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Requirements and Proposed Solutions for Future Smart Distribution Substations

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Abstract: This paper proposes a novel solution for the secondary system of a primary distribution substation. First an evaluation is made of the changes that are to be expected for distribution substations in the future. Distributed generation, electric vehicles and other active resources will change the behavior of the distribution network in a manner that will have a great deal of implications for distribution substations. The question is how the role of the distribution substations will change when the visions of smart grids become reality. The proposed solution consists of bay level protection and control IEDs forming the backbone of the secondary system. The functionality is complemented with a substation level Station Computer, providing value added and advanced functionality. In addition, required communication and time synchronization methods are presented. A life cycle cost evaluation is also performed on the proposed solution, and it is compared with the current dominant concept based exclusively on bay level devices.

Key words: Life cycle costing, power distribution reliability, smart grids, substations.

1. Introduction

The first question to be answered when thinking about new requirements is what exactly constitutes a primary distribution substation? What is the definition of a distribution substation? Wikipedia defines electrical substations as [1]:

An electrical substation is a subsidiary station of an electricity generation, transmission and distribution system where voltage is transformed from high to low or the reverse using transformers.

In the International Electrotechnical Vocabulary of IEC 60050 [2] a substation is defined as follows:

The part of a power system, concentrated in a given place, including mainly the terminations of transmission or distribution lines switchgear and housing and which may also include transformers. It generally includes facilities necessary for system security and control (e.g. the protective devices).

The key point in both definitions is the change from transmission to distribution–a substation is the connection point between different voltage levels. There is the incoming feeder (normally just one or a few) from a higher voltage level (transmission lines) and several outgoing feeders on a lower voltage level (distribution lines).

An aspect that is emphasized in this paper is the data processing functions of the substation. A substation is not only an ‘energy hub’ but also an ‘information hub’. As it delivers energy to a large network at a certain voltage level, the substation also monitors and controls the network. The substation is responsible for keeping the network operational and running safely. Also many control operations from the network control center (NCC) are focused on the substations. For this purpose a more information-oriented definition is needed and proposed here:

An electrical substation is a subsidiary station of an electricity generation, transmission and distribution

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system providing monitoring and protection of the associated network, and functioning as the main connection point for network control and monitoring functions.

2. Main Drivers and Market Trends

This chapter describes the main drivers and market trends behind the new requirements.

2.1 The Global Situation and the Climate Change

The biggest current global risk at the moment dealt with in general discussions is the climate change. The amount of CO_2 emission has reached an all-time-high and is still rising. The connection between CO_2 emission and the climate change has been extensively proven by the IPCC Climate Change 2007 reports, although there is still some criticism of the results.

A clear outcome is that CO_2 emissions need to be reduced all around the world. Global conferences have been arranged, and the EU has already declared its targets in the 20-20-20 program. By 2020 the EU is committed to reducing CO_2 emissions by 20%, to increasing the utilization of distributed generation to 20% and to improving energy efficiency by 20%.

At the same time energy consumption is expected to increase as shown in Fig. 1 [3]. The amount of zero-carbon fuels is expected to increase, which also will increase the percentage of electrical energy as compared to the total energy consumption. The main target is to decrease CO_2 overall emissions as shown in Fig. 2. This creates a very challenging perspective. How can emissions be reduced when, at the same time, energy production will increase?

Addressing these challenges calls for many different actions, some of which are presented in Fig. 2. A major burden of this challenge also falls on electricity networks. Power systems need to be optimized in order to maintain high productivity, but in an environmentally sustainable fashion. This challenge has triggered a wealth of smart grid initiatives around the world, and it has also been a driver for this paper.

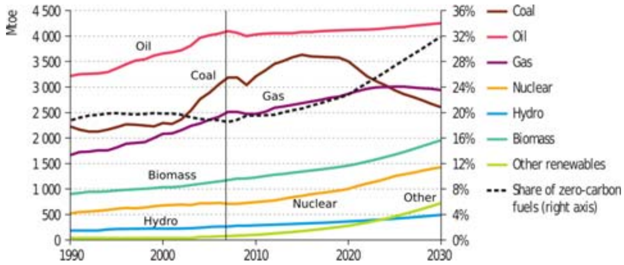

Fig. 1 Expected increase in energy consumption (Mtoe = million ton of oil equivalent) and in the share of zero-carbon fuels.

