Cost-effective Communication and Control Architectures for Active Low Voltage Grids

MIKEL ARMENDÁRIZ

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KTH, Royal Institute of Technology
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Abstract:

The monitoring and control of low voltage distribution grids has historically been disregarded due to the unidirectional flow of power. However, nowadays the electric power system is being modernized to enable a sustainable energy system. This is assisted by the smart grids concept, which incorporates the new types of loads, the active energy consumers, often called 'prosumers', and the higher requirements for reliability and quality of service. The number of prosumers is increasing since many houses, apartments, commercial building and public institutions are beginning to produce energy, mainly through solar photovoltaic panels on their rooftop. These installations are principally promoted by the fall in the cost of renewable energy technologies, especially solar panels. Thus, while the small-scale renewables can reduce the electricity bill for the consumers, they can also generate problems for the distribution grid operators because the non-consumed energy surplus is exported to the grid and that requires updating the existing electricity infrastructures. This new paradigm adds new regulatory, economic, and technical type of challenges. In response to this new situation, this thesis investigates the communication and control architectures that are required for active low voltage grid monitoring and control applications, considering the regulatory constraints and the efficient utilization of the assets from a distribution system operator's perspective.

Hence, this thesis contributes by proposing a framework and optimization studies to assess the required communication and the control solutions (*i.e.*, sensors and actuators) from a cost-effective point of view. This is done by including the economic aspects (CAPEX & OPEX) into the optimization formulation. The communication solutions are twofold: first, the optimal sensor placement configuration that is required to perform low voltage state estimation is covered. Then, the optimal metering infrastructure designs for active low voltage monitoring application are studied. The control solutions are threefold and cover the decentralized and coordinated distribution automation applications: first, control strategies are proposed to allow the integration of microgrid-like structures into the distribution grids. Second, the procedure to optimally place the control actuators (*i.e.*, tap changers) for running the control strategies is studied. Third, a decentralized and multiagent-based control solution is proposed for self-healing and feeder reconfiguration applications. In addition, a framework model and its corresponding simulation tool are developed for studying and assessing the reliability of the ICT infrastructure that enables the active low voltage grid monitoring and control applications.

As concluding remarks, the technology readiness level shows that the required communication and control architectures for enhancing the active low voltage grids with new services are mature, as they are for high voltage grids. However, the deployment of technology at low voltage grids is restricted to assets owned by the distribution system operator. This condition limits the operability of the grid and requires solutions that prioritize cost-effectiveness over comprehensiveness and complexity. Thus, the results from the presented studies show that it is essential to perform thorough cost-benefit analyses of the potential improvement solutions for each grid, because this will allow deploying the right technology only at the necessary locations.

Keywords: Active low voltage distribution grids, CAPEX & OPEX, communication & control architectures, cost-effectiveness, MPC, multiagent systems, photovoltaics, voltage control.

Sammanfattning:

Övervakning och styrning av lågspänningsnät har historiskt sett förbisetts på grund av enkelriktat effektflöde. Nuförtiden moderniseras dock elsystemet för att möjliggöra ett hållbart energisystem. Detta stöds av smartgrids-konceptet, som medföljer aktiva energikonsumenter, ofta kallade "prosumers", och högre krav på tillförlitlighet och servicekvalitet. Antalet prosumers ökar eftersom många hus, lägenheter, kommersiella byggnader och offentliga institutioner börjar producera energi, främst genom solpaneler på taket. Dessa installationer främjas främst av nedgången i kostnaden för förnybar energiteknik, särskilt solpaneler. Även om små förnyelsebara förnybara energikällor kan minska elräkningen för konsumenterna, kan de också skapa problem för distributionsnätoperatörerna eftersom den oförbrukade energin exporteras till nätet, vilket kräver en uppdatering av den befintlig elinfrastrukturen. Detta nya paradigm medför både ekonomiska och tekniska utmaningar.

Denna avhandling undersöker de kommunikations- och kontrollarkitekturer som krävs för aktiva övervaknings- och kontrollapplikationer för lågspänningsnät, med tanke på de lagstadgade begränsningarna och det effektiva utnyttjandet av tillgångarna från en distributionssystemoperatörs perspektiv. Denna avhandling bidrar med en ram- och optimeringsstudie för att bedöma den nödvändiga kommunikationen och kontrollösningarna (d.v.s. sensorer och manöverdon) från en kostnadseffektiv synvinkel. Detta görs genom att inkludera de ekonomiska aspekterna (CAPEX & OPEX) i optimeringsformuleringen. Studierna i den här avhandlingen behandlar två typer av kommunikationslösningar: Dels uppskattas den optimala sensorplaceringskonfigurationen som krävs för att utföra tillståndsestimering av lågspänningsnätet. Dels studeras de optimala mätningsinfrastrukturerna för lågspänningsövervakning av aktiva applikationer. Tre typer av kontrollösningar inkluderas i studien och täcker de decentraliserade och samordnade distributionsautomatiseringsapplikationerna: För det första föreslås kontrollstrategier för att möjliggöra integration av mikrogridliknande strukturer i distributionsnätet. För det andra studeras hur styrmanövreringsorganen (d.v.s. kretsväxlare) kan placeras för att driva styrstrategierna optimalt. För det tredje föreslås en decentraliserad och multiagentbaserad kontrolllösning för självläkning och feederkonfigurationsapplikationer. Dessutom utvecklas en rammodell och motsvarande simuleringsverktyg för att studera och bedöma tillförlitligheten för IKT-infrastrukturen, som möjliggör aktiva övervaknings- och kontrollapplikationer för lågspänningsnät.

Teknikens beredskapsnivå visar att de nödvändiga kommunikations- och kontrollarkitekturerna för att förbättra aktiva lågspänningsnät med nya tjänster är lika mogna som för högspänningsnät. Den tekniska implementeringen vid lågspänningsnät begränsas dock till de tillgångar som endast kan ägas av distributionssystemoperatören. Detta faktum begränsar operativiteten och kräver lösningar som prioriterar kostnadseffektivitet över omfattning och komplexitet. Det är därför viktigt att genomföra en grundlig kostnads-nyttoanalys av de potentiella förbättringslösningarna för varje enskilt nät, eftersom detta kommer bidra till en ökad förståelse för när och var en viss teknik bör användas.

Nyckelord: Aktiva lågspänningsdistributionsnät, CAPEX & OPEX, kommunikations- och kontrollarkitekturer, kostnadseffektivitet, MPC, multiagent-system, solceller, spänningsreglering.

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Stockholm, October 2017.
Mikel Armendáriz

Papers

List of included papers

PAPER I: Armendariz, M., Babazadeh, D. Barchiesi, M., L. Nordström, ”A Method to Place Meters in Active Low Voltage Distribution Networks using BPSO Algorithm”, *IEEE 19th Power Systems Computation Conference (PSCC 2016), Genova, Italy, 2016.*

PAPER II: Armendariz, M., Johansson C., Nordström L., Yunta Huete A., García Lobo. M., "Method to design optimal communication architectures in advanced metering infrastructures." *IET Generation, Transmission & Distribution 11.2 (2017): 339-346.*

PAPER III: Armendáriz, M., Heleno M., Cardoso G., Mashayekh S., Stadler M., Nordström L., “Coordinated Microgrid Investment and Planning Process Considering the System Operator” *Elsevier Applied Energy, 200 (2017), 132-140*.

PAPER IV: Armendariz, M., Paridari, K., Wallin, E., Nordström L., “Comparative Study of Optimal Controller Placement Considering Uncertainty in PV Growth and Distribution Grid Expansion” *Electric Power Systems Research 155C (2018) pp. 48-57.*

PAPER V: Eriksson, M., **Armendariz, M**., Vasilenko, O., Saleem, A., & Nordström, L. ”Multiagent-Based Distribution Automation Solution for Self-Healing Grids”., *IEEE Transactions on Industrial Electronics, 62(4), pp. 2620-2628. 2015.*

PAPER VI: Armendariz, M., Gonzalez R., Korman M., Nordström L., ”Method for Reliability Analysis of Distribution Grid Communications Using PRMs-Monte Carlo Methods”, *IEEE Power and Energy Society General Meeting (PESGM) 2017. Chicago, IL., USA, July 2017.*

Author contributions

In Paper I, the general research concept was initiated and developed by Armendariz and Nordström. The algorithm was designed by Armendariz with support from Babazadeh. The programming was done by Barchiesi. The paper was fully authored by Armendariz.
In Paper II, the general research concept was initiated and developed by Armendariz and Nordström. The algorithm was designed by Armendariz and the programming was done by Johansson. Yunta and García supported and reviewed the paper. The paper was fully authored by Armendariz.
In Paper III, the general research concept was initiated and developed by Armendariz and Heleno. The design and implementation was done by Armendariz. Cardoso, Mashayekh, Stadler and Nordström reviewed the research. The paper was fully authored by Armendariz.

In Paper IV, the general research concept was initiated and developed by Armendariz and Nordström. The design and implementation was done by Armendariz. Paridari and Wallin supported and reviewed the research. The paper was fully authored by Armendariz.

In Paper V, the general research concept was done by Armendariz, Eriksson and Nordström. The programming and implementation was done by Eriksson and Vasilenko. The paper was written by Armendariz with contributions from Eriksson, Vasilenko, Saleem and Norström.

In Paper VI, the general research concept was initiated and developed by Armendariz and Nordström. The design was done by Armendariz and the programming was done by Gonzalez. Korman supported and reviewed the research. The paper was fully authored by Armendariz.

Publications not included in the thesis

PAPER VII: Babazadeh, D., **Armendariz, M.**, Nordström, L., Tonti, A., Borghetti, A., & Nucci, C. A. ”Two-stage network processor for an independent HVDC grid supervisory control”. *IEEE Power and Energy Society General Meeting (PESGM) 2016 (pp. 1-5). Boston, MA., USA, July 2016.*

PAPER VIII: Armendariz, M., Babazadeh D. Brodén, D., Nordström, L., "Strategies to improve the voltage quality in active low-voltage distribution networks using DSO's assets." *IET Generation, Transmission & Distribution 11.1 (2017): 73-81.*

PAPER IX: Armendariz, M., Brodén, D., Honeth, N., Nordström, L., ”A Method to Identify Exposed Nodes in Low Voltage Distribution Grids with High PV Penetration”, *IEEE Power and Energy Society General Meeting (PESGM) 2015. Denver, CO., USA, July 2015.*

PAPER X: Armendariz, M., Brugeron, M, Saleem, A., Nordström, L., “Facilitating Distribution Grid Network Simulation Through Automated Common Information Model Data Conversion”, *IEEE PowerTech 2015. Eindhoven, The Netherlands, June 2015.*

PAPER XI: Armendariz, M., ” Voltage Control Strategy to Minimize Distribution Power Losses from DSO Perspective”, *Energy Informatics Conference 2014, ETH - Zürich, Switzerland, Nov 2014.*

PAPER XII: Armendariz, M., Chenine, M., Nordström, L., & Al-Hammouri, A. “A co-simulation platform for medium/low voltage monitoring and control applications” *IEEE Innovative Smart Grid Technologies Conference (ISGT), 2014 IEEE PES (pp. 1-5), Washington D.C., USA, February 2014.*

PAPER XIII: Wu, Y., Nordström, L., Saleem, A., Zhu, K., Honeth, N., & **Armendariz, M**. “Perspectives on Peer-to-Peer Data Delivery Architectures for Next Generation Power Systems”, *17th IEEE International Conference on Intelligent Systems Applications to Power Systems (ISAP), Tokyo, Japan, July 1-4, 2013.*

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List of Acronyms

AI: Artificial Intelligence
AMI: Advanced Metering Infrastructure
AMR: Automatic Meter Reading
AVR: Automatic Voltage Regulator
BAU Business As Usual
BPSO: Binary Particle Swarm Optimization
CAIDI: Customer Average Interruption Duration Index
CAPEX: Capital Expenditures
CHP Combined Heat and Power
CM: Cost of Meter configuration
CS: Control Strategy
DC: physical Data Concentrator.
DER: Distributed Energy Resources
DG: Distributed Generation
DMS: Distribution Management System
DR: Demand Response
DRES: Distributed Renewable Energy Sources
DSO: Distribution System Operator
EAAT: Enterprise Architecture Analysis Tool
E.G.: Exempli Gratia
EU European Union
EV: Electric Vehicle
FAN: Field Area Network
FiT: Feed-in Tariffs
FLISR: Fault Location, Isolation, Service Restoration
GB: Global Best
GW: Gateway
HAN: Home Area Network
HE: Head-End
I.E.: Id Est
IED: Intelligent Electronic Device
ICT: Information and Communication Technology
IEEE: Institute of Electrical and Electronics Engineers
LV: Low Voltage
LVCDC: Low Voltage Cable Distribution Cabinet
MC: Monte Carlo
MDMS: Meter Data Management System
MPC: Model Predictive Control
MINLP: Mixed-Integer Nonlinear Problem
MILP: Mixed-Integer Linear Problem
MV: Medium Voltage
NAN: Neighborhood Area Network
NPC: Net Present Cost
OLTC: On Load Tap Changer
OPEX: Operational Expenditures
PCC: Point of Common Coupling

PMU: Phasor Measurement Units
PRM: Probabilistic Relational Models
PV: Photovoltaic
QoS: Quality of Service
R: Resistance
RMSE: Root-Mean-Square Error
RTU: Remote Terminal Unit
SAIDI: System Average Interruption Duration Index
SCADA: Supervisory Control and Data Acquisition
SE: State Estimation
SM: Smart Meter
SS: Secondary Substation
SVC: Static VAR Compensators
TSO: Transmission System Operator
U: Voltage
VAT: Value Added Tax
VDC: Virtual data concentrator
VEE: Voltage Error Estimation
VSC: Voltage Source Converter
WAN: Wide Area Network
WMN: Workforce Mobile Network
X: Reactance
Z: Impedance

Part I
Introduction

Chapter 1

1. Introduction

This thesis is divided into two parts: part I and part II. In part I, an introduction to the research topic is conducted, the research context is introduced, the related work is described and the main findings and conclusions are presented. Then, in part II the papers that are included in this thesis are presented.
This first chapter of part I includes a general background on Active Low Voltage Grids and the motivation for the topic of research. Moreover, it states the research objectives and it summarizes the main contributions of this thesis.

1.1 Background and motivation

The electric power system is encountering fundamental changes in its structure. An important transformation corresponds to the way the energy has been traditionally supplied, starting from large and synchronous generator-based power stations (*e.g.,* fossil fuel power stations, nuclear power plants, hydropower stations, etc.) via transmission and distribution grids to load centers (*e.g.,* industry, commercial buildings, households, etc.). Nowadays however, supply and demand technologies are changing and so is the flow of the energy. The generation units are shifting toward lighter-weight generators (*e.g.,* gas-fired turbines) and variable resources (*e.g.,* offshore and onshore windfarms, photovoltaic power stations, etc.) and the grid is becoming more decentralized by hosting an increasing number of distributed and variable small-scale generation resources (*e.g.,* domestic rooftop photovoltaic systems, heat-pumps, electric vehicles (EV), etc.), see Fig. 1.

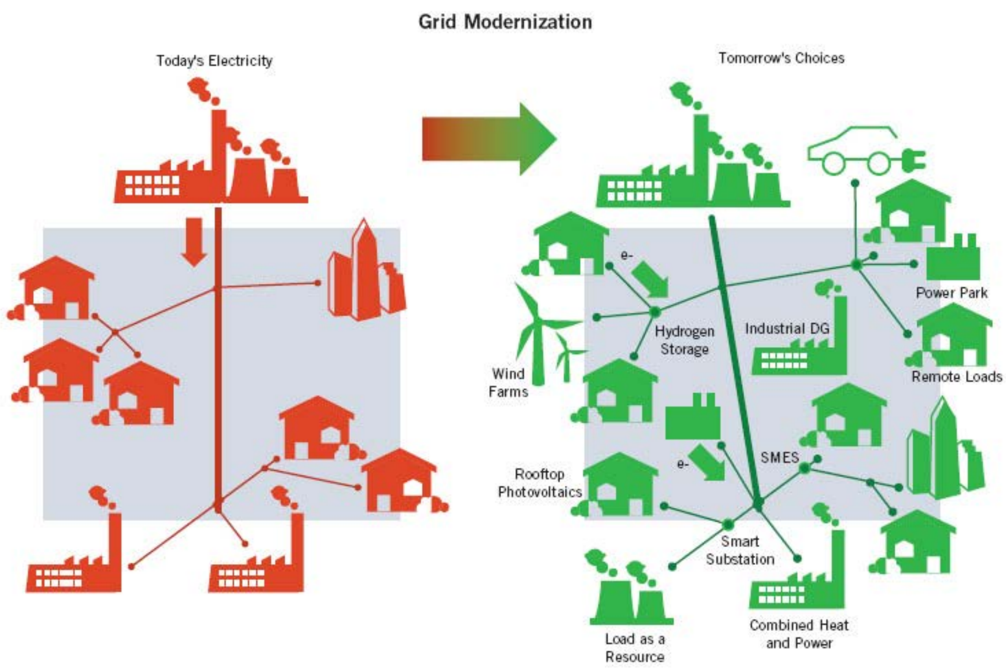


Fig. 1. The IEEE´s version of the Smart Grid involves distributed generation, information networks, and system coordination, a drastic from the existing utility configurations. (Source: IEEE).

All things considered the electric power system infrastructure and in particular the distribution grid is being essentially required to operate under some stress conditions that were not initially devised. Moreover, such operation requires much greater flexibility, agility and adaptability to changes in the system, specially, when the incorporation of variable Distributed Energy Resources (DER) into the Medium Voltage (MV) and Low Voltage (LV) grids is concerned [1]. In Fig. 2 the main differences regarding the traditional Distribution System Operator (DSO) versus the future DSO role are depicted, divided by grid operations, connection of power units and grid planning. Thus, inevitably the current grid modernization also leads to an enhancement of the corresponding communication and control architectures in order to guarantee the necessary quality of service performance. In essence, the enhancement of these new architectures consists of deploying sensors and actuators in the grid for improving the grid observability and controllability. Besides, considering the dimension of the distribution grid, such technological rollout should be carried out from a cost-effective approach. These architectures are required for supporting the monitoring applications, the control applications and ultimately the grid operation and maintenance. Clearly, they must rely on an Information and Communication Technology (ICT) infrastructure that should be sized in such a way that it can provide an adequate level of intelligence for operating the grid without risking reliability and cyber security, and at the same time it does not represent an economic burden. Hence, cost-effective architecture solutions (both infrastructures and applications) will be highly prioritized in the ongoing DSO modernization process.

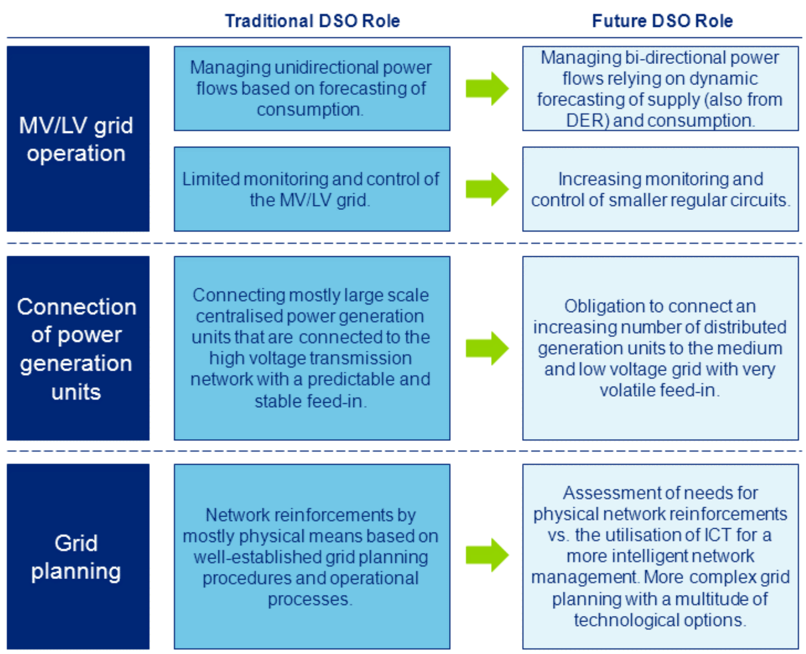


Fig. 2. Traditional DSO’s role vs future DSO’s role. (Source: DISCERN FP7 project [2]).

When we focus on the MV/LV grids, we see that the Photovoltaic (PV) installations have exponentially increased over the last decades and a more accelerated growth, pulled by the emerging economies, is expected by 2020 [3]. This trend is driven by the falling prices of PV modules, *i.e.* between 2010 and 2020 the reduction of the average price of the PV systems is projected to be 75% [4]. For instance, in Fig. 3 a) the price trend for turnkey photovoltaic systems is shown for the Swedish PV market, which has experienced a large decrease since 2010. Consequently, as shown in Fig. 3 b) the market for grid-connected PV systems has grown rapidly in Sweden.

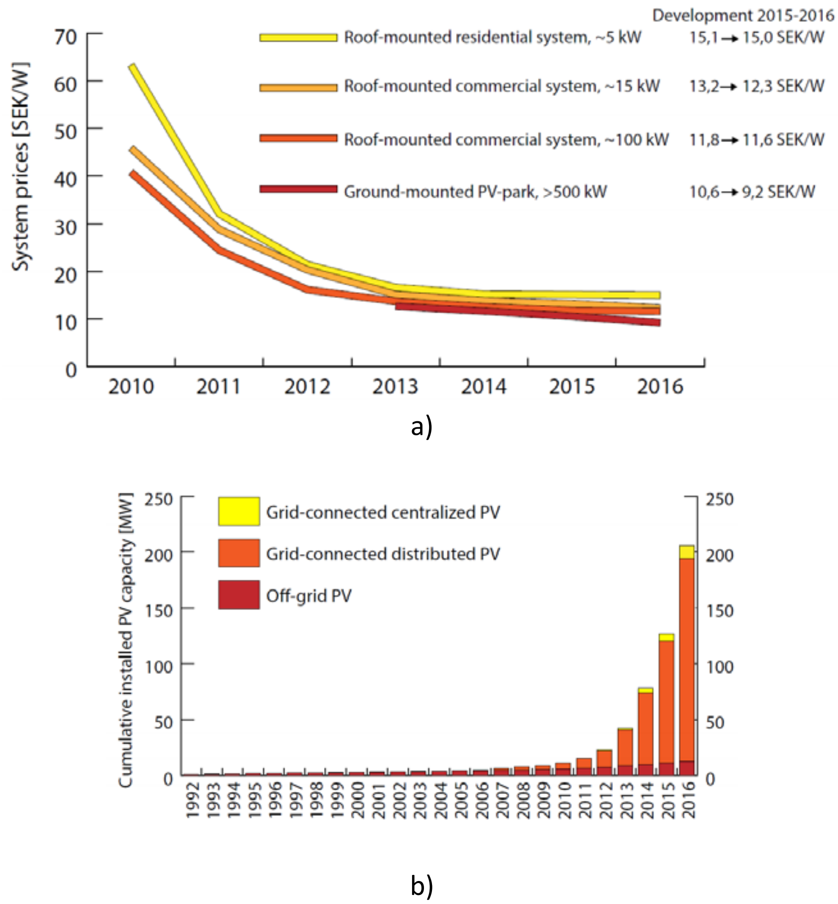


Fig. 3. The Swedish PV market: a) Weighted average prices for turnkey photovoltaic systems (excluding VAT) over the years, reported by Swedish installation companies. b) The cumulative installed PV capacity in Sweden [5].

Moreover, policy and regulatory measures have been incentivizing photovoltaic investments, such as Feed-in Tariffs (FiT) [6], which is a well-established policy to accelerate the renewable energy deployment into the grid. This is performed by offering long-term contracts to PV producers (*e.g.* usually 10-20 years) to sell their electricity to the market under a fixed/ premium-based tariff above the market rate. This is typically based on the cost of generation of each technology, capacity and location of the project (see [7] and [8]). The advantage of this instrument for the PV investors is that since it provides long-term contract predictability and security, the investment risks and financing costs are lower. However, it can also influence the electricity prices and distort the wholesale electricity market, as mentioned in [9], where a detailed analysis of FiT policy is performed. Examples of FiT schemes in Europe are shown in [7] and in [11]. Other additional measures are capital subsidies for equipment purchase [5] as well as financial incentives and remuneration compensation schemes, such as self-consumption [12], net-metering [13] and net-billing [14].

The advantages of PV and renewable Distributed Generation (DG) in general is that they can contribute to the power system with a series of benefits, such as peak shaving, electricity loss reduction along transmission and distribution lines, increased reliability and overall decrease of greenhouse gas emissions [15]-[18]. On the contrary new challenges arise, especially in MV/LV grids, which are mainly resistive (*i.e.*, R/X > 1) and typically follow a radial topology. These characteristics make them be more vulnerable to the unpredictable fluctuations of the non-dispatchable distributed generation. In Fig. 4, the effect on power flow direction fluctuation caused by PV generation is depicted for the current and the future Active LV (ALV) [1] distribution grid. These challenges can impact the power quality *e.g.*, PV systems can produce voltage rise, unbalanced lines, reverse power flows and thermal overloading of the components, relay coordination problems, higher harmonic content, increase energy losses at LV grids, etc. Detailed description and examples of power quality issues can be read in [19], [20].

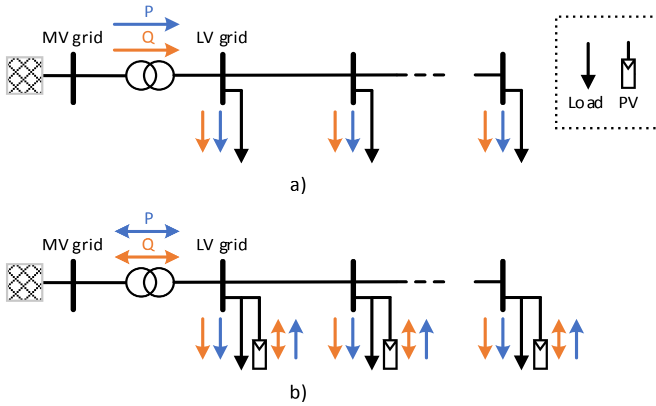


Fig. 4. a) Unidirectional energy flow in traditional LV grid. b) Bidirectional energy flow in future ALV distribution grid.

In order to guarantee the power quality, DSOs have to comply with the state-specific electricity grid codes and the regulatory framework, which specifies the required reliability level for distribution grids and the admissible voltage profile within an acceptable band. Two examples of such codes and standards are the regulation by the Swedish Energy Markets Inspectorate, that specifies the outage times and the obligation to report power outages for assessing the security of supply in the power grids EIFS 2015:4 [21] and the European standard EN 50160 [22] for voltage characteristics in public distribution systems.

Therefore, in this thesis voltage magnitude variations and power service interruptions are used as power quality performance indicators for ALV distribution grids. In addition, several proposed control solutions to guarantee the power quality can be found in the literature. These solutions are of different nature depending on where they are applied and how they interact with the power system. DSO-side solutions require that it is only DSOs who shall install and operate the assets without interacting with the customers. Here we can find solutions such as grid reinforcement, on load tap changer (OLTC) control, static var control, energy storage, microgrids, grid reconfiguration, etc. On the contrary, prosumer solutions specify that prosumers modify their P/Q injection or absorption to the grid, without the direct intervention of the DSOs. Examples are *e.g.*, active power curtailment of PV inverters, reactive power control of PV inverters, etc. Additionally, in-between solutions can also be found. These require active interaction between users and the corresponding DSO and they are enabled by an ICT infrastructure. Typical examples are consumption shifting by demand response programs and combination of the previous presented solutions *e.g.*, OLTC control + PV inverter control. In Table 1 these solutions are classified according to which domain they belong and the type of control architecture that they can be fit in, *i.e.*, centralized, coordinated and distributed control (see Fig 5). Centralized architectures require a strong ICT infrastructure to be able to connect the

[1] The traditional LV grid becomes active LV when DER is incorporated into the system leading to bidirectional power flows.

MV/LV Secondary Substations (SS) with the Distribution Management System (DMS) in order to perform the decision making and receive and send commands, especially if the objective consists of real-time control. Coordinated architectures require a less complex ICT infrastructure since the decision making can be located at the MV and LV substations level and use local measurements and adjacent information to perform the control (*e.g.*, substation measurements, Smart Meter (SM) measurements, etc.). On the other extreme we can find distributed architectures, which do not require communicating with upper-level systems and simply rely on local and adjacent information to perform the decision making. Clearly, even though such control structure cannot guarantee optimal results and yields less efficient results than the centralized or coordinated approaches, it can be sufficient to solve the local problem. However, if the ICT infrastructure fails, the controllers in the distributed and in the coordinated control architectures could still operate with local information, whereas the centralized controller may fail because the control decisions are carried out at the DMS level.

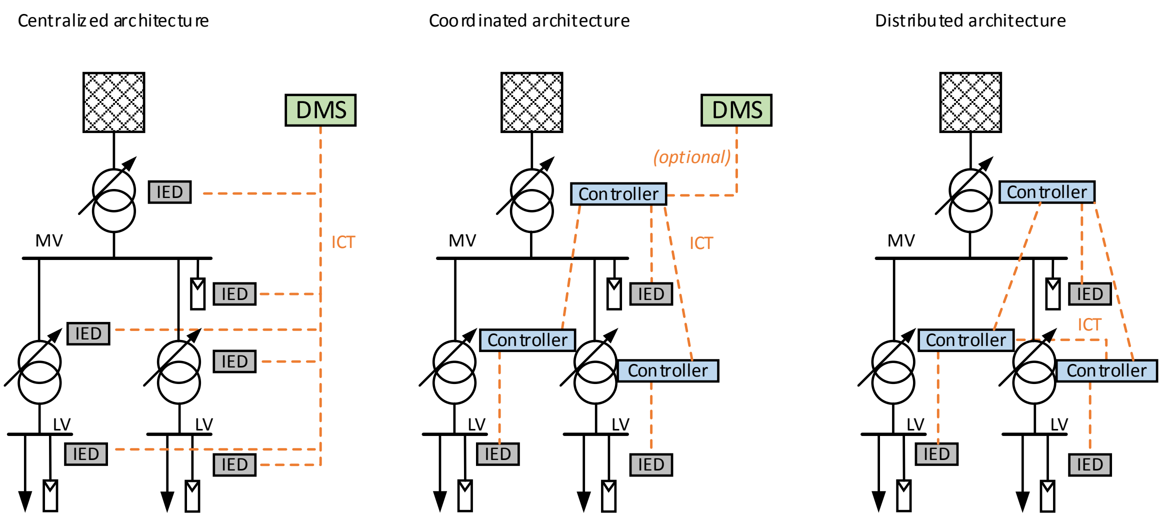


Fig 5. Overview of the control architectures.

Table 1: Control architectures versus application domain

Domain	Control architecture		
	Centralized	Coordinated	Distributed
DSO	• DMS • Grid reconfiguration	• HV/MV + MV/LV OLTC • HV/MV + MV/LV OLTC + DSTATCOM • Multi-microgrids • Grid reconfiguration	• Grid reinforcement • MV/LV OLTC • DSTATCOM • Energy storage • Microgrids • Grid reconfiguration
PROSUMER			• P curtailment of PV • Q control of PV
IN-BETWEEN	• DR	• P curtailment of PV • Q curtailment of PV • OLTC/ DSTATCOM + P/Q control of PV	

A summary of the mentioned technological solutions is presented below, distinguishing between DSO-side solutions and prosumer/ in-between solutions.

