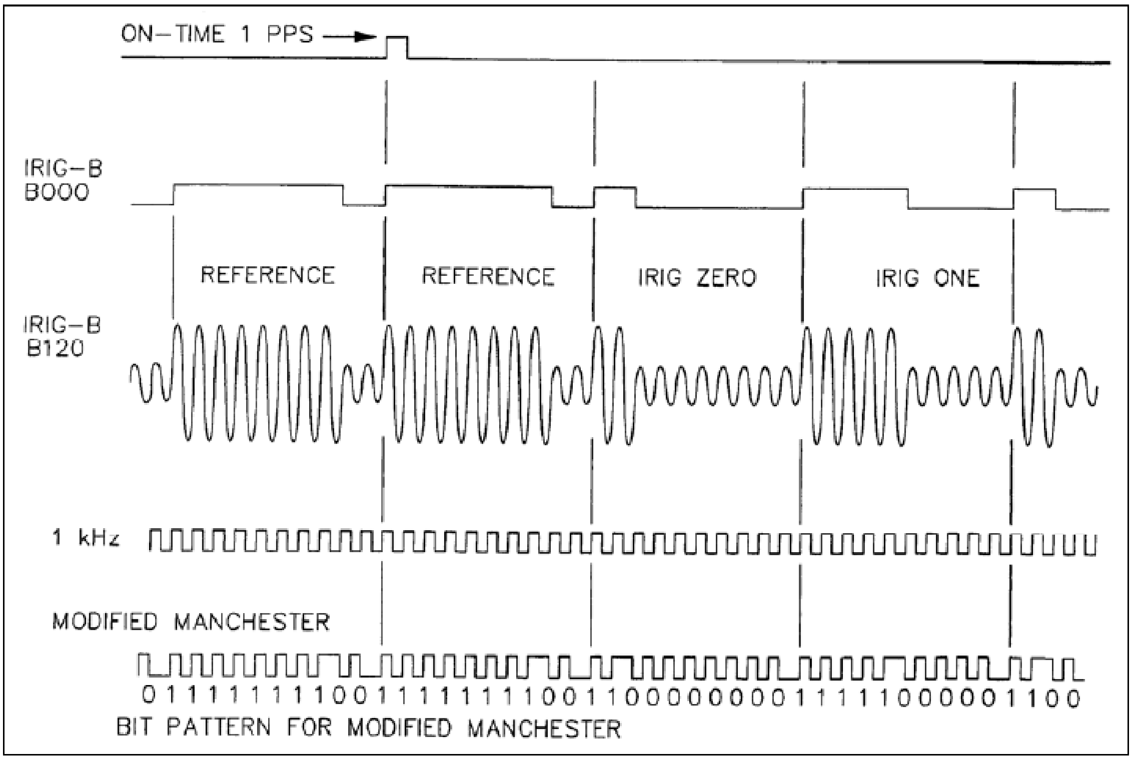

Figure 12. IRIG-B waveform, TTL and Manchester coding (IRIG 200-04 2004: 30).

From Figures 11 and 12 can be seen that every field starts with a reference marker, also known as position indicators. They are used by the receivers to indicate where every coded field ends and where another starts.

The third digit in the format tells the coded expressions used. Table 3 shows these expressions. When considering the use of IRIG-B as a reference time source for PTP, then the year information would be needed. It can be obtained from codes 4 to 7, but 4 and 5 also contain control flags (CF) or control bits. IRIG-standard does not specify what to do with those specifically. It is left for different industries to create guidelines on how to use them.

Table 3. IRIG coded expressions. (Modified from IRIG 200-04 2004: 23).

Code	**Expressions**
0	BCD_{TOY}, CF, SBS
1	BCD_{TOY}, CF
2	BCD_{TOY}
3	BCD_{TOY}, SBS
4	BCD_{TOY}, BCD_{YEAR}, CF, SBS
5	BCD_{TOY}, BCD_{YEAR}, CF
6	BCD_{TOY}, BCD_{YEAR}
7	BCD_{TOY}, BCD_{YEAR}, SBS

3.2.2 Standard extensions for control field assignments

The RCC has left control bits to be assigned according to the needs of different applications. This has been done by different standardization organizations such as IEEE (Institute of Electrical and Electronics Engineers). One such need when considering the power utility industry is the handling of leap seconds. As IRIG-B signal is broadcasting UTC with or without a local offset, downstream devices are subjected to leap seconds. Devices act differently when subjected to sudden jumps in seconds. IEEE noticed this and proposed that control bits could be used to warn devices of a coming leap second in the IEEE standard 1344-1995 (IEEE 1344-1995 1995: 3). Also included in this extension set are daylight savings, local time offset, time quality and a parity bit for correct data assurance. This extension was then adopted in Annex D of *IEEE Standard for*

Synchrophasor Measurements for Power Systems which was then revisioned in 2011 as IEEE C37.118.1-2011 –standard (IEEE C37.118.1-2011 2011: 39). The only difference is the swapping the sign of the local time offset.

Leap seconds are a way of combatting Earth's irrational rotation adding or subtracting a second whenever UTC gets to 0,9 seconds out of synch with the atomic time (TAI). As of writing this thesis, 37 leap seconds have been added to UTC and all of them have been positive. IEEE 1344-1995/IEEE C37.118 extension is the most widely used in the power systems industry, but not all masters support it. This can cause difficulties in selecting the correct master for the end devices. Alternatively, end devices should be designed to handle unannounced leap seconds without catastrophic results. In 2012, leap second caused temporary outages in some Internet services and before that, reportedly, a new air-traffic control radar system suddenly replayed radar tracks from exactly one year prior during a leap second event (Wolman 2015).

4 RELIABILITY AND AVAILABILITY ANALYSIS

When conducting project work around SAS, one key factor when deciding different devices and topologies is the reliability and availability of the whole SAS. Many governments have introduced stricter regulations around power outages. This has effects on the planning phase for power utility companies. One tool that can be used in deciding over systems and topologies is the reliability and availability analysis. If a device can be seen as reliable, then it needs to fit a certain time frame where it is expected to fulfil its requirements and function normally. In reliability engineering, it is defined as the probability of success and it can be measured with failure rate λ, the instantaneous rate of failure per unit of time. In the case of SAS, usually, this can be analysed in mean time to failure (MTTF) rates. MTTF gives an approximation for the time of failure for every device and it is defined with:

$$MTTF = \int_0^\infty R(t)\, dt = \int_0^\infty e^{-\lambda t}\, dt = \frac{1}{\lambda}, \tag{1}$$

where $R(t)$ is the reliability exponential distribution function and t is the unit of time. (Kanabar 2011: 176-177.)

Another common metric in reliability engineering is the availability index. Availability is defined as the ratio of the total time a functional unit is capable of being used during a given interval to the length of the interval. Together with MTTF, this can be calculated with the mean time to repair (MTTR) and usually in SAS calculations MTTR is assumed to be eight hours. Availability A is calculated with the following (Kanabar 2011: 177):

$$A = \frac{MTTF}{MTTF+MTTR}. \tag{2}$$

4.1 Reliability and availability calculation

The calculated (Billionton & Allan 1992; Anderson et. al. 2005) MTTF and availability for different SA devices are shown in Table 4. Calculations were carried out with the assumption that the failure event modes are independent, the reliability of the communication link is so high that it isn't taken into consideration and that the MTTR is eight hours for the individual components.

Table 4. Reliability and availability of substation automation devices (Kanabar & Siddhu 2011).

SAS component	MTTF / [a]	Availability
Protection IED	150	0,999993912
Control IED	150	0,999993912
Merging Unit	150	0,999993912
Ethernet Switch	50	0,999981735
Time synchronization	150	0,999993912

4.2 Reliability block diagram method

With the calculations and formulas shown in this chapter individual reliability and availability for SA devices is now known. But when considering whole system reliability and availability, more calculations must be made. Reliability block diagram (RBD) method can be used to simplify the calculations and it provides a visual representation for system analysis. The basic gist of the RBD method is to take the system topology into consideration. If a function requires multiple devices in order to work, then these devices are put in series. If there is a possibility for the function to work through redundant means, then these redundant devices are put in parallel. Visually these can be presented as in Figure 13. (Kanabar & Siddhu 2011.)

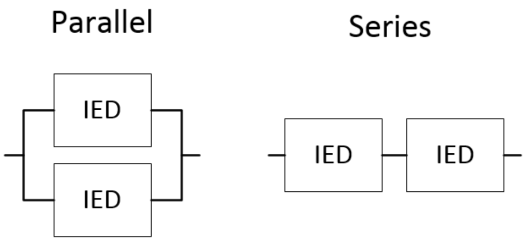

Figure 13. Parallel and series RBD representation of a function that requires two IEDs.