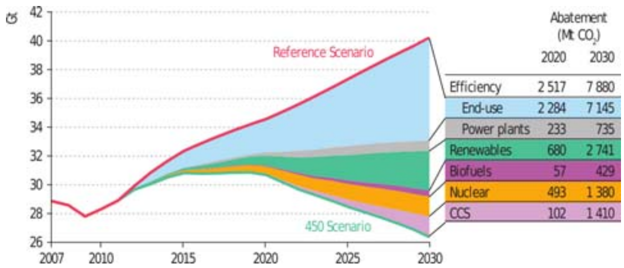

Fig. 2 Targeted decrease in CO_2 emissions.

2.2 The Market Situation and the Foreseeable Trends in Substation Automation

Substation automation has traditionally been a business of long time-frames and a conservative approach regarding technological advancements. The primary equipment in the substations has a typical life span of 30 to 50 years, and upgrades of the secondary equipment have often been forced to follow almost the same cycle.

This business area is now undergoing major changes. Part of the changes comes from the legislation, as in the Nordic countries the medium voltage (MV) electricity distribution sector was opened to a free market. Regulations resulting from this development create new reporting and monitoring requirements for electricity distribution companies. Customers must be recompensed for interruptions in the supply of their electricity. Variations in the power quality need to be monitored. In the regulation model the emphasis is on the quality of the distributed energy. So higher quality will generate higher profits for the network operators.

The control of the network is also moving further away from the actual physical network. Mergers between many companies have created bigger players in the distribution business. In addition, communication network technology has developed fast over the past years, enabling a more centralized network control. This all has resulted in an increased need for acquisition of data from larger networks and also for pre-processing data before being viewed by the NCC personnel.

The rapid growth of distributed generation (DG) also poses new challenges to the MV network, as it is now being used in a different fashion than it initially was designed for. This is a good example of future changes in the business, which will require fast response from electricity distribution companies.

In addition to new equipment, the basic infrastructure of the distribution network will also change [4]. At present many EU countries are engaged in the transfer of overhead lines into underground cables. This also increases the number of compensation coils in the network, which has a large impact on the protection schemes.

Utilities are not keen on undertaking continuous and costly upgrades of the whole protection system, but there is still a clear need to adapt to the new requirements. The need to increase the level of automation in the distribution system has been clearly noticed both on the vendor side [5] and on the utility side [6].

3. New Requirements

This chapter describes the new requirements for distribution substations in more detail. Various existing research publications already deal with many aspects of future smart grids. Items seen to affect distribution substations most are dealt with here.

3.1 Advanced Control of Distribution Networks

Post-fault power restoration [7] and self healing networks are a common topic in the smart grid visions. When a fault appears in the distribution network, the substation should automatically locate and isolate the fault, and restore electricity distribution automatically to all healthy parts of the network. Sometimes distribution networks also need to be operated in islanded mode and controlled from the substation.

This situation requires advanced control operations to be carried out by the substation, which at the moment are conducted in the NCC. Part of the functionality currently residing in SCADA and DMS systems must be moved from the NCC level to the station level.

3.2 Automatic Adaptation to Changes in Topology, Production and Consumption

In addition to fault situations, fast and automatic response is also needed for changes during normal operation. The number of active resources in the network can vary greatly, which might also require load shedding functionality running at the station level [8]. Dynamic load response becomes more critical as the share of uncontrollable production increases in the network.

In addition to control operations, changes in topology and active resources require adaptations in protection and monitoring functions. Parametrization of functions need to be adjusted in order to adapt to each network status.

3.3 More Accurate and Selective Network Protection

As society becomes increasingly dependent on electricity, the requirements for uninterrupted distribution of electricity become stricter. The call for uninterrupted distribution is also becoming more self-evident in the legislation of many countries. Interruptions in electricity distribution need to be recorded for statistical analysis and customers must be compensated for interruptions exceeding a certain duration.

This also requires enhancements in protection functions, and new more accurate protection functions are needed. This includes managing new fault types, such as high impedance earth faults, and also more accurate fault location.

3.4 Accurate Condition Monitoring and Asset Management of Primary Equipment

Smart grids need to enable optimized utilization of all network resources. This means that all network components need to be constantly monitored so that the condition of the components and the necessary maintenance operations are accurately identified.