DSO-side solutions

Grid Reinforcement

This traditional grid reinforcement practice consists of replacing the transformers with higher capacity ones and the underground and hanging cables with conductors with a larger cross-sectional area that can supply the load and avoid voltage and thermal/capacity problems. The reason is that a cable with larger cross-sectional area shows lower impedance (Z) and therefore it produces smaller voltage variations (drop or rise). This solution is also the typical one to supply the load without violating the thermal ratings. It corresponds to the business as usual (BAU) *fit & forget* approach, which is a costly practice due to the civil works that it requires, especially for underground feeders (see [23] - [29]).

Coordinated on load tap changer control

The OLTCs are typically used in HV/MV primary substations and it is common practice that MV/LV SS are not fitted with tap changers. However, when the transformers are equipped with tap changers to regulate the voltage, these are usually manually operated to perform line drop compensation to seasonal load changes such as winter/summer conditions. This setup is not the most appropriate one to respond to load variations caused by the intermittent PV generation. Thus, by properly adding automation to some of the tap changers at MV/LV transformers and coordinating the control with HV/MV OLTCs it is possible to perform active voltage control in the LV grid (see examples in [30] - [32]). An issue to consider is the fact that in order to overcome the fast and irregular voltage fluctuations caused by PV production, the taps have to change frequently and this makes mechanically-operated OLTCs to wear out [33]. The new generation of OLTCs is based on solid state technology and power electronic-based transformers, which offers improved performance, mainly related to switching frequencies and response times [34]. This is still a novel technology and therefore, the control algorithm that regulates the primary and SS's OLTCs operations should minimize the tap changes. Additionally, in order to keep a proper balance between power quality improvement and deployment & operation cost, a challenge exists in properly choosing which substations should be selected for automation refurbishment.

There are already DSOs implementing prototypes and pilot projects using OLTCs at SS (see examples in [35] - [37]). Hence, the practical results from these studies, once benchmarked against other solutions, will contribute to assessing the OLTC deployment potential in ALV distribution grids.

Static VAR compensator (SVC) – Distribution static synchronous compensator (DSTATCOM)

SVC/DSTATCOMs can be connected at the point of common coupling (PCC) and be installed at the distribution transformer in parallel to the feeder (see [38]) and also along the LV grid *e.g.,* in the middle of the line (see [39]). This solution can be an option to perform fast voltage regulation, to smooth the flicker or to balance the source currents. But it is a disproportionate solution to perform steady state LV voltage control due to it is not necessary to regulate the PCC voltage at *e.g.* 1.0 p.u, instead a permissible voltage range is allowed (*e.g.,* ±10%), see [40]. This approach is based on a voltage-source converter (VSC) and it can act as either a source or sink of reactive power. By incorporating a source of energy to this solution (*e.g.,* batteries), the inverter can also provide active power regulation and work in four quadrants (*e.g.,* inject/ absorb active and reactive power). This approach is principally used in higher voltage grids such as HV and MV grids (see [41], [42]) due to the higher reactance characteristic and not that much in LV grids.

Energy storage

Storage technology and in particular battery prices (*e.g.*, Lead acid/ Lithium-ion batteries) are decreasing drastically as described in [43]. Eventually, they could be used locally by DSOs as local flexible resources, which could significantly reduce grid costs and become an alternative solution to the traditional grid reinforcement practices. For instance, batteries can be installed at the SS (*i.e.* MV/LV) in order to reduce the short-term mismatch between supply and demand. This can be achieved by storing excess electricity during generation peak hours (such as at midday) and then delivering it at times of high demand but little generation (such as at night). Thus, balancing services and peak shaving services could be provided and the power demand would be lighted.

There are of course regulatory-related issues that should be further adjusted around this solution to guarantee energy unbundling. The reason is that it is common that many DSOs are part of vertically integrated utilities that own generation businesses and if a DSO operates significant volumes of energy storage at distribution level that could distort the wholesale electricity market (see electricity market regulation in EU [44]). Recent examples using batteries as energy storage systems are shown in [45] - [47].

Microgrids

Microgrids are formed by a group of loads and DER (*e.g.*, households + PV + small scale combined heat and power (CHP), batteries, etc.) that act as a single controllable unit. This unit can operate by connecting and disconnecting from the grid. When the microgrid is connected to the grid it is called “grid-connected” and it is operated following a decentralized approach [48]. On the contrary, when it is disconnected from the grid it is called “off-grid” or “isolated microgrid” and it is operated following a centralized mode [49]. Proper definitions and trends in microgrid control can be found in [50] and [51].

The main advantage of forming a grid-connected microgrid is that it can provide a set of services that can improve the operations of the regulated grid. Additionally, it can bring financial benefits to the microgrid owner by improving the self-consumption and selling the excess power to the grid. This will definitely depend on the purpose that the microgrid serves and on the way it is designed and dimensioned. Thus, microgrids can be dimensioned following different criteria and they can be valid to support the following necessities:

- Energy efficiency improvement.
- Self-consumption and minimization of overall energy consumption.
- Environmental impact reduction (*e.g.,* CO_2 reduction).
- Grid operational benefits *e.g.,* power supply resiliency improvement, power quality improvement: peak shaving, loss reduction, congestion relief, voltage control, etc.

Broadly speaking, microgrids can be divided into two groups *i.e.,* utility or network microgrids and customer microgrids.

On the one hand we can find the utility microgrids, which are owned and operated by utilities, typically by the DSOs. Therefore, they must comply with the grid codes and state-specific electricity regulation. These types of microgrids usually serve as a controllable entity that DSOs can use to improve the reliability and/or the power quality of a part of their grid that shows weaker performance characteristics. Besides, utility microgrids are usually considered as alternative solutions to the traditional grid reinforcement practices mentioned earlier. Thus, this type of microgrids could be a temporary solution to defer in time the required grid refurbishment investments.

The criterion to design a utility microgrid will principally depend on the final purpose that is required to be achieved by the DSO. Examples of typical services are *e.g.,* peak-shaving, voltage control improvement, loss reduction, resiliency improvement, self-consumption, etc.

On the other hand, we can find the customer microgrids, which are typically implemented as a private investment and unlike the utility microgrids, the purpose here is to achieve a minimization of the overall energy consumption. Its design is usually the result of a complex investment and planning optimization problem, which takes into account economic parameters (*e.g.,* energy tariffs, remuneration tariffs, feed-in, DER costs, etc.), energy-related and environmental parameters (*e.g.,* CO2 reduction). Several tools can be found in literature to address this problem, such as REopt [52], RETScreen [53], SAM [54], HOMER [55] and DER-CAM (Distributed Energy Resources Customer Adoption Model) [56].

Grid reconfiguration

MV grids are usually built following a meshed topology but they are operated in radial structure. Thus, by avoiding loops the protection coordination can be simplified. Contrarily, LV grids are usually built and operated radially, and depending on the number of customers and location (*e.g.*, urban and dense sub-urban grids) they can be built as a meshed grid and be reconfigured to solve grid constraints. As explained in [57] and [58], the typical grid constraint applications that can be addressed by grid reconfiguration comprise loss-minimization, load balancing, service restoration and reliability improvement. In order to solve such constraints, the topological structure of their feeders can be locally or remotely reconfigured by opening/closing the actuators *e.g.,* breakers, sectionalizes tie switches, etc. Generally, when the actuators are located in MV grids the reconfiguration can be dynamically and remotely performed by the DSO following a centralized approach or a coordinated and multiagent systems-based approach (see examples in [59] - [62]). As mentioned in [58], the dynamically controlled grid reconfiguration is a solution to relax the grid constraints by triggering the actuators and effectively adapting to the new operating grid conditions. However, the frequent use of the actuators includes an inherent cost that should be considered (*e.g.,* wear, tear, risk of component failure, etc.). Hence, special attention is being paid lately by the research community to fulfil the grid constraints and to reduce the switching of the actuators by solving complex mixed-integer nonlinear optimization problems (MINLP) using mathematical programming and heuristic techniques (see [63] - [65]). For actuators located at LV grids though, the reconfiguration is usually performed manually and locally by the DSO. At this level the topology changes are less frequent *e.g.,* on a yearly/season basis to accommodate the grid structure to the mid-term operational planning conditions.

<u>Prosumer/ in-between solutions</u>

Active power curtailment of PV inverters

This solution consists of reducing the active power injection by the PV inverters. It can be the case that the installed capacity generates more active power than what the grid can handle without incurring power quality problems, such as overvoltages or component overloading problems during certain hours. In such cases, the injection can be restricted to a fixed level that is negotiated with the utility, so that feed-in peak-shaving can be performed in certain hours. This procedure is known as static curtailment. By executing active power curtailment there is energy that is not feed-in to the grid, so it is wasted and prosumers are forced to miss the chance to sell it. However, there can be a contract between the prosumer and the utility that regulates how to perform the remuneration of the energy not feed-in while performing peak-shaving services. Additionally, the active power curtailment can fluctuate depending on the voltage at the connection point: P(U), by applying *e.g.*, droop-based active power curtailment [66]. This procedure is known as dynamic curtailment and can be a more efficient use of the curtailment solution. It can work standalone as a distributed control architecture. However, it requires to be connected to an ICT infrastructure for participating as an agent in a coordinated control architecture. Obviously, the energy loss represents the main downside of these curtailment solutions. Examples of both static and dynamic active power curtailment are shown in [67] - [70].

Reactive power control of PV inverters

This practice consists of regulating the PV inverters to inject/ absorb reactive power in order to mitigate the voltage violations (over or undervoltages): Q(U). The effectiveness of this approach mostly depends on the R/X characteristic of the grid that the inverter is connected to. Thus, unlike with P inverter control, Q inverter control is a more suitable solution for MV grids than for LV grids because of the higher reactance characteristic of the former ones. The downside of this practice is that it can result in higher currents and losses along the cables, in addition to lower power factors at the input of the feeder. Besides, even though this solution is technically feasible, same as with P inverter control, depending on how it is implemented (*e.g.*, centralized, coordinated or distributed control architecture) it needs an ICT infrastructure to coordinate and send commands to the inverters. This communication layer increases the complexity of the solution and incorporates regulatory concerns to this solution. The reason is that it is rare that the regulation allows DSOs to have access to the private PV inverters behind the meter. Examples of performed research on the use of reactive power control of PV inverters can be found in [71] - [74].

Consumption shifting – demand response

Demand Response (DR) procedures can be applied to decrease the load in peak hour conditions, demand curtailment and rescheduling in response to day-ahead and real-time market prices. These procedures can be considered as ancillary services for DSO operations, which can perform voltage support, active and reactive power balance, frequency regulation and power factor correction. As pointed out in [75], by improving the reliability of the power system and by lowering the peak demand, DR can reduce the overall capital cost investments and it can be used for deferring the investments in grid reinforcement. These programs and in particular real-time DR require a comprehensive ICT infrastructure that can support two-way communication between customers and utility, a monitoring system and control devices to interact with the loads *e.g.*, load control switches, thermostats, etc. Examples using DR procedures to mitigate grid problems are shown in [76] - [79].

Lastly, it is common in transmission and high-voltage distribution grids to monitor the buses employing real-time measurements. However, according to Eurelectric most European distribution lines are low and medium voltage (*i.e.*, 60%: < 1kV, 37%: 1 - 100 kV, 3% > 100 kV), which require more than 4 million distribution transformers and around 10700 HV/MV interconnection points [80]. Thus, obviously even if it were technically feasible, it would be very costly and work intensive to deploy and maintain the communication and control architectures needed for operating the distribution grid in real-time as it is done for the transmission grid. Instead, when possible, a more realistic approach is to deploy sensors only in specific MV/LV locations (*e.g.*, some SS, some distribution cabinets, end of some lines, etc.) and compensate the lack of measurements with estimated pseudo-measurements. And similarly, the automation of transformers, or other type of actuators if required, should be carried out in an optimal way that allows deploying and operating as few actuators as possible. So that the economic impact of the technological deployment has the minimum effect on DSO's Capital Expenditures (CAPEX) and Operational Expenditures (OPEX). In fact, the decision of deploying a specific technological solution will highly take into consideration its feasibility (in terms of reliable standard solutions that satisfy the regulatory requirements) but ultimately it will lean towards the principal driver: the economic terms.
Therefore, in any case the required communication and control architectures for enabling ALV distribution grids will not reach the comprehensive monitoring and control capabilities and coverage available at the transmission grid (*e.g.*, transient stability control). However, regardless the combination of the technical solutions that will be deployed, the grids will have to be modernized with *e.g.*, sensors, switchgears, controlgears and an overhead ICT infrastructure to adapt to the new varying conditions in ALV distribution grids. Consequently, in summary, reliable and cost-effective architecture solutions are of special interest in this thesis.

1.2 Research goal and objectives

Based on the presented background, the research goal of this thesis is formulated as:

- To propose cost-effective and reliable communication and control architectures for ALV grids.

In achieving this goal, this thesis addresses the following research objectives:

- **OBJ 1:** To identify, propose and develop cost-effective communication architectures for ALV distribution grids.

- **OBJ 2:** To identify, propose and develop cost-effective control architectures for ALV distribution grids with minimal impact on prosumer market participation.

- **OBJ 3:** To propose and develop a framework to model and assess the reliability of the communication and control architectures for ALV distribution grids.

1.3 Main contributions related to research objectives

The objectives of this thesis together with the description of the achieved main contributions are summarized in Fig. 6. The cost-effectiveness of the proposed tools is achieved by incorporating the cost aspects into the design optimality criterion, while guaranteeing the effective performance of each of the developed solutions in terms of quality and reliability.

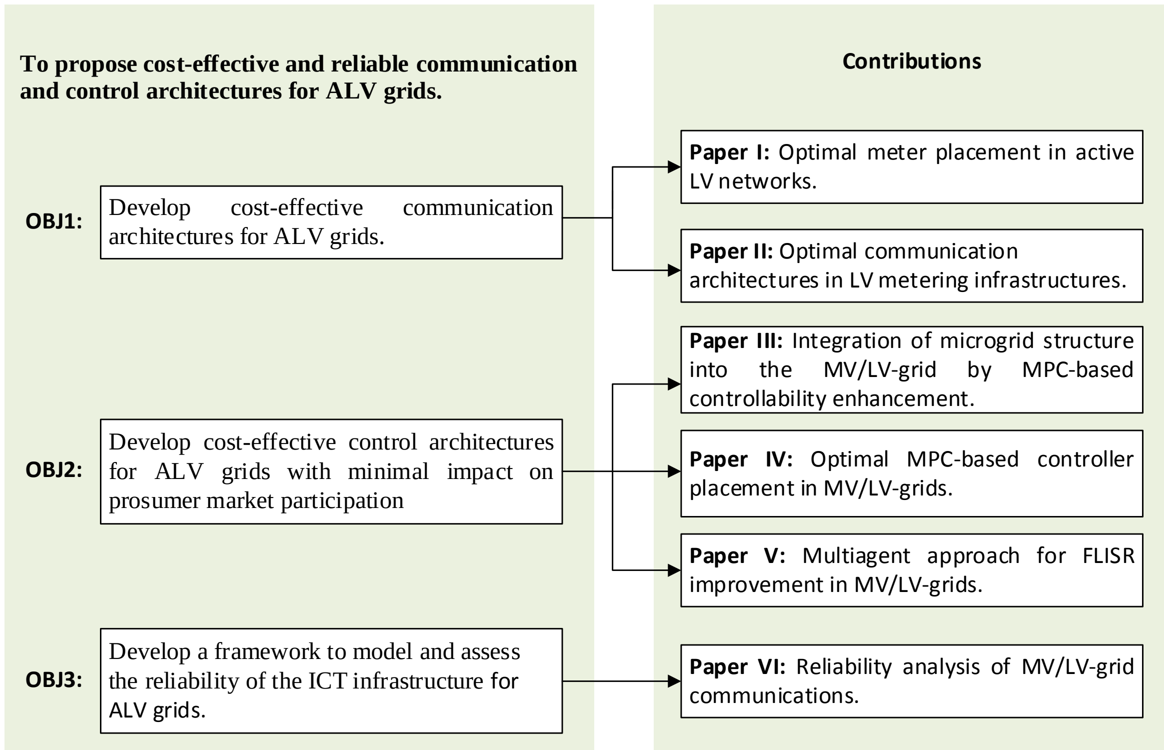


Fig. 6. An overview of the thesis contributions with respect to the research objectives.

Firstly, OBJ1 covers the developed cost-effective communication architectures for ALV distribution grids by studying the optimal meter placement configuration required to perform LV State Estimation (SE) and the optimal Advanced Metering Infrastructure (AMI) designs for LV monitoring applications. The main contributions regarding OBJ1 are summarized as follows:

- In Paper I a method based on Binary Particle Swarm Optimization (BPSO) is proposed to optimally place the current and voltage sensors in LV grids. The optimality criterion is determined by the LV SE-error and the cost associated to a particular meter deployment configuration. Both cases using SM measurements and pseudo-measurements are tested.

- In Paper II a method to design optimal AMI communication architectures is proposed. It clusters the energy meters that share similar characteristics (*e.g.,* distance to the SS and mutual proximity) and it connects each cluster to the AMI head-end through a communication architecture formed by wireless and Power Line Communication (PLC) technologies. The optimality criterion is determined by the CAPEX, the OPEX and the quality of service (QoS) achieved in each the communication architecture.

Secondly, OBJ2 covers the developed cost-effective control architectures for ALV distribution grids by studying decentralized and coordinated distribution automation applications. The focus has been threefold: 1) to apply control strategies to effectively allow the integration of a microgrid-like grid structures into the MV/LV distribution grid; 2) to develop a procedure to optimally place the actuators that operate the controllers for such strategies; 3) to apply distributed multiagent control systems to perform self-healing and feeder reconfiguration applications.

The main contributions regarding OBJ2 are summarized as follows:

- In Paper III a concerted microgrid investment approach is proposed, in which the DSO and a microgrid owner can cooperate, so that the PV capacity installed by microgrid at the MV/LV grid can be increased without causing voltage problems to the adjacent ALV grids. It is suggested and proved that in order to avoid such voltage problems the grid controllability can be upgraded by applying coordinated and cost-effective voltage predictive control strategies.

- In Paper IV a method is proposed to optimally place voltage controllers that can remove the possible overvoltage problems caused by ALV grids. It extends the control strategies applied in Paper III by considering the uncertainties related to PV growth and distribution grid expansion.

- In Paper V a multiagent-based distribution automation solution is proposed to be used by self-healing MV/LV grids in order to solve the service restoration part of the Fault Location, Isolation and Service Restoration (FLISR) task. It is shown that the multiagent control architecture can outperform the current restoration procedures in terms of power service interruption duration, yielding a power quality improvement.

Lastly, OBJ3 covers the developed framework model to study and assess the reliability of the required ALV distribution grid communication architectures. The main contributions regarding OBJ3 are summarized as follows:

- In Paper VI a method to perform reliability analysis of communication systems used in ALV distribution grids is proposed. It is based on Probabilistic Relational Models (PRM) to indicate the probabilistic dependencies between the components that form the communication system and it is implemented by Monte Carlo (MC) methods. The method can be used for performing reliability predictions of simulated communication systems for ALV grids and therefore it can be extended for evaluating the reliability of the communication architectures proposed in Paper II.

Finally, in Table 2 the covered topics by this thesis are summarized for each publication.

Table 2: Covered topics by the publications

Topic	Publication					
	I	II	III	IV	V	VI
Monitoring	✓	✓				✓
Communications	✓	✓			✓	✓
Distribution automation - control			✓	✓	✓	
Quasi-static load-flow			✓	✓	✓	
Power grid modeling	✓		✓	✓		
Power quality performance	✓	✓	✓	✓	✓	✓
Cost-effective solutions	✓	✓	✓	✓	✓	
Optimization	✓	✓	✓	✓	✓	

1.4 Research scope and limitations

The power quality performance in MV/LV grids is one of the elements of the future electricity grids and it is strongly being studied by the scientific community. It is being approached from several angles, which can be classified into consumer side applications (*e.g.*, demand response, home energy management system, Automatic Meter Reading (AMR)/AMI), supplier side applications (*e.g.*, distributed storage and generation, vehicle-to-grid), prosumer side applications (*e.g.*, microgrids and active customers) and DSO side applications (*e.g.*, volt-var control, distribution automation, self-healing and feeder reconfiguration, cybersecurity and communications). In this thesis the studied applications that impact the power quality of ALV distribution grids cover grid monitoring, voltage control and reliability aspects (power and communication). These applications principally belong in the DSO domain and in order to have a minimal influence on the electricity markets they are restricted to only using assets owned by the DSO (*e.g.*, Intelligent Electronic Devices (IED), OLTC, SM, meter data concentrators, reclosers, etc.). Of course, this limits the potential of grid operability and it requires prioritizing cost-effective solutions. The reason for such limitation is the fact that the European Commission (EC) requires its Member States to separate their DSO's grid activities from generation and retailing businesses, as stated in the Directive 2009/72/EC [81]. Thus, although there are additional solutions that clearly would increase the potential of power quality improvement of LV grids, by for instance having direct control over the consumers/prosumers (*e.g.*, residential PV inverter control, residential heat pump control, demand response-based short-term price signal commands, etc.), this would be considered as a breach of DSO unbundling.

Chapter 2

2. Research Context

This chapter provides the research context to this thesis by focusing on active MV/LV distribution grid monitoring and control operations. Such operations require building complex system of systems and best examples are found in large scale industrial projects. Thus, in this chapter we identify and highlight the required system architecture, the related functions, and the recommendations and learned lessons from EU-funded energy research and innovation projects.

2.1 Smart grid architectures for monitoring and control MV/LV operations

The management of the power system requires involving and coordinating multiple and diverse stakeholders (*e.g.,* energy producers, utilities, consumers, experts, etc.). These stakeholders form a complex and heterogeneous system architecture that allow interoperating multiple business functions. At the distribution domain they enable the grid operations, asset management, operational planning and optimization, maintenance and construction, extension planning, customer support and meter reading business functions [82]. Thus, in order to guarantee a sustainable evolution of the current grid by adopting the new requirements, applications and new technologies, the use of the reference architectures are recommended. Examples are the Smart Grid Architecture Model (SGAM) [83], NIST's conceptual model [84] or the Smart Grid Standards Architecture as defined in IEC 62357 [85]. Next, we describe the SGAM framework and the use case methodology.

Use case methodology and SGAM framework

The use case methodology is a way to describe system requirements in a smart grid environment. It is properly standardized in the IEC 62559 "Use Case Methodology" standard series in three parts: Part 1 describes how the methodology will be used within the IEC for standardization activities [86]; Part 2 presents the use case template [87]; and Part 3 includes the UML data model and XML schemas to exchange use cases across software applications [88]. A use case specifies a set of the actions that are performed by a system in order to achieve a goal. This goal is stablished by one or multiple actors, which can be persons, systems, etc. The way the actors achieve the goal is described by the use case in several scenarios, each of which details the sequence of steps of exchanging the information with each other. This information exchange details the functional and non-functional requirements *e.g.,* data management, quality of service, or security issues.
The architecture of the solutions that meet such requirements can be obtained by using the use case methodology in combination with the SGAM framework [83]. As described in [89], it is required to: 1) map the use case actors into components (devices or applications) within the physical distribution of the Smart Grid solution; 2) represent the communication protocols and data models necessary to achieve interoperability; 3) show how the components, protocols and data models relate with the technical functions and business goals of the solution.

The SGAM provides a framework for describing the architectural representation of smart grid use cases. One of the main features is that it is valid for presenting a use case in a technology neutral manner. The SGAM is formed by the smart grid plane and the interoperability layers (see Fig. 7). On the one hand, the dimensions that form the plane correspond to the physical domains of the electrical energy conversion chain (*i.e.*, Bulk generation, Transmission, Distribution, DER and Customer Premises) and the hierarchical zones for the management of the electrical process (*i.e.*, Market, Enterprise, Operation, Station, Field and Process). On the other hand, the layers correspond to the business processes policies and regulatory constraints (Business layer), the required system functions and services to achieve the business goals (Function layer), the exchanged information and data models to realize the functions (Information layer), the required communication protocols (Communication layer) and the necessary equipment and components (Component layer). These layers represent the five categories that fully interoperable systems address.

Once the use cases are created and mapped to the SGAM framework, the obtained result consists of a textual documentation of components, information, communication, functions, and business processes for a particular smart grid scenario. Therefore, this information is clear to be shared across different departments of the same company and with other partners within a large project consortium, as it was done in the DISCERN project. Next, we show a use case example for enhancing the monitoring and observability of low voltage grid components.

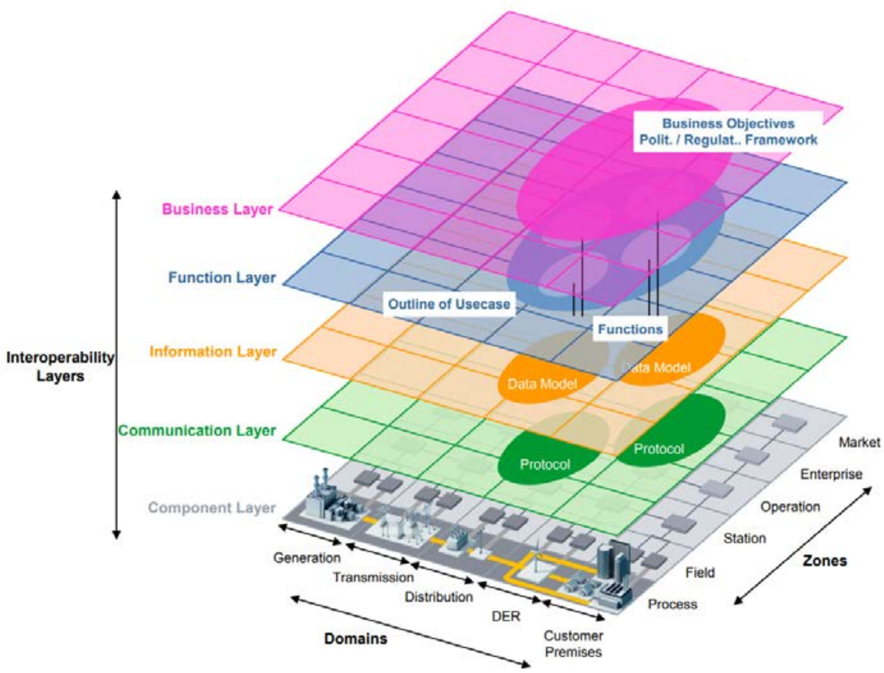


Fig. 7. The SGAM framework. (Courtesy: CEN – CENELEC - ETSI Smart Grid Coordination Group).

Example of a smart grid use-case from DISCERN project

The overall aim of the DISCERN project was to provide guidance to the DSO community in Europe on how to cost-effectively manage new requirements arising from large scale introduction of renewables in the distribution grids. Here, the set of solutions include optimal MV grid monitoring and automation as well as monitoring of the LV grid together with solutions for optimal deployment of communication and measurement solutions for Automatic Meter Reading (AMR) in urban and rural areas both for billing, but also for identification of technical and non-technical losses. In order to obtain these solutions, the problem and requirement specifications are implemented in the form of use case descriptions and SGAM architectural views. So than then, the available technical solutions can be identified. For instance, the sub-functionality called “Real time monitoring of LV grid” focuses on enhancing the monitoring and observability aspects of grid components down to low voltage levels. It consists of improving the LV grids monitoring by installing additional sensors and IEDs at the SS that collect and calculate magnitudes at both primary phase lines and LV busbar levels. Thus, the resulting two streams of LV data correspond to 1) SM readings from client’s premises; 2) Measurements in the SS (at feeder level and at the LV part of the distribution transformer). And the obtained data allows covering alarms, power quality, harmonics, events, SM data, etc. The use case specifies the information exchanged and the system requirements regarding *e.g.*, configuration issues, QoS issues, security issues, etc. The use case diagram description is shown in Fig. 8, where the actors interact within the use case by participating in the technical functions. In addition to this data, the scenario description and the diagrams are used for creating the corresponding SGAM models. The use case data, the scenarios and the models created for the sub-functionality covered in this example can be found in [90]. By using the DISCERN tool support [89] for knowledge sharing that was developed within DISCERN project the SGAM models can be created in Microsoft Visio and they can be exported in an XML format. In fact, this tool is used in paper VI for obtaining the XML SGAM model templates of this same sub-functionality example for analyzing the reliability of the communication systems.

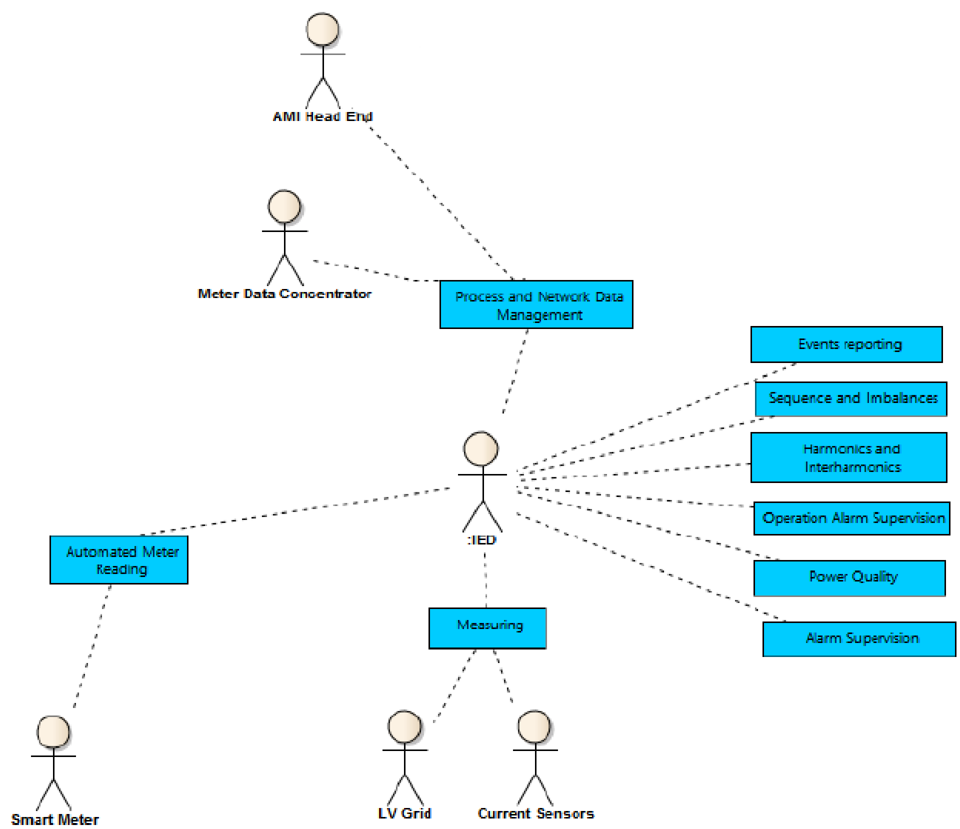


Fig. 8. Use case diagram of the sub-functionality called “Real time monitoring of LV grid” from the DISCERN project.

2.2 Functions to support the monitoring and control operations

Each of the business functions that are applied in the distribution domain are composed of a set of sub-functions, these are defined in IEC 61968-1 standard [82]. For instance, the grid operations are based on grid operation monitoring, grid control, fault management, operation feedback analysis, operation statistics & reporting, calculations – real time and dispatcher training sub-functions. Similarly, we can take each and every sub-function, break them down and analyze the main algorithms that are implemented in each of them. In this thesis the focus is on the algorithms that are related to grid monitoring and control operations. For example, grid monitoring sub-functions utilize SE algorithms, which are applied in Paper I. Grid control sub-functions utilize *e.g.*, load and production forecasting algorithms, voltage control algorithms (applied in papers III and IV) and system restoration algorithms (applied in paper V). A general description is presented next and the specific related work analysis on each of the applied algorithms is conducted in Chapter 3.