MTTF and availability calculations for series and parallel functions can be calculated after building RBD representations of the whole systems. Reliability for the series system can be calculated with the following:

$$R_s(t) = R_1(t)R_2(t) = e^{-\lambda_1 \mathrm{t}} e^{-\lambda_2 \mathrm{t}}. \tag{3}$$

Combining formula (3) with formula (1) yields us the MTTF for the series system:

$$MTTF_s = \int_0^\infty R_s(t)\, dt = \int_0^\infty e^{-(\lambda_1+\lambda_2)\mathrm{t}}\, dt = \frac{1}{\lambda_1+\lambda_2} = \frac{MTTF_1 \cdot MTTF_2}{MTTF_1+MTTF_2}, \tag{4}$$

where indexes 1 and 2 signify the two devices.

Availability for the series system A_s can be calculated more easily by multiplying individual availabilities together:

$$A_s = A_1 \cdot A_2. \tag{5}$$

For parallel systems, the reliability function R_p is:

$$R_p(t) = R_1(t) + R_2(t) - R_1(t)R_2(t) = e^{-\lambda_1 \mathrm{t}} + e^{-\lambda_2 \mathrm{t}} - e^{-(\lambda_1+\lambda_2)\mathrm{t}}. \tag{6}$$

MTTF for the parallel system is then calculated combining formulas (1) and (6):

$$MTTF_p = \int_0^\infty R_p(t)\, dt = \frac{1}{\lambda_1} + \frac{1}{\lambda_2} - \frac{1}{\lambda_1+\lambda_2} = MTTF_1 + MTTF_2 - \frac{MTTF_1 \cdot MTTF_2}{MTTF_1+MTTF_2}. \tag{7}$$

Availability for the parallel system is calculated with the following formula (8):

$$A_p = A_1 + A_2 - A_1 \cdot A_2. \tag{8}$$

With the formulas represented in this chapter even complicated systems reliabilities and availabilities can be calculated since every system can be divided to parallel and series representations and these can be calculated one by one, eventually leading to the system level reliability and availability. (Kanabar & Siddhu 2011.)

5 COMPARISON OF TIME SYNCHRONIZATION TOPOLOGIES

Previously, communication network and time synchronization distribution have used separate paths with latter using coaxial cabling. Now with network based time synchronization protocols such as NTP or PTP, synchronization and communication can use the same infrastructure minimizing cabling. However, in the case of station expansion, this usually means replacing previous network equipment, such as switches, with new ones thus increasing costs. One solution to this problem is to expand networks with retrofits utilizing the already existing equipment.

IRIG-B is one of the most popular time synchronization methods distributed via coaxial cabling. Therefore, it was chosen as the second method of synchronization for this case study. This chapter takes a look at a simple redundant substation topology where communication network and synchronization distribution are separated. A simple feeder bank is chosen as a subject of closer investigation as it gives a good starting point when considering different retrofitting options. Figure 14 presents the original station feeder bank. Much of the equipment is omitted as it does not play a role in time synchronization. These include, but are not limited to, connections to other banks, station communication devices, station computers, and printers.

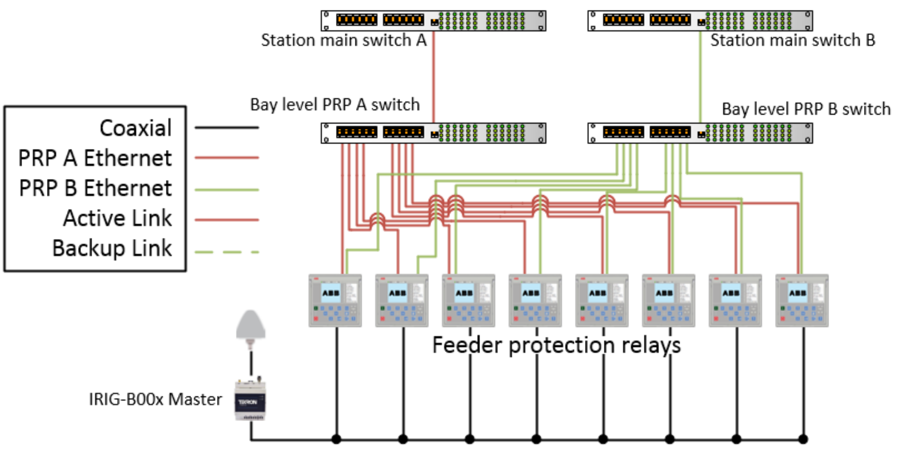

Figure 14. Case substation feeder bank section.

Three requirements are set. First requirement is to upgrade relays to more current technology and to PTP time synchronization in order to enable the use of sampled values in protection schemes. Secondly, the goal is to reduce cabling by eliminating coaxial wiring used to propagate the time synchronization signals. Thirdly, the accuracy requirements for the bay level devices have to exceed T5 class of IEC 61850-5 ed.2 so that IEC 61850-9-2 sampled values can be used in the system. Thirdly, redundancy must be improved from the starting point. Goal is to minimize the single point of failures (SPOF) on a given system.

It can be immediately seen where the single point of failure lies in this system: The IRIG-B master. There is a limit to the number of devices it can provide time synchronization to and distributing the time synchronization signal to other banks is limited so probably requiring multiple masters and antennas. These reasons make IRIG-B not desirable when building new substations.

This chapter presents 3 different cases. All of them utilizing same PRP network and PTP as the synchronization method. Each case is presented in its own section. Accuracy characteristics, SPOF, disturbance handling, reliability and availability calculations and investment costs associated with every case is also discussed. Cost calculations are based on approximated list prices where applicable. There are also many different manufacturers with a variety of modular options as well, therefore only a specific set with similar options have been chosen to do this comparison.

5.1 Case 1: Redundant PTP topology with PTP GPS clock

The first solution case utilizes PTP time synchronization over the whole substation network. Redundancy is fulfilled using PRP-capable PTP master. Many GPS PTP grandmasters do not have this functionality, so achieving full redundancy would require two masters. Figure 15 presents the topology of case 1.

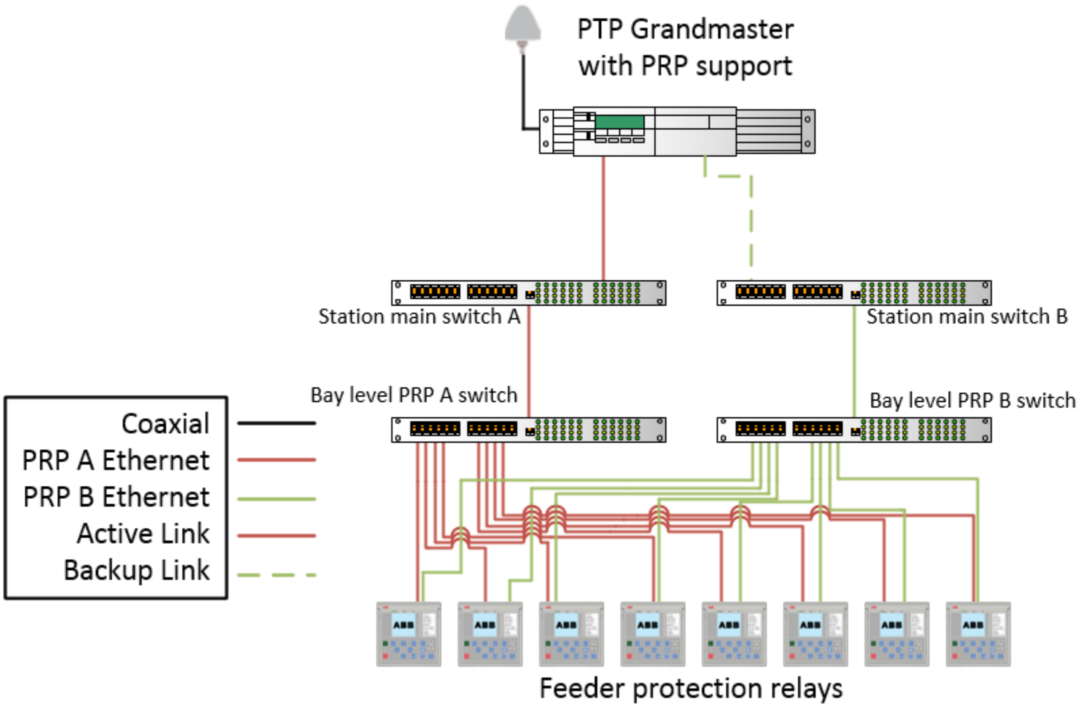

Figure 15. PRP redundant topology with PTP time synchronization.