Using condition monitoring information for evaluating future maintenance needs is a frequent topic in research publications. Condition Based Maintenance (CBM) and Reliability Based Maintenance (RBM) [9] are a focal point for many utilities. Before these methods can be properly utilized, efficient data collection and processing must be possible at the station level [10].

3.5 Multi-Vendor Platform with Open Interfaces and Large Data Streams

As networks get more complex, more data will flow through substations, and also more interested parties need access to this data. Utilities are increasingly interested in outsourcing parts of their existing services, and this outsourcing to 3rd party service providers requires clear and open IT interfaces to the process data of the substation. A good example of the integration needs of different IT systems is the AMR infrastructure, which in the near future will also be used by the fault diagnostics and load shedding functionality of substations.

When the functionality in a substation increases, the amount of vendors providing functionality to the substation also increases. This means that in addition to open process data interfaces, open interfaces are also needed for the SW platforms utilizing the data. In the future, the same SW platform will run applications from many vendors, in the same manner as already seen in less critical environments such as personal computers or mobile phones.

3.6 Cyber-Secure Firewall of the Distribution Network

When enhanced communication is used in the distribution network, cyber-security becomes an essential part of the overall security. A secure product is not sufficient, as potential vulnerabilities may arise from insecure integration into existing infrastructures [11]. While a substation can form a separate secured island for energy distribution, it must also provide a bullet-proof information firewall for parties communicating with the substation and the associated distribution network.

3.7 Low Life Cycle Costs

The above chapters describe new requirements for the substation. The speed at which these requirements change is also expected to increase, which makes the life cycle cost calculations difficult. Utilities do not want to suffer from continuous and costly update and upgrade processes for the whole protection system, but still the need to adapt to new requirements is clear.

There are many factors which affect the cost-efficiency of the distribution substation and the overall life cycle costs. The most self-evident but, perhaps the least significant part in the long run, is the installation cost. Taking into account only this aspect would lead to a falsely simplified view, where novel secondary systems would decrease the life cycle costs only if the initial installation cost is lower than before.

The maintenance and upgrade costs of a distribution substation can be of the same order as the original installation costs. As future distribution systems are expected to be more dynamic than static, smooth and cheap update possibilities are an important item affecting the life cycle costs. Advanced condition monitoring functionality in the distribution system would also support the planning of these activities.

More difficult to estimate, but still the item which can have the largest impact on the overall costs, is the profit of increased reliability of the distribution network. Currently utilities in the Nordic countries are obliged to pay compensation to customers, when there is a long interruption in the electricity supply. Power quality is gaining increased importance, and in the near future the quality of the delivered electrical energy could also carry a price tag.

4. Architecture of the Secondary System of a Smart Substation

This chapter describes the elements of the solution that is proposed to cover the new requirements of future smart substations. The concept is based on centralized protection and control functionality, which complements but does not replace the functionality of bay level protection and control IEDs. The concept is presented in Ref. [12] and the overall picture is also presented in Fig. 3.

Below the main components are presented in detail.

4.1 Protection and Control Terminals

In this concept the protection and control terminals are still seen as the backbone of the secondary system. They handle the time-critical basic protection functions and they also communicate with a centralized station computer.

4.2 Station Computer

The station computer handles all advanced functionality. As the primary protection is covered by bay level IEDs, the functionality in the station computer can be updated on the fly without affecting the safety of the network, allowing fast and smooth updates.

The station computer holds two categories of functionality. First the time-critical protection functionality, which needs real-time process data and directly affects network safety. This functionality has strict reliability and safety requirements and should not be opened up to many interested parties.

The offline functionality, on the other hand, can operate on historic information. This functionality only indirectly affects network safety via e.g. condition monitoring and fault analysis functions. In this functionality open interfaces can be provided to 3rd party functions, and multi-vendor SW platforms are possible. The division is presented in Fig. 4. A more detailed division on bay level and centralized functionality is described in Ref. [13].

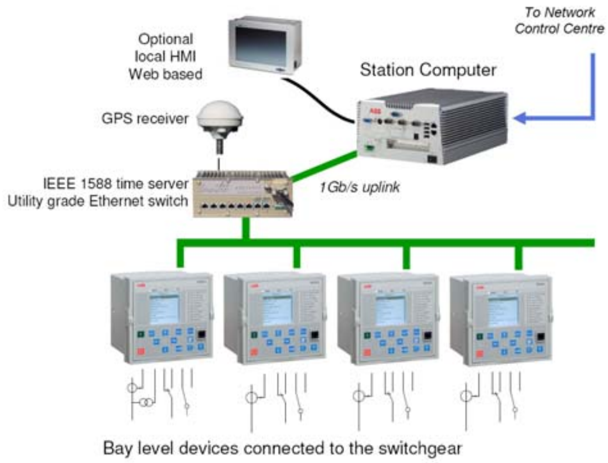

Fig. 3 Overall setup of centralized protection and control system.