Distribution system state-estimation algorithm

The goal of running SE algorithms is to obtain the estimation of the grid state (*i.e.*, node voltages, power flows and current flows) that provides the lowest error by using the available information (*e.g.*, grid topology, line parameters, measurements and load/generation profiles). The SE technique is largely applied in the transmission grid and the states variables are the complex voltage of the nodes. In distribution grids however, due to the radial nature of the grids, it is preferable to use the branch complex currents as state variables to make the computation is faster, more robust [91] - [93]. Thus, as in Paper I, the branch current SE is performed by applying a weighted least squares (WLS) method, the most common and a well stablished SE technique that is based on the minimization of weighted measurement residuals [94], [95]. Its formulation is based on the linearization of the relationship between measurements and state variables, as shown in (1). Where z denotes the vector containing the measurements (*e.g.*, voltage, current, and active and reactive power flows or power injection), x represents the state variables (branch complex currents), the vector function h(x) relates the measurements to the state variables, and *e* represents the noise in the measurements.

$$z = h(x) + e \tag{1}$$

The objective function of the minimization problem corresponds to the weighted least square function (2). Here the goal is to minimize the weighted differences between measured variables and their estimated values. The weights are defined by R, which is the diagonal vector containing the variance of the measurement noise, assuming that the uncertainty of this noise is characterized by a Gaussian distribution. Here it is important to point out that when pseudo-measurements are used (as it is the case in Paper I), these are assigned a higher standard deviation of the measurement error (σ_{pseudo}) to represent low accuracy, because it is based on non-measured data.

$$J(x) = [z - h(x)]^T R^{-1} [z - h(x)] \tag{2}$$

The optimality condition is satisfied when $\partial J(x)/\partial x$ is set to zero, as shown in equation (3), where $H = [\partial h(x)/\partial x]$ is the Jacobian of the measurement function.

$$g(x) = \frac{\partial J(x)}{\partial x} = -H^T(x)R^{-1}[z - h(x)] = 0 \tag{3}$$

From here the x state variables can be iteratively computed using (4), where G(x) represents $\partial g(x)/\partial x$ and superscript k is the iteration number.

$$\Delta x^k = -[G(x^k)]^{-1} g(x^k) \tag{4}$$

Once the branch complex currents are estimated, then the grid voltages are computed through a backward/forward sweep calculation [96]. In Paper I, the vector z includes measurements at SS, grid level and also at PQ buses through SM and less accurate pseudo-measurements.

Voltage control architecture solution based on the deployment potential

A summary of the technological solutions to control MV/LV distribution grids was presented in the introduction chapter of this thesis. In connection to this, a thorough evaluation of the solutions is carried out within the iGREENGrid project [97]. The solutions cover MV/LV monitoring, voltage control and congestion management. The detailed results of the most promising solutions based on their deployment potential are presented the deliverable D4.2 [98]. The criterion for determining the deployment potential considers the following characteristics: performance of the solution, social aspects, scalability and reliability, investment risk, technical complexity considering system, component and interoperability features. In addition, the technical requirements, regulatory requirements and economical requirements are also studied for each solution. The following 13 categories cover the technical requirements, which are identified as high/medium/low: large number of measurements, implementation of a central control system, monitoring and control of end-users' devices, installation and operation of non-standard equipment, uni/bidirectional communications, type of communications, time requirement for the system, bandwidth, number of types of standards of communication needed, cybersecurity, coordination and control of high number of devices, retrofit old devices (e.g. inverters) to support new functionalities, and standardization of smart grid components. Regarding the regulatory requirements, these are covered by the following 6 categories, also identified as high/medium/low: MV national existing grid code for RES, LV national existing grid code for RES, regulation for reactive power, voltage control, curtailment provision, regulation for energy storage systems, required information to be accessed by DSO and definition of TSO and DSO roles. Finally, regarding the economical requirements, the relative importance of the CAPEX and OPEX of each solution is also identified as high/medium/low. The highlighted conclusions regarding MV monitoring show that offline field measurements could be enough to perform offline load-flow studies if real-time control requirement were not present. On the contrary, if real-time control were to be applied, solutions such as RTUs or SE could be used. Regarding LV monitoring, if the AMI could provide voltage measuring capabilities, it would be a cost-effective solution, especially when using statistical data to reduce bandwidth/memory /data processing requirements. This solution shows potential benefits that could largely outweigh the costs.
On the voltage control aspects, the most promising solution for MV grids corresponds to OLTC control. Similarly, in LV grids OLTC control is also a suitable solution. In addition, in some cases Automatic Voltage Regulators (AVR) can be a simpler solution in terms of short-term deployment, for example when temporary solutions are required until the grid has been reinforced.

Load and production forecasting

The load and the production forecasts are used both for operations and planning purposes. These forecasts and specifically long-term forecasting (years ahead) are used in planning activities for infrastructure development and for deciding suitable locations for large DER plants such as windparks and solar power plants.
In operations however, the forecasting is used for the stabilization of the power market, where the supply must match the demand, and for grid operations. In grid operations and specifically at the distribution level operations, the forecast activity is a more complex task and it is based on predicting the power flow at substations, feeders, transformers, and customers with a typical forecasting horizon of minutes to days-ahead. In addition, when the forecast is performed considering small systems (*e.g.*, feeders or branches) it is even harder than performing it for larger systems (*e.g.*, aggregation of feeders and substations) and it provides lower accuracy. This is because the aggregated values at large systems are more stable and regular, mainly resulting from the law of large numbers as explained in [99], [100]. However, as explained in [101], there can be the cases that the feeders are dominated by few large customers (*e.g.*, schools, commercial buildings, etc.). When that is the case a customer-specific prediction can be used to obtain a feeder power flow predictions.
In general, the forecasting of load and power production (*e.g.*, from PVs and wind) is very useful to predict the behavior of the distribution system. For instance, substation and feeder forecasts can provide DSOs with advanced warnings on potential substation, feeder and branch overloading. Thus, the information can be used to efficiently perform feeder switching, reconfiguration and to balance loads/prosumers among the feeders as they can relieve the overloading of the components and reduce system losses. Similarly, the load and production forecast can be used to feed voltage predictions models. For instance, in Papers III and IV, where voltage control is performed by applying Model Predictive Control (MPC), the linear models use these load and PV production forecasts as input values. Another practical application of load and production forecasting models corresponds to the scheduling and dispatching of energy storage systems to shave peak loads.
A thorough overview regarding load and production forecasting methods is done within the IDE4L FP7 project [102]. These can be generally classified as statistical models ([103], [105]) or Artificial Intelligence-based models (AI) ([106], [107]); in addition, there are physical models that are used for production forecasting, which use a micro-scale model of a wind turbine or photovoltaic panels. In [102] the statistical models, such as stochastic time series, are recommended for load forecasting predictions due to the robustness, small computation demand. Similarly, for production forecasting the statistical models are recommended because they provide better results than physical models for short-term horizons and they require less information about the plant.

2.3 Recommendations and learned lessons on cost-effective solutions applied to active distribution grid operations

This section highlights the aspects that act as a barrier to the integration of DRES into the distribution grids. In addition, we summarize the principal recommendations and learned lessons on cost-effective solutions applied to distribution grid operations from a practical perspective. In fact, this section is based on the experience that is obtained from EU projects, such as DISCERN, IGREENGrid and Grid4EU.

Identified barriers for cost-effectively connecting DRES into the distribution grid

The primary obstacles that can jeopardize the integration of DRES into the distribution grids can be categorized into three categories: regulatory, economical and technical. The barriers are identified by IGREENGrid project and they are presented in Table 3. Besides, these barriers are corroborated with the results of other EU projects (ADDRESS, More MicroGrids and EcoGrid EU).
Currently, both the technical and the economical type of problems are thoroughly being covered by the EU consortiums, which are formed by the research community, the utilities and the technology providers. Once the cost-effective solutions have matured and are ready to be deployed, then the policies and regulatory reforms will have to be ready take place. Otherwise, there is a risk to lose the momentum to integrate the DRES into the MV/LV grids following a cost-effective way. Thus, it is important to update the country-specific regulatory frameworks in parallel to the cost-effective technical solutions.
In connection to this, a summary of recommendations and learned lessons is presented next, with special focus on the cost-effective aspects.

Table 3: Type of identified barriers to the integration of DRES in the distribution grid (from IGREENGrid project [97])

Barriers	Type		
	Regulatory	Economical	Technical
Regulation does not allow DSO to control DER (including DRES)	X	-	-
Coordination between TSO & DSO is insufficient for the DRES integration	X	-	-
Lack of a proper regulation for the DRES connection	X	-	-
Lack of adequate remuneration of DSO services	X	X	-
DRES do not have any incentive to take part in the network operation	X	X	-
Rules for interaction with new actors are not clearly defined	X	-	X
Lack of standard “Smart Grid” solution components	-	X	X
Distribution network processed are not up to date with the realities of the integrations of DRES in European countries	-	X	X
Lack of experiences of DSO operating news devices systems	-	X	X
Unaffordable ICT solutions for telecontrol in remote area	-	X	-
Power system reliability affected by massive DRES penetration	-	X	X

Recommendations and learned lessons

The several EU innovation projects that during the last years have been covering the integration of DER into the distribution system provide a set of recommendations and best-practices. From these projects, the cost-effective implementation solutions that are able to provide scalability and replicability potential are the most interesting ones. The main identified aspects on the topic of cost-effective communication and control architectures for active LV grids are summarized in this section.

- When designing smart grid systems (*e.g.*, systems for distribution grid), it is very important to have good communication and system understanding among the actors that are involved in that process. In DISCERN it was proved that the use case and the SGAM approach are an effective <u>solution to support system design and improve internal and DSO-vendor communications</u>.

- There is a disparity of protocol and data models between systems. In order to enable the system integration and the interoperability between information and control systems it is advisable to use standard profiles for communications and data models. From DISCERN it is recommended to adopt the Common Information Model (CIM) as the data model. Besides, it is identified the need to develop companion profiles that would guarantee the interoperability between the communication standards, such as the IEC 62056-5-3 DLMS/COSEM, IEC 60870-5-104, and IEC 61850.

- The recommendation provided by DISCERN regarding IT security requirements for communication and control architectures consists of mapping the SGAM models into the NISTIR 7628 reference model [103] that is developed by NIST. Thus, it is possible to identify which logical interface categories apply in a particular SGAM solution and, in that way, infer the high-level IT security requirements that shall be met by the systems implementing the solution.

- Regarding the monitoring operations to improve the observability of LV grids, it is shown in GRID4EU and DISCERN projects that the use of sensors and measurement devices installed at SSs can be justified to collect measurements at feeder level and provide data on load profiles and power quality. Additionally, this data can be used together with the data obtained from the customers' SMs to provide information for operational decision making *e.g.,* fault identification reducing outage times, overvoltage/undervoltage identification, line capacity identification, etc. The major challenges include handling and processing the large amount of data generated by the sensors and meters. In addition, in order to guarantee that the process of data gathering is as reliable and economically efficient as possible, several requirements should be considered when designing the AMR/AMI communication infrastructure. These requirements include features such as dispersions of customers, grid topology and quality of the available ICT systems.

- Regarding the control operations to improve the voltage level of MV/LV grids, both GRID4EU and IGREENGrid projects show that OLTC actuators can be a suitable deployment solution, in primary substation and secondary substation respectively. Specially, the distributed solutions that are based on local actuators (*e.g.,* OLTC) and which require lower communication needs (local measurements) are a cost-effective alternative to traditional grid reinforcement, provided that they can fulfill the grid requirements. In addition, the study of the specific MV/LV grid is crucial to find the proper control solution. The reason is that in the case of local problems, such as when having concentrated DG in a certain region of the grid, the OLTC can help solving the problem of overvoltage, but its effect can be to worsen the voltage at other feeders with high demand and low voltage. In fact, this situation is tested in Paper III and it is shown that the power quality improves when the MV and LV substations are properly coordinated and equipped with OLTC actuators.

Chapter 3

3. Related Work

This chapter presents the scientifically related work activities within the context of communication and control architectures for ALV distribution grids. The related work is divided into three categories: first, the works that cover the communication architectures for monitoring operations. Second, the works related to control architectures, with special focus on algorithms for the studied control functions. Third, the works related to the reliability of the ICT infrastructures that enables the monitoring and control operations at the distribution level.

3.1 Communication architectures for ALV grids

In relation to this thesis, the following two main aspects are studied within the topic of communication architectures for ALV grids: the placement of monitoring devices and the cost-optimal AMI architectures.

Monitoring-sensor placement

In state estimation, the estimation algorithm, the measurement system configuration and the performance are highly dependent on the specific applications for which estimation results are provided. For instance, branch current estimations are required for grid congestion or thermal problems, voltage estimations are needed to identify voltage problems and power flow estimations are required to perform optimal power flows and contingency analysis. In addition, when the purpose of the SE is to obtain information to perform *e.g.* OLTC control, the allowable estimation error for the voltage magnitude should be within the voltage deviation per transformer tap. Thus, clearly the allowable SE's error depends on the application. As emphasized by [108], it is extremely important to associate the correct uncertainty to the estimated values, because by using accurate estimations the electrical system could be operated more efficiently, for instance, by reducing the safety margins that are too conservative.

The process of replacing missing measurements with most-likely estimates is known as pseudo-measurement generation. This type of measurement estimates are using in Paper I in addition to real physical sensors. In this work, pseudo-measurements are assigned a higher standard deviation of the measurement error to represent low accuracy, because it is based on non-measured data. In addition, due to the stochastic nature of the PV generation and load, the pseudo-measurement modelling process is not trivial. In fact, it involves using historical AMI profiles or statistical data to form pseudo-measurements for household loads and historic PV generation profiles (scaled down to the installed capacity of each unit) or statistical data to form PV generation pseudo-measurements. The modeling of LV pseudo-measurements is covered by [109] - [115]. An important consideration is that the error distribution function for LV pseudo-measurements has to be chosen depending on the number of the aggregated customers. The reason is that when aggregated data is used, the relative error of the pseudo-measurement is reduced and it is more reliable for the SE. In [109] non-Gaussian error distribution functions for load and generation units are generated based on real measurements from a German SM pilot project. In [110] the work is continued by generating active power pseudo-measurements for small scale PV generation units. In [111] a Bayesian approach is used to model the non-Gaussian behavior of the measurements regardless their statistical model and it is suited to include measurements from synchronized Phasor Measurement Units (PMUs). In [112] two classes of pseudo-measurements are generated; the first one assumes that only passive loads are connected to the LV busses and the second one considers the active loads (*e.g.*, PV, CHP, etc.). In both cases the error distribution functions are assumed to be Gaussian, following the approach to simply use basic and cost effective input to SE in LV to provide an acceptable SE. It is shown that little further information on the power profiles that constitute the pseudo-measurements can improve the performance of the estimation drastically. Following this approach the measurement errors that we use in Paper I are assumed to be Gaussian, both for pseudo-measurements and for real measurements.

Since the distribution grids consist of numerous regional substations, feeders and nodes, it requires a high computing time for performing the SE for the entire grid. Thus, a way to simplify the process consists of dividing the distribution grid into several sub-areas (*e.g.*, LV grids) according to geographical, topological, and measurement points and then to solve the SE of each sub-area using local estimators. This process is known as multi-area SE. A comprehensive review of SE methodologies for distribution systems is available in [113]. Some approaches require continuously exchanging data with the neighboring areas with its corresponding communication bottleneck and heavy computation expenses [114], and some others are based on an overlapping zone approach that use a distributed architecture with minimum communication costs (*e.g.*, voltage estimations on the shared nodes and their associated uncertainty) [115]. The latency requirements for monitoring systems are also discussed in [115] and it is concluded that latency is strongly tied to the particular application needs (from tens of milliseconds for fault location isolation and service restoration to seconds or tens of seconds for voltage regulation updates). However, the main focus in this thesis is on understanding how to configure the monitoring devices for each particular area (LV gird). In [109] an approach to evaluate the impact of different meter placements configurations on the SE's accuracy is proposed. Using Monte Carlo techniques, multiple measurement sets are generated using the corresponding relative error distribution functions for each measurement. Thus, the error distribution function can be formed for each state variable. The proposed approach in this paper consists of calculating the distance between the 5% and 95% percentile for each state variable's error distribution function as a measure of the estimator's accuracy. Additionally, the expected value of the estimation error is calculated. Thus, the lower these two measures are, the better the estimation's accuracy is and by comparing these values for different measurement positions the impact on the accuracy can be evaluated. In [110] a cost-optimal meter placement is proposed, which is based on the SE's accuracy approach presented in [109]. The method consists of determining which customers should be equipped with SMs capable of sending real-time values for active and reactive power, in order to keep the estimation error of complex voltage below 1% with a 95% confidence interval. The possible combinations to select which SMs should be upgraded depends exponentially on the number of the nodes and in this work a heuristic-approach is used to reduce the number of combinations. In [116] also a probabilistic approach is proposed for meter placement based on Monte Carlo simulations with similar objective, to bring down the relative errors in the estimated system states below a predefined threshold in more than 95% of the simulated cases. In [117] the meter and PMU placement is focused on the robustness of the solution by optimizing the worst case estimation accuracy among all possible configurations. In addition to N-1 robustness, in [118] the degradation of metrological performance is also considered as the goal of the optimization process. In [119] three meter placement schemes are proposed based on heuristic rules that consider the sensitivity analysis of the voltage standard deviation achieved by the meter placement configurations. These schemes utilize current and voltage meter combinations and different level of robustness is shown to meter failures. The cost-effectiveness aspects are covered in this study by comparing the required number of meters, cost and the performance of each scheme (measured as the maximum voltage standard deviation). Similar approach is taken in Paper I, where the cost-effectiveness of the proposed solution is considered in the optimization criterion by quantifying both the meter's CAPEX and OPEX. In addition, we use the obtained estimation of the voltage error as a quality indicator for determining the location in the grid for placing the metering devices (*i.e.*, current and voltage sensors).

AMI architectures

The AMI is one possible means to achieve cost-effective communication in ALV grids. It is an infrastructure that in most cases is already deployed and even though there can be regulatory-related restrictions, it is technically available. Therefore, it requires investigation even though the principal reason for its roll-out is not directly grid control.
Regarding the AMI architecture, it integrates a number of technologies to be able to establish a communication link between the loads (or prosumers) and the utility. The architecture is composed of SMs, communication networks, Meter Data Management Systems (MDMS), and means to integrate the data into software application platforms. In order to enable the system integration and to make sure that the devices from different technology providers communicate and share the information effectively, the use of communication standards and protocols is required. As presented in [120], the most popular protocols are ZigBee, Modbus, M-Bus, DLMS/IEC62056, IEC61107 and ANSI C.12.18. Besides, the proper design and configuration of the communication infrastructure is vital for the effective operation of the AMI architecture. In ([120] - [122], [162]) authors analyze the factors that should be considered and the requirements that should be satisfied when designing AMI architectures. These include elements such as, rate of data to transfer and its range, the standards to transmit the data securely, the integrity of the data, the latency, the availability and the reliability of the links, the required bandwidth, the QoS, and the number of required repeaters. Of course, the communication technology requirements are very much dependent on the type of the application (*e.g.*, meter reading, price signals, etc.). A summary of available technologies is presented in Table 4.

Table 4: Example of the technologies used for AMI architectures

Technology	Data rate (kbps)	Range (km)	Latency (ms)	Advantage	Disadvantage
ZigBee	20–250	0.01-1	15	Low power consumption	Limited range
PLC	Up to 100s	Up to3	10	Lines are in place	Need to bypass the transformer
Wi-Fi	Up to $100 \cdot 10^6$	0.1	100	High data rate	Limited range
Wireless-GPRS	100s	30	1000	High range	Limited connections

From a practical point of view, authors in [123] show in a white paper the best practices on AMI design, where they present the results from a field test that assumes wireless mesh topologies. They identify the reliability, redundancy, bandwidth and the budget as the key items that such projects should consider and understand. In addition, as shown in [120], the three types of elements that influence most in the AMI deployment cost correspond to the SMs, communication network technology and data collection, analysis, storage and system management. Hence, looking into the long-term AMI's CAPEX and OPEX, hardware elements are more critical than software elements. The reason is that further expansion/software updates are possible with minimum cost, while extra hardware deployments for communication, data collection and storage facilities imply higher investment costs. Thus, the selection of the elements that form the communication technology and the deployment of such elements should be done cost-effective from the beginning. These devices include protocol gateways, data concentrators and signal repeaters. The communication medium is also a critical element of the AMI architecture and the options are several *e.g.*, PLC, optical fiber, wireless-GSM/GPRS, Wi-Fi, copper link, satellite, etc. Comprehensive summaries are presented in ([120] - [122]). A popular technology due to its low cost and convenience is the PLC, which uses the existing electricity grid as the physical medium. However, it offers low bandwidth and shows data distortion around the transformers, which require other techniques to bypass them. Another potential communication medium alternative for transferring both the data and control signals that is growing is the GPRS technology [123]. It could be used in remote places where customers are dispersed, besides it is considered as a cost-effective option that can be both reliable and scalable. However, as specified in [126], the availability and the quality of the signal have to be determined before deploying it. In any case, assuming all the possible media alternative solutions the GPRS and the PLC technologies are the preferred ones by the utilities due to their easy maintenance and economic factors, OPEX principally [121].

Finally, it is important to point out that the interoperability feature is key aspect that needs to be assessed in this kind of projects, especially when systems are built on top of legacy systems. For instance, the transitioning from AMR to AMI infrastructures, which can be basically seen as enhanced AMR with bidirectional communication capabilities, should support the additional applications. Therefore, aspects such as security, reliability, and QoS capabilities must be guaranteed in such technological transitions. And as described in [127], in order to guarantee such aspects the use of technical standards turns necessary, especially for liberalized metering markets, where devices from different technology providers must communicate effectively.

3.2 Control architectures for ALV grids

In relation to this thesis, the following two main aspects are studied within the topic of control architectures for ALV grids: the voltage control problem and power restoration by system reconfiguration. Specifically, this section focuses on the related works regarding the algorithms for voltage control and for power system restoration.

Voltage control algorithms

The topic of voltage control for distribution grids has raised special attention from the scientific community. Generally, the voltage control algorithms can be divided into rule-based algorithms and optimization-based algorithms. In [128] and [129] the two types of control alternatives are thoroughly discussed. The rule-based algorithms are generally applied in simple grids, where the control possibilities are small, *e.g.*, the traditional radial distribution grid. The classical example is the busbar voltage control that keeps the level within an operative range (*e.g.*, deadband). These algorithms are rather simple, deterministic and do not have convergence problems. However, when the control objectives are several and when the number of controllable devices (actuators) increases, the rule-based algorithms become more complex. In such cases the optimization-based algorithms fit better because they can deal with several control objectives by defining a customized cost function and a set of constraints. For instance, the problem formulation can incorporate active power losses, energy consumption, voltage profile improvement and asset utilization such as tap changer operations and capacitor switching operations ([130] - [137]). Of course, depending on how the modeling of the cost function and the constraints is done, the mathematical complexity varies and it can span from simple linear programing setups to complex non-linear problems that require larger computational power (*e.g.*, MINLP). For real-time applications, the computational time is a key factor that cannot exceed the requirements, thus it can be prioritized over the exactness of the objective. Thus, non-convex or complex elements such as absolute values can be relaxed to quadratic forms. Methods like metaheuristic algorithms can be an alternative solution to overcome the computational burden and they can be applied to obtain the solutions with less computational effort than optimization algorithms, even though they might not converge to a global optimum [130], [131]. In [132] distributed voltage control methods are reviewed, which only need local information and no communication among controllers at different levels. [133] and [134] focus on the microgrid control and perform a survey on distributed voltage control methods and trends. These methods include MPC and MAS-techniques, which are used in Paper III, IV and V. The coordinated voltage control schemes are studied in [128], [135] - [137], showing how to combine the actuators for voltage rise mitigation under DG penetration (PV, wind).

These methods and algorithms principally assume that the actuators or controllable resources are already available and then they generally focus on operating them in a cost-effective way. However, in addition to operating the assets effectively, the decision regarding what type of controllers to use and where to place them in the grid is also a key problem, because it has direct implications on the investment costs. A classic example corresponds to the capacitor and voltage regulator placement problem, which corresponds to a combinatorial optimization problem that due to the large solution space, most of the cases use metaheuristic searching algorithms ([138], [139]).

Most of the works provide solutions to the asset (capacitor and voltage regulators) placement problem without considering the grid expansion planning ([139] - [142]).

Other authors like [143] - [145] consider the multistage long-term expansion planning for determining the optimal place to locate the assets *e.g.*, capacitor banks, voltage regulators, distributed generation, etc. The multistage approach defines the optimal location, type, capacity of the investments and the most appropriate time to make such investments. Thus, the continuous growth of the demand is considered. Similar to this, in Paper IV, the distribution grid multistage expansion planning is performed considering the distribution operations, specially focusing on the implications of DG in voltage control requirements.

Power restoration by system reconfiguration

The system reconfiguration is a task within the FLISR process. It is a critical task because it involves restoring the maximum out-of-service loads with the minimum number of switching operations within a very short time. Thus, it can enhance the system reliability by maximizing the restored loads and reducing the outage time. In addition, it is a task that should be automatically performed in order to enhance the system with self-healing grid capability. The literature shows centralized and distributed system reconfiguration implementations [146] - [159]. The centralized configuration is the best configuration for guaranteeing that the algorithm provides the best solution to the system reconfiguration problem. However, as for the rest of the previously describe applications, the centralized configuration system for reconfiguration algorithms require a more complex ICT infrastructure, which is less robust against failures than distributed and decentralized systems. Besides, centralized configurations require a single decision-making software component to process large amount of data in little time. Thus, it is less attractive to deploy centralized FLISR applications in distribution grids.

As an alternative solution, distributed system reconfiguration algorithms can avoid the centralized SCADA-based decision making by making each distribution substation responsible for controlling and analyzing its own grid [146]. Thus, substations can be coordinated to share information with their neighbors to reconfigure the grid when a fault is located. By following this distributed approach, the substations can make decisions based on their local information (*e.g.,* sensors, IEDs) and since the information is distributed among the substations and there is not a central control system, a failure in one of the substations does not cause the reconfiguration algorithm to fail. The reason is that neighboring controllers at the same hierarchical level could take over the functions of the faulted substation, at the expense of reducing the performance of the system.

From an economical point of view, as shown in [147], the complex ICT infrastructure required for centralized systems implies a larger CAPEX investment. In distributed systems however, the distances between the controllers and the complexity of the required ICT infrastructure is not that large. Hence, the CAPEX investments are smaller and can be done following a modular approach. As explained in [147], the distributed configuration can be deployed and implemented by MAS framework. This framework is based on pieces of code called agents, which are intelligent units that can be executed in a distributed way. The agents have problem solving capabilities and can communicate, coordinate and debate with other agents to make decisions based on consensus. Examples that apply decentralized MAS for self-healing applications include [148] - [152]. The use of DG after a major outage is also considered for MAS-based system restoration in [150] and [152]. The approach of using MAS for self-healing applications was also proposed and applied in Paper V. In this paper the grid topology is reduced to an undirected, weighted graph and then a distributed implementation of Prim’s minimum spanning tree algorithm is executed to solve the service restoration problem.

Regarding the algorithms for system reconfiguration, the literature shows heuristics, expert systems, metaheuristics, and mathematical programming-based implementations to solve the combinatorial optimization problem. The heuristic implementations presented in [153] - [155], focus on reducing the search space by using rules of thumb based on the experience. The expert systems are knowledge-based techniques that are implemented as a set of rules [156]. The mathematical programming-based implementations can obtain optimal solutions, but since the computational complexity of such problems is usually NP-hard[2], the time required for solving the problem in real time fashion cannot be afforded [148]. Another alternative solution that overcomes the computational burden is to apply metaheuristic implementations as it was discussed for the controller placement problem, which include *e.g.,* neural networks, genetic algorithms, fuzzy theory, particle swarm optimization, simulated annealing, and ant colony optimization [157] - [159].

[2] Nondeterministic polynomial time.

3.3 ICT infrastructure reliability

The ICT infrastructure that is needed for the proper operation of the distribution grid consist of a broad set of communication networks, which act as a bridge between the distribution and the adjacent domains, *i.e.,* generation, transmission, and customer domains. The power distribution domain contains substations, feeders, and end-user loads/prosumers over a large geographic area. These elements are connected by a Wide Area Network (WAN) to the utility control center. Within the distribution communication domain, three types of communication sub-networks are usually found: Neighborhood Area Networks (NANs), Field Area Networks (FANs) and Workforce Mobile Networks (WMNs). A description of these sub-networks can be found in [160]. NANs typically correspond to the previously described AMI architectures that connect the SMs with the MDMS. Their purpose is to facilitate the AMR/AMI operations (*e.g.,* energy consumption reading, meter and grid events and alarms, price signal updates for DR applications, etc.). The FANs allow the information exchange between the control center and the distribution substations and the equipment deployed at feeder level (*e.g.,* meters, sensors, PMUs, IEDs, RTUs). The typical applications lay within substation automation (*i.e.,* monitoring, protection and control functions at substation and feeder level) and the typically used protocols at FANs for telecontrol and protection purposes are IEC 61850, IEC-60870-5-101/103/104 and DNP 3 [161]. However, applications such as DER or microgrid integration are emerging and these are connected to the FANs. The WMNs are the networks used by the workforce in day-to-day operations *e.g.,* maintenance, dispatch, etc. The principal characteristic is that the need to have access the NANs and FANs for maintenance purposes and for collecting the status of the equipment. In ([160] - [163]) the traffic characteristics and requirements for NAN, FAN and WAN are presented, specifically the focus is on the typical data sizes, the data sampling requirements, as well as reliability and latency requirements for each application. They show that high reliability and low latency are required for NAN/FAN applications and very high reliability, cybersecurity and extremely low latency are required for WAN applications. Thus, a key objective for ICT infrastructures in smart grid systems is to guarantee the service reliability levels. In Table 5 the typical reliability requirements and cybersecurity-related vulnerabilities are shown for NAN/FAN applications.

Table 5: Typical reliability requirements and cybersecurity-related vulnerabilities for NAN/FAN applications

Application	Reliability (%)	Traffic characteristics	Cybersecurity vulnerabilities
AMR/AMI	>98	Delay tolerant, periodic/ event based	• Denial of service • Man-in-the-middle • Unauthorized interception of communications with the intention of changing/stealing data
Substation automation	>99.5	Delay sensitive, event based	• Inadequate access control • Denial of service • Unsecure networks • Misconfigured firewall
Firmware/ program/ configuration updates	>98	Delay tolerant, event based	• Inadequate access control • Denial of service • Insecure networks • Misconfigured firewall
DER/ microgrid/ EV	>99.5	Delay sensitive, event based	• Denial of service • Man-in-the-middle • Unauthorized interception of communications with the intention of changing/stealing data

A reliability model for the ICT infrastructure is presented in [164], where dedicated wireless technology (WiMAX) and fiber optics are used to represent the communication network. In [165] the impact of ICT architectures on the reliability of wide area measurement system applications is studied, where co-simulation studies are conducted using OPNET to simulate a detailed hierarchical ICT infrastructure and Matlab/Simulink for power system simulations. An analytical methodology for assessing the impact of the monitoring functions in the distribution system's reliability is presented in [166] using Markov models. In [167] instead, a probabilistic technique for the assessment of the reliability of a power system is proposed, which considers the ICT architecture and it is based on sequential Monte Carlo simulations. They show that an increase in the failure rate of the ICT infrastructure results in an increase in the load curtailment. In [168] sequential Monte Carlo simulations are also used to quantify the reliability performance of DR schemes in distribution grids considering the influence of ICT architecture availability. The ICT is based on wireless technology and its availability is based on weather distributions elaborated from statistical data. Other works that use ICT and power system co-simulation for reliability studies include ([169] - [171]).