5.1.1 Accuracy

PTP is capable of sub-microsecond accuracies as presented in chapter 3. With GPS-masters and PTP compliant devices, accuracies of ±100ns can be achieved. This means that requirement of ±1µs is fulfilled with this system. But only if the PTP master is available. Otherwise, quality of internal oscillators of substation network devices determines the accuracy.

5.1.2 Disturbance handling and reliability calculations

The SPOF of this system lies in the single PTP grandmaster. If this fails, then the first secondary master as deemed by BMC algorithm acts as the synchronization source for the rest of the system. This would lower the accuracy rating of the synchronization, but all of the relays would be synchronized to a single source thus achieving station wide synchronization. This is usually done by setting one of the station switches as a boundary clock with second highest priority. Another way is to let BMC decide the device. This will select the next best accuracy as the time reference. Rest of the paths are redundant in this system, so a switch failure will not affect the same way.

For reliability calculations, the time synchronization signal path in terms of the last user, which is a slave IED, is examined. With this topology, every IED is a slave to the master in the upper chain. Taking this into consideration the time synchronization signal is a parallel path with two Ethernet switches in series connecting to the slave IED. RBD of this topology is represented in Figure 16.

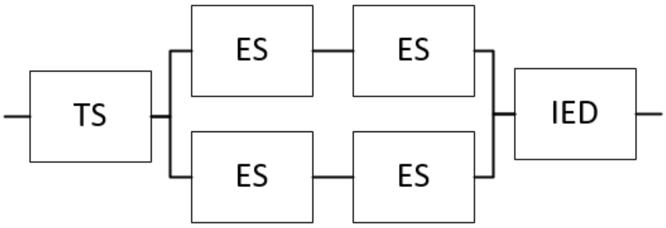

Figure 16. RBD of case 1 topology.

Now with RBD from Figure 16 MTTF and availability can be calculated for the whole system with time synchronization point of view. With the help of formulas found in chapter 4, MTTF calculation for double parallel Ethernet switches can be represented by formula:

$$MTTF_{DPES} = \frac{MTTF_{ES}}{2} + \frac{MTTF_{ES}}{2} - \frac{\frac{MTTF_{ES}}{2}\frac{MTTF_{ES}}{2}}{\frac{MTTF_{ES}}{2}+\frac{MTTF_{ES}}{2}} = \frac{3}{4}MTTF_{ES} \tag{9}$$

Now the system can be calculated as three-part series connection:

$$MTTF_{case1} = \frac{1}{\frac{1}{MTTF_{TS}}+\frac{1}{\frac{3}{4}MTTF_{ES}}+\frac{1}{MTTF_{IED}}} = 25\ a, \tag{10}$$

where $MTTF_{TS}$ = MTTF for time synchronization, $MTTF_{ES}$ = MTTF for Ethernet switches and $MTTF_{IED}$ = MTTF for IEDs found in Table 4.

Availability can be calculated with formulas shown in chapter 4. Availability for double parallel Ethernet switches is:

$$A_{DPES} = A_{ES}^2 + A_{ES}^2 - A_{ES}^2 \cdot A_{ES}^2 = A_{ES}^2(2 - A_{ES}^2) \tag{11}$$

Now, for the whole topology:

$$A_{case1} = A_{TS} \cdot A_{ES}^2(2 - A_{ES}^2) \cdot A_{IED} = 0{,}999987823, \tag{12}$$

where A_{TS} = availability for time synchronization devices, A_{ES} = availability for Ethernet switches, A_{IED} = availability IEDs found in Table 4.

5.1.3 Investment costs

This system case requires a high amount of investment as everything needs to be updated if sub-microsecond accuracies are required in the bay level devices. This includes all of the switches which need to support PTP TC functionality. List of devices and costs associated with them are shown in Table 5. PTP grandmaster is the most expensive as PRP support is not a common feature of PTP masters. Other solutions are to use two masters with individual antennas or to use a diplexer with a single antenna. To handle the high traffic in the station network, station level switches are chosen with more robust options such as 4 Gigabit-Ethernet ports. Bay level switches can do without these options.

Table 5. Investment costs of Case 1.

Device	Features	Cost [USD exc. VAT]
Tekron NTS 03-G+	PRP, PTPv2	5000
ABB AFS675 x 2	PTPv2 1/2-step, Power Profile, Redundant, Gigabit-Ethernet x4 / 20 x 10/100 BASE TX	8000
ABB AFS650 x 2	9-port 10/100 BASE TX	5000
Antenna + Cabling	60 m coax cable, mounting bracket	700
Aggregate sum:		18 700,0

5.2 Case 2: Redundant PTP topology with PTP GPS clock and IRIG-B Backup

In the next case system, PTP redundancy is achieved using a cheaper master without PRP support and a protection relay or a bay level device as a first secondary clock utilizing IRIG-B synchronization. In the case of primary master failure, the device would act as a clock master for the substation. This case is hypothetical, as there currently is no protection relay capable of IRIG-B to PTP conversion on the market but there are some Ethernet switches and devices that could be connected to bay-level which are capable of converting from IRIG-B to PTP. This topology is presented in Figure 17. IRIG-B cabling can be reduced, or if even more redundancy is wanted the cabling can be left there. Then more secondary masters would become available.

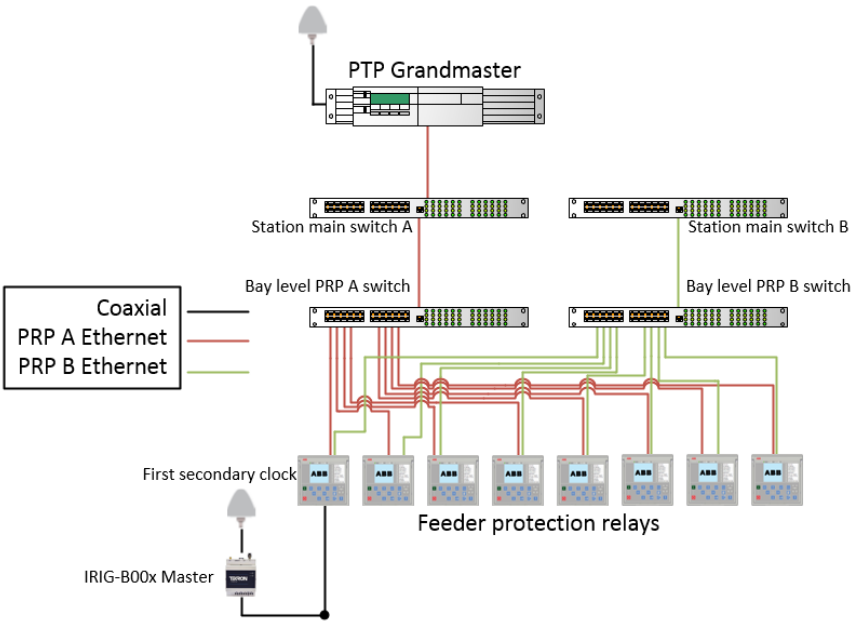

Figure 17. Topology for case 2.

5.2.1 Accuracy

The accuracy of this topology depends on the quality of the masters as with the first case but now there is no SPOF. A relatively affordable GPS PTP Grandmaster, such as Tekron TTM 01-G with PTP license, can provide sub-microsecond accuracies (Tekron 2017). An unmodulated DC IRIG-B master, such as SEL-2401 which promises an average of ±100 ns, provides sub-microsecond accuracies as well (SEL 2017). This means that even if the primary master fails, the system can continue with operations requiring the highest accuracy classification of T5.

5.2.2 Disturbance handling and reliability calculations

Without redundancy in the station main switches, there are 3 points which will drop the grandmaster from the view of the relays: the master itself, station switch, and PRP bay level switch A. All of these would then make the IRIG-B receiving protection relay as the PTP master. Figure 18 presents the RBD of case 2 topology.

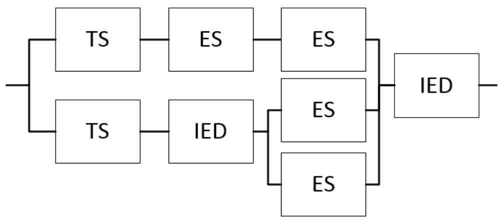

Figure 18. RBD of Figure 17 topology.