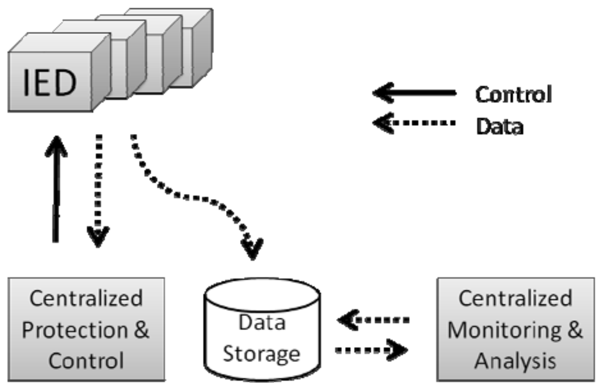

Fig. 4 Separate functionality for centralized protection and monitoring.

4.3 IEC 61850 Station Communication

The introduction and the increasing acceptance of the IEC 61850 standard have made available fast and standardized Ethernet-based communication. First, the station bus (part 8-1 of the standard) allows the replacement of copper wiring on a horizontal level between IED devices. Secondly, the process bus (part 9-2) makes the digitized measurement information from instrument transformers available in a standardized way for other devices.

The IEC 61850 station bus utilizing GOOSE messages is already very common in distribution substations, but the process bus has so far been extensively used only in transmission applications. The assumption is that the process bus also will become more common in distribution substations in the near future.

4.4 IEEE 1588 Time Synchronization

With Ethernet-based technology it is possible to achieve software-based time synchronization with an accuracy of 1 ms quite easily and without help from HW. This is also what the IEC 61850 standard refers to as the basic time synchronization accuracy class (T1) [14].

The most common protocol at the moment is SNTP, which is suitable for local substation synchronization. But if the SNTP server is behind multiple Ethernet nodes, the latency increases and makes time synchronization more inaccurate. This does not make SNTP an ideal solution for system-wide implementation. Normally a GPS or equivalent time synchronization source is required in every substation.

IEEE 1588 [15] handles these issues and makes it possible to achieve a time synchronization accuracy of 1 µs. This is required if an IEC 61850 process bus is used. IEEE 1588 provides a cost-efficient and accurate method for system-wide time synchronization, where network devices are able to correct the node delays into time synchronization frames.

5. Life Cycle Costing of Different Scenarios

According to Refs. [16, 17] the Life Cycle Cost (LCC) of the equipment in an electricity substation can be broken down into the cost of acquisition $C_A(t)$, the operation cost $C_O(t)$ and the renewal cost $C_R(t)$, see Eq. (1).

$$C_{LC}(t) = C_A(t) + C_O(t) + C_R(t) \tag{1}$$

In Eq. (1) $C_{LC}(t)$ describes the overall life cycle costs. The operation costs can be further divided into maintenance cost $C_M(t)$ (scheduled maintenance) and failure cost $C_F(t)$ (unscheduled maintenance), see Eq. (2).

$$C_O(t) = C_M(t) + C_F(t) \tag{2}$$

The failure cost $C_F(t)$ itself is a summation of the component replacement cost $C_{CR}(t)$ and the penalty cost for undelivered energy $C_P(t)$, see Eq. (3).

$$C_F(t) = C_{CR}(t) + C_P(t) \tag{3}$$

In this chapter the life cycle cost of the proposed setup is compared against other scenarios. Three different scenarios are evaluated:

(1) All functionality is decentralized in IEDs, the IEDs need to be high-end (HE) relays.

(2) All functionality is centralized within a station computer (two station computers are needed, since a backup computer is required), measurements are retrieved from merging units.

(3) Setup proposed in this paper: Combined solution with a station computer and IEDs. IEDs can be low-end (LE) relays, since high-end functionality is included in the station computer.

These three scenarios are evaluated with different cost factors–acquisition costs, renewal costs, maintenance costs and failure costs causing penalties due to undelivered energy.