Another alternative to assess the reliability of distribution grid communications is by using methods and techniques from the Enterprise Architecture (EA) discipline [172]. The use of EA models, which are supported by a formal framework for analysis, is an approach to managing and optimizing complex systems and processes such as ICT systems. An example corresponds to the Probabilistic Relational Models (PRMs), which are used in [173] to perform reliability analysis of IEC 61850-based substation automation system functions such as control and protection. PRM-approach is also used in [174] for analyzing the reliability of ICT for power systems, and in [175] for computing the probabilistic availability of control and automation systems for active distribution networks. The EA discipline is also implemented in Paper VI, where the focus is on analyzing the reliability levels offered by the hardware and software that form the distribution grid communications infrastructure. Here the applied PRM-approach is enhanced by MC methods. Thus, we can include the probabilistic characteristics to the reliability study for distribution grid communications. And as it is explained in Paper VI and later on in this thesis, we first obtain the availability attributes and then we infer the reliability attributes.

Chapter 4

4. Research Results and Discussions

This chapter presents the research results of the thesis by summarizing and discussing the contributions of the included papers.

4.1 Study on cost-effective communication architectures

The first part of the thesis consists of investigating the cost-effective communication architectures that assist the expansion of ALV distribution grids. What purpose they serve and what characteristic are important. In connection to that, the economic characteristics of the communication architectures are studied by considering the impact of both CAPEX and OPEX into the monitoring performance, the *cost versus observability* and *cost versus QoS* relationships being especially important.
Two problems are investigated and the corresponding cost-effective solutions are provided. Firstly, the sensor placement problem is studied by proposing a method to optimally place meters in ALV distribution grids by considering the tradeoff between the SE error and the cost regarding the meter deployment configuration (CAPEX and OPEX). Secondly, the assignment of the measurement devices like SM to the AMI-head-end is explored through proposing the optimal communication architecture that considers both the cost and the packet loss QoS indicator.

4.1.1. Sensor placement problem in ALV grids

Problem Description

The monitoring of ALV distribution grids is gaining attention due to the increasing demand to perform SE at LV distribution grids for supporting control applications such as voltage control, FLISR, DR and non-technical loss estimation. Hence, in order to perform the SE following a cost-effective approach, the DSOs face the technical challenges of determining how many sensors/meters they require and where these should be placed in the LV grid. The reason is that the cost of adding measurement devices can be high, and careful selection of new measurement locations is important. Thus, only the required number of meters should be deployed in order to reach the system's observability, whilst providing the lowest possible SE error. Besides, ALV grids can include a high number of real-time measurements but these are generally limited to few locations (mostly current and voltage magnitudes) and grid observability is not achieved unless pseudo-measurements are used to compensate the lack of measurements. Moreover, research is done in this direction and new sources of data and sensors are being used to improve the system's observability and generate pseudo-measures *e.g.,* DG and EV inverters, SMs, etc. ([109] - [115]). As explained in [176], it is important to notice that some sources can provide data at high rate, such as microseconds (*e.g.,* PMU), some at every few seconds (*e.g.,* IEDs at distribution substations) and some others (the large majority) at minute or longer intervals (*e.g.,* SMs). The highly accurate data that can be obtained from PMUs could be useful to improve the SE's performance. However, the high cost of such devices represents a burden for their immediate massive deployment in distribution systems. Instead, the use of SMs to obtain the power injection at customer nodes is an alternative that should be considered. In any case, the algorithms that are able to incorporate data from heterogeneous sources will definitely contribute to improve the SE at ALV distribution grids.

Proposed method

We propose a cost-effective method for placing metering devices at ALV distribution grids in order to perform the SE at ALV grids. The meters correspond to current and voltage sensors that can be located at MV/LV SS and LV Cable Distribution Cabinets (LVCDC) as shown in Fig. 9. A multi-objective optimization problem is casted, in which the optimality is determined by minimizing the weighted Euclidean norm of the vector formed by next two components:

- The LV SE error named as the Voltage Error Estimation (VEE).
- The cost associated to a particular meter deployment configuration, named as Cost of Meter configuration (CM). It includes the CAPEX and OPEX of voltage sensors, current sensors and SMs obtained from [2].

In addition, the constraints of the optimization problem are set to guarantee the observability of the ALV grid. The optimization problem is solved by implementing a BPSO algorithm, which is a discrete binary version of the general Particle Swarm Optimization (PSO) algorithm. The proper explanation and details of the algorithm can be consulted in the paper. Besides, it is assumed that the three-phase lines are balanced, which allows simplifying the system to a single phase equivalent system. In addition, we assume that the MV/LV SS are equipped with voltage and current sensors and the BPSO solves the optimization problem by providing the required branches and nodes at certain LVCDC, so that the P and Q flows can be derived. Two types of measurements are employed to track the consumed/generated power at the end-point nodes. These correspond to SM measurements and pseudo-measurements. The latter ones can be obtained by applying statistical processing to SM historical data from similar systems. Since SM provide real measurements and pseudo-measurements are estimated measurements, the standard deviation of the measurement error obtained by the SM is smaller than the standard deviation of the measurement error obtained by the pseudo-measurements: $\sigma_{PS} > \sigma_{SM}$. The measurement uncertainty data is retrieved from [2].
Four types of scenarios are simulated as depicted in Table 6, which correspond to Case I (using pseudo-measurements) and Case II (using SM) with variations in the weight factors to prioritize VEE or CM.

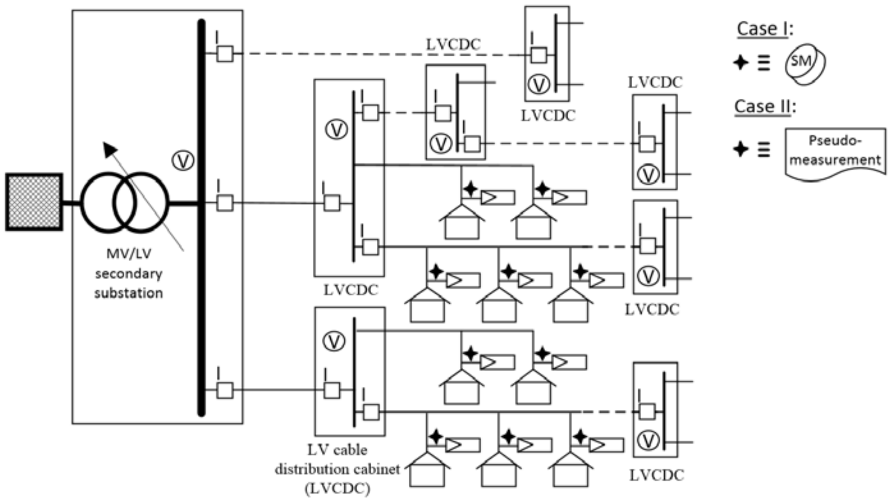


Fig. 9. LV Schematic diagram showing the LVCDC.

Table 6: Simulated scenarios. Where, $\mathbf{w_{fe}}$ and $\mathbf{w_{fc}}$correspond to the VEE and CM weight factors respectively

Scenario #	Case I / Case II	$\mathbf{w_{fe}}$	$\mathbf{w_{fc}}$	σ_{SM}	σ_{PS}
1	Case II	1	1	0.0001	-
2	Case II	1	9	0.0001	-
3	Case I	1	1	-	0.003
4	Case I	1	9	-	0.003

The results for the simulated scenarios using the ALV grid in Fig. 10 are presented as a Pareto front in Fig. 11 showing the equally optimal particles. Each particle represents a meter deployment configuration.

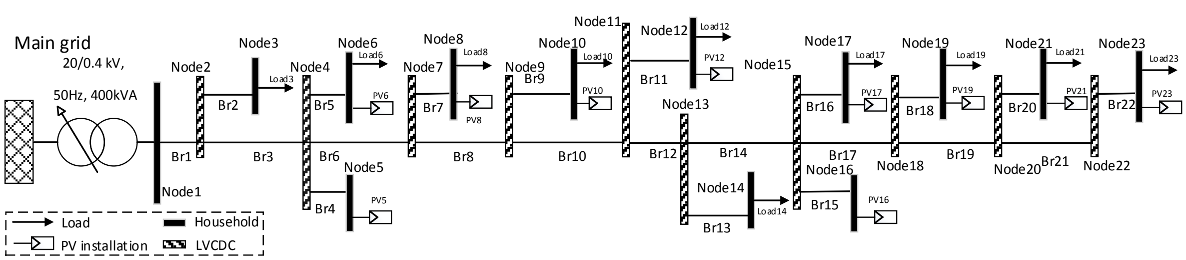


Fig. 10. Modified Cigré LV Benchmark grid.

The horizontal axis corresponds to the CM and the vertical axis corresponds to the VEE. The axes are normalized to the maximum values representing the extreme configurations, *i.e.*, meters deployed in all the LVCDC ($1+^2$ particle at lower right corner of the graph) and no meter deployed in any LVCDC ($1+^1$ particle at upper left corner of the graph). The different configuration solutions are represented by a "+" sign and two identification numbers. The number on the side represents the iteration number of the algorithm and the upper right number identifies the particle of the population. In scenario#1 and #2 (Fig. 11 a)

and b) respectively) a horizontal offset can be observed that represents the cost of having physical SM meters. The configuration solutions that during the optimization cycle have been generated more than once are identified with a magenta cross and the solutions that have been considered as global best (GB) are identified with the green "+" sign. In this work a single optimal solution (called final GB particle) is obtained by minimizing the Euclidean norm of the vector that defines each particle and this is identified by a red circle.
The evolution of the GB particles for the four scenarios is shown in Fig. 12. The algorithm stops when the optimality criterion is met, which in this case corresponds to either the fitness function of the final GB particle remains stable for 10 iterations or when the number of iterations is larger than the preset limit (*i.e.*, 200 iterations).

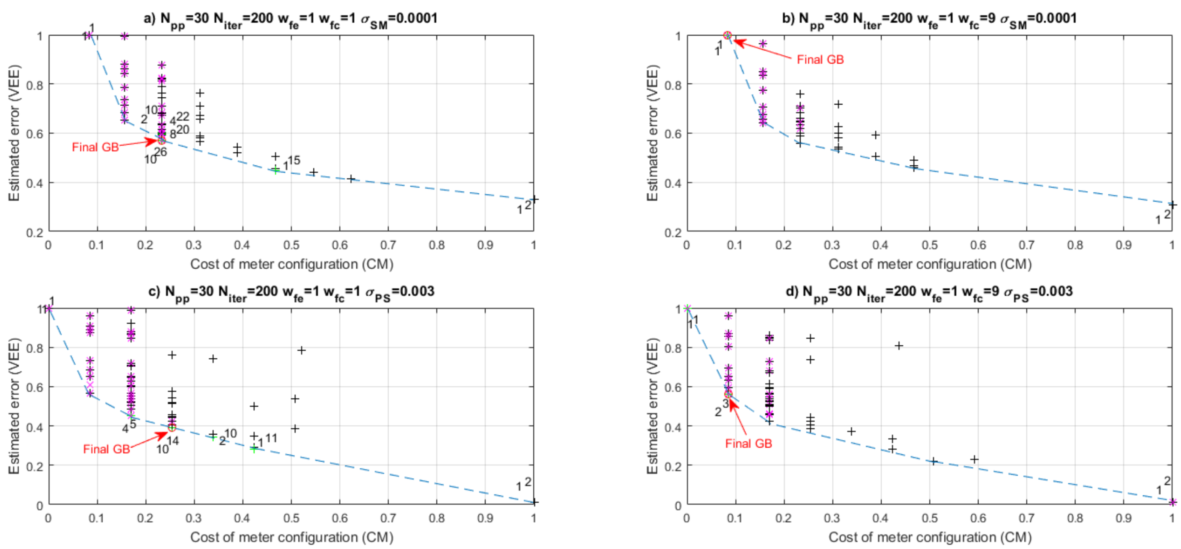


Fig. 11. The simulation results showing the Pareto front for each simulated scenario. a) scenario #1, b) scenario #2, c) scenario #3 and d) scenario #4. The number on the side of the final GB particle represents the iteration number and the upper right number identifies the particle of the population.

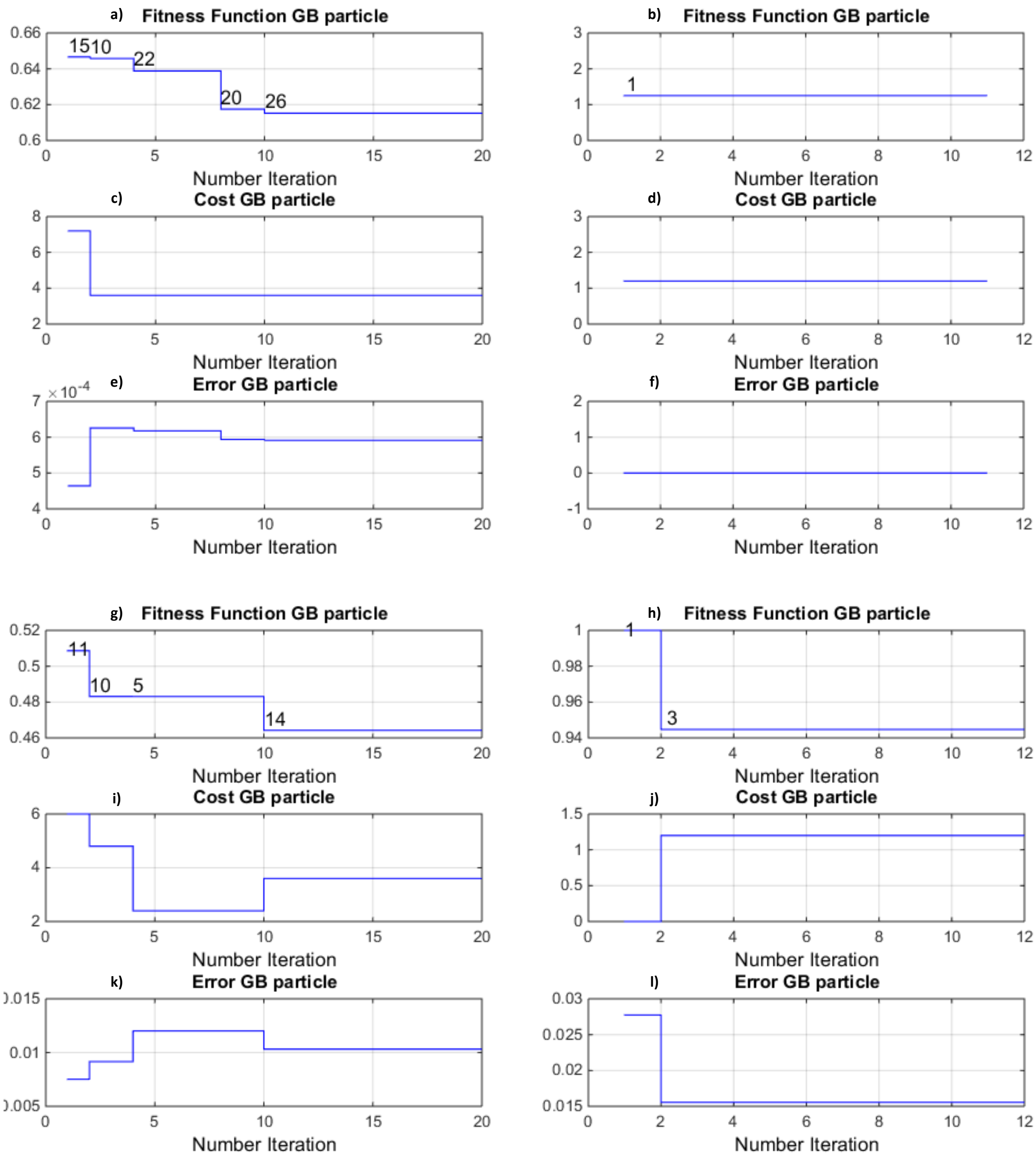


Fig. 12. The evolution of the Fitness function, the CM component and the evolution of the VEE component for the tested scenarios. a), c) and e) correspond to scenario#1, b), d) and f) correspond to scenario#2, g), i) and k) correspond to scenario#3 and h), j) and l) correspond to scenario#4. The numbers on the curves represent the GB particle at each iteration of the algorithm, yielding the final GB particle.

Finally, the representation of the corresponding final GB particle is depicted in Table 7. Here we show the optimal meter location for each scenario. As expected, simulation results show an increment in the cost parameter and a decrement in the error estimation parameter when the number of deployed sensors is incremented. In addition, by using pseudo-measurements the cost function to be minimized (defined by the weighted norm) can be reduced even though additional sensors are required. The reason is that the cost of pseudo-measurements is lower than the cost of CM and the difference can be used to finance the required extra sensors.

Table 7: Optimal meter location

Scenario#	Case	LVCDC				SM/ pseudo	Components		Weighted norm
		V sensor		I sensor					
		Qty.	nodes	Qty.	branches		CM	VEE	
1	Case II	2	4, 7	2	6, 12	SM	0.23	0.57	0.61
2	Case II	0	-	0	-	SM	0.08	1	1.23
3	Case I	3	7, 11, 18	3	8, 12, 19	pseudo	0.25	0.39	0.46
4	Case I	1	7	1	8	Pseudo	0.09	0.56	0.9

4.1.2. Assignment of measurement devices to the AMI-head-end

Problem Description

The AMI metering systems are formed by the measurement devices that perform the customer data collection (*e.g.*, electronic SMs), the communication network between the customer and a service provider, and the MDMS that manages the data storage and analysis to provide the information in useful form to the corresponding utility. As described by EPRI [177], the AMI metering systems can bring benefits both for the DSO and the customer. For the DSO the asset management can be improved and functions such as energy theft detection, outage management and meter reading can be easier performed. For the customer, the billing accuracy can be improved, the service restoration can be performed faster and the meter failures can also be detected earlier. Generally, all these benefits can be translated into financial benefits that can be summarized to reduced equipment and equipment maintenance costs, reduced support expenses, faster restoration and shorter outages, and improvements in inventory management. From a technical point of view, a critical component in AMI systems and especially in the communication network is the physical Data Concentrator (DC). Typically, DCs are placed at the SS and they communicate with the SMs located at customer sites. The DC also communicates with the AMI system's head-end creating a hierarchical structure. There may be situations such as low customer density, where it can be economically better to communicate directly from SM to head-end, bypassing the communication network hierarchy. For such cases, in order to provide a uniform technical interface for the head-end, the communication with the SMs can be done through a Virtual Data Concentrator (VDC). This VDC corresponds to an application that runs at central systems and concentrates the detailed and time-based information obtained from the remote SMs. These concentrated measurements are then dispatched to the MDMS, which is a server that collects all the measurements within the AMI system.

There are several communication technologies that can be applied for AMI communication (*e.g.*, radio frequency, cellular, fiber optics, and PLC). Consequently, there are several possibilities for DSOs to connect the SM devices with the AMI system.

Thus, methods and tools for creating optimal cost-effective communication architectures of AMI that assist assigning the SMs to the AMI-head-end by considering the cost aspects are required for AMI planning and deployment.

Proposed method

The proposed cost-effective method corresponds to designing the most suitable way for the SMs to be connected to the Advanced Metering Infrastructure (AMI) head-end through a communication architecture formed by wireless and Power Line Communication (PLC) technologies. The communication architecture design is achieved by solving a combinatorial optimization problem that minimizes the CAPEX, the OPEX and the QoS achieved in each of the communication architectures, as shown in Fig. 13. The method is depicted in Fig. 14 and it requires grouping the SMs with similar communications connections characteristics, so that the QoS can be estimated for both type of SMs connected through PLC or through wireless technology. The QoS corresponds to the packet loss ratio indicator that is defined as the ratio formed by the non-received packets and the sent packets. That SM grouping is performed by Smart Metering Clustering Tool (SMCT) and it consists of creating suitable groups of SMs with similar communications connections characteristics (*e.g.*, distance to the SS and mutual proximity). Hence, two type of groupings or clustering are implemented depending on the transmission media: one for PLC and another one for wireless communication-based SMs. Each group is then checked against a simulation repository matrix that assigns the corresponding packet loss ratio to each cluster depending on the number of HouseHold (HH)-nodes per cluster, the distance to the SS and the base transceiver station, and the number of PLC clusters sharing the same feeder. By HH-nodes we indicate the group of SS that are located at the same building. The detailed description of the method is presented in the paper.

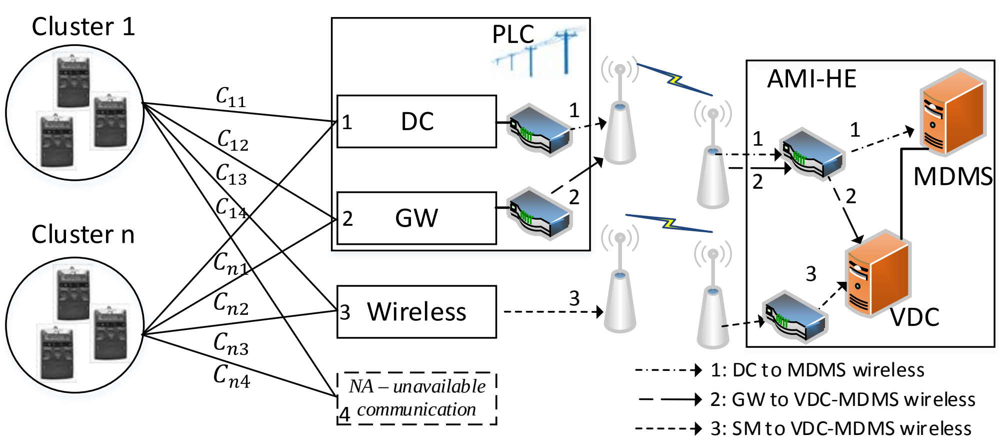


Fig. 13. Combinatorial problem, where the SM clusters are assigned to 4 possible scenarios (*i.e.*, DC, GW, Wireless, NA).

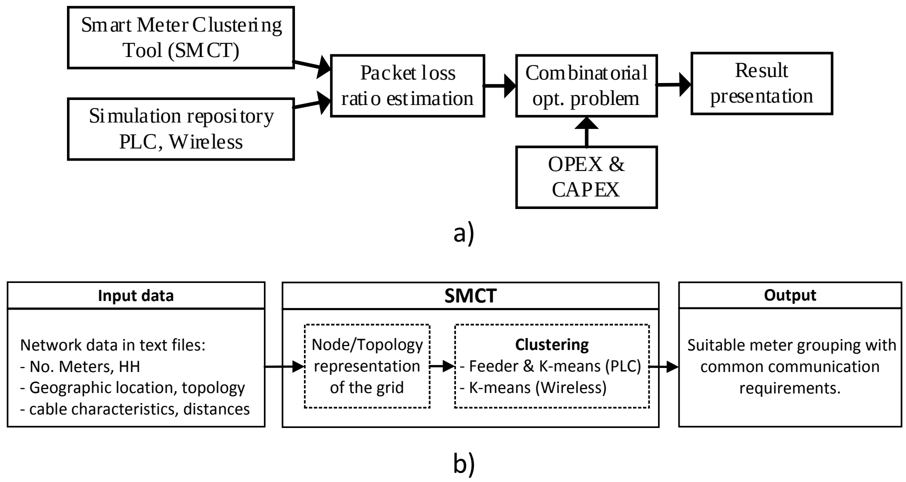


Fig. 14. a) The proposed meter assignment method's block diagram. b) The Smart Metering Clustering Tool block diagram (SMCT).

The considered communication architecture alternatives are shown in Table 8 and they combine PLC and wireless technologies. The main reasons for using these alternatives are the communication solution availability and the cost. The scenario #1 assumes that the SM data is concentrated by a Data Concentrator (DC) that is located at the SS, whereas the scenario #2 and #3 assume that it is at the head-end level where the information is concentrated by a Virtual DC (VDC). In #2 the SM data is collected and sent over a Gateway (GW) and in #3 it is directly sent from the SM to the VDC. The scenario #4 represents the cases when the SMs are not assigned to any of the previous scenarios due to communication unavailability caused by poor communication quality.

Table 8: Communication architecture scenario alternatives

Scenario	Data Source *(From)*	Comm. Technology	Device at SS	Comm. Technology	AMI-HE *(To)*
#1	SM	PLC	DC	Wireless	MDMS
#2	SM	PLC	GW	Wireless	VDC-MDMS
#3	SM		Wireless		VDC-MDMS
#4	SM	*Not assigned - communication unavailability*			

The proposed meter assignment method is applied to a case-study based on the data retrieved from the DISCERN project [2]. The corresponding LV grid contains 150 SM grouped into 63 HH-nodes. The two type of clustering corresponding to the PLC and the wireless communication are shown in Fig. 15. It can be observed that the PLC clustering technique considers the mutual proximity of the SMs and the cables to which the SMs are connected. However, the wireless clustering disregards the later characteristic. Both clustering are performed by K-means clustering method.

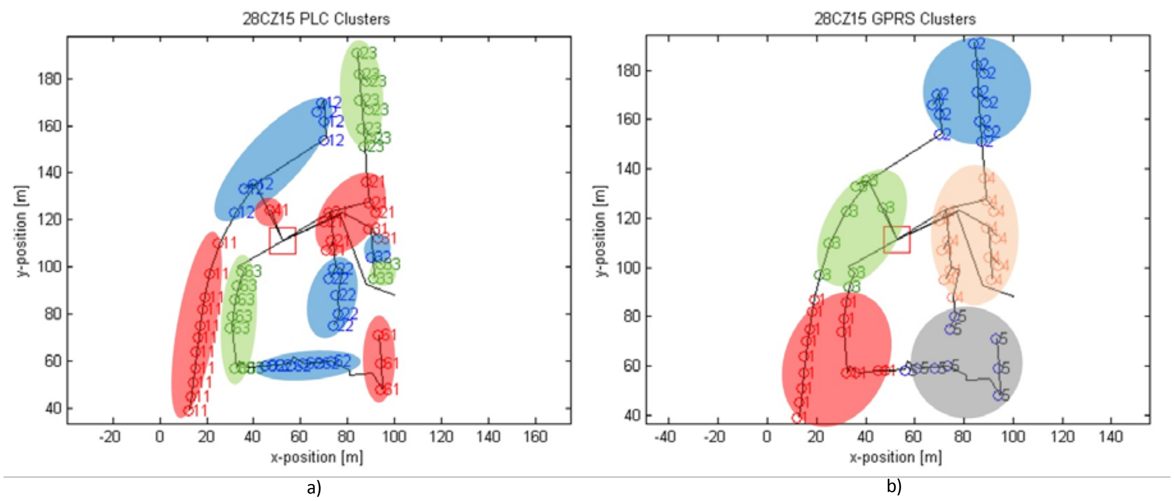


Fig. 15. The 28CZ15 LV grid from [2] is represented and clustered. The number at each node indicates to which cluster each node belongs. a) shows the generated 11 clusters for PLC and b) shows the generated 5 clusters for wireless.

Table 9: The packet loss threshold (T_i) and SM threshold (N_j) variation for the test-cases

Test Cases		Packet loss threshold T_i (%)	SM threshold N_j
#1	*DC*	5	∞
	GW	5	50
	VDC	5	∞
#2	*DC*	90	∞
	GW	90	200
	VDC	90	∞
#3	*DC*	90	∞
	GW	90	50
	VDC	90	∞

In order to design the optimal communication architecture design, the combinatorial optimization problem is solved for three test-cases. These cases differ in the QoS requirements (T_i) and the number of acceptable SMs per scenario (N_j) as defined in Table 9. The estimated lifetime of the DC, GW, VDC and SM devices corresponds to 15, 15, 8 and 15 years respectively and the annual OPEX costs are calculated applying a weighted average cost of capital (WACC) of 5%.

In Fig. 16 the total cumulative cost of the communication architecture is shown over a period of twenty year lifetime for the considered three test-cases. In the test-case #1 high PLC QoS requirements are considered and it automatically disables the DC and GW scenarios. Thus, in this test-case #1 the wireless scenario is the only solution given the initial conditions. The cost increase step at the 15th year is due to the lifetime of the SM devices. There is similarly a cost increase at the 8th year due to the replacement of the VDC system. However this cost does not have noticeable impact at the SS because it is divided among all the SS in the MV grid.
In the test-case #2 only the DC scenario and the wireless scenario are present because the GW's threshold is set smaller than the number of SM assigned to the network (50 < 150), hence disabling the GW scenario. The cost of DC over time comes close to the cost of the wireless scenario when reaching the end-of-life for DC and SM (15 years). This situation is explained due to lower CAPEX values for wireless but higher OPEX values as opposed to

DC. However, since both DC and wireless have similar lifetime and the costs due to reinstallations are applied at the same time, the wireless option remains as the least cost solution.

Lastly, in the test-case #3, the GW threshold is set larger than the number of SMs of the network (200 > 150), enabling the GW scenario to take place. In this test-case, the wireless scenario remains being the least costly solution over time, followed by the GW scenario until the 5th year, when DC becomes less costly than GW but still more costly than the wireless solution. At the 15th year, the DC, GW and SM systems are reinstalled and the wireless options remains as the least cost solution.

The QoS requirement is modified to allow the comparison of the communication architectures over time. For the given configuration parameters, the cost evolution over time shows that the VDC with wireless communication solution (scenario alternative #3 in Table 8) is the lowest cost option that performs best in both the short term and the long term, while satisfying the communication availability requirements.

Finally, the performed simulations show that the OPEX, the CAPEX and the lifetime of the devices determine the cost driver of the optimal solution. Thus, it is concluded that the optimal choice of communication is determined by the cost driver, which is represented by the communication technology, and by the packet loss QoS indicator.

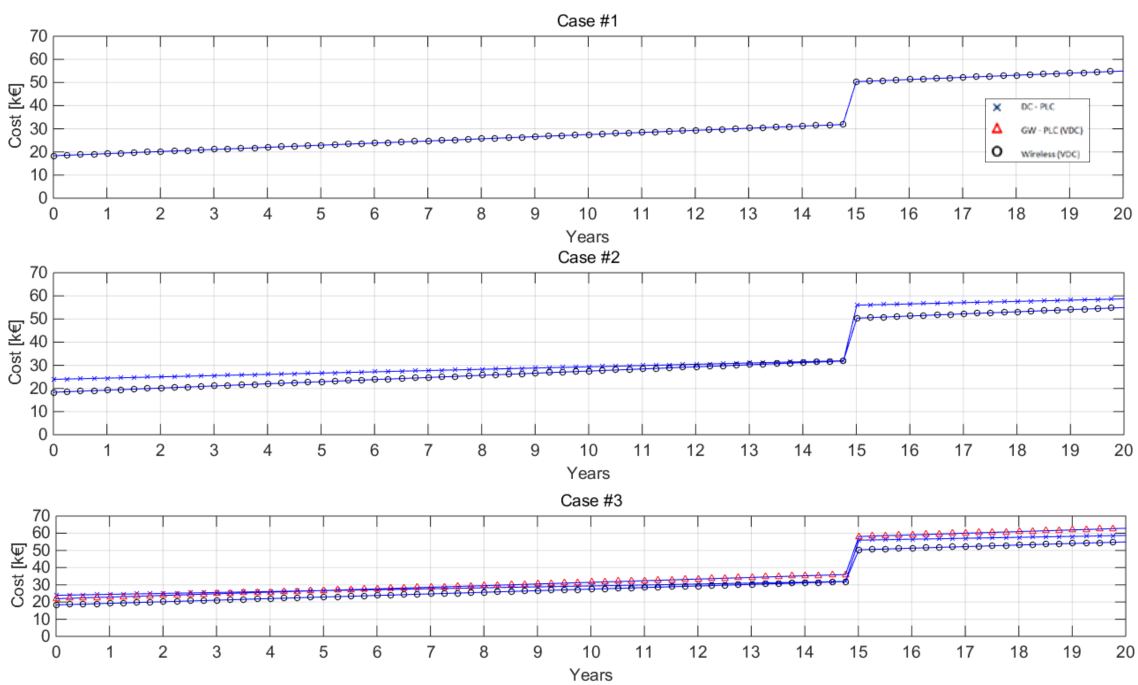


Fig. 16. The cumulative cost evolution for the tested cases: Test-case #1, test-case #2 and test-case #3.