In order to make calculations simpler, MTTF for the parallel paths are first calculated, then for the whole time synchronization chain:

$$MTTF_{TS1} = \frac{1}{\frac{1}{MTTF_{TS}}+\frac{2}{MTTF_{ES}}} \tag{13}$$

$$MTTF_{TS2} = \frac{1}{\frac{1}{MTTF_{TS}}+\frac{1}{MTTF_{IED}}+\frac{2}{3 \cdot MTTF_{ES}}} \tag{14}$$

$$\lambda_{TSW} = \frac{1}{MTTF_{TSW}} = \frac{1}{MTTF_{TS1}+MTTF_{TS2}-\frac{MTTF_{TS1} \cdot MTTF_{TS2}}{MTTF_{TS1}+MTTF_{TS2}}} \tag{15}$$

MTTF for this system then can be calculated from these formulas as:

$$MTTF_{case2} = \frac{1}{\lambda_{TSW}+\lambda_{IED}} = 34{,}788\ a. \tag{16}$$

Availability can then be calculated with the following formulas:

$$A_{TS1} = A_{TS} \cdot A_{ES}^2 \quad (17)$$

$$A_{TS2} = A_{TS} \cdot A_{IED} \cdot (2A_{ES} - A_{ES}^2) \quad (18)$$

$$A_{TSW} = A_{TS1} + A_{TS2} - A_{TS1} \cdot A_{TS2} \quad (19)$$

$$A_{case2} = A_{TSW} \cdot A_{IED} = 0{,}9999939113 \quad (20)$$

5.2.3 Investment costs

As the PTP grandmaster can now be cheaper as requirements set for it are a bit relaxed, the investment costs are reduced. Ethernet switches, however, need to be PTP compliant and with more functionality. Depending on the condition and quality of the IRIG-B master or masters they would need to be replaced as well. These are included in the cost calculations which are shown in Table 6.

Table 6. Case 2 cost calculations.

Device	**Features**	**Cost [USD exc. VAT]**
Tekron TTM01-G	PTPv2	1 250
ABB AFS675 x 2	PTPv2 1/2-step, Power Profile, Redundant, Gigabit-Ethernet x4 / 20 x 10/100 BASE TX	8000
ABB AFS650 x 2	9-port 10/100 BASE TX	5000
Antenna+Cabling	15 m coax cable, mounting bracket	550
SEL-2401	IRIG-B00x master with Antenna and cabling	550
Aggregate sum:		15350,00

5.3 Case 3: Redundant PTP topology with IRIG-B Grandmaster

The third case requires minimal amount of new investment in terms of distribution of PTP time synchronization via Ethernet as one of the protection relays acts as a first primary master. With BMC algorithm, this would be either of the IRIG-B connected relays but the closest relay to the IRIG-B master should be prioritized as the propagation delay is smallest with less cabling in the path. Redundancy can be achieved either by adding another IRIG-B master and connecting it to a protection relay or by daisy-chaining as in the original topology. Both of these options depend on the starting point. For this analysis, the prior is chosen as the starting point utilizes only one IRIG-B master. Figure 19 represents this third case topology.

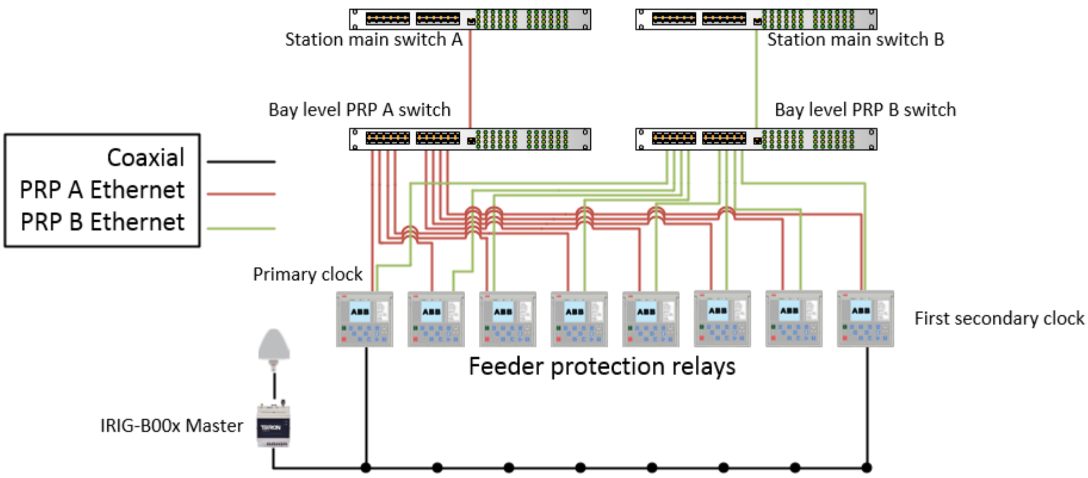

Figure 19. Case 3 topology.

5.3.1 Accuracy

As with case 2, the accuracy is the same as in the secondary master situation, but now protection relays connected to IRIG-B master would act as the primary master in the substation network. Protection relay acting as PTP master would have sub-microsecond accuracy depending on the used master.

5.3.2 Disturbance handling and reliability calculations

Depending on the number of masters and connected devices that support IRIG-B to PTP conversion, redundancy is excellent as there are now two paths that convey synchronization and upper-level devices do not necessarily require PTP capabilities. There is a SPOF in this topology: the IRIG-B master. Figure 20 holds the RBD presentation of case 3.

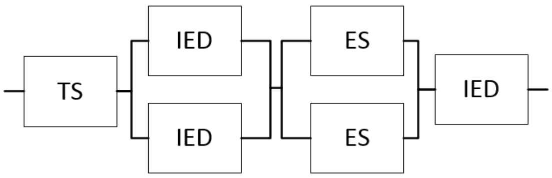

Figure 20. RBD presentation of Figure 19.

In order to calculate the complete MTTF of this topology we need to first calculate the serial MTTF of the pair of parallel paths of IED and ES. MTTF for series connected IED and ES is:

$$MTTF_{IED+ES} = \frac{MTTF_{IED} \cdot MTTF_{ES}}{MTTF_{IED}+MTTF_{ES}} = \frac{150+50}{150 \cdot 50} = 37{,}5\ a. \tag{21}$$

Afterwards, MTTF for the parallel portion $MTTF_{p(IED+ES)}$ of the RBD representation can be calculated with:

$$MTTF_{p(IED+ES)} = 2 \cdot\ MTTF_{IED+ES} - \frac{1}{2} MTTF_{IED+ES} = 56{,}25\ a. \tag{22}$$

MTTF for this system then can be calculated from Figure 19 as:

$$MTTF_{case3} = \frac{1}{\lambda_{TS}+\lambda_{p(IED+ES)}+\lambda_{IED}} = 32{,}142857\ a, \tag{23}$$

where $\lambda_{p(IED+ES)}$ is the failure rate of the parallel chain of IED and an ES.

Availability can then be calculated with the following formula:

$$A_{case3} = A_{TS} \cdot \left(2A_{IED} - {A_{IED}}^2\right) \cdot \left(2A_{ES} - {A_{ES}}^2\right) \cdot A_{IED} = 0{,}9999878237 \quad (24)$$

5.3.3 Investment costs

This topology is the most cost-effective as station level switches can be without PTP capabilities depending on the whole station. If only bay level devices require sub-microsecond accuracies, then only the redundant bay level switches need PTP TC functionality to convey synchronization with enough accuracy. Also, already present IRIG-B masters can be utilized again thus saving even more costs. Cost calculations are shown in Table 7. ABB AFS650 9-port switch was chosen as it has sufficient ports and has PTP capabilities as well.

Table 7. Cost calculations for case 3.

Device	**Features**	**Cost [USD exc. VAT]**
ABB AFS650 x 4	9-port 10/100 BASE TX	10 000
SEL-2401	IRIG-B00x master with Antenna and cabling	548,0
Aggregate sum:		10 548,00

As IRIG-B masters are cheaper than PTP grandmasters, this topology immediately takes the first position as far as investment costs are concerned. Even a redundant system with two masters and antennas would be cheaper than case 2.