5.1 Acquisition Costs

For obtaining acquisition costs rough estimations need to be made for unit prices (both acquisition and renewal) and for foreseen intervals for renewal, presented in Table 1. Price estimates include both the price for equipment and the labor cost (installation and commissioning), which in Finland are normally divided 50/50.

With all other items the renewal price is the same as the acquisition price, except for the station computer. The station computer is expected to be updated more frequently, and in these cases most of the renewal actions consist only of software updates. In a fully centralized setup the second station computer is only needed for the backup functionality, and therefore the same update interval is simply estimated as for the low-end relays.

Table 1 Price and renewal interval for different equipment.

	Price/k€	Renewal price/k€	Renewal interval/a
High-end relays	6	6	15
Low-end relays	3	3	20
Merging units	1	1	20
Station computer	20	3	2
Station computer (Backup)	20	20	20

When using the unit prices from Table 1, acquisition costs for different scenarios are according to Fig. 5.

Based on Fig. 5 one can conclude that using only bay level high-end relays is the most cost-effective solution in most of the cases. When a substation has more than seven feeders, the solution proposed in this paper is the most cost-effective. When the number of feeders exceeds 10, having fully centralized setup renders the lowest acquisition costs.

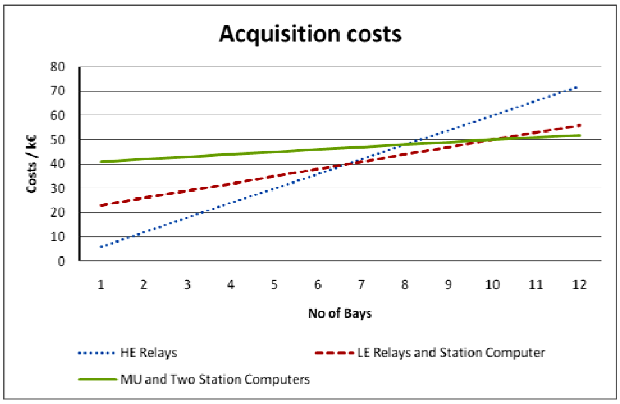

Fig. 5 Acquisition costs for different scenarios.

5.2 Acquisition and Renewal Costs

When also taking into account the renewal costs, the situation changes. High-end relays have a shorter life cycle, since new requirements need to be fulfilled in the IEDs. This forces a faster upgrade cycle to be applied than with other scenarios (15 years). The life cycle of low-end relays and a backup station computer is estimated to be the same (20 years). The life cycle for the station computer is set to as short as two years, in order to describe the dynamic nature of a future substation. On the other hand, these upgrades are mainly SW updates, which mean inexpensive renewals. With these parameters overall costs for a 40 year period would be according to Fig. 6.

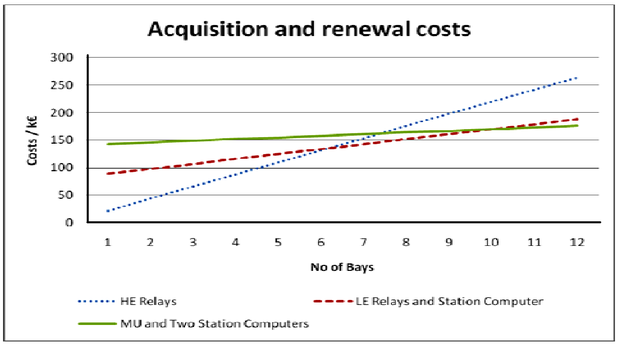

Fig. 6 Acquisition and renewal costs for different scenarios.

This addition already makes the scenario with a station computer and low-end relays more cost-effective, when the substation has only six feeders.

5.3 Acquisition, Renewal and Maintenance Costs

The next item to be included in the life cycle cost is the scheduled maintenance. The secondary system always needs scheduled testing, regardless of the selected scenario. These maintenance activities are not taken into account as such, but instead only such activities that differ between the scenarios are calculated, like the maintenance activities during the renewal. Previous calculations took into account only the equipment cost during the renewal. But a renewal also requires other actions from utilities not directly related to the equipment, such as project planning, gathering of quotations, vendor selection, planning of temporary network topology during the renewal, execution of switching operations for backup connections, etc. Accurate statistics for these costs were not available, but according to estimations from Finnish utilities these operations require roughly one and a half man month per substation, which in Finland amount to approx. 15 k€ additional costs.