4.2 Study on cost-effective control architectures

The second objective of the thesis focuses on studying the cost-effectiveness needed for developing decentralized and coordinated distribution automation applications that enable the expansion of ALV distribution grids. In addition, due to the reasons explained previously, the technical solutions with minimal impact on prosumer market participation are exclusively studied. Although technical solutions that would imply operating assets located behind the customer's meter could also be valid for improving the controllability of the ALV distribution grids in a cost-effective manner.

In this topic, the economic characteristics of the control architectures are studied by considering the impact of both CAPEX and OPEX into the control performance, being the *cost versus controllability* relationship especially important.
In this area three problems are investigated and the corresponding cost-effective solutions are provided. Firstly, the integration of microgrids-like structures is examined by enhancing the controllability of the grid operations, in which characteristics such as number of controller operations (*e.g.*, OLTC's tap changes) are considered. Then, the optimal way to deploy such controllability infrastructure is studied by considering both the deployment cost and operational cost. And lastly, it is shown that the distribution grid's reconfiguration time can be significantly reduced by using decentralized and coordinated multiagent system-based control architectures as grid's controllability enhancement.

4.2.1. Integration of microgrids into ALV distribution grids by controllability enhancement

Problem Description

The microgrid investment and planning is a complex problem that considers different energy generation and storage technologies and multiple energy vectors to supply energy loads, typically while trying to minimize both CAPEX and OPEX. In grid-connected microgrids the dispatch leads an hourly energy flow between the microgrid and the distribution grid at the PCC. When the local generation exceeds the local consumption, the energy surplus is fed into the grid and particularly, in large microgrid infrastructures a more dramatic fluctuation is expected at the PCC power profile. Thus, a technical steady-state validation of the investments needs to be completed by the DSO in order to ensure that the grid can host the PCC profile without violating the normal operation of the distribution system. Therefore, this validation determines the microgrid generation capacity limit that should not be crossed to guarantee a normal operation of the system. Clearly, by reducing the microgrid's generation capacity the remuneration from the PV feed-in is also lowered in comparison with the optimal (but now infeasible) solution.
Thus, there is clearly room for cost-effective solutions that allow integrating microgrid-like structures into ALV distribution grids without violating the normal operation and by keeping the original microgrid's generation capacity as close to the optimal solution.

Proposed method

The proposed method to overcome such problem consists of enhancing controllability of the ALV distribution grid operations by investing in OLTC asset control. This investment can be concerted between the DSO and microgrid owner. Thus the amount of PV capacity (or other type of generation) installed by the microgrid can be maximized without causing voltage problems to the distribution grid and at the same time, the controllability upgrade increases the hosting capacity for other parts of the distribution grid. This solution results in a win-win situation for both parties.
The controllability enhancement is carried out by OLTC asset control, which allows minimizing the OPEX part of the investment by applying MPC, even though any other technological alternative could also be incorporated (*e.g.*, dead-band control). The control architecture is shown in Fig. 17. The bus voltage reference trajectories are defined by the vector $\vec{r}$ and are set to *1pu*. These reference trajectories can be kept constant or they can even be dynamically imposed by a Supervisory Control and Data Acquisition - Distribution Management System (SCADA-DMS) that operates the MV-LV grid. The measurements

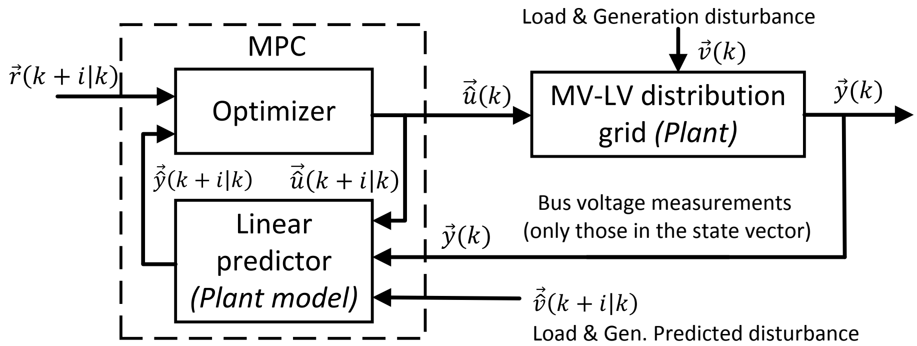


Fig. 17. MPC-based control architecture.

correspond to the controlled signals of the physical process and represent the bus voltages at the LV distribution grid; these are defined by the vector $\vec{y}$ and are assumed to be obtained by the AMI. The objective of the control architecture is to obtain a sequence for the tap positions defined by the $\vec{u}$ vector so that the $\vec{y}$ vector follows the $\vec{r}$ vector. Besides, a linearized plant model is used to obtain the predictions of the bus voltages, $\hat{\vec{y}}$. This model requires the active and reactive power increments in the LV grid caused by the load and the PV generation units and it can be obtained from a load and a PV generation forecaster.
A key issue corresponds to determining the appropriate location in the grid for the OLTC assets that need to be controlled. Thus, in this work three locations for the Control Strategies (CS) are compared as introduced in previous work [178]:

- CS-A: Manipulate the OLTC connected to the power transformer at the MV substation.
- CS-B: Manipulate the OLTCs deployed at the LV substations that experience overvoltages.´
- CS-C: Manipulate two types of OLTCs: the OLTC at the MV substation and the OLTCs at the LV substations that do not experience overvoltages and can experience undervoltages as a side effect of manipulating the OLTC at the MV substation.

The arbitrary radial distribution grid containing four LV substations that is shown in Fig. 18 is used to test the controllability enhancement.

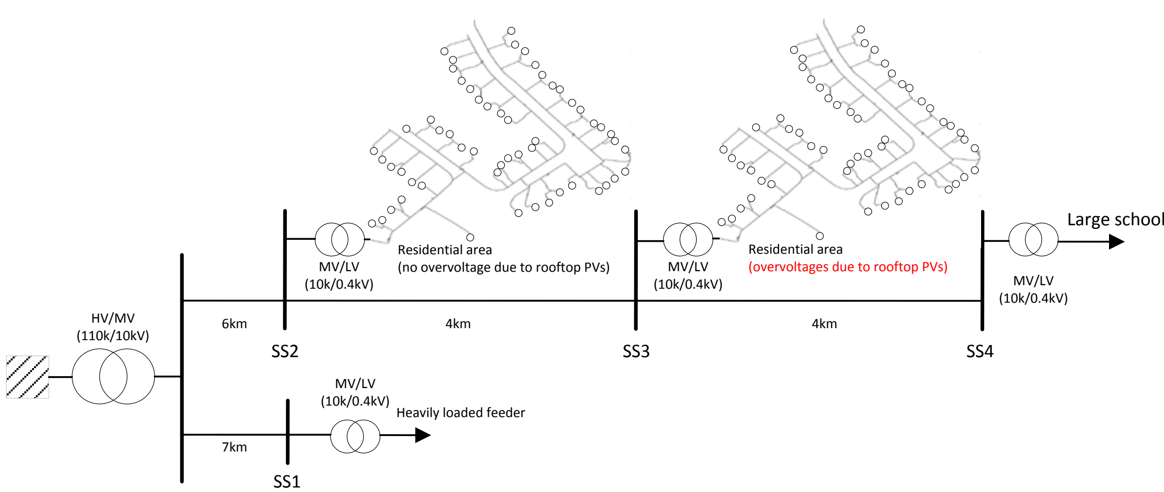


Fig. 18. ALV distribution grid hosting a large school that forms a microgrid at SS4 MV/LV SS.

Table 10: Microgrid investment cost comparison

Microgrid investment	Energy cost (k$/year)	Controllability cost		Total cost (k$/year)	Energy savings (%)
		CAPEX (k$/20year)	OPEX (k$/year)		
Reference case	149.10	-	-	149.10	-
Standard investment approach (restricted)	106.60	-	-	106.60	28.50
Coordinated investment approach: controllability cost by microgrid owner					
CS-A	96.00	0.6	0.21	96.81	35.07
CS-B	92.90	0.3	0.07	93.27	37.45
CS-C	92.90	0.9	0.35	94.15	36.86
Coordinated investment approach: controllability cost by DSO					
CS-A	96.00	-	-	96.00	35.60
CS-B	92.90	-	-	92.90	37.70
CS-C	92.90	-	-	92.90	37.70

The economic evaluation for the microgrid owner is shown in Table 10. Firstly, the reference case is shown, which corresponds to the situation before the DER investments. Secondly, the standard investment approach is shown, in which the feed-in power needs to be reduced until a feasible solution that does not violate the normal operation of the distribution system is found. Finally, the coordinated investment approach is shown, where the controllability upgrading costs can be covered by the microgrid owner or the DSO. Even if all the costs were allocated to the microgrid owner (worst case scenario); the coordinated process would still be a better solution than the standard approach (passive role of DSO) for both actors: microgrid owner and DSO. In any of the cases, the controllability enhancement activities should be performed by the DSO and these could be financed by the microgrid owner or even by prorating the costs among the additional PV installations (prosumers) that are installed on the feeder. Besides, it is worth mentioning that from a regulatory perspective, these two approaches could be used to allow this collaboration: either by incrementing the energy tariff considering the annualized lifecycle cost of the investments or by applying a reduction to the PV feed-in price remuneration.

Lastly, regarding the quality of the controllability enhancement, as shown in Table 11 the assets can be deployed to simply remove the overvoltages only by acting on the problematic feeder that hosts the problems. Or alternatively, extra assets can be deployed, so that the voltage quality of the rest of the grid can be improved. Hence, according to the obtained results the *CS-C* or *compensation strategy* seems to be the strategy that fits best the microgrid's and the grid operator's objectives: energy savings and voltage profile improvement for the distribution grid.

Table 11: Voltage quality versus controllability cost for each microgrid design

Microgrid investment	RMSE (%) reduction in 24h (avg. year)	Location of OLTCs	Controllability cost Total (k$/year)
Reference case - No control	0	-	-
Standard investment approach			
Unrestricted design - No control	-12	-	-
Restricted design - Curtailment	0	-	-
Coordinated investment approach			
CS-A	15	HV/MV	0.81
CS-B	-2	SS3	0.37
CS-C	16	HV/MV, SS1	1.25

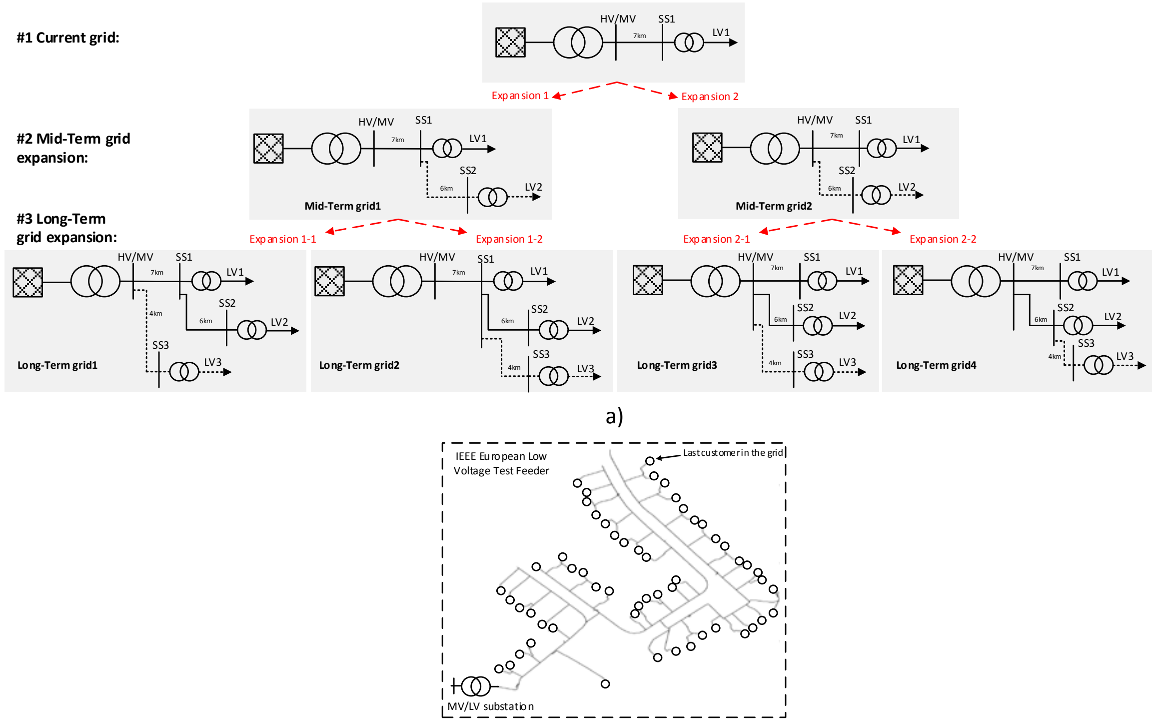
4.2.2. Optimal controller placement

Problem Description

The proper placement of controllers is a key issue when the controllability enhancement is concerned. The reason is that when it is implemented correctly it can improve both the grid performance (*e.g.*, voltage profile, system losses, reliability of supply, etc.) as well as the grid's hosting capacity, yielding room for private DER investments, as shown in Paper III. Hence, the controller placement problem becomes a serious matter and it attracts the interest of multiple actors in the electricity market that have a strategic role in the ALV distribution grid expansion, *e.g.*, DSOs, DER investors, regulators, and policy makers [179]. In particular, the DSO (the decision maker) needs procedures for finding the optimal location of the controllers in the distribution system because the utilization of the control equipment, such as OLTCs, principally depends on their CAPEX. Thus, methods that allow a cost-effective deployment of the controllers are of special interest.

Proposed method

We proposed a cost-effective method to deploy voltage controllers in the ALV distribution grid to remove the possible overvoltage problems that can be caused by the incorporation of the DG at LV grids. The method considers the temporal aspects of the distribution grid planning and the uncertainty in PV growth and distribution grid expansion. Thus, we include grid operations and its corresponding cost into the planning process. The tested voltage control architecture corresponds to a MPC approach as introduced in Paper III. We assume that the controllers are utility's controllable resources such as OLTCs that can be deployed at HV/MV or MV/LV substations. However, any other technological alternative can also be incorporated and serve as a complement to OLTC control (*e.g.*, DSTATCOM, microgrids).
In addition, we perform a comparative study in which we show that an optimal controller placement (permanent or temporary) can defer the CAPEX and provide operational flexibility and efficiency in contrast to the traditional grid reinforcement approach.
In Fig. 19 we show the grid expansion alternatives over time for the arbitrary current MV grid. Each expansion alternative is considered to follow four PV penetration annual growth rate alternatives (*i.e.*, 1%, 2.5%, 5% and 7.5%), yielding sixteen different possible scenarios, as depicted in Table 12.



a)

b)

Fig. 19. a) One-line diagram of the MV grid expansion alternatives over time. b) One-line diagram of the IEEE European LV test feeder that corresponds to LV1, LV2 and LV3.

Table 12: The set of simulated scenarios consisting of the combination of four grid expansion alternatives and four PV growth rates

Scenario	PV growth rate	Grid expansion
01:	1.0%	*Expansion 1 → Expansion 1-1*
02:		*Expansion 1 → Expansion 1-2*
03:		*Expansion 2 → Expansion 2-1*
04:		*Expansion 2 → Expansion 2-2*
05:	2.5%	*Expansion 1 → Expansion 1-1*
06:		*Expansion 1 → Expansion 1-2*
07:		*Expansion 2 → Expansion 2-1*
08:		*Expansion 2 → Expansion 2-2*
09:	5.0%	*Expansion 1 → Expansion 1-1*
10:		*Expansion 1 → Expansion 1-2*
11:		*Expansion 2 → Expansion 2-1*
12:		*Expansion 2 → Expansion 2-2*
13:	7.5%	*Expansion 1 → Expansion 1-1*
14:		*Expansion 1 → Expansion 1-2*
15:		*Expansion 2 → Expansion 2-1*
16:		*Expansion 2 → Expansion 2-2*

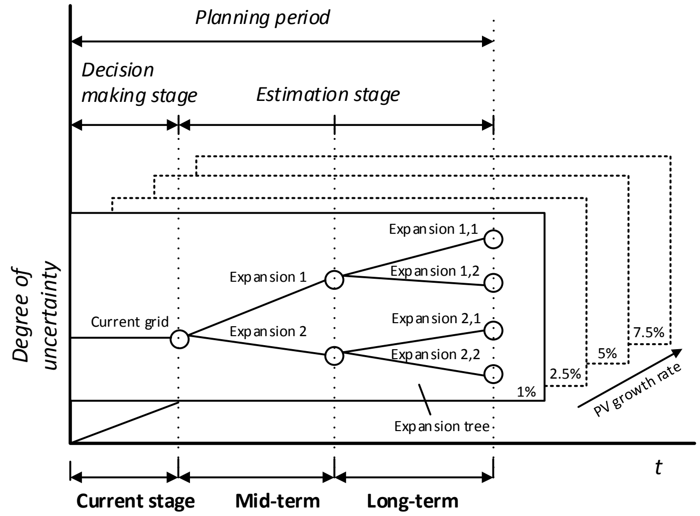


Fig. 20. Grid expansion scenario tree over the planning period for each PV growth rate.

The Net Present Cost (NPC) indicator is used to quantify the required cost to remove the overvoltages in the grid for each of the actuator placement combinations. A time span of 15 years that is divided into three phases is assumed for the planning period (*i.e.*, Current stage, mid-term and long-term), as shown in Fig. 20.

The economic evaluation results depicted in Fig. 21 indicate that the scenarios 1-4 and 7 do not require grid reinforcement nor actuator deployment investments, obviously due to the fact that none of these scenarios show voltage problems. In addition, the traditional grid reinforcement costs are not applicable either to the scenarios 8, 13, and 14, because the possible grid problems in these scenarios must be removed by dimensioning and installing the new lines accordingly. Thus, the calculated actuator-deployment costs for these three scenarios can similarly be avoided (both for permanent and temporary solutions).

Hence, the scenarios that are interesting to compare are the 5, 6, 9, 10, 11, 12, 15 and 16. From these results we can infer that the optimal actuator placement is more economical than the traditional grid reinforcement solution because it shows lower NPC values in all the scenarios. Furthermore, by comparing the two actuator placement alternatives (*i.e.*, permanent vs. temporary), the results show that the temporary deployment solution can be even less costly than the permanent deployment solution. The reason is that the temporary approach provides more flexibility by giving the possibility to deploy and remove the assets when necessary. For instance, in scenario 15 and in scenario 16 an OLTC is deployed in SS2 in the mid-term to remove an specific voltage grid problem in LV2. Then, later in the long-term the grid problems arise in LV1 and LV2. Hence, the OLTC at SS2 is removed and an OLTC is placed at the HV/MV transformer, which is sufficient to remove the long-term grid problems in LV1, LV2 and in LV3. This solution shows lower cost than the permanent solution that consists of keeping the OLTC at SS2 and deploying another two OLTCs, one at SS1 and another one at SS3.

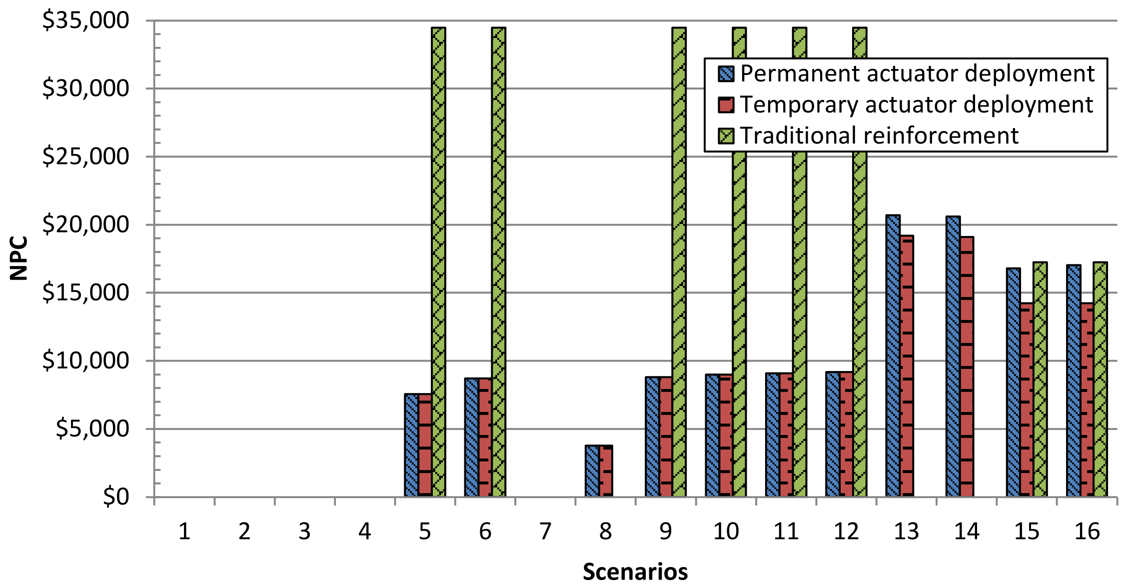


Fig. 21. Economic evaluation: NPC versus scenario.

In order to illustrate the performance of the control operations the simulation results corresponding to the scenario 16 (*i.e.*, Expansion 2-2 and PV growth rate of 7.5%) are shown in Fig. 22. This scenario is selected for illustration purposes because it clearly stresses the grids and it helps to shows the overvoltages In Fig. 22 a), b) and c) the voltage service level are plotted for the customers at the LV1, LV2 and LV3 grids, respectively. It can be seen that if no control mechanisms are applied, overvoltages emerge in the three LV grids. It can be seen that the voltage rise is positively correlated with the distance to the secondary substation and the customers located furthest see the highest overvoltage levels. However, if the lines are reinforced or if the actuators (*e.g.* OLTCs) are deployed, the voltage service level is kept within the $1 \pm 0.1pu$ acceptable threshold. In Fig. 22 d) the 24h voltage service profile is shown for the last customer located in LV1 for *spring – weekend* conditions. In this scenario, the difference in voltage service level between permanent and temporary OLTCs deployment corresponds to the number of actuators needed and to how well these can improve the voltage profile. In this case the permanent solution requires three OLTCs, one at each of the LV grids. In contrast, the temporary solution only deploys one OLTC at the HV/MV substation, which is sufficient to remove the overvoltages but not improve the voltage profile as much as the permanent solution.

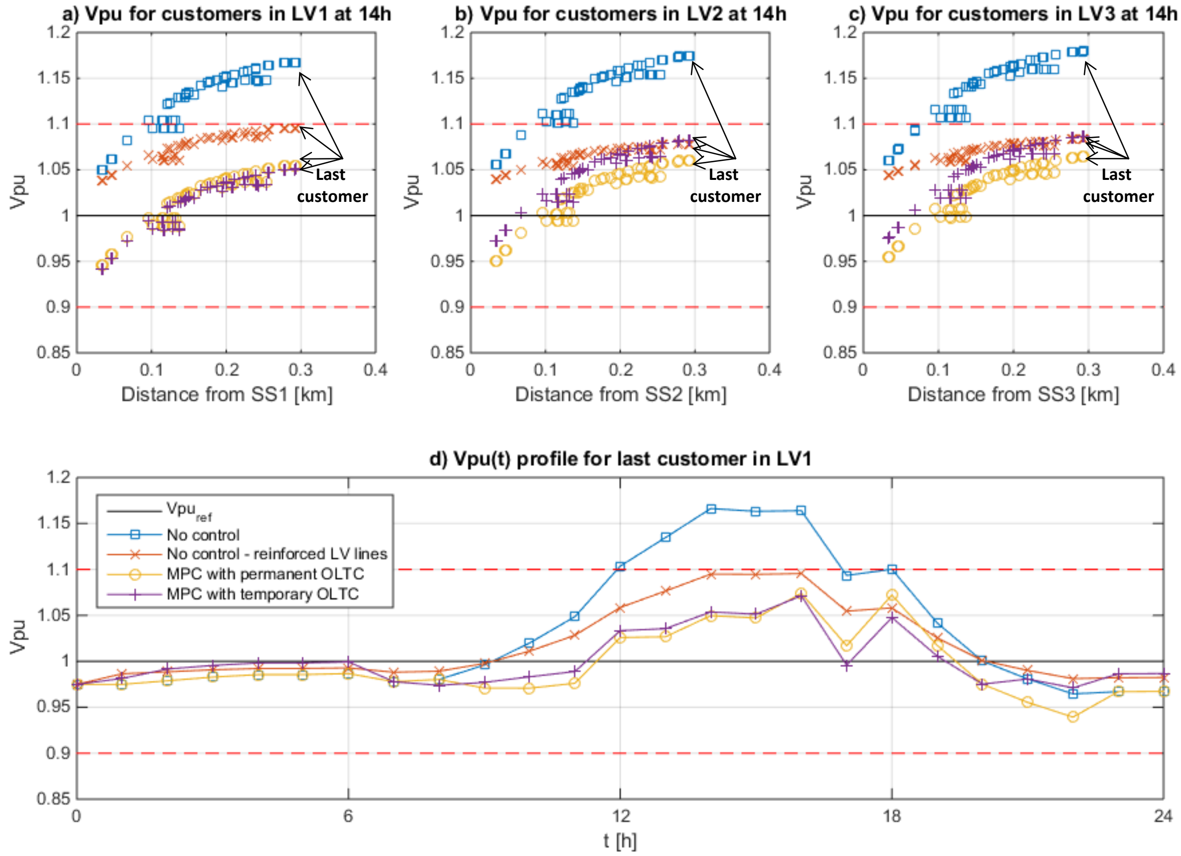


Fig. 22. Simulation results at 14h (peak hour) for the scenario no. 16 showing the power quality analysis: a) Vpu for customers in LV1 vs the distance to the SS1, b) Vpu for customers in LV2 vs the distance to the SS2, c) Vpu for customers in LV3 vs the distance to the SS3, d) 24h profile of Vpu for the last customer in LV1 grid.

4.2.3. Coordinated and multiagent systems-based control architectures for ALV distribution grid reconfiguration

Problem Description

A process in power system distribution automation that is attracting attention and is making progress corresponds to power system restoration [180] (*e.g.*, black-start, load restoration and grid reconfiguration for FLISR). It is a process that has traditionally been performed manually, which directly impacts the outage durations because service crew require time for traveling to locate, isolate and restore the faults. Nowadays however, the evolution in methods and technologies are becoming more mature and they are enabling to automate the system and service restoration practices [181]. The prerequisite is that the technology should be robust, scalable, easy to deploy and cost-effective due to the size of the distribution system. This process corresponds to an important step towards achieving the self-healing grid concept.

Proposed method

The proposed method for distribution automation focuses on deploying a coordinated and multiagent-based control architecture that permits automating the service restoration part of the FLISR problem. By deploying and operating such control architecture the distribution grid's reconfiguration time can be significantly reduced. Thus, it outperforms the current

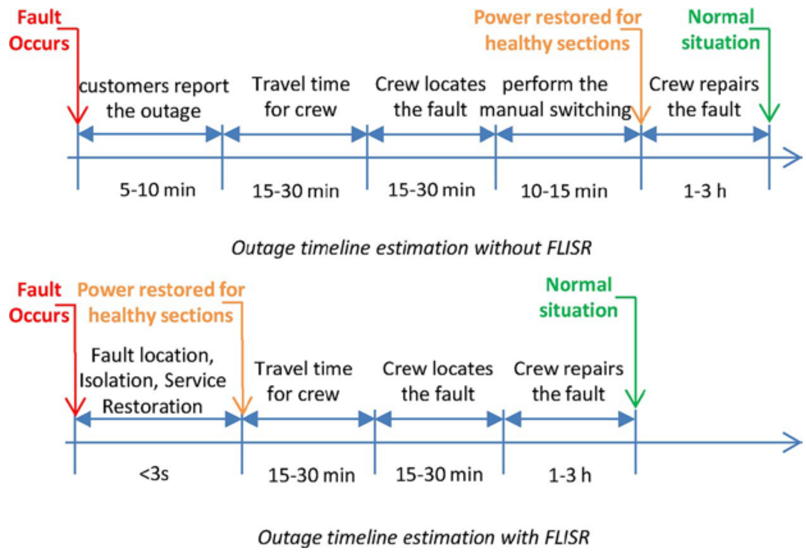


Fig. 23. Outage timelines with and without FLISR.

restoration procedures in terms of power service interruption duration, from minutes and hours to seconds because it avoids the required time for the service crew to travel, locate the fault and perform the manual switching (see Fig. 23). This time-reduction should yield a power quality improvement that should be translated into better performance indexes, such as SAIDI and CAIDI.

In this method, the distribution grid is modeled as a graph and the restoration problem is formulated as a graph-theoretic problem, where the objective consists of obtaining the minimum spanning tree that connects all the nodes that form the graph. In Fig. 24 the topology of the tested grid and its graph-theoretical representation are shown. In the simulations we assume that at least one of the two possible buses that are connected to the HV/MV substation is energized (*i.e.*, bus B1, bus B2).
The method is implemented as a multiagent system that uses a distributed version of Prim's minimum spanning tree algorithm [182] to solve the service restoration task. The three types of agents that form the multiagent system are: Substation Control Agent (SCA), Load Control Agent (LCA) and Restoration Agent (RA). These agent types are described in Table 13.

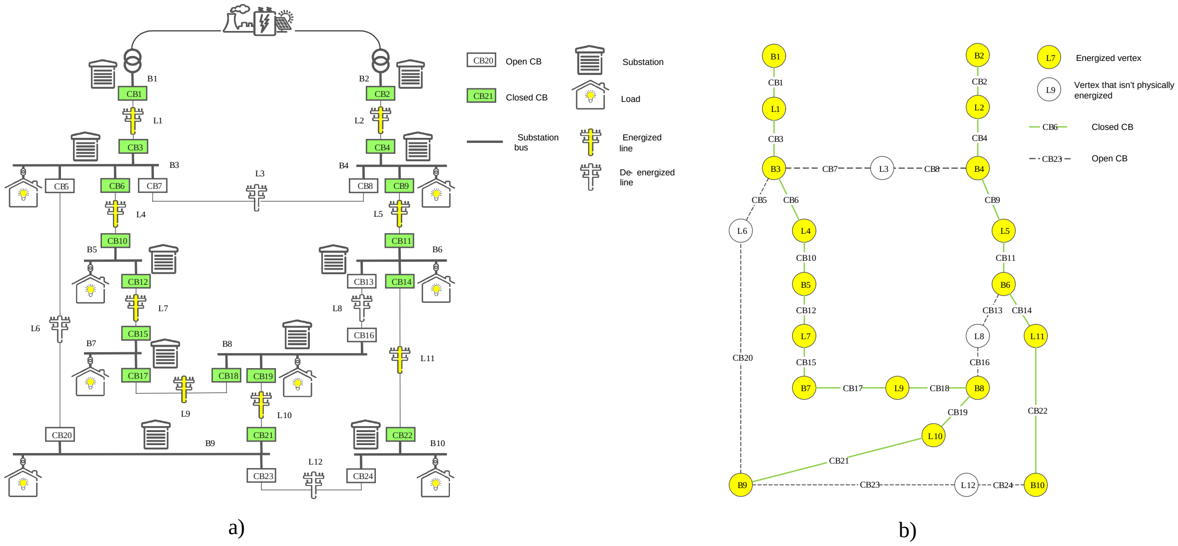


Fig. 24. a) Topology of the tested grid and b) its graph representation.