5.4 Comparison summary

Depending on the time synchronization requirements of the devices in the substation there can be many different topologies which fulfil the same requirements. Usually, process level devices require more accurate time synchronization than station level devices so shifting the masters closer to process level would be the wisest choice. Looking at the cases analysed in this chapter it can be deduced that case 3 offers the best value for money as it fulfils the T5 performance class of ±1µs. It also provides flexibility since if the whole station requires this accuracy the station level switches can then be upgraded to have PTP capabilities thus, in turn, providing rest of the devices with accurate time synchronization. And if only bay level devices require this then cost of retrofitting a T5 performance class time synchronization topology are kept to a minimum, therefore, making case 3 the ideal topology. However, as there are no protection relays currently capable of converting IRIG-B to PTP, this is a topology waiting for future. Case 3 does have a SPOF in the single IRIG-B master, but adding another master with another antenna eliminates it while still being below the cost of case 2. This would increase the reliability and availability as well.

Case 2 is a compromise of cases 1 and 3 as it combines the robust accuracy of a GPS PTP grandmaster with redundancy provided by the IRIG-B first secondary. This is the second most expensive solution as the station and bay level switches need to have PTP TC functionality and this case requires at least one new master and antenna installation.

Case 1 is the most expensive solution as the redundancy aspects require most features of the master as well as the switches thus increasing costs comparing to case 2. Case 1 also has a SPOF in the GPS master making T5 performance class out of the question when the master drops.

In terms of reliability and availability calculations, case 2 topology is the winner overall just edging case 3 with MTTF of 34.8 years versus 32.14 years of case 3. Clear loser though is the topology of case 1 with MTTF of 25 years. This can be explained with a redundant GPS master system since there is a very clear SPOF in the master, as well as the two sets of Ethernet switches having lower MTTFs than the rest of the devices. Case 2 has no SPOF with regards to the time synchronization. That is why it is the winner in this comparison.

By moving PTP grandmaster closer to the slaves in the network, reliability increases. A single IRIG-B master daisy-chained to a couple of devices in every bay, eliminates the reliability of Ethernet switches from the MTTF calculations of a given system. SPOF is still present in the single master solution, but by using more than 1 IRIG-B master with individual antennae, the SPOF of a given system can be eliminated. The results in this chapter show that this can be done at relatively low cost.

6 GENERAL DESIGN OF AN IRIG-B PTP GRANDMASTER

This chapter describes the design of a bay level device capable of acting as a PTP grandmaster with IRIG-B input. There are already some devices that could fulfil this niche, but the goal of this chapter is to describe general requirements that would fit the user scenarios described in the previous chapter.

6.1 General design

The bay level device capable of converting IRIG-B to PTP frames requires these separate blocks: standalone IRIG-B decoder block, PTP block with OC capabilities and BMC stack and internal crystal oscillator (XO). Hardware inputs are needed for the IRIG-B input and at least one Ethernet port. Redundant Ethernet protocols such as PRP require more ports. A general block diagram of the design is represented in Figure 21.

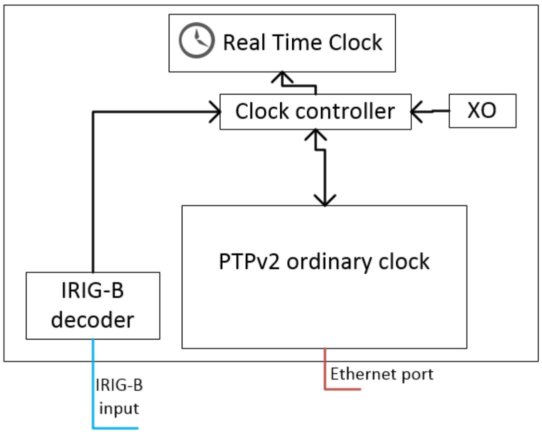

Figure 21. General block diagram for the device.

The main block in this design is the clock controller block. It takes various inputs from different blocks and synchronizes the real-time clock (RTC) of the device. With a valid IRIG-B input it tells the PTPv2 OC block that it can operate with promoted PTP announce parameters. These parameters are explained in section 6.4. It can also take synchronization from PTPv2 OC block if BMC deems a better master in the network. Without any valid synchronization, the RTC is then syntonized using the internal oscillator (XO). PTPv2 OC block handles the communication with the network. Some cybersecurity aspects will need to be considered since the device is connected to a station-wide Ethernet network and could be used in cyber-attacks or attacks can be directed towards it.

The basic flow of the software is as follows. During the start-up sequence of the software, the device polls the IRIG-B input. If the polling returns a state indicating that the IRIG-B decoding, and the timestamp is valid, the value for clockClass is announced as 13. An additional check for the holdover needs to be done before announcing the promoted clockClass. The state of holdover happens when the IRIG-B signal is lost, and the length of that period is determined by the ability of the internal oscillator to hold the announced accuracy from UTC. BMC algorithm then decides if which clock acts as the grandmaster. When different states are found through the IRIG-B input polling, the defaultDS parameters are updated accordingly. Basic flow chart of the program is shown in Figure 22. IRIG-B task is responsible for reading the time offset parameter, as well as the reading or writing of the HMI time depending on the conditions. In parallel to the IRIG-B task, a separate PTP task is also running. The PTP task is responsible for reading the defaultDS datasets set by the IRIG-B task and it also reads the user-settable PTP parameters shown in Table 8.

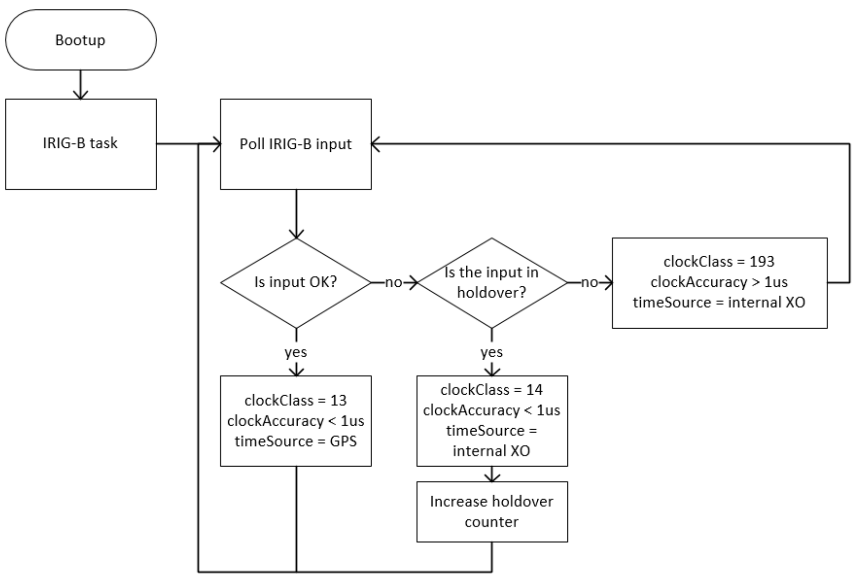

Figure 22. Flowchart of the proposed bay-level device software.

6.2 User settable parameters

In order to act as a functioning and usable device, some parameters need to be user settable. Some are mandated by the IEEE 1588/IEC 61588 standard and others are for the usability of the device. These parameters are listed and explained in the Table 8.

Table 8. User settable parameters.

Parameter	Reason
PTP priority 1	Required by IEC 61855 Ed.2
PTP priority 2	Required by IEC 61855 Ed.2
PTP domain ID	Required by IEC 61855 Ed.2
Reference time offset	IRIG-B could be in local, but PTP is in UTC. Offset should be settable
Time	If there is no valid signal, then the clock is free running thus the time can be set manually.

Additionally, if the device has WHMI that can be used to set the parameters, the device will have to have a settable IP address. MAC address should be a universally administrated by the device manufacturer.

6.3 IRIG-B input specification

Firstly, T5 performance class of IEC 61850-7-2 eliminates the use of AM modulated IRIG-B-formats. Since DC does not have a carrier frequency, the only thing left to decide is the coded expression. As described in chapter 3 PTP requires the full date and year information and this mandates that these are provided by the device. This, in turn, entails the use of IRIG-B004 or IRIGB005-format, since these formats carry the year in BCD.

6.4 PTP specification

PTP capable devices with OC functionality requires some information in order to participate in the BMC algorithm. The full algorithm and dataset members are described in chapter 3. If the device has a valid IRIG-B input and it is synchronized to it, then the dataset shown in Table 9 is used.

Table 9. Values for PTP datasets.