These maintenance costs have the same interval as the primary protection of the station, which in this example means 15 years for a fully decentralized setup and 20 years for both centralized setups. With these additions the costs for the secondary system are according to Fig. 7.

This addition makes the centralized setup even more economically favourable, even for a substation with just five feeders a centralized setup can be justified.

5.4 Acquisition, Renewal, Maintenance and Failure Costs

Although more difficult to estimate, the item which

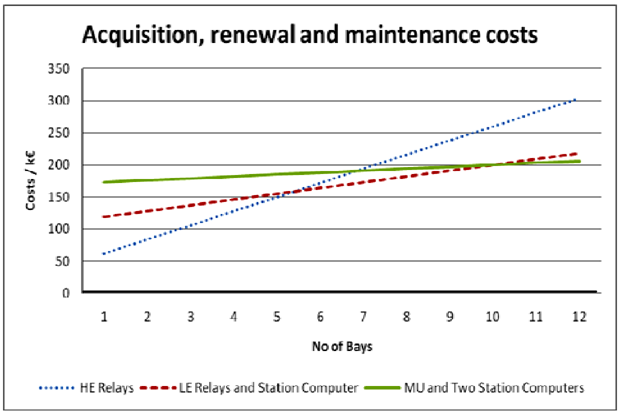

Fig. 7 Acquisition, renewal and maintenance costs for different scenarios.

can have a major impact on the overall costs, is the profit gained by increasing the reliability of the distribution network. When the substation functionality is up-to-date, protection is more selective (less unwanted trips), fault situations are cleared faster and fault areas are narrower, maintenance needs are more accurately known, etc.

This aspect is however very difficult to estimate. What is the reliability of a 10 year old secondary system, in comparison to a 1 year old system? How often does the secondary system malfunction? What is the answer to these two questions after 10 years? Especially for distribution networks, accurate statistics do not exist since utilities have not had enough resources to collect and analyze statistics on secondary system failures. The financial consequences of faulty operations can also vary greatly. One unwanted trip in an outgoing feeder might not have any real effect on the energy not supplied (ENS). On the other hand one single missing operation in the outgoing feeder protection can cause the protection in the incoming feeder to operate. This causes an interruption for the entire network fed from the substation, and can cost as much as all the other interruptions within the same year combined [12].

An effort to estimate the cost of protection failures has been conducted in Norway [18]. The paper presents the main results from a study of incorrect operations of protection and control systems on the voltage levels 1-420 kV in Norway, comprising mainly false and missing operations. The statistics for the period 1999-2003 show that false or unwanted operation is a major fault type and that the relative number of faults and the contribution to ENS increase with the rising voltage level. The research estimated that of all the ENS due to faults in the distribution network approx. 5% is due to failures in the protection system, and that approx 1.5% of all operations were faulty. Of all failures 46% were unwanted operations and 6% missing operations, 48% of failures were not accurately specified. Unfortunately the detailed results for distribution networks were insufficient, and provided only an overview for the percentage of faulty operations.

According to Ref. [19] the average outage time of a distribution feeder due to a fault was 1.62 hours in Finland during 2008, consisting of 6.74 different faults. When using the estimated 1.5% as the portion of faulty operations, one can estimate that an “imperfect” secondary system causes an additional outage of 1.46 minutes due to 0.10 incorrect operations, per year and per feeder. Changing these 1.46 minutes to reliability indicators, one can draw a graph of protection system reliability, presented in Fig. 8.

In Fig. 8 the reliability for year zero was estimated based on the outage time of 1.62 hours per year. The solid line in the figure presents the estimated maximum achievable reliability. Here an assumption is made that after 15 years only 0.5% of all operations would be faulty (an improvement of 1% unit would happen). The dashed line in the figure presents the change in the reliability of the decentralized setup. After the installation the reliability starts decreasing for several reasons. The equipment is aging or the parameterization becomes outdated due to changes in the network. This is shown in the figure as a falling slope, based on the assumption that without upgrade measures 2.5% of all operations would be faulty after 15 years.