Table 13: Description of the multiagent system

Agent	Description
SCA	Responsible for controlling one substation's equipment. It informs affected RAs of events and status changes in the grid, and if a fault occurs, the SCAs cooperate to locate the fault by comparing the measurements. If an agent (or grid operator) wants to change the state of a device (*e.g.*, close a circuit breaker), it sends a request to the specific SCA that controls the targeted equipment.
LCA	It is responsible for one tree in the grid topology graph. It monitors the tree's feeder to ensure that its used capacity does not exceed its limits.
RA	It is responsible for one node in the grid topology graph, and its task is to ensure that the node is energized *i.e.*, belongs to a tree.

The important feature of the proposed method is that it assures that a power restoration plan will be found after only a few rounds of negotiations between the substations (*i.e.*, the agents that for the system). And this number of rounds cannot exceed the number of the affected substations.
The main characteristics of the proposed multiagent algorithm are summarized:

- Robustness against multiple distinct blackouts (also local communication blackouts) due to the fact that each blackout is locally managed.
- Scalability. Since each blackout is locally managed, it allows plug-and-play operation and expansion.
- The instantaneous communication requirement is only linearly dependent with the blackout size as the RAs negotiate locally. The linear growth permits the system to avoid communication outage states even in large blackout areas.
- It tries to level out the relative load of the feeders, which allows the algorithm to be applicable not only for the FLISR scenario but also for black-starts.

4.3 Framework for reliable ICT infrastructures in ALV grids

Problem Description

The ICT infrastructure that supports the monitoring and control applications that have been previously presented for enabling the ALV distribution grids expansion must rely on two-way communication systems. These systems are formed by *e.g.,* sensors and AMI, Intelligent Electronic Devices (IEDs) and Remote Terminal Units (RTUs), power line communication infrastructure, fiber optics, phone lines, wireless-based solutions (e.g. RF, WiMAX, cellular, etc.) and the corresponding information technology interfaces (e.g. routers, gateways, links, servers, etc.). The key elements that should be considered for implementing an ICT infrastructure in ALV grids are the cybersecurity, the scalability, the use of interoperable standards and the reliability of the systems [183]. Assuming all these elements, we can facilitate the necessary exchange of data and information for operating the system (real-time mode depending on the application). Therefore, it results in highly importance that the communication systems are in an operative state and performing as they should most of the time. For that reason, tools, test-beds and methods that allow testing and inspecting such features for ALV grids are of special interest. In particular, those that allow analyzing the interaction between the ICT infrastructure and the physical system, so that a thorough real system performance evaluation can be done. The proposed test-beds in [184] - [186] can simulate cyber-attacks as well as validate mitigation methods in a hardware-in-the-loop environment and some even consider IEC 61850 substation automation standard. However, since the communication systems for distribution grids consist of the interconnection of several components and systems, alternatives to describing the systems relationships in terms of analytical and deterministic expressions are needed. The reason is that it is very complex to model and to consider the effect of different combinations of values for different inputs, such as the observed availability for the physical components.

Proposed method

The proposed method corresponds to a framework that is valid to perform reliability analysis of ICT infrastructures. It has been tested and focused on ALV distribution grids applications, *e.g.*, the monitoring and observability of LV grid components, although it can similarly be applied to test protection applications or MV grid applications (*e.g.*, substation automation). These studies can be used for performing reliability predictions of simulated communication systems and for evaluating the reliability of real systems.

The reliability analysis of the systems is performed by using PRM and can be used as a representation language for structured statistical models. PRM combine a logical representation (including entities, attributes and relationships) with probabilistic semantics based on Bayesian Networks [187]. These models include a relational component (*e.g.,* OR-gates to provide system redundancies, AND-gates to determine series dependencies) to designate the probabilistic dependencies between attributes of the architecture's objects. In addition, PRM is extended by applying MC methods, which enhance the study by including a probabilistic approach. Thus, we add a stochastic characterization to the simulations by generating draws from a probability distribution, which allows circumventing the classical analytical and deterministic expressions to calculate system's reliability. Precisely, the input uncertainties such as the actual availability of a certain device are represented by probability distributions and MC methods are used to build the models. The obtained results correspond to the availability attribute; however, assuming that the availability and

the reliability are correlated by the maintainability attribute and considering that the maintainability of the elements that form the system remains constant, we can infer that the reliability percentage values will correspond to the availability percentage values.
The communication system architecture is designed following the SGAM framework; specifically the component layer is used. And then this design is modeled by the Enterprise Architecture Analysis Tool (EAAT) [188], which allows running the simulations.
Four case-studies are carried out in order to evaluate the reliability of the communication systems in distribution grids. These cases are obtained and shown in the DISCERN project [2] and they cover: MV grid monitoring & automation, LV grid monitoring & optimal deployment of communication and measurements solutions for AMR in urban and rural areas both for billing and for identification of technical and non-technical losses. An example that focuses on enhanced monitoring and observability of LV grid components using the AMI system is used for illustration purposes. It is performed by collecting and storing measurements, events and the alarms that are created by the IEDs in the LV grid. And its purpose is to use that information in the future for performing power quality analysis in order to improve LV grid operations. Fig. 25 shows the modelling template by the EAAT that is used for obtaining the system's availability values. The infrastructure functions realize the infrastructure services, while these provide the meaningful information from the layer to the user. The availability values are assigned to both the devices and the links that connect the devices through the infrastructure services and functions. And as mentioned earlier, the reliability parameters are induced by the calculated availability values.
The availability (and thus the reliability) values are also affected by the component and system configuration. Thus, as the systems grow in complexity the corresponding reliability decreases. In a series configuration, a failure of any component results in the failure of the entire system and the more components in series the larger will be the availability (and reliability) reduction. The reliability results (both devices and systems) for this case-study can be seen in Table 14 and the effect of having components and systems in series can be appreciated, being the reliability of the sensors of 99.9% and the whole system's reliability being reduced down to 97.1%.

Table 14: Reliability values for the studied communication architecture

Hardware/Section	**(%)**
LV Voltage sensor	99.9
LV Current sensor	99.9
Link between AMI Head End server and Meter Data Management System (MDMS) server	99.1
Link between MDMS, distribution operator and reporting KPI	99.1
Link between Current sensor and IED	98.1
Link between IED and Meter Data Aggregator	98.1
Link between Meter Data Aggregator & AMI Head End server	98.1
IED	96.1
Link between Voltage sensor and IED	95.1
Meter Data Concentrator	95.0
SM	94.1
Meter Data Management System server	94.1
Link between IED and SM	93.1
AMI Head End server	93.1
Total system reliability: from the sensors up to the operator.	**97.1**

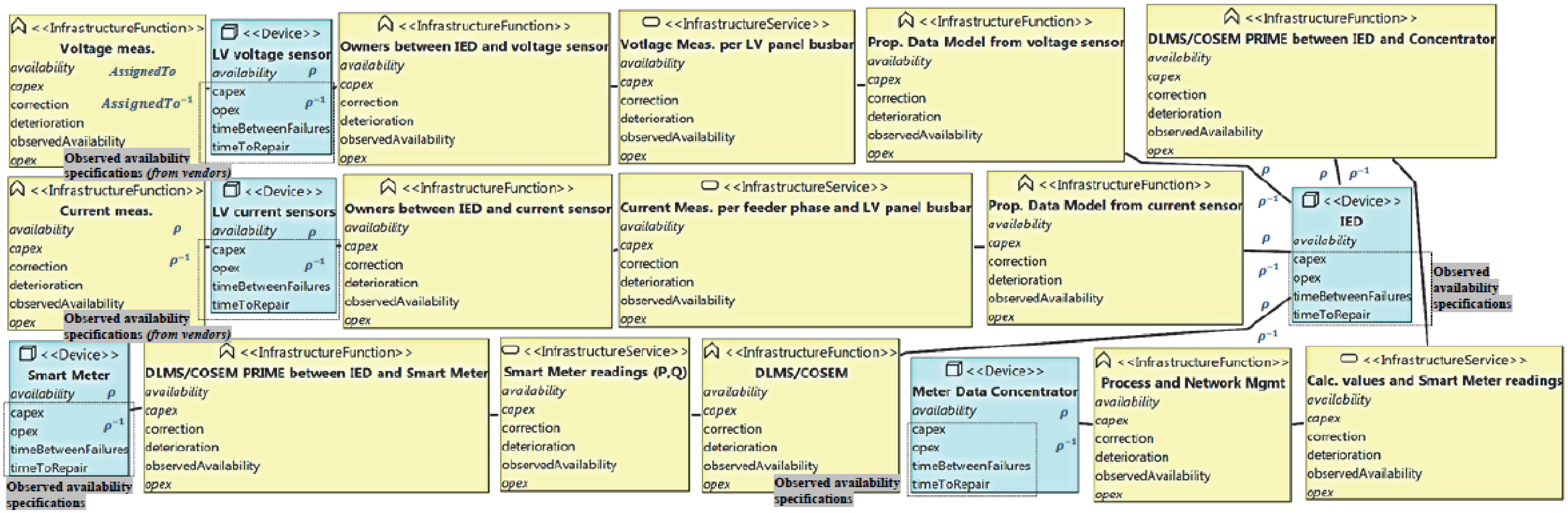


Fig. 25. Example of a modelling template snippet of a use-case to enhance the monitoring and observability of low voltage grid components. The template is created by EAAT's object modeler and shows the information model of the use-case.

Chapter 5

5. Conclusion and Future Work

5.1 Conclusion

In this thesis the communication and control architectures for ALV grids have been addressed from a cost-effective point of view. This chapter completes the discussion with a review of the most important conclusions summarized as key messages related to the research objectives.

In studying the communication architectures we focus on the optimal meter placement configuration required to perform LV SE and the optimal AMI designs for LV monitoring applications. The LV distribution grid is the part of the electrical grid that hosts the large majority of loads/prosumer units. In monitoring this part of the grid, it turns critical to understand how many sensors are required and in which location these should be placed. When possible, due to economic reasons only the required number of sensors should be deployed, even if that means sacrificing the state estimation redundancies. Hence, in this thesis a cost-effective approach is applied to determine the required number of sensors in order to reach the system's observability, whilst providing the lowest possible SE error.

One possible solution that can be used to achieve cost-effective communication is to use the AMI, because it is an infrastructure that in most cases is already deployed for billing activities and even though there can be regulatory-related limitations *e.g.*, restrictions to use customer data, the infrastructure is technically available. A critical component in this type of systems is the DC, which concentrates the meter data and it is typically located at the MV/LV SS. In cases where the customer density is low it can be economically justified to bypass the communication network hierarchy and communicate directly from SM to AMI - head-end using wireless technology and merge the data through a VDC. Thus, in our proposed method to design the communication architectures for AMI systems we assume wireless and PLC technologies, and DC and VDC meter data concentrating alternatives. And the obtained result is a cost-effective communication architecture that considers the number of customers, their location in the grid and the CAPEX, the OPEX and the QoS of each communication architecture alternative.

Regarding the studied control architectures for ALV distribution grids, we focus on enhancing grid controllability by placing actuators (*e.g.*, OLTCs) that facilitate decentralized and coordinated distribution automation applications. The integration of distributed generation and in particular microgrid-like structures into the ALV distribution grids is dependent on the power exchange fluctuations at the PCC. Such fluctuations can cause problems in the adjacent grid (*i.e.*, thermal overloading of the components and voltage rise/drop). Thus, case-specific technical validation studies are required to assess each particular generation capacity investment. Hence, in order to mitigate the inefficient solution that is to reduce the microgrid's generation capacity, we propose a method that consists of enhancing the controllability of the ALV distribution grid operations by investing in OLTC asset control. Consequently, the installed generation capacity can be maximized and the grid problems can be reduced. Such control investment provides an efficient utilization of the components (*i.e.*, reduced number of operations) by applying linear model-based predictive control.

The placement of the required controllers/actuators in the ALV distribution grid represents a lower cost alternative compared to the traditional grid reinforcement that is required for augmenting the DG hosting capacity, for improving the power quality and for facilitating the ALV grids. In addition, it is of key importance to understand where and when the actuators should be placed in the grid. Hence, we also propose a method that consists of enhancing the grid controllability by optimally deploying the fewest controllers/actuators in the grid that can defer the traditional grid reinforcement expansion solutions. Thus, the optimality criterion includes the time aspects of the distribution grid planning and the uncertainty in PV growth and distribution grid expansion. Therefore, the costs corresponding to the grid operations can be included into the ALV distribution grid planning processes.

The enhanced controllability is also applied to distributed multiagent control systems to perform self-healing and feeder reconfiguration applications. Thus, although processes such as grid reconfiguration or power system restoration have been traditionally performed manually at the distribution grid level, nowadays the grids are starting to behave more actively and they are operated closer to their technical limits. Consequently, in order to achieve the power quality & reliability requirements a need to automate these processes is growing. Hence, we propose a coordinated and multiagent-based control architecture that permits automating the service restoration part of the FLISR problem. This architecture allows reducing the power service interruption duration, from minutes and hours to seconds because it avoids the required time for the service crew to travel, locate the fault and perform the manual switching.

Lastly, we shall consider that the presented communication and control architectures must rely on an ICT infrastructure that should meet the following requirements: It should not jeopardize the cyber security and reliability by providing high probability of sustaining its operative functionality during working conditions, while at the same time being cost-effective. This includes resiliency against failures in components, subsystems and communication links. In order to evaluate and analyze the reliability of such systems we propose a simulation tool. This tool can be used to perform reliability estimations of simulated ICT systems, but also for evaluating the reliability of already implemented communication architectures, as shown with the presented use-case.

A final note regarding the cost-effectiveness of the proposed methods to enhance the monitoring and control architectures: the economic aspects have been included by integrating a cost term into the formulation of each method. Thus, this term refers to the CAPEX and the OPEX of the corresponding solution. The CAPEX is mainly covered by deploying the essentially required number of components (*e.g.*, sensors, actuators, DC, GW, etc.) and the OPEX corresponds to the efficient utilization of such components to perform the tasks (*e.g.*, reduced no. of operations, maintenance of the equipment, etc.).

Hence, the investment in enhanced communication and control architectures shows that there is potential to facilitate the ALV distribution grid expansion by avoiding/deferring the otherwise required traditional and more expensive grid reinforcements. But of course, it is important to consider that by nature all the grids are different, which implies that a deployed solution could behave differently depending on the grid's characteristics (*e.g.*, levels of DG with respect to the load, number of customers, length of the feeders, etc.).

Therefore, in order to determine the most suitable communication and control architecture for a specific distribution grid, it turns necessary to perform a thorough cost-benefit analysis of the possible solutions together with an evaluation of the grid's medium/long-term grid expansion planning.

5.2 Future work

This chapter concludes the thesis with the following research continuations suggestions: Regarding the ALV distribution grid characteristics, in this thesis we have assumed that the three-phase lines are balanced, which allows us to simplify the power system to a single phase equivalent system. However, small scale residential rooftop PV systems are commonly installed through single-phase connections and that can lead to unbalanced behavior of LV lines. Therefore, future works should consider the unbalanced behavior of LV lines. This will allow improving the monitoring and the control applications for each phase of the system. In addition, the dynamic behavior of the ALV system should be considered in the future, especially PMU-like sensors could be deployed for protection coordination functions. In this thesis we have limited to only using assets owned by the DSO and we have omitted the potential use of having direct control over the assets behind the meter, such as battery and PV inverters. However, if the later assets were counted for grid control, there would be additional controllable degrees of freedom, which clearly would increase the potential of power quality improvement. Finally, the increased digitalization of electric power infrastructure requires that the technologies, processes and practices should be operated considering the cybersecurity threads and the possible attack vectors. Thus, the performance of the proposed methods in this thesis should be evaluated with regard to cybersecurity. And a possible research direction is to analyze the resiliency of the monitoring and control architectures against the typical cyber-attacks such as Denial-of-Service (DoS) or Man-in-the-Middle (MitM).

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PART II

Papers I to VI

Paper I

A Method to Place Meters in Active Low Voltage Distribution Networks using BPSO Algorithm

A Method to Place Meters in Active Low Voltage Distribution Networks using BPSO Algorithm

M. Armendariz, D. Babazadeh, L. Nordström
Department of Electric Power and Energy Systems
EE School, KTH - Royal Institute of Technology
Stockholm, Sweden
{mikel, davood, larsno}@kth.se

M. Barchiesi
Department of Electrical, Electronic and Inf. Engineering
University of Bologna
Bologna, Italy
michele.barchiesi@studio.unibo.it

***Abstract*— This paper proposes a method to be used by a Distribution System Operator (DSO) to optimally place sensors at medium voltage/ low voltage (MV/LV) substation and some low voltage cable distribution cabinets. This method aims to improve the estimation of the grid states at low voltage distribution networks. This method formulates a multi-objective optimization problem to determine the optimal meter placement configuration. This formulation minimizes the low voltage state estimation error and the cost associated to a particular meter deployment configuration. The method uses Binary Particle Swarm Optimization (BPSO) to solve the optimization problem and it has been tested on a network based on the Cigré LV benchmark grid. The simulation results show that the method can be applied to both situations where smart meter measurements are available and situations where they are not. In the latter situation the measurements are replaced by pseudo-measurements, which represent meter readings by using smart meter historical data and prediction models.**

Keywords—Active Low Voltage Distribution Networks, BPSO, Meter Placement Problem, Multi-objective Optimization, Observability Analysis, State Estimation.

I. INTRODUCTION

THE integration of distributed energy resources (RES) at radial low voltage distribution networks is becoming more popular. Typical examples are photovoltaic power stations mounted on the rooftop of residential or commercial buildings. The massive installations of these systems can induce power quality problems (e.g. overvoltages), increase in power losses, reverse power flows and reliability issues in the grid [1]. Current power system regulation models can specify that part of Distribution System Operators' (DSO) revenue has to be based on how well they cope with their quality targets [2]. Therefore, DSOs are incentivized to invest in enhancing the monitoring and the real-time supervision of the low voltage side of the electrical grid to meet the new control requirements [3]-[5]. Since nowadays this part of the grid is poorly observed (e.g. very few medium voltage/ low voltage (MV/LV) substations are monitored), this work focuses on improving the estimation of the grid states at this level. For obvious economic reasons, it is not feasible to fully deploy meters throughout the entire distribution network. Hence, it is important to determine where in the grid the DSOs should place meters to be able to perform state estimation using the required minimum number of meters.

There are relevant publications that have addressed the meter placement problem in active distribution networks e.g. [6] proposes a heuristic approach to identify the measuring points on the network with higher voltage variations, [7] and [8] present the meter placement as a stochastic optimization problem using Monte Carlo simulations, in [9] the robustness of a Genetic Algorithm (GA)-based method for optimal meter placement is studied and in the dissertation presented in [10], the author provides a thorough and updated literature review on power distribution system state estimation and meter placement algorithms. In the latter work special emphasis is put on both distributed state estimation as a future challenge and on the unbalanced characteristics of the lines.

In our study, balanced three phase lines are considered due to that being the case in the Swedish LV distribution system. Furthermore, the backward/forward sweep method is applied in section II.E to run the load flow calculation in the branch current state estimation. This restricts the network topology to radial networks but this is mostly the case in LV distribution.

Regarding the optimization-problem solving methods, in the last decades computational intelligence-based techniques such as GA and swarm intelligence (e.g. Ant Colony Optimization, Bacteria Foraging, Tabu Search, etc.) have gain considerable attention in several areas due to its simplicity, efficiency of finding optimal/near-optimal solutions, flexibility, robustness and adaptation capacity. Among all of them, particle swarm optimization (PSO) [11] stands out due to its simplicity and efficiency, covering a broad area of applications beyond the device placement problem: e.g. power economic dispatch [12], [13], power system reliability and security [14], capacitor placement [15], Volt-VAR control [16], [17], etc. In our study, the discrete binary version of the PSO algorithm is proposed (described in section II.D).

Traditionally, the publications about distribution system state estimation (DSSE) have mainly focused on MV level (e.g. 20-10kV) and have disregarded LV (e.g. 400V in Europe) This study focuses on LV and it provides an alternative methodology, which employs the use of smart meters and pseudo-meters for system observability in conjunction with BPSO to optimize the meter location in the LV grid, casted as a multi-objective problem.

This paper is organized as follows: First, the meter placement problem is introduced and then the proposed method is presented. After that, a case-study is described and finally the conclusions and the perspectives for future research work are introduced.

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II. METHOD

A. Meter Placement Problem Description

The multi-objective problem presented in this paper consists of determining the optimal meter placement configuration in distribution LV networks. The optimality is determined by the low voltage state estimation error and the cost associated to a particular meter deployment configuration. Two main cases are studied and described in Table I.

Table I. CASE-STUDIES.

Cases	Characteristics that define each case
Case I	- Smart meter measurements are not available and instead *pseudo-measurements* are used. - MV/LV substation is monitored (voltage and current). - Degree of freedom: The required branches at certain LV cable distribution cabinets are monitored (voltage and current).
Case II	- Smart meter measurements are available. - MV/LV substation is monitored (voltage and current). - Degree of freedom: The required branches at certain LV cable distribution cabinets are monitored (voltage and current).

Case I describes a situation where smart meter measurements are not available. This can be the case for countries where the DSO is only allowed to use the meter readings for billing purposes but not for system operation activities. Instead, pseudo-measurements based on consumer's historical data and statistical load models can be used to create a representation of meter readings: the resultant of combining load consumption and PV generation. Case II instead considers that the DSO is able and allowed to use the smart meter measurements for system operation activities (e.g. LV monitoring) apart from for billing activities.

The MV/LV substation is monitored for both Case I and Case II. This means two things: first, the low voltage side of the transformer is measured with a voltage sensor. And second, all the feeders connected to that feeder bus are measured with current sensors. In both Case I and Case II, the degree of freedom that permits obtaining an optimal solution corresponds to monitoring the required branches at certain LV cable distribution cabinets. This means that for each specific network topology configuration, the fact of monitoring some branches at certain LV cable distribution cabinets can improve the quality of the state estimation that much that it would pay off the meter installation cost. The schematic diagram in Figure 1 shows the location of the LV cable distribution cabinets (LVCDC) where the monitoring system can be deployed.

B. Mathematical Problem Formulation

The multi-objective optimization problem, see equation (1), consists of minimizing the weighted Euclidean norm of the vector formed by two components: the first component reflects the cost of meter configuration (CM) and the second component reflects the accuracy of the estimation error defined by the Voltage Error Estimation (VEE). The components are normalized with respect to the maximum values ($VEE(\bar{X})_{max}$ and $CM(\bar{X})_{max}$) so that both components can be in the same scale: from 0 to 1. The weights w_{fe} and w_{fc} correspond to the voltage error and cost weight factors that can be used to prioritize one component against the other if required.

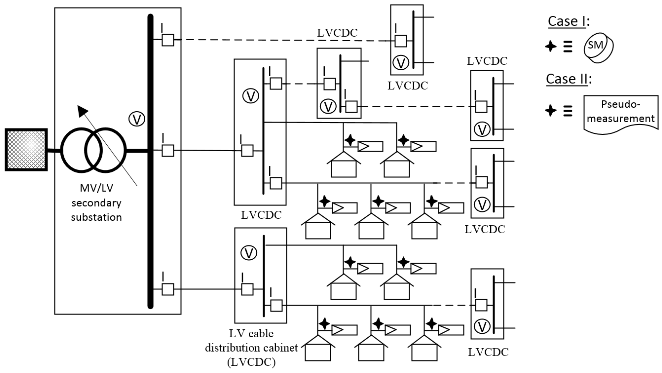


Figure 1. LV Schematic diagram showing the LVCDC.

$$min. F(\bar{X}) = \left\| \left(w_{fc} \cdot CM(\bar{X}), w_{fe} \cdot VEE(\bar{X}) \right) \right\|_2 = \\ = \sqrt{\left(w_{fc} \cdot \frac{CM(\bar{X})}{CM(\bar{X})_{max}}\right)^2 + \left(w_{fe} \cdot \frac{VEE(\bar{X})}{VEE(\bar{X})_{max}}\right)^2} \quad (1)$$

The CM component is defined in equation (2) and it quantifies the monetary cost of a particular meter configuration within a feeder. It reflects the unit cost associated to voltage sensors, current sensors and smart meters.

$$CM = (N_{Vs} \cdot UC_{Vs}) + (N_{Is} \cdot UC_{Is}) + (N_{SM} \cdot UC_{SM}) \quad (2)$$

Where,

N_{Vs}: number of voltage sensors.

N_{Is}: number of current sensors.

N_{SM}: number of smart meters.

UC_{Vs}: unit cost of voltage sensors.

UC_{Is}: unit cost of current sensors.

UC_{SM}: unit cost of smart meters.

The VEE component is defined as the summation of the square roots of the difference squared between the real and imaginary parts of the reference voltage vector and the estimated voltage vector, and it is normalized to the magnitude of the reference voltage vector. See equation (3).

$$VEE = \sum_{i=1}^{N_T} \sqrt{\frac{\left(V_{iR_{EST}} - V_{iR_{REF}}\right)^2 + \left(V_{iI_{EST}} - V_{iI_{REF}}\right)^2}{V^2{}_{iR_{REF}} + V^2{}_{iI_{REF}}}} \quad (3)$$

Where,

$V_{iR_{EST}}$: real part of the estimated voltage vector.

$V_{iI_{EST}}$: imaginary part of the estimated voltage vector.

$V_{iR_{REF}}$: real part of the reference voltage vector.

$V_{iI_{REF}}$: imaginary part of the reference voltage vector.

N_T: total number of buses in the network ($N_T = N_B + N_C$).

Both the CM and VEE values are obtained for a specific decision variable vector configuration: $\bar{X}$, which consists of six binary vectors as defined in equation (4) and in Table II.

$$\bar{X} = [X_V, X_{I_{bus}}, X_{I_{branch_F}}, X_{I_{branch_T}}, X_{SM_{bus}}, X_{SM_{bus}}] \quad (4)$$

Table II. DESCRIPTION OF THE DECISION VARIABLE VECTOR $\bar{X}$.

Elements of $\bar{x}$	Size of vector	Description of the vector
X_V	$1 \times N_C$	Vector that specifies the voltage sensor location at LV cable distribution cabinets. A value of *1* in a position of the vector represents a voltage sensor at the LV cable distribution cabinet associated to that positon.
$X_{I_{bus}}$	$1 \times N_C$	Vector that specifies the zero injection buses. A value of *1* in a position of the vector represents a zero injection bus at the LV cable distribution cabinet associated to that position.
$X_{I_{branch_F}}$ (From)	$1 \times N_L$	Vector that together with I_{branch_F} is used to specify the monitored branches at LV cable distribution cabinets.
$X_{I_{branch_T}}$ (To)	$1 \times N_L$	Vector that together with I_{branch_T} is used to specify the monitored branches at LV cable distribution cabinets.
$X_{SM_{bus}}$	$1 \times N_B$	Vector that specifies the smart meter location at LV networks. A value of *1* in a position of the vector represents a SM at the bus associated to that positon.
$X_{PS_{bus}}$	$1 \times N_B$	Vector that specifies the *pseudo meter* location at LV networks. A value of *1* in a position of the vector represents a PS at the bus associated to that positon.

N_C represents the total number of LV cable distribution cabinets in the LV feeder, where current and voltage sensors can be deployed. N_L represents the total number of branches connected to the LV cable distribution cabinets. And N_B represents the total number of households in the LV feeder, where either SM or pseudo-measurements are used.

Consequently, the size of the $\bar{X}$ vector is determined as depicted in equation (5).

$$1 \times (2 \cdot N_C + 2 \cdot N_L + 2 \cdot N_B) \quad (5)$$

The constraints of the optimization problem determine that the observability of the LV system should be achieved and that the I_{bus}, SM_{bus} and the PS_{bus} vectors should be specified based on the topology of the network. This means that the end node positions (e.g. households) and zero injection buses shall be determined a priori before the optimization problem is solved. Additionally, SM_{bus} and PS_{bus} are complementary vectors. In this setup either pseudo-measurements or smart meter measurements are applied, but not both at the same time.

C. Measurement alternatives

To address the meter placement problem, it turns necessary to specify the type of available instrumentation and its characteristics. The following sub-sections will explain the specifics.

1) Meter Measurements

In this study, the MV/LV secondary substations are assumed to be monitored by voltage and current sensors. The meter measurements specifically refer to the instrumentation used for monitoring the phase voltages and the required branch currents at certain LV cable distribution cabinets, in such a way that the active and reactive power flows can be derived.

2) Smart Meters (SM)

Currently, typical smart meters have the capability to collect many electrical parameters (e.g. power and energy registers, tariff registers, voltage and current registers, etc.). In this study, the end-point nodes are considered as PQ nodes and consequently, the SM's active and reactive power registers are used, which represent import (consumption) or export (generation) power: P_{imp} Q_{imp}.

3) Pseudo-measurements

There are situations where smart meter measurements are not available (e.g. P_{imp}, Q_{imp}) and instead the so-called pseudo-measurements are applied. This type of measurements relies on different type of consumer load modeling, based on statistical processing of smart meter historical data from similar systems to provide measurement estimations to unmeasured loads [18]. These models provide an average expected value with a certain accuracy, which increases as the elements under estimation are aggregated. For example, it is more accurate to estimate the consumption at the substation level than at household level. Furthermore, the time aspect also has a significant effect on the quality of the standard deviation of the estimated pseudo-measurement. As explained in [19], the estimation effectiveness decreases as the time delays in data transmission rise.

4) Measurement Error

Every time a measurement is taken there is an error associated to it (e.g. e_i) and the uncertainty of this error can be characterized by a Gaussian (i.e. Normal) distribution. A confidence interval is used to associate standard deviation (σ_i) of the measurement (and pseudo-measurement) with its mean value (μ_i). Therefore, by knowing the measurement error of the applied instrument and defining a certain confidence interval is possible to calculate the value of the standard deviation for each type of measurement. Since in statistics $\mu \pm 3\sigma$ represents a 99.73% confidence interval, for a given maximum error percentage (*e*%) of the *i*th measurement regarding the average (μ_i), it is possible to obtain the standard deviation as defined in equation (6).

$$\sigma_i = \frac{\mu_i \cdot e\%}{3 \cdot 100} \quad (6)$$

D. Proposed Method Using BPSO Algorithm

The proposed method is based on the discrete binary version of the general metaheuristic approach known as Particle Swarm Optimization (PSO) algorithm. Proper description and explanations for binary PSO (BPSO) can be found in [20] and [21]. As a summary, the main characteristics of BPSO algorithm are provided as follows:

- Each *i*th particle corresponds to an instance of the decision variable $\bar{X}$, i.e. $\bar{X}_i^k = [x_1^k, \dots, x_i^k \dots, x_{dp}^k]$, where *k* represents the iteration number and *dp* is the dimension of the particle.
- The population is a set of particles in the swarm, where Npp represents the number of particle in the population, i.e. $\overline{POP} = [\bar{X}_1, \dots, \bar{X}_i, \dots, \bar{X}_{Npp}]$.
- The best position of particle *i* at iteration *k* represents the position whose fitness value is the lowest among the previous particle's position, i.e. $\overline{PB}_i^k = [pb_1^k, \dots, pb_i^k, \dots, pb_{dp}^k]$.
- The best *i*th particle among all the best particles ($\overline{PB}_i^k$) at the current iteration *k* represents the global best particle, i.e. $\overline{GB}^k = [gb_1^k, \dots, gb_1^k, \dots, gb_{dp}^k]$.

- At each kth iteration each ith particle is associated to a position ($\bar{X}_i^k$) and also to a velocity, i.e. $\bar{V}_i^k = [v_1^k, \dots, v_{dp}^k]$. The velocity vector is updated at each kth iteration by equation (7). Where w is the inertia weight, c_1 and c_2 are the acceleration constants and $r_1$and $r_2$are two uniform random numbers in the range [0, 1].

$$V_i^{k+1} = wV_i^k + c_1 r_1 \left(pb_i^k - X_i^k\right) + c_2 r_2 \left(gb_i^k - X_i^k\right) \qquad (7)$$

$$w = w_2 + (w_2 - w_1) \cdot \left(\frac{(k_{max} - k)}{k_{max}}\right) \qquad (8)$$

The w inertia weight is calculated as defined in equation (8), where w_1 and w_2 are respectively the initial value and the final value for the inertia weight, k_{max} represents the maximum number of iterations and k the current iteration.