Dataset member	Value	Explanation
grandmasterClockQuality.clockClass	13	A clock that is synchronized to an application specific time source.
timePropertiesDS.timeSource	20	GPS

The rest of the parameters are set as mandated by the IEC 61588 Ed.2 –standard. The first degradation for clockClass is 14 when the IRIG-B signal is lost but the device is within holdover specification. This depends on the quality of the internal oscillator used as it will be the source of syntonization when there is no valid time reference signal. Then after the internal drift has exceeded the holdover specification, i.e. enough time has passed since receiving a valid signal, the clockClass will degrade according to IEC 61588. This can be either 58 or 193 if the device is wanted to act as a slave to another clock or not (IEC 61588 2009: 55). When the IRIG-B signal is lost, and the device is in hold-over, the timeSource value should also be changed to internal oscillator. This is represented with the enumerator A0 in hexadecimal.

The IEEE1588/IEC61588 standard limits certain port states to certain clock classes. This basically boils down to clock classes under 128 not permitted to be slaves to another clock in the domain (IEC 61588 2011: 54-55). This requires a solution of fluent changing of the clock class of the OC in the bay level device if it is wanted to act as a slave. The network situation can be monitored and as soon as a new BMC process is discovered the clock class can be promoted to 13. If the device is not selected as the master, the clockClass demoted to 193 allowing the synchronization to an external clock. Normally, a clock port with a clockClass value of 13 would remain in a passive state until new BMC selection. Figure 23 shows the flowchart of this functionality.

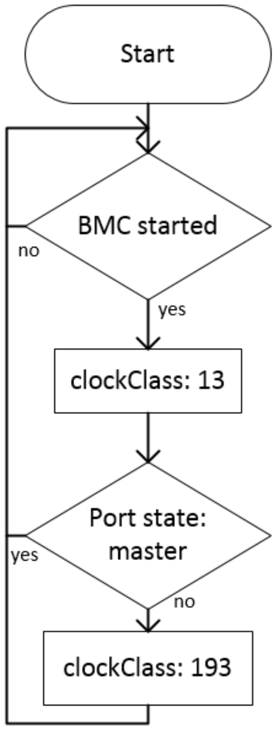

Figure 23. Flowchart of the fluid clock class selection done by the PTP stack.

6.5 Validation criteria

Since the device can be used as a PTP grandmaster in the use of T5-performance class application, this mandates the accuracy of the time synchronization to be in ±1μs -range. In the backup use scenario, there are some aspects to be considered. Firstly, if the primary synchronization source is down, the primary grandmaster clock can still advertise a higher clockClass while being in a holdover state. When the primary source then drops to the second degradation clockClass, the secondary master should become the active grandmaster. Likewise, if the IRIG-B master is lost, then the device should degrade the clock class according to the holdover specification, i.e. the capability of the XO to hold a certain accuracy for a time period, of the internal XO used. This degradation flow is shown in Figure 24. The times shown in the figure will vary according to the hardware and the optimization of the software. PTP is a permissive protocol since the messaging can be asymmetrical and message intervals are long.

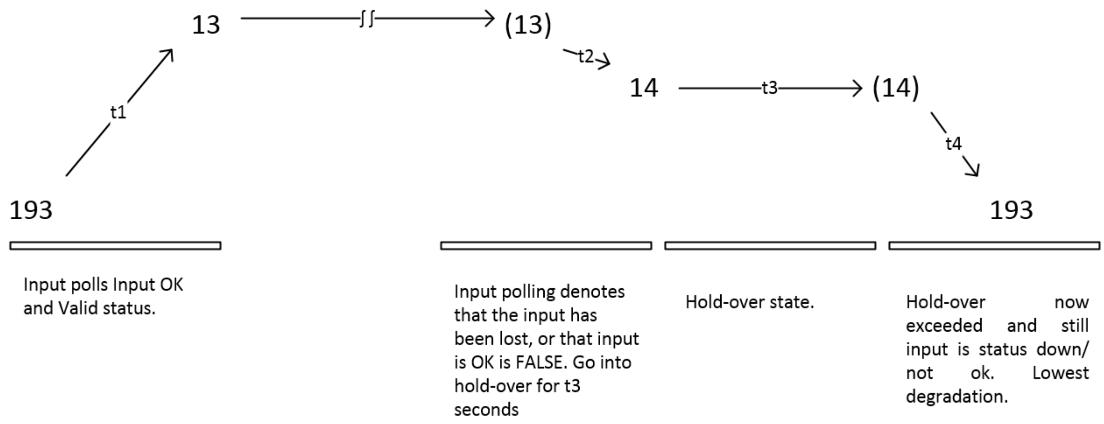

Figure 24. Flow of clockClass in the bay level device.

6.6 Other solutions

As of writing this thesis, bay level devices with IRIG-B to PTP conversion capabilities are not exactly numerous. But, there are some alternative solutions that would essentially have the same effect albeit with a different cost. RuggedCOM RSG2488 by Siemens has the capability to convert to and from PTP and IRIG-B with the optional GPS module (Siemens 2017). The switch with the module has a list price of over 6000 USD making it more expensive than the solution in case 3 but the end effect is the same. A redundant system would then increase costs even more. There is also GMR-series time server made by Masterclock Incorporated which can act as an IRIG-B to PTP translator. This option would require the IRIG-B master to be present. GMR-series can also act as GPS PTP grandmaster (Masterclock 2016). The manufacturer does not announce the list price of this device on its website.

All the topologies presented Chapter 5 have a common problem: Availability, vulnerability, and strength of GPS signal. Researchers at Aalto University detected (Aalto University 2016) a time discrepancy of 13.7 microseconds. The discrepancy was later discovered to be caused by a software error in an older SVN23 satellite (Saarinen 2016).

According to a study made by United States Air Force (Benshoof 2005) only a pW (10^{-12} W) order of power is required to jam a GPS signal at the receiving antenna. To fully have a redundant satellite-based time synchronization topology in substations the satellite sources should be redundant. This means that achieving full redundancy requires at least two masters using two different satellite sources such as GPS, Russian Glonass, Chinese BeiDou, or the European Galileo. As of writing this thesis, there exist GPS PTP synchronization masters which are able to receive synchronization from multiple sources at the same time. The European Galileo satellite constellation provides a third alternative to the two constellations used in western countries. Some GPS masters already have support for the Galileo positioning system such as Meinberg GNS181 receiver module (Meinberg 2017b). The more sources are used, more robust a given time synchronization scheme is. Therefore, it can be recommended to use time synchronization masters capable of receiving synchronization signals from different constellations, be they PTP or IRIG-B masters.

7 CONCLUSIONS

The complexity of the smart grid and the requirement for real-time information exchange increases the demand for accurate time synchronization schemes that are deployed to ever increasing areas. The future lies in wireless communication using terrestrial radios networks. PTP standard has a profile used by the telecom industry and these wireless synchronization networks can be used in the smart grid IEDs. One future option is also to use Synchronous Ethernet (SyncE). It is used in the telecom industry, data centers and audio-video bridging (Laird 2012). The main advantage of SyncE over PTP is that it's not affected by high traffic load of the network because the frequency synchronization is added to the Ethernet physical layer, but it can be used only for frequency synchronization as opposed to the time-of-day synchronization of PTP. Combination of PTP and SyncE standards is called the White Rabbit project and it is led by CERN (European Organization for Nuclear Research) (Laird 2012). The goal of the White Rabbit project is sub-nanosecond accuracy among thousands of nodes spanning distances of as much as 10km (Lipinski 2012). CERN is interested in accurate time synchronization since the particle accelerator called the Large Hadron Collider has thousands of devices that measure data at different points of the accelerator. The accelerator has a circumference of 27km.

As substations are more digitalized, the requirements for accurate, and robust time synchronization methods and topologies become apparent. This, in turn, increases costs and reliability of communication networks becomes a talking point. Adding redundancy in system topologies is a good way to increase reliability and availability of a given system but when it comes to accurate PTP GPS masters, the cost may go over the threshold set by the stakeholders. A solution was presented in this thesis. In order to have redundant and performance class T5 capable time synchronization topology, IRIG-B as main synchronization method of a few bay-level devices or as a secondary synchronization source can be used. Additionally, single grandmaster solutions can be improved at relatively low cost by adding IRIG-B master for redundancy. The added master can be daisy-chained to individual bays where connected devices act as PTP masters. Therefore, the objectives presented in Section 1.2 can be determined as achieved.