The reliability shown in Fig. 8 is calculated based solely on incorrect operations, because other statistics were not available (and even those statistics were limited). Other causes for poor reliability in this context could be are e.g. incorrect fault location, incorrect condition monitoring causing premature

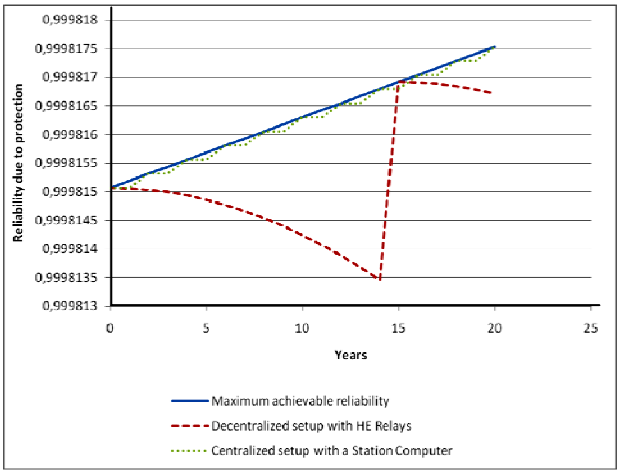

Fig. 8 Reliability of protection.

maintenance, simply any functionality where an upgrade would improve the cost-efficiency of the protection system. But Fig. 8 clearly shows the benefit of the centralized setup, presented in the Figure as a dotted line. The functionality is constantly near the state-of-the-art level due to frequent updates, but the maintenance costs are kept at a minimum.

For evaluating the financial consequences of outages a term for customer outage costs ("Keskeytyksestä aiheutunut haitta", KAH) has been defined in Finland. The costs for different customer groups are presented in Table 2 [20].

When using the average outage cost in Table 2 and an average feeder power of 0.80 MW [19], the combined life cycle costs for the same 40 year period is shown in Fig. 9.

In Fig. 9 only the difference in reliability is taken into account, not the actual reliability. Graphically this is represented by the triangular area in Fig. 8. This final figure shows the impact of reliability. With the assumptions made a substation with only four feeders should utilize the centralized setup with a station computer.

Note that the calculations above are not intended for accurate and full scale life cycle cost analysis. The main purpose is to indicate all areas where centralized and decentralized setups have an impact on overall life cycle costs, and to provide the methodology for calculations. Especially for failure costs more studies

Table 2 Customer outage costs in Finland for different customer groups.

	€/kW	€/kWh
Households	0.36	4.29
Agriculture	0.45	9.38
Industry	3.52	24.45
Public	1.89	15.08
Services	2.65	29.89
Average in Finland, based on energy share and interruption frequency	1.1	11.00

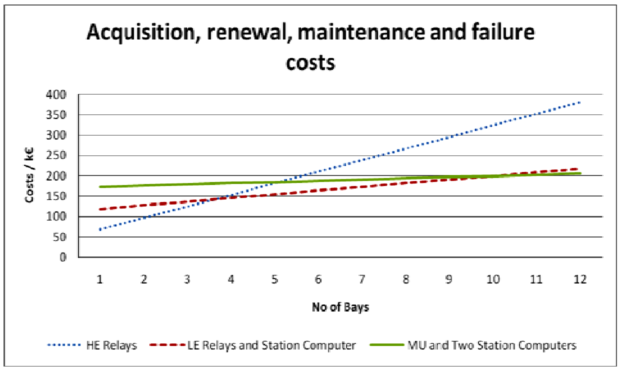

Fig. 9 Combined lifecycle costs including failure costs.

are needed, with different fault cases and a deeper statistical analysis.

6. Summary

Due to an increasing share of distributed generation and other active resources more intelligence is needed also in primary distribution substations. As the significance of these "Smart Grid impacts" is not yet known, a faster upgrade cycle than before is expected for the secondary system. To address these life cycle cost challenges a new concept is proposed, which utilizes a centralized station computer and new communication and time synchronization standards.

In small substations the currently prevailing approach to use only bay level IEDs will still be economically justifiable in the future. On the other hand, according to calculations presented in this paper, a substation with more than three feeder bays should utilize centralized station computers.

The calculations presented here very much depend on the initial costs given in Table 1, and especially on the estimations related to protection system reliability. For better results more research would be required concerning the reliability of the protection system. Depending on the given values, the substation size limit, after which the centralized setup becomes more cost-effective, can vary. But the main result is apparent, the larger the substation, the more likely a centralized station computer will decrease life cycle costs. The requirements presented in section 3 can also force faster renewal cycles to be implemented on the decentralized setup than the estimated 15 years, making the benefits of centralization even more persuasive.

Acknowledgments

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