Similarly, the ith particle needs to be updated at each kth iteration by equation (9). However, to apply the binary particular case, which specifies that the PSO should find the solution in a binary search space, a sigmoid transformation to the velocity component is applied as specified in equation (10), and therefore, equation (11) replaces equation (9).

$$X_i^{k+1} = X_i^k + V_i^{k+1} \qquad (9)$$

$$Sigmoid\left(V_i^{k+1}\right) = \frac{1}{1 + e^{-V_i^{k+1}}} \qquad (10)$$

$$X_i^{k+1} = \begin{cases} 1, & r < Sigmoid\left(V_i^{k+1}\right) \\ 0, & otherwise \end{cases} \qquad (11)$$

Where r is a uniform random number in the range [0, 1].

The proposed method considers the previously detailed BPSO characteristics (see Figure 2) and described in the following steps:

- Step0: Initialization. At this step the initial particle swarm is randomly generated and the position and velocities of the particles are initialized, i.e. $\bar{X}_i^1 = [x_1^1, \dots, x_{dp}^1]$, $\overline{POP}^1 = [\bar{X}_1^1, \dots, \bar{X}_{Npp}^1]$ and $\bar{V}_i^1 = [v_1^1, \dots, v_{dp}^1]$. In this initial swarm, the two extreme situations are also considered: the configuration without any additional measurement devices (minimal cost and maximum state estimation error) and the configuration where the measurement devices are installed on each node and branch (high cost and minimum state estimation error). Then, the initial configuration is assessed and the corresponding CM and VEE values are calculated. After that, the initial fitness function ($FF(\bar{x}_i^1)$) is calculated using equation (12) and the initial particle best ($\overline{PB}^1$) and global best ($\overline{GB}^1$) are found.

$$FF\left(\bar{X}_i^k\right) = \sqrt{\left(w_{fe} \cdot \frac{VEE(\bar{X}_i^k)}{VEE_{max}}\right)^2 + \left(w_{fc} \cdot \frac{CM(\bar{X}_i^k)}{CM_{max}}\right)^2} \qquad (12)$$

- Step1: Evaluate the termination criteria. At this step the algorithm is stopped if any of the following optimality conditions apply:
  - The number of iterations exceeds the maximum number of iterations: $k_{max} > k$.
  - The fitness function of the GB particle remains stable for a number of iterations ($k_{breakloop}$).
- Step2: Update the counter ($k = k + 1$).
- Step3: Calculate the new velocity ($\bar{V}_i^k$) and new position of the swarm ($\bar{X}_i^k$). With these positions a new swarm configuration is achieved and consequently new meter placement alternatives are obtained.
- Step4: The new configuration is assessed and the corresponding CM and VEE values are calculated.
- Step5: Evaluate the fitness function ($FF\left(\bar{X}_i^k\right)$) and find particle best PB ($\overline{PB}^k$) and global best GB ($\overline{GB}^k$) using equation (13) and (14).

$$\begin{cases} \overline{PB}_i^k = \bar{X}_i^k, & FF\left(\bar{X}_i^k\right) < FF\left(\overline{PB}_i^{k-1}\right) \\ \overline{PB}_i^k = \overline{PB}_i^{k-1}, & otherwise \end{cases} \qquad (13)$$

$$\begin{cases} \overline{GB}^k = \overline{GB}^k, & \min\{FF(\overline{PB}^k)\} < FF(\overline{GB}^{k-1}) \\ \overline{GB}^k = \overline{GB}^{k-1}, & otherwise \end{cases} \qquad (14)$$

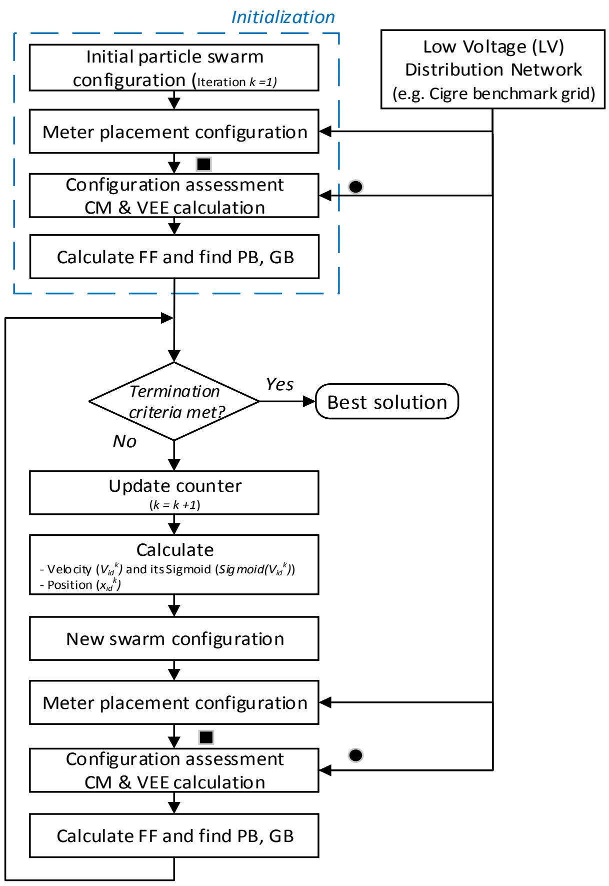
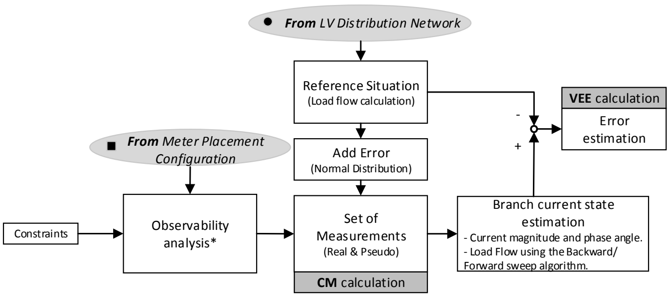


Figure 2. The proposed method for meter placement.

E. Meter Placement Configuration Assessment

The meter placement configuration assessment part of the algorithm is run to be able to obtain the CM and VEE components for each particle (i.e. meter configuration). It requires two inputs: the branch matrix representing the LV distribution network and the meter placement configuration for the LV network under study. The Figure 3 shows the block diagram description.



* *Numerical approach based on [22]. It checks redundant measurements and makes sure that the number of measurements are equal or greater than the state variables.*

Figure 3. The meter placement configuration assessment through CM and VEE calculation. The filled square and circle represent two different inputs from the meter placement configuration and the LV network respectively.

1) Observability & Redundancy Check

The observability analysis is executed to check whether the meter deployment for a specified configuration is adequate or not to meet the constraint of full observability of the network, it also checks that the measurements are sufficient to perform state estimation. Since the network under study is a radial LV distribution system, the non-observable situations that could arise if a meter would break down are not that critical as they would be at higher distribution levels or at the transmission grid. Therefore, there is no necessity for the grid observability to contain redundancies if that implies deploying additional devices. This is the reason why a redundancy check is performed in addition to the observability test, as presented in [22], where authors propose a numerical approach for observability analysis considering redundant measurements.

2) CM Calculation

Starting from the LV distribution network and assuming full observability, the load flow study is performed to obtain all the variables of interest for a given configuration (i.e. complex voltages for all nodes, complex currents and power flows along all branches of the network). The results from the load flow study are considered to be the reference situation and these results are compared to the results obtained from the state estimation, so that the estimation error can be calculated.

The set of measurements is generated using a meter deployment configuration that fulfils the observability criteria. The measurement values are obtained by adding a normally distributed error to the reference situation. The standard deviation (σ) of the error depends on the measurement alternative used (i.e. meter or pseudo-meter). Once the set of meters that form a particular configuration are known the CM is calculated as defined in equation (2). The CM parameters covers the investment costs (e.g. Capital Expenditures (CAPEX)) and the Operational Expenditures (OPEX) [23].

Similarly, the net present value analysis (NPV) [24] can be applied for each asset deployment configuration considering e.g. the next 10 years after the deployment. The NPV in a financial tool that can be used for helping in decision making processes such as in expansion projects like this. It takes into account the asset investment (e.g. meters), the depreciation of the assets and the cash flow. The meter deployment configuration with a positive NPV is a profitable investment while negative NPV corresponds to financial losses. Therefore, NPV maximization could be used to replace CM indicator minimization in the equation (1).

3) Branch Current State Estimation

Each deployment configuration provides a set of measurements that unfortunately, does not contain the complete state of the system. However, there are techniques such as state estimation, which take all the measurements and use them to determine the principal behavior of the system at any point in time. The State Estimation (SE) technique is largely applied at the transmission network, where the states variables are the complex voltage of the nodes. In distribution networks however, due to the radial nature of the networks, it is preferable to use the branch complex currents as state variables because the computation is faster, more robust and the current measurements are easier to handle [25], [26]. The Weighted Least Square (WLS) estimator is applied and it is based on the minimization of weighted measurement residuals. It is formulated as equation (15). Once the complex currents are obtained, it is possible to take advantage of the radial characteristic of the network and calculate the nodes' complex voltages by distribution load flow using the backward/forward sweep method [27]. The assumption of balanced three-phase lines allows to apply the three phase to single phase equivalence transformation.

$$Min.\quad J(x) = [z - h(x)]^T R^{-1} [z - h(x)] \tag{15}$$

Where,

x: system state vector.

$z_i = h_i(x) + e_i$: ith measurements.

$h_i(x)$: ith nonlinear function relating meas. i to the state variable.

e_i: ith measurement error.

4) VEE Calculation

The VEE indicator as defined in equation (3) can be calculated by using the complex voltages from the reference situation and the branch current SE. The SE results can be biased by the randomness in the error function that is used to create the set of measurements. Therefore, a way to avoid such bias effect is to apply Monte Carlo method for N_{iter} iterations each time using a different set of measurements generated through the error probability function. And the resulting VEE average value is used.

III. CASE-STUDY

A. Case-Study Description

The proposed meter deployment method is illustrated with a case-study and four different scenarios are applied to the feeder shown in Figure 4. This feeder corresponds to a residential feeder, which contains 12 active residential nodes (e.g. prosumers), 22 branches and 10 LVCDC. The cable characteristics are obtained from the network proposed in [28]. The four different scenarios are simulated in this study as depicted in Table IV. These simulated scenarios are based on Case I (i.e. pseudo-measurements) and Case II (i.e. smart meters) with variations in the weight factors. The BPSO parameters are specified in Table III.

Table III. BPSO SIMULATION PARAMETERS.

Parameter	N_{pp}	N_{iter}	c_1	c_2	w_1	w_2	k_{max}	$k_{breakloop}$
Value	30	200	0.5	0.3	0.3	0.1	200	10

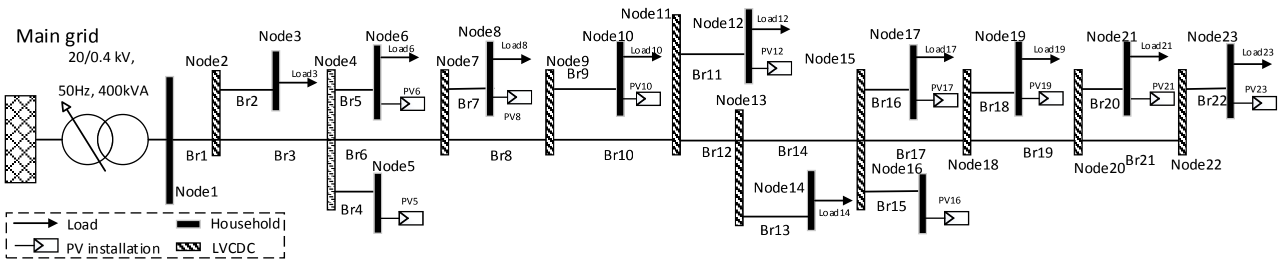


Figure 4. Modified Cigré LV Benchmark network.

Table IV. SIMULATED SCENARIOS.

Scenario #	Case I / Case II	w_{fe}	w_{fc}	σ_{SM}	σ_{PS}
1	Case II	1	1	0.0001	-
2	Case II	1	9	0.0001	-
3	Case I	1	1	-	0.003
4	Case I	1	9	-	0.003

B. Simulation Results

In Figure 5 the simulations results are shown for the four scenarios. X-axis represents the cost of meter configuration (CM) and Y-axis represents the Voltage Error Estimation (VEE). Both axes are normalized to the maximum values representing the extreme configurations, i.e. meters deployed in all the LVCDC ($1+^2$ particle) and no meter deployed in any LVCDC ($1+^1$ particle). The different configuration solutions are represented by a "+" sign and two identification numbers. The number on the side represents the iteration number and the upper right number identifies the particle of the population. In scenario#1 and #2 a horizontal offset can be observed that represents the cost of having physical SM meters. The configuration solutions that during the optimization cycle have been generated more than once are identified with a magenta cross and the solutions that have been considered as global best are identified with the green "+" sign. A Pareto front can be observed from the simulated scenarios. This front is formed by all the equally optimal solutions. In this work a single optimal solution is obtained by minimizing the Euclidean norm of the vector that defines each configuration solution. This single optimal solution is identified by a red circle, which represents the final global best. Figure 6 shows the evolution of the fitness function and the components forming the fitness function. The algorithm finds the optimal solution after 10 iterations for scenarios characterized by same weight factors and it converges faster for the scenarios that prioritize the configuration cost (e.g. scenario #2 and #4).

Table V. OPTIMAL METER LOCATION

Scenario#	LVCDC				SM/ Pseudo	Components	
	V sensor		I sensor				
	Qty.	nodes	Qty.	branches		CM	VEE
1	2	4, 7	2	6, 12	SM	0.23	0.57
2	0	-	0	-	SM	0.08	1
3	3	7, 11, 18	3	8, 12, 19	Pseudo	0.25	0.39
4	1	7	1	8	Pseudo	0.09	0.56

In all the simulated scenarios the algorithm stops when one of the optimality conditions is met, i.e. the fitness function of the GB particle remains stable for 10 iterations. The meter deployment location for each scenario is shown in Table V. As expected, scenarios considering pseudo measurements (e.g. scenario #3 and #4) require additional nodes to be monitored than scenarios considering SM data (e.g. scenario #1 and #2). This can be explained by the fact that the pseudo measurement data considers a larger standard deviation (σ) of the measurements than the SM data does. Thus, to fulfil observability requirements additional sensors are required. In scenario #2 the meter deployment cost is heavily penalized in comparison to the estimation error. Therefore, even though a solution is obtained, since no device is deployed this solution provides the maximum VEE error.

IV. Conclusions and Future Work

In this paper a method to optimally place meters in active LV distribution networks is presented. The method formulates a multi-objective optimization problem, which minimizes the low voltage state estimation error and the cost associated to a particular meter deployment configuration.

A BPSO based approach is used to solve the optimization problem. The results provide a Pareto front showing all the equally optimal solutions, which can be used in the meter placement decision making process. The final GB solution is proposed as the single optimal solution that minimizes the Euclidean norm of the vector that defines each configuration solution. The method was successfully applied on a modified Cigré LV benchmark network and it can be applied to situations where smart meter measurements are available and situations where these measurements are not available.

As expected, simulation results show an increment in the cost parameter and a decrement in the error estimation parameter when the number of deployed measurements is incremented. The main contributions of this project are the problem formulation as a multi-objective optimization problem and the use of smart meters and pseudo-meters for system observability. Future work will capture the unbalance behavior of the distribution lines as well as meshed topologies.

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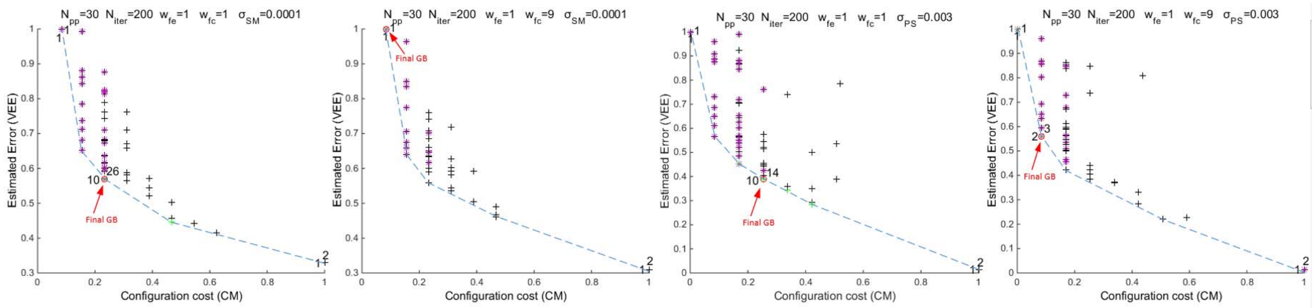

Figure 5. The simulation results showing the Pareto front for each simulated scenario. From left to right: scenario #1, scenario #2, scenario #3 and scenario #4.

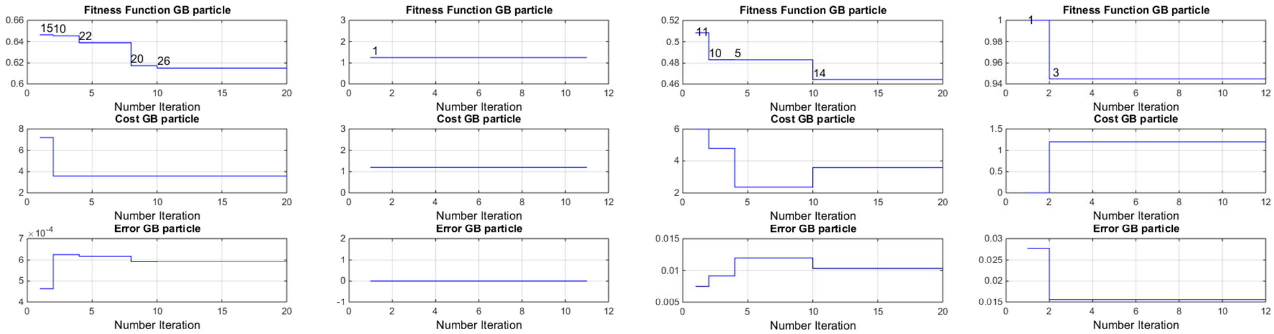

Figure 6. The graphs showing the evolution of the Fitness Function, the CM component and the evolution of the VEE component for the tested scenarios. From left to right: scenario#1, scenario#2, scenario#3, scenario#4. The numbers on the curves represent the GB particle at each iteration: $\overline{\mathbf{GB}}^{\mathbf{k}}$.

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Paper II

Method to design optimal communication architectures in advanced metering infrastructures

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Research Article

Method to design optimal communication architectures in advanced metering infrastructures

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Mikel Armendariz[1] ✉, Christian Johansson[1], Lars Nordström[1], Angel Yunta Huete[2], Miguel García Lobo[3]

[1]*Department of Electric Power and Energy Systems, KTH – Royal Institute of Technology, Osquldas väg 10-VII, SE-100 44 Stockholm, Sweden*
[2]*Unión Fenosa Distribución, Calle Antonio López 193 pl. 01, 28026 Madrid, Spain*
[3]*Gas Natural Fenosa Engineering, Calle Acanto 11-13, 28045 Madrid, Spain*
✉ *E-mail: mikel@kth.se*

Abstract: This study proposes a method to determine the optimal communication architecture in advance metering infrastructures (AMI). The method starts by indicating suitable groups of meters that share similar characteristics such as distance to the secondary substation and mutual proximity. Then it connects each group of meters to the AMI-head end through a communication architecture formed by wireless and power line communication technologies. The optimality criterion takes into account the capital expenditures, operational expenditures and the quality of service in the communication architecture. The method is tested on a low voltage (LV) network based on real utility data provided by EU FP7 DISCERN project partners. These tests show that the method is consistent with planning foresight and can be useful to assist in the AMI communication architecture designing process.

1 Introduction

In recent years, the traditional electricity production and consumption paradigms are being altered. This changing process is in a way triggered due to distributed energy resources, which are increasingly being connected to the low- and medium-voltage side of the electric distribution systems. Consequently, the distribution system operators (DSOs) are adapting the way they operate and maintain the electric distribution grid.

Therefore, driven by the smart grids concept and assisted by the new advances in information and communications technologies (ICT), the electric utilities are making significant progress in improving the maturity level of their business processes. Such maturity upgrade covers the traditional and typically manual processes of grid observability and consumption measurement for billing purposes. This upgrade covers also the new business processes such as automatic system state estimation and observability, technical and non-technical energy loss identification and the soon-to-be-implemented demand response schemes. All these processes require an effective bidirectional advanced metering infrastructure (AMI), which is formed by energy measurement functions, metering devices, central data collection systems and a communication network that connects all of them [1, 2].

A critical component in an AMI system is the physical data concentrator (DC). Typically, concentrators are placed at secondary substations and communicate with the meters at customer sites connected to the low voltage (LV) network supplied by that secondary substation. The concentrator also communicates with the AMI system's head End creating a hierarchical structure [2]. There may be situations such as low customer density, where it can be economically better to communicate directly from meter to head end, bypassing the communication hierarchy. To provide a uniform technical interface for the head end, the communication with the meter can be done through a virtual DC (VDC). This VDC is an application that runs at central systems and concentrates the measurements obtained from remote meters. These concentrated measurements are then dispatched to the meter data management system (MDMS), which is a server that collects all the measurements within the AMI system [3]. Additionally, there are several communication technologies that can be applied for metering infrastructure communication [e.g. GSM/GPRS, UMTS, Wi-Fi, ZigBee, fibre optics and power line communication (PLC)] [4]. Thus, there are several possibilities for DSOs to connect the smart electricity meter devices with the AMI system.

An overview of the current ICT status for smart grids and AMI is presented in [5–7]. In [8], an analysis is done where the functional and non-functional requirements are specified for automatic meter reading (AMR) data collection systems using virtualised and physical concentrators. These requirements focus on both the devices and its communication architectures, e.g. the metering functions, polling cycles, alarms, communication bandwidth and protocols. In [9], the wireless and PLC-based smart meter communication standards used in Europe are compared. In [10–12], the focus is exclusively on PLC description, standard comparison, quality of service (QoS) requirements and implementation experiences. In [13, 14], however, the studies focus on wireless communication requirements for smart grid applications (e.g. AMI).

As far as the general telecommunication network planning process is concerned, there are business, network and operation support-related needs that have to be covered [15]. These needs are translated into specific requirements such as functionality, cost, reliability, maintainability and expandability [16]. At the topological design phase, the meter assignation of the AMI network is implemented. Thus, this is the phase in which this study fits. This paper contributes by proposing a method to assist in the AMI communication architecture designing process by selecting the most suitable technology for each scenario. For simplicity, in the presented case study only GSM/GPRS and PLC AMI communication solutions are considered, however, they can be incorporated to the method if required. It is formulated as an assignment problem, which is common in other fields besides telecommunications such as operation research and supply chain management for project planning and manpower planning [17].

This paper is organised as follows. First, the proposed method, the communication scenarios, the meter clustering tool and the

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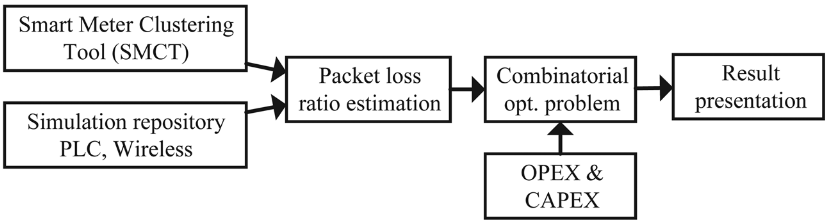

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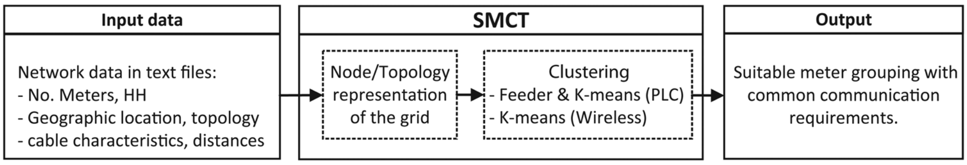

b

Fig. 1 *Block diagram of and smart metering clustering tool*

a Proposed meter assignment method's block diagram
b Smart metering clustering tool block diagram

simulation repository are presented. After that, a case study is described and finally the conclusions and the perspectives for future research work are introduced.

2 Method

2.1 Proposed method

The proposed method connects groups of meters to the AMI-head end through a communication architecture formed by wireless and PLC technologies. It consists of solving a combinatorial optimisation problem to select the most suitable communication technology for each group of meters. The method is described in Fig. 1*a*. The method starts by grouping meters with similar communications connections characteristics so that the packet losses can be estimated for both type of meters connected through PLC or through wireless technology. The packet loss ratio (PLR) estimation (i.e. packet drop ratio) is used as a QoS indicator that enables (or disables) a possible communication combination in the combinatorial problem. The PLR indicator is defined as the ratio formed by dividing the number of non-received packets by the number of sent packets [18]: packet loss ratio = (#packets lost)/(#packets sent). The smaller value of the ratio indicates the better performance of the communication.

Finally, the combinatorial optimisation problem is implemented, which provides the combinatorial solution with minimum cost that satisfies the quality constraints. The communication scenarios are described in Section 2.2 and the details for each part of the method are explained in Section 2.3–Section 2.6.

2.2 Communication scenarios

Two media alternatives or communication technologies are considered in this study: PLC and wireless (e.g. GSM/GPRS). The main reasons for using these two alternatives are the communication solution availability and the cost. In the case of PLC, most of the physical infrastructure (e.g. power lines) already exists, whereas GPRS uses the widespread GSM network. Both communication solutions provide low data rates, which are fairly acceptable for AMR-AMI purposes. The communication scenario setups considered in this paper are summarised in Table 1 and described as follows.

In scenario #1, the smart meter-based clusters are linked by PLC solution to a DC that is located at the secondary substation. This concentrator forwards the aggregated information to the head end by means of wireless solutions, in this case GSM/GPRS.

In scenario #2, the smart meter-based clusters are linked by PLC solution to a gateway (GW) that is located at the secondary substation. This GW, unlike the DC in scenario #1, does not concentrate the information and it is a simpler system that only forwards the received information to the head end by means of GSM/GPRS. It is at head-end level where the information is concentrated by the VDC system.

In scenario #3, the smart meter-based clusters bypass the secondary substation and are directly linked to the head end by means of GSM/GPRS. Same as in scenario #2, it is at the VDC system where the information is concentrated.

The scenario #4 represents the cases when the smart meters are not assigned to any of the previous scenarios due to communication unavailability caused by poor communication quality.

2.3 Smart meter clustering tool (SMCT)

The SMCT is created to indicate suitable groups of meters with similar communications connections characteristics. By clustering the meters, the communication topology is simplified and as a result the possible combinations in the combinatorial optimisation problem are reduced.

The SMCT block diagram is shown in Fig. 1*b* and it is formed by two stages: the topology creation part followed by the clustering part. As input, the tool requires text files specifying the LV grid characteristics (e.g. cable link characteristics, cable identification and connections) and geographic location of secondary substations and load points (e.g. the households). Using the input data the SMCT generates geographic representations of the grid and on these it performs a clustering of the meters along the LV feeders to indicate suitable groupings of the smart meters for PLC or wireless communication connection.

The granularity level that the SMCT considers goes down to the household-nodes (HH-nodes). This assumption denotes that all the meters concentrated at a certain HH-node are assumed to be connected by the same communication solution.

2.3.1 Topology creation: The load points are represented as HH-nodes and they can be seen as meter hubs that are identified by their identification code, position in the network (i.e. X and Y coordinates) and their contracted power. The contracted power varies from one HH-node to another and it depends on the number of customers connected to each household. To be able to calculate the cable distance from each HH-node to the secondary substation, the link nodes are required. The link nodes represent the terminal points that characterise each straight cable section. Alike HH-nodes, the link nodes are positioned in the network using the X and Y coordinates. The HH-nodes are assigned to their closest

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Table 1 Communication scenarios considered in this study

Scenario	Data source (*from*)	Communication technology	Device at SS	Communication technology	AMI-HE (*To*)
#1	SM	PLC	DC	wireless	MDMS
#2	SM	PLC	GW	wireless	VDC-MDMS
#3	SM	wireless			VDC-MDMS
#4	SM		*not assigned – communication unavailability*		

SS, secondary substation; SM, smart meter; DC, physical data concentrator; GW, gateway; AMI-HE, advanced metering infrastructure head end; VDC, virtual data concentrator; MDMS, meter data management system

link nodes as it is shown in Fig. 2. The third types of nodes that characterise the topology of the network are the so-called feeder nodes. These nodes are located at the secondary substation and branch outwards towards the HH-nodes. The feeder nodes allow dividing the secondary substation into several feeders and they are used to set the end of the power line path from the HH-nodes to the secondary substation.

2.3.2 PLC and wireless clustering: To indicate suitable groups of meters that share similar communication connection characteristics, the surrounding environment of the meters has to be considered. Then, depending on the transmission media (guided/unguided), the environment will be different. Two different methods for smart meter clustering are proposed, one for PLC and another one for wireless communication-based meters.

PLC is a communication technology that uses the electric power distribution wiring to connect the meters to the data aggregators, with no additional infrastructure required. However, power line cables are a harsh data transmission medium that due to its nature show a fluctuation of the channel characteristics, e.g. impedance, background and impulsive noise, signal attenuation and signal fading effects due to the multiplicative noise [19]. As presented in [20, 21], due to the structure of the electric power distribution networks, the fundamental elements influencing the reliability of PLC-based smart grid applications are the signal attenuation caused by the cable losses, which increases with the frequency and the length of the cables, and the multipath propagation caused by the branched structure of the network and unmatched line ends. Additionally, as meters share the physical media with other meters that belong to the same feeder and in situations of high traffic on the network the channel could be congested. To accommodate the channel characteristics, the distance from the meter to the secondary substation and the density of proximate meters are investigated. One approach to estimate the distance and density of the meters in a network is to cluster the data points representing the meter positions. Then, by using the clusters the distances and the meter densities can be approximated.

A first step in PLC clustering is to classify the meters by the feeders that spread out the secondary substation and each feeder is represented by a node located at the secondary substation. If a path exists between a meter and one of these feeder nodes (several in case of meshed grids), the meter is assigned to the closest feeder node. The shortest path is calculated using Dijkstra's algorithm [22]. Then, the meters sharing the same feeder node are clustered into groups by proximity. *K*-means clustering method is chosen for its simplicity and general usage. The *K* parameter represents the number of clusters that the population is divided into, and it is selected ex-ante and validated by the silhouette method [23]. It requires *K* to be smaller or equal to the number of smart meters and it cannot be greater than the number of maximum adjacent clusters simulated. In Fig. 3*a*, the *K*-means meter clustering is shown, which is applied to PLC-based communication.

When communicating over wireless media such as GSM/GPRS, it is not necessary to consider the electrical cable lines. Here though, the meters are linked point-to-point to the closest base transceiver station (BTS), which in turn forwards the data towards the AMI-HE system. Therefore, wireless *K*-means clustering approach can be applied to group the meters regardless to which feeder they belong and it is not upper-bounded by the number of maximum simulated adjacent clusters as the PLC clustering is. The SMCT applies (1) to determine the *K* parameter for wireless *K*-means clustering. This equation is proposed in [24] and it is obtained by heuristic techniques. The parameter *n* represents the number of data points to be clustered, in this case the number of active HH-nodes

$$K \cong \sqrt{\frac{n}{2}} \tag{1}$$

With *K*-means a centroid is created from the set of meter data points, which is used to calculate the average point-to-point distance from the cluster to the BTS. This distance, together with the density of the clustered meters and the number of adjacent clusters (i.e. the number of PLC clusters sharing the same feeder), is used to obtain the PLR from the simulation repository. In Fig. 3*b*, the *K*-means meter clustering is shown, which is applied to wireless-based communication.