8 SUMMARY

The objectives of this thesis were to examine the advantages of using IRIG-B in conjunction with PTP synchronization. Before the main body of work, a short introduction to the subject was given. Then, a theoretical background was presented for SAS, communication and redundancy protocols, time synchronization, and finally reliability and availability calculations. In Chapter 5, a case comparison was made with three different case topologies and a winner was found to be the topology of case 3 which was represented in Section 5.3. Additionally, it was shown that using IRIG-B as a primary or a secondary synchronization source is not only cheaper, but it also increases the MTTF and availability of the given system. Using a system with IRIG-B as a secondary or primary synchronization source with PTP increased the MTTF of the example topology by 7 years or more compared to case 1. Availability was increased by a small margin when comparing cases 2 and 3 to case 1. Some generalizations had to be made, but the results give a good representation that can be adapted to different topologies. A general design and features required from a bay level device capable of IRIG-B to PTP conversion were presented in Chapter 6. Some functional requirements were discussed as well as user-settable parameters. Also, the shortcomings of using only one satellite constellation such as just GPS was discussed. A recommendation of using at least two constellation sources was given. Then, conclusions were drawn in Chapter 7 and the objectives set in Chapter 1 were deemed as fulfilled.

REFERENCES

Aalto University (2016). GPS-kellonajan outo hyppäys huomattiin Metsähovissa [online]. [26.10.2017] Available: https://blogs.aalto.fi/metsahovi /gps-kellonajan-outo-hyppays-huomattiin-metsahovissa/#.WfHHilu0OxK

ABB (2010). *ABB review special report: IEC 61850* [online]. The corporate technical journal. [19.9.2017], 64 p. Available: http://www05.abb.com/global/scot/scot271.nsf/veritydisplay /ba5c0d1cacc015a7c12577840033f1a2/$file /abb_sr_iec_61850_72dpi.pdf

ABB (2012). Non-conventional instrument transformers [online]. *Advanced GIS substation with IEC 61850-9-2 LE process bus*. [17.10.2017], 12 p. Available: http://www02.abb.com/global/gad/gad02181.nsf/0 /972b57391b2140d0c1257a620046043b/$file /Non-conventional+instrument+transformers+-+Advanced+GIS+substations +with+IEC+61850-9-2+LE+process+bus.pdf

ABB (2017a). Internal presentation: *Medium Voltage Products – Finland. Making Grids Smarter*.

ABB (2017b). Transformer protection and control RET620 IEC [online]. [20.10.2017] Available: http://new.abb.com/medium-voltage/distribution-automation /numerical-relays/transformer-protection-and-control /transformer-protection-and-control-ret620-iec

Anderson, L., K. Brand, C. Brunner & W. Wimmer (2005). Reliability investigations for SA communication architectures based on IEC 61850. *2005 IEEE Russia Power Tech*. St. Petersburg, Russia, June 27-30.

Benshoof, Paul (2005). *Civilian GPS Systems and Potential Vulnerabilities*. Available: www.gps.gov/cgsic/international/2005/prague/benshoof.ppt

Billinton, R. & R. N. Allan (1992). *Reliability Evaluation of Engineering Systems*. 2nd edition. New York: Springer US. 453 p. ISBN 978-0-306-44063-2.

Bio, M. J. (2007). Air-Insulated Substations – Bus/Switching Configurations. In: *Electric Power Substations Engineering*, 27-34. Ed. John D. McDonald. Boca Raton: CRC Press. ISBN 9781439856383.

Burke, J., A. Sahazizian & T. Kertesz (2007). How a Substation Happens. In: *Electric Power Substations Engineering*, 1-8. Ed. John D. McDonald. Boca Raton: CRC Press. ISBN 9781439856383.

EndRun (2017). *IRIG Time Codes* [online]. [17.9.2017] Available: https://www.endruntechnologies.com/timecodes.htm

Fingrid (2017). *Suomen sähköjärjestelmä* [online]. [24.10.2017] Available: https://www.fingrid.fi/kantaverkko/suomen-sahkojarjestelma/

FSMLabs (2017). *Smart and dumb clients and the ”so-called” Best Master Clock Algorithm in PTP IEEE 1588* [online]. [19.12.2017] Available: https://medium.com/fsmlabs/smart-and-dumb-clients-and-the-so-called-best -master-clock-algorithm-in-ptp-ieee-1588-6739608d4cff

Harris, D. L. & D. Childress (2007). High-Voltage Switching Equipment. In: *Electric Power Substations Engineering*, 35-65. Ed. John D. McDonald. Boca Raton: CRC Press. ISBN 9781439856383.

Hirschmann (2014). *Media Redundancy Concepts* [online]. High Availability in Industrial Ethernet. [21.10.2017], 9p. Available: http://www.hirschmann.com/en /Hirschmann_Produkte/Industrial_Ethernet/Technologies /HSR_uE2u80u93_High_Availability_Seamless_Redundancy/index.phtml

IEC 61588 (2009). *Precision clock synchronization protocol for networked measurement and control systems*, 2nd edition. 292 p.

IEC 61850-5 (2013). *Communication networks and systems for power utility automation - Part 5: Communication requirements for functions and device models*, 2nd edition. 306 p.

IEC 61850-9-2 (2011). *Communication networks and systems for power utility automation - Part 9-2: Specific communication service mapping (SCSM) - Sampled values over ISO/IEC 8802-3*, 2nd edition. 70 p.

IEC 62439-3 (2016). *Industrial communication networks – High availability automation networks – Part 3: Parallel Redundancy Protocol (PRP) and High-availability Seamless Redundancy (HSR), 3rd edition.* 356 p.

IEEE 100 (2000). *The Authorative Dictionary of IEEE Standards Terms*. 7th edition. 1363 p.

IEEE 1344-1995 (1995). *IEEE Standard for Synchrophasors for Power Systems.* 36p.

IEEE C37.118.1-2011 (2011). *IEEE Standard for Synchrophasor Measurements for Power Systems*. 2nd edition. 61 p.

Industrial Networking (2006). *IEEE 1588 - Precise Time Synchronization as the Basis for Real TimeApplications in Automation* [online]. [29.9.2017], 8 p. Available: http://kurser.iha.dk/eit/tidrts/SupplementingCourseMaterial /IEEE1588PreciseTimeSynchronization.pdf

IRIG Std. 200-04 (2004). *IRIG Serial Time Code Formats*. 73 p.

Kanabar, M. G. & T. S. Sidhu (2009). Reliability and availability analysis of IEC 61850 based substation communication architectures. *2009 IEEE Power & Energy Society General Meeting.* Calgary, Canada, July 26-30.

Kanabar, M. G. (2011). *Investigating Performance and Reliability of Process Bus Networks for Digital Protective Relaying*. University of Western Ontario. Department of Electrical and Computer engineering. Academic dissertation. Electronic Thesis and Dissertation Repository. Available: http://ir.lib.uwo.ca/etd/272

Laird, J. (2012). *PTP Background and Overview* [online]. [5.12.2017] Available: https://www.iol.unh.edu/sites/default/files/knowledgebase/1588/ptp_overview.pdf

Lipinski, M. (2012). *White Rabbit: a next generation synchronization and control network for large distributed systems* [online]. [5.12.2017] Available: http://www.ieee802.org/1/files/public/docs2012 /new-avb-cummings-white-rabbit-0512-v1.pdf

Masterclock (2016). *GMR1000 AND GMR5000 User Manual.* Available: https://static1.squarespace.com/static/55f05c0ce4b03bbf99b13c15/t /586d0a0dbebafbc7475d2233/1483541027180 /GMR+Series+User+Manual+v2+2016.12.pdf

McDonald, J. D. (2007). Substation Integration and Automation. In: *Electric Power Substations Engineering*, 113-133. Ed. John D. McDonald. Boca Raton: CRC Press. ISBN 9781439856383.

Meinberg (2017a). *One-step or Two-step?* [online]. [23.9.2017] Available: https://blog.meinbergglobal.com/2013/10/28/one-step-two-step/

Meinberg (2017b). *IMS-GNS Clock: IMS Clock Module with Multi GNSS Receiver for GPS, Galileo, GLONASS and Beidou* [online]. [5.12.2017] Available: https://www.meinbergglobal.com/english/products /gps-glonass-galileo-beidou-receiver.htm

Meinberg (2017c). *What's coming In the Next Edition of IEEE 1588?* [online]. [19.12.2017] Available: https://blog.meinbergglobal.com/2017/09/24 /whats-coming-next-edition-ieee-1588/

Momoh, J. A. (2008). *Electric Power Distribution, Automation, Protection and Control*. Boca Raton: CRC Press. 360 p. ISBN 9780849368356.

NERC PRC-018-1 (2006). *Disturbance Monitoring Equipment Installation and Data Reporting*. Available: http://www.nerc.com/files/prc-018-1.pdf

Peer, J., E. Sagen, S. Achanta & V. Skendzic (2011) The Future of Time: Evolving Requirements for Precise Time Synchronization in the Electric Power Industry. *13th Annual Western Power Delivery Automation Conference*. Spokane, Washington, March 29-31.

Quadros (2017). *RTXC Quadros Real-Time Operating System* [online]. [7.9.2017] Available: http://quadros.com/products/operating-systems /rtxc-quadros-rtos-advanced/

Razo-Hernandez, J. R., V. Martin, D. G. Lieberman, J. P. Amezquita-Sanchez, L. A. Morales-Hernandez & A. Domingue-Gonzalez (2016). IRIG-B decoder based on FPGA for synchronization in PMUs by considering different input formats. *2016 IEEE International Autumn Meeting on Power, Electronics and Computing (ROPEC)*. Ixtapa, Mexico, November 9-11.

Saarinen, J. (2016). *Satellite failure caused global GPS timing anomaly* [online]. [21.10.2017] Available: https://www.itnews.com.au/news /satellite-failure-caused-global-gps-timing-anomaly-414237

SEL (2017). *SEL-2401Satellite-Synchronized Clock* [online]. [4.9.2017] Available: https://selinc.com/products/2401/

Siemens (2016). *SIPROTEC 6MU805 - Merging Unit for conventional instrument transformer* [online]. [17.10.2017], 8 p. Available: https://www.downloads.siemens.com/download-center/download?DLA09_668

Siemens (2017). *RUGGEDCOM RSG2488* [online]. [4.9.2017] Available: http://w3.siemens.com/mcms/industrial-communication/en /rugged-communication/ruggedcom-portfolio/switches-routers-layer-2 /rack-switches/Pages/rsg2488.aspx

Sleva, A. F. (2009). *Protective Relay Principles*. Boca Raton: CRC Press. 349 p. ISBN 9780824753726.

Taikina-aho, M. (2011). *Redundant IEC 61850 communication protocols in substation automation*. University of Vaasa. Faculty of Technology. Master's Thesis.

Tekron (2017). *Compact GNSS Clock: TTM 01-G* [online]. [11.9.2017] Available: https://tekron.com/power/compact-gnss-clock-ttm01g/#undefined

UCA International Users Group (2004). *Implementation Guideline for Digital Interface to Instrument Transformers using IEC 61850-9-2* [online]. [21.9.2017] Available: http://iec61850.ucaiug.org/Implementation%20Guidelines /DigIF_spec_9-2LE_R2-1_040707-CB.pdf

Weibel, H. & Béchaz, D. (2004). IEEE 1588 Implementation and Performance of Time Stamping Techniques. *2004 Conference on IEEE 1588*. Gaithersburg, United States of America, September 27-29. Available: https://sites.zhaw.ch/~wlan/IEEE1588/PTP_Timestamping_Methods_Paper.pdf

Weibel, H. (2008). *Tutorial on Parallel Redundancy Protocol* [online]. [26.10.2017] Available: https://www.zhaw.ch/storage/engineering/institute-zentren/ines/forschung-und-entwicklung/time-synchronisation/tutorial-on-prp.pdf

Wolman, D. (2015). *Just a Second* [online]. [21.10.2017] Available: http://www.slate.com/articles/health_and_science/science/2015/06/next_leap _second_june_30_dangers_to_software_military_gps_banking_air_traffic.html

APPENDICES

APPENDIX 1. PTP datasets

This appendix contains all of the datasets gathered from IEC 61588 –standard in table format. These are used in various phases to synchronize, determine the best master clock and identify a clocks capability. Information is given on the other field about the member. Different datasets are separated into different tables.

Table 10. Dataset members of transparentClockDefaultDS. (IEC 61588: 75.)

Member	Information
clockIdendity	An 8-octet array consisting of manufacturer specific part and the MAC-address of the TC.
numberPorts	Number of PTP ports the TC has.
delayMechanism	Delay measurement mechanism the clock uses: E2E or P2P
primaryDomain	the domainNumber of the primary syntonization domain

Table 11. Dataset members of *defaultDS*. (IEC 61588 65-67.)

Member	**Info**
twoStepFlag	Boolean value indicating if clock is two- or one step clock.
clockIdendity	An 8-octet array consisting of manufacturer specific part and the MAC-address of the device.
numberPorts	Number of PTP ports in the device, for OCs this is 1.
clockQuality.clockClass	8-bit unsigned integer denoting the traceability of the time distributed by the clock. Allowed values specified in Table 5 of clause 7.6.2.5 of IEC 61588 –standard.
clockQuality.clockAccuracy	A two-digit hexadecimal estimation enumeration of a clocks precision. Values with corresponding accuracies are shown in Table 6 of clause 7.6.2.5 of IEC 61588 –standard.
clockQuality.offsetScaledLogVariance	A 16-bit unsigned integer estimation, or computation, of the variations of a clock from a linear timescale when not synchronized to another source such as GPS.
priority1	Configurable value indicating that the clock belongs to a set of ordered clocks ranging from 0 to 255.
priority2	Secondary configurable value indicating that the clock belongs to a set of ordered clocks ranging from 0 to 255.
domainNumber	Operating domain identification, value ranging from 0 (default) to 255.
slaveOnly	A special Boolean flag indicating that the clock is a slave only clock.

Table 12. Dataset members for currentDS dataset. (IEC 61588: 68.)

Member	**Information**
stepsRemoved	signifies the number of communication paths between a local clock and the grandmaster clock
offsetFromMaster	signifies the current value of time difference between a master and slave clock and it is computed by the slave
currentDS.meanPathDelay	signifies the mean propagation delay between the master and the slave clock and is computed by the slave

Table 13. Dataset members for parentDS. (IEC 61588: 68-70)

Member	Information
parentPortIdentity	Master's SYNC message issuing port's portIdentity
parentStats	Signifies the statistical validity of the next 2 members computed by the slave clock.
observedParentOffsetScaledLogVariance	An estimate of the master clock's observed PTP variance by the slave clock. If not computed then parentStats is set as false.
observedParentClockPhaseChangeRate	A 32-bit integer estimate of the master clock's phase change rate as observed by the slave.
grandmasterIdentity	Contains the defaultDS.clockIdentity of the grandmaster.
grandmasterClockQuality	Contains the grandmaster's defaultDS.clockQuality structure.
grandmasterPriority1	Configurable value indicating that the grandmaster clock belongs to a set of ordered clocks ranging from 0 to 255.
grandmasterPriority2	Secondary configurable value indicating that the grandmaster clock belongs to a set of ordered clocks ranging from 0 to 255.

Table 14. Contents of timePropertiesDS dataset. (IEC 61588: 70-72)

Member	Information
currentUtcOffset	Offset between TAI and UTC if known
currentUtcOffsetValid	If current offset between UTC and TAI is known to be valid, value is TRUE. Otherwise FALSE.
leap59	Indication (TRUE) that the last minute of the current UTC day contains 59 seconds. If the Epoch is not PTP, then this value is FALSE.
leap61	Indication (TRUE) that the last minute of the current UTC day contains 61 seconds. If the Epoch is not PTP, then this value is FALSE.
timeTraceable	Indication (TRUE) if the timescale and the value of currentUtcOffset are traceable to a primary reference. Otherwise FALSE.
frequencyTraceable	Indication (TRUE) if the frequency determining the timescale is traceable to a primary reference. Otherwise FALSE.
ptpTimescale	Indicatio (TRUE) if the clock timescale of the grandmaster clock is PTP. Otherwise FALSE
timeSource	Source of time used by the grandmaster clock

Table 15. Contents of portDS dataset. (IEC 61588: 72-74.)

Member	**Information**
portIdendity	PortIdendity value of the local port
portState	Current state of the protocol enging associated with this port. See Table 8 of IEC 61588:2009.
logMinDelayReqInterval	Base 2 logarithm of the minDelayReqInterval.
peerMeanPathDelay	An estimate of the current one-way propagation delay on the link. Only active if delay mechanism is P2P.
logAnnounceInterval	Base 2 logarithm of the mean announce interval.
announceReceiptTimeout	Integral multiple of announceInterval.
logSyncInterval	Base 2 logarithm of the mean SyncInterval for multicast messages.
delayMechanism	Propagation delay measuring option used by the port: 0x01 = E2E, 0x02 = P2P, 0xFE = DISABLED
logMinPdelayReqInterval	Base 2 logarithm of the minPdelayReqInterval
versionNumber	PTP version number used on the port.