2.4 Simulation repository

The meter clustering provides an advantage by simplifying a complex topology into cluster entities characterised by three parameters: (i)

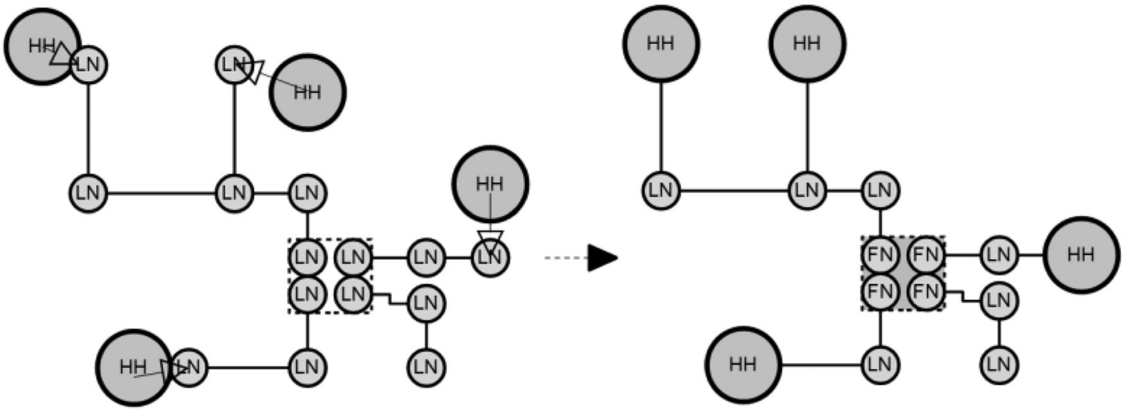

Fig. 2 *HH-nodes assigned to closest link nodes (LL)*

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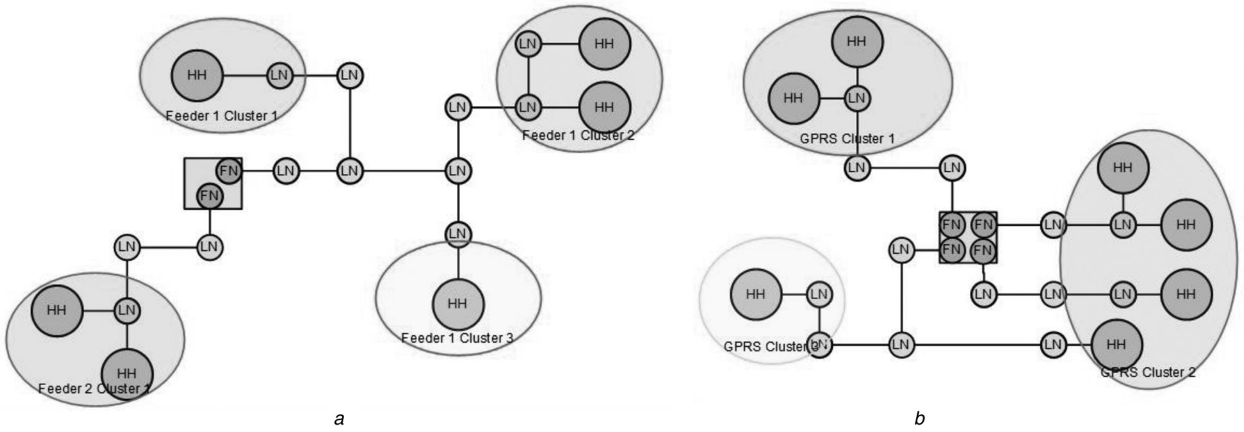

Fig. 3 *K-means meter clustering*

a Example of a network with two feeders where the HH-nodes containing the meters are clustered for PLC-based communication. One feeder contains three *K*-means clusters and the other feeder contains a single cluster
b Example of a network with four feeders where the HH-nodes containing the meters are clustered by *K*-means technique for wireless-based communication. This example shows how the meters grouped in cluster 2 belong to three different feeders

density (D): the amount of HH-nodes per cluster; (ii) distance (L): the distance to the secondary substation and the BTS for the PLC and wireless cases, respectively; and (iii) number of adjacent clusters (Q).

These three parameters are checked against a simulation repository matrix that assigns a corresponding PLR to each cluster. To construct such simulation repository, a set of simulations is performed as described in the following two sections.

2.4.1 Packet loss ratio estimation – PLC: The PLC simulations are carried out using NS-3 discrete event network simulator and the PLC-specific properties are specified by an external module from [25]. The communication channel follows the PRIME standard [26], which uses the upper CENELEC A frequency band ranging from 42 to 95 kHz. A pre-defined worst-case background noise level of $1e^{-12}$ dBm is applied, which consists of the aggregation of all noise sources. The LV grid is formed by short distances, where the simulated lengths range from 1 to 250 m. These cables are modelled considering the NAYY150SE cable characteristics and the signal reflections are prevented by termination impedances at the end of the cable lines. The meters are configured to form a multi-hop network that repeat the signal towards the secondary substation.

Carrier sense multiple access with collision avoidance is implemented as the channel access method and automatic repeat request as the error-control method for data transmission. To enable the data transmissions, IPv4 is installed on all smart meter nodes and a traffic-generator application is implemented to generate user datagram protocol (UDP) packets with a size of 341 bytes and data rate of 21.4 kbps [27], for a cycle of 200 s. To analyse the packets sent and received, a flow monitor module is implemented. This module monitors and registers the packet-related events occurring at each node. Specifically, it registers the transmitted packets, received packets, packet delay and packet loss (drop) ratio.

To simulate an arbitrary power line network, the smart meter clusters are characterised by D, L and Q parameters as shown in Fig. 4. In this example, there is a single feeder connected to the DC and it is split into two branches, each of them representing one cluster ($Q = 2$) that contains three HH-nodes ($D = 3$). In this case, the L parameter is set to 25 m.

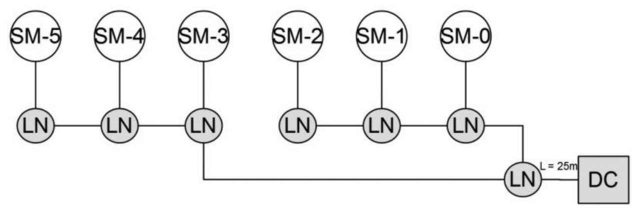

Fig. 4 *Simulation placement of a [D, L, Q] = [3, 25, 2] topology*

2.4.2 Packet loss ratio estimation – wireless: Although the smart meters are stationary, the GSM/GPRS network shares its buffer with mobile users that travel between cellular networks. The number of mobile users is time and geographic location dependent and it is larger in urban areas than in rural areas. Typically, for time slot allocation GSM (e.g. calls) is prioritised over GPRS, although this can vary from one service provider to another. Another issue to be addressed is whether the clustered groups of meters reside within the same cell or on the contrary they are scattered across multiple cells. Even within the same cell, signals may be picked up by other BTS due to signal strength or low availability. Additionally, depending on the service provider, the queuing process may follow different schemes such as various versions of first in first out (FIFO), first come first served, earliest deadline first and shortest job first.

Different simulations are performed by D'Arienzo *et al.* [28] considering different queuing schemes, arrival rates and ratios between GSM and GPRS traffic. The results from these simulations are used in the wireless packet loss simulation repository. A FIFO queue scheme and a Poisson process are considered. The λ_{arrival} parameter is used to represent the arrival rate of GSM/GPRS traffic and it is distributed as follows: 20% for GPRS and 80% for GSM.

Equation (2) shows the PLR for GPRS service based on the λ_{arrival} parameter

$$\begin{cases} \max\left(\text{PLR}_{\text{GPRS}}\left(\lambda_{\text{arrival}}\right)\right) \simeq 0.77\% \\ \min\left(\text{PLR}_{\text{GPRS}}\left(\lambda_{\text{arrival}}\right)\right) \simeq 0.00\% \end{cases} \rightarrow \qquad (2)$$
$$\text{PLR}_{\text{GPRS}} \simeq 0.385 \mp 0.385$$

2.4.3 Packet loss ratio estimation – repository matrix: The simulation repository matrix provides PLR estimations for the clusters using both PLC and wireless technologies.

Fig. 5 shows the simulation repository results for both PLC and wireless technology. For the PLC cases, the D, L and Q parameters are represented and three simulation instances are provided, each of which considers different Q values: 1, 2 and 3. A front can be observed in all the PLC-related simulation results, which is shifted as the Q value is modified. This front roughly determines when the PLR moves from ~80 to 100%

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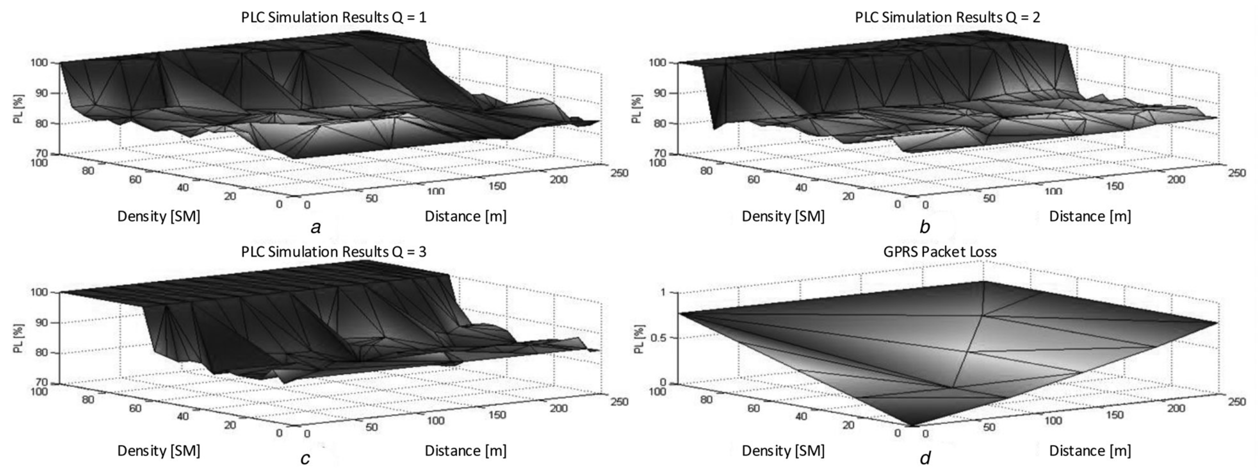

Fig. 5 *PLR simulation repository results for PLC*

a Q = 1
b Q = 2
c Q = 3
d Wireless GSM/GPRS

based on the *D* and *L* parameters. As expected, the more adjacent clusters a particular cluster has, the more sensitive the packet loss will be to *D* and *L* parameters. The type of the cable can affect the PLR estimation by means of signal attenuation caused by the cable losses due to material resistivity (Ω m). Therefore, the study could be extended by adding another dimension to the repository matrix including different instances corresponding to different type of typical cable characteristics (e.g. underground cables NAYY, overhead cables AOHL).

As the wireless technology-related simulation plot shows, the PLR is correlated with both the distance and the density parameters. As expected, the PLR hits the maximum values when both distances and densities are highest. However, the PLR s are relatively very low compared with the ones obtained from applying PLC technology, roughly in the order of 1/160 to 7/1000. The low PLR is held by the service level agreement between the DSO and the wireless communication service provider to keep the QoS metrics at high levels.

2.5 Assignment problem formulation

2.5.1 Operational expenditures (OPEX) and capital expenditures (CAPEX) definition: The cost of assigning smart meters to DC or VDC differs depending on the CAPEX, OPEX [29] and specific communication scenario setup (see Table 1). CAPEX characterises the expenditures derived from procuring fixed assets or adding costs to existing fixed assets. This category includes costs such as deployment of DCs and smart meters, infrastructure upgrades and hardware upgrades. Similarly, one could also use the term transitional CAPEX, which represents the cost difference between the old system and the new system. For a DSO that owns the power lines, assuming that the communication network has been installed in business as usual situation, for instance for tele control purposes, the transitional CAPEX related to PLC cabling purchases can be disregarded. OPEX denotes the ongoing expenditures to uphold the network and its communication system (e.g. system maintenance, tariff and licence fees, operation costs etc.).

2.5.2 Mathematical problem formulation: The general task of assigning clusters of smart meters to the head end in the AMI network can be generally described as an assignment problem [30]. In general terms, an assignment problem is the description of a problem which task is to find a maximum (or minimum) weight matching in a bipartite graph. A weighted bipartite graph is a graph in which each edge has an assigned value (weight). For the case under study each edge represents the combinatorial cost.

Fig. 6 shows the network model of the combinatorial assignment problem where the clusters of meters are connected to the four scenarios (i.e. DC, GW, wireless and NA).

In an assignment problem, the objective is to assign *n* agents (in this case the clusters of meters) to *m* tasks (in this case scenarios) while minimising the total cost of the assignment and requiring that each task is assigned to exactly one agent and exactly one agent is assigned to each task, as in (3)–(5) and assuming that $n = m$. Where c_{ij} is the cost of assigning agent *i* to task *j*

$$\min F(x_{ij}) = \sum_{j \in \boldsymbol{J}} \sum_{i \in \boldsymbol{I}} c_{ij} x_{ij} \tag{3}$$

Subject to

$$\sum_{j \in \boldsymbol{J}} x_{ij} = 1, \quad \forall i \in \boldsymbol{I} = [1, \ldots, n] \tag{4}$$

$$\sum_{i \in \boldsymbol{I}} x_{ij} = 1, \quad \forall j \in \boldsymbol{J} = [1, \ldots, m] \tag{5}$$

Instead, the current meter assignment problem studied in this work is casted as a linear semi-assignment problem [31], which is a generalisation of the assignment problem. This problem however consists of assigning *m* tasks to *n* agents assuming that $m < n$, so that some tasks are assigned to more than one agent and some tasks are not assigned at all. This is specified by replacing (5) with (7), which limits the number of agents a task can be assigned to, and by adding the constraints (8)–(10). Constraint (8) sets the summation of d_j to *n*, where d_j is the number of agents assigned to task *j*. Constraints (9) and (10) specify how the cost c_{ij} is calculated based on S_{ij} parameter and CAPEX and OPEX values. S_{ij} parameter is used as QoS signal that enables/disables an assignation based on the PLR threshold (T_j) set for scenario #*j*. The parameter R_{ij} represents the PLR of cluster *i* assigned to scenario #*j*. Therefore, a scenario will be enabled ($S_{ij} = 0$) if the PLR is smaller than the threshold and disabled otherwise ($S_{ij} = \infty$).

Finally, (11) shows the binary decision variable x_{ij} that takes a unitary value when an agent *i* (i.e. a cluster of meters) is allocated to task *j* (i.e. DC, GW, wireless or not assigned cluster).

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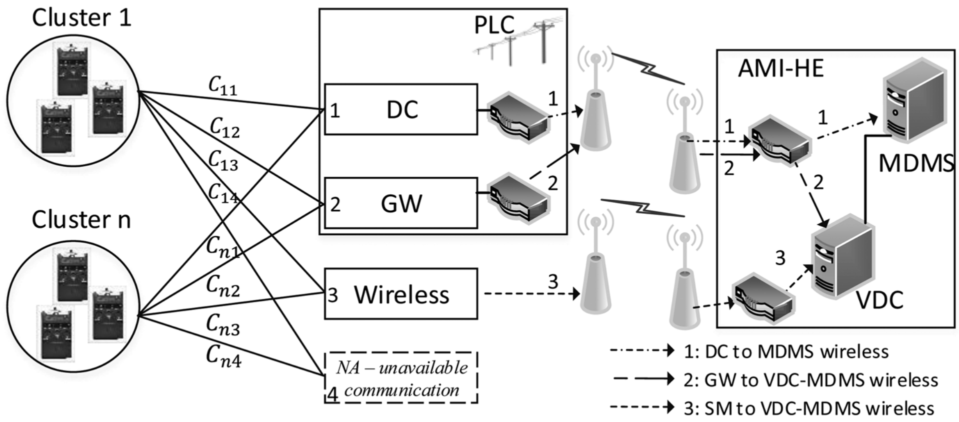


Fig. 6 *Combinatorial problem, where n agents to the left are assigned to m = 4 tasks (scenarios) to the centre*

There are four communication scenarios (see Table 1), therefore $m = 4$, and they are defined in the vector $\boldsymbol{J}$ as in (6)

$$\boldsymbol{J} = [\text{scenario}_1,\ \text{scenario}_2,\ \text{scenario}_3,\ \text{scenario}_4] \tag{6}$$

$$\sum_{i \in I} x_{ij} = d_j, \quad \forall j \in \boldsymbol{J} \tag{7}$$

$$\sum_j d_j = n \tag{8}$$

$$c_{ij} = \text{CAPEX}_{ij} + \text{OPEX}_{ij} + S_{ij} \tag{9}$$

$$S_{ij} = \begin{cases} 0, & \text{if } R_{ij} < T_j \\ \infty, & \text{else} \end{cases} \tag{10}$$

$$x_{ij} = \begin{cases} 1, & \text{if cluster } i \text{ is assigned to scenario } j \\ 0, & \text{else} \end{cases}, \quad \forall (i, j) \in I, J \tag{11}$$

The threshold of maximum agents assigned to each scenario is defined by the following equation

$$\boldsymbol{N} = [\boldsymbol{N}_{\text{DC}}, \boldsymbol{N}_{\text{GW}}, \boldsymbol{N}_{\text{GPRS}}, n] \tag{12}$$

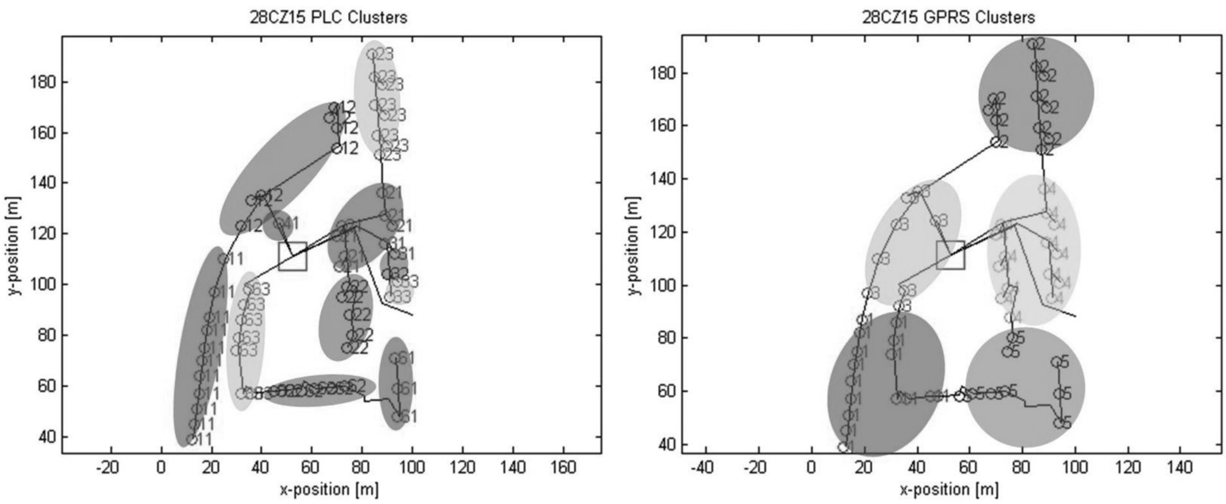
The constraints for the scenarios are specified in the following equation

$$d_j \le N_j, \quad \forall j \in \boldsymbol{J} \tag{13}$$

2.6 On optimality and complexity

The linear semi-assignment problem is a special case of the transportation problem, which is a special case of the minimum-cost flow problem [32] and consequently, a special case of linear optimisation.

Often, the Hungarian method is used for solving combinatorial optimisation problems in polynomial time [33], but in this case it cannot be applied because there is an additional constraint that restricts that only one of the tasks can be used per network. However, since more than one agent per task is allowed, calculating the minimum cost becomes as simple as selecting the lowest cost option for each smart meter, as $F(x_{ij})$ would be minimised. This simplifies the practical method of finding the minimum cost of assigning all smart meters to the scenarios by summing up the costs of having all smart meters assigned to the tasks and by selecting the lowest cost option. Furthermore, due to scenario #1 and scenario #2 being mutually exclusive (i.e. either DC or GW), only one of the three scenarios (#1–#3) will be assigned to all able



a   *b*

Fig. 7 *28CZ15 LV network from PRICE project is represented and clustered. The number at each node indicates to which cluster each node belongs*

a Generated 11 clusters for PLC
b Generated five clusters for wireless

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Table 2 Packet loss threshold (T_i) and SM threshold (N_j) variation for the test cases and the OPEX and CAPEX device costs

Test cases		Packet loss threshold T_i, %	SM threshold N_j	Smart meter CAPEX, €/SM	Smart meter OPEX, €/year/SM	Comm. CAPEX, €/SM	Comm. OPEX, €/year/SM	DC/GW CAPEX, €	DC/GW OPEX, €/year	VDC CAPEX, €/network	VDC OPEX, €/year/network
#1	DC	5	∞	SM_C	SM_O	$Comm_{CDC}$	$Comm_{CDC}$	DC/GW_C	DC/GW_O	n/a	n/a
	GW	5	50	SM_C	SM_O	$Comm_{CGW}$	$Comm_{OGW}$	DC/GW_C	DC/GW_O	n/a	n/a
	VDC	5	∞	SM_C	SM_O	$Comm_{CVDC}$	$Comm_{OVDC}$	n/a	n/a	VDC_C	VDC_O
#2	DC	90	∞	SM_C	SM_O	$Comm_{CDC}$	$Comm_{ODC}$	DC/GW_C	DC/GW_O	n/a	n/a
	GW	90	200	SM_C	SM_O	$Comm_{CGW}$	$Comm_{OGW}$	DC/GW_C	DC/GW_O	n/a	n/a
	VDC	90	∞	SM_C	SM_O	$Comm_{CVDC}$	$Comm_{OVDC}$	n/a	n/a	VDC_C	VDC_O
#3	DC	90	∞	SM_C	SM_O	$Comm_{CDC}$	$Comm_{ODC}$	DC/GW_C	DC/GW_O	n/a	n/a
	GW	90	50	SM_C	SM_O	$Comm_{CGW}$	$Comm_{OGW}$	DC/GW_C	DC/GW_O	n/a	n/a
	VDC	90	∞	SM_C	SM_O	$Comm_{CVDC}$	$Comm_{OVDC}$	n/a	n/a	VDC_C	VDC_O

agents in the network. Scenario#1 (i.e. DC) is prioritised over scenario #2 (i.e. GW) and therefore a correction rule is applied.

In case the cost function cannot be minimised for all the three scenarios (#1–#3) (i.e. due to the PLR threshold is violated: $R_{ij} > T_j$), then the scenario #4 is assigned. This scenario indicates that the meters in a cluster cannot communicate with the AMI-HE system and are therefore are not assigned to a DC nor to a VDC.

The shortest path problem calculations are obtained by Dijkstra's algorithm, which implementation's time complexity is $O(\log(N) \cdot E)$, where N represents the number of nodes and E the number of edges.

3 Case study

The proposed meter assignment method is applied to a LV network that is based on real utility data provided by the PRICE demonstration project (http://www.priceproject.es), which is a project operated by the Spanish DSOs *Iberdrola Distribución* and *Unión Fenosa Distribución.* The SMCT is applied to the provided LV network and the combinatorial optimisation problem is completed to assign the meters to either DC or VDC. The LV network consists of 63 HH-nodes connected to a secondary substation by means of underground cables. This secondary substation provides electricity services to ∼150 customers, which represents two to five smart meters per HH-node depending on the contracted power.

3.1 Results

First, the SMCT is applied to the provided LV network yielding two results: the network representation of the provided grid and the suitable groups of meters with similar communication connection characteristics (see Figs. 7*a* and *b*). These groups represent the created clusters for PLC and for wireless communication.

Then, the optimisation problem is solved for the obtained clusters. Three test cases are run modifying the packet loss threshold (T_i) and SM threshold (N_j), as specified in Table 2. This table also shows the OPEX and CAPEX unit cost list for the DC, GW, VDC and SM devices, where the estimated lifetime being 15, 15, 8 and 15 years, respectively. The annual OPEX costs are calculated applying a weighted average cost of capital of 5%. This economic information is of key importance in request for tender processes and therefore for confidentiality reasons the economic values have been masked.

Finally, Fig. 8 shows the total cumulative cost of the network over time for the three test cases considering the systems' lifetime. A

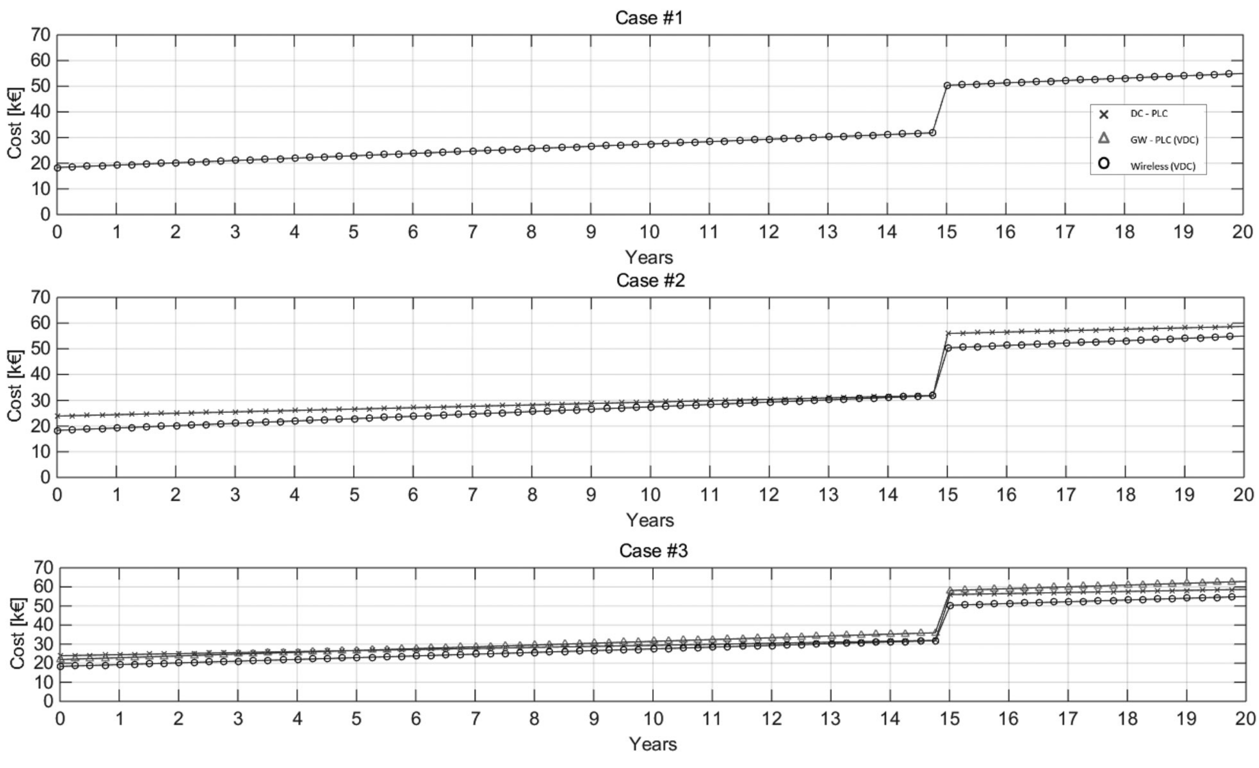

Fig. 8 *Cumulative cost evolution over time for the tested cases: test-case #1, test-case #2 and test-case #3 (see Table 2)*

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period of 20 years is considered for the simulations so that the effect of the systems' lifetime can be observed.

In the test case #1, high PLC QoS requirements are considered, i.e. lower PLR threshold for PLC (5%) than the simulated PLR for the network (Ri1 < T1 and Ri2 < T2). This assumption automatically disables the DC and GW scenarios. Thus, in this test case #1, the wireless scenario is the only solution given the initial conditions. The cost increase step at the 15th year is due to the lifetime of the SM devices. There is similarly a cost increase at the eighth year due to the replacement of the VDC system. However, this cost does not have noticeable impact at the secondary substation because it is divided among all the own secondary substations (38k SS).

In test case #2, only the DC scenario and the wireless scenario are present. This is due to the gateway threshold N2 is set larger than the number of smart meters assigned to the network, hence disabling the GW scenario. The cost of DC over time comes close to the cost of the wireless scenario when reaching the end-of-life for DC and SM (15 years). This situation can be explained due to lower CAPEX values for wireless but higher OPEX values as opposed to DC (14). However, since both DC and wireless have similar lifetime and the costs due to reinstallations are applied at the same time, the wireless option remains as the least cost solution

$$\begin{aligned} \mathrm{SM}_C + \mathrm{Comm}_{\mathrm{CVDC}} + \frac{\mathrm{VDC}_C}{\mathrm{network}} &< \mathrm{SM}_C + \mathrm{Comm}_{\mathrm{CDC}} + \mathrm{DC/GW}_C \\ \mathrm{SM}_O + \mathrm{Comm}_{\mathrm{OVDC}} + \frac{\mathrm{VDC}_O}{\mathrm{network}} &> \mathrm{SM}_O + \mathrm{Comm}_{\mathrm{ODC}} + \mathrm{DC/GW}_O \end{aligned} \tag{14}$$

In the test case #3, the GW threshold N2 is set less than the number of smart meters of the network, enabling the GW scenario to take place. In this test case, the wireless scenario remains being the least costly solution over time, followed by the GW scenario until the fifth year, when DC becomes less costly than GW but still more costly than the wireless solution. At the 15th year, the DC, GW and SM systems are reinstalled and the wireless options remain as the least cost solution.

4 Conclusions

In this paper, a method is presented to determine the optimal communication architecture of AMI infrastructures. The communication technology (i.e. GSM/GPRS and PLC) represents the cost driver that together with the packet loss QoS indicator determine the optimal choice of communication. The method is applied to a case study that is based on real grid data. This case study shows the assignment's cost evolution over time, where the influence of the systems' lifetime is present. Three different tests are considered in this case study, where the PLR threshold indicator varies to allow the comparison of the communication technologies over time. For the given configuration parameters, which are obtained from a real case, the cost evolution over time shows that the VDC with wireless communication solution (e.g. GSM/GPRS) is the lowest monetary cost option that performs best in both the short term and the long term, while satisfying the communication availability requirements. The current simulations show that the OPEX, the CAPEX and the lifetime of the devices determine the cost driver of the optimal solution. These tests show that the method is consistent with planning foresight and can be useful to assist in the AMI communication architecture designing process.

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Paper III

Coordinated Microgrid Investment and Planning Process Considering the System Operator

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Coordinated microgrid investment and planning process considering the system operator

M. Armendáriz [a,*], M. Heleno [b], G. Cardoso [b], S. Mashayekh [b], M. Stadler [b], L. Nordström [a]

[a] *KTH Royal Institute of Technology, Osquldas väg 10, 7 tr, Stockholm, Sweden*
[b] *Ernest Orlando Lawrence Berkeley National Lab, 1 Cyclotron Rd, Berkeley, CA 94720, United States*

HIGHLIGHTS

- A coordinated approach to the ugrid investment and planning problem is proposed.
- Assets can be installed in the grid capable of enhancing the grid controllability.
- The assets improve the voltage profile and the PV hosting potential.
- The grid upgrading could be financed by the microgrid owner.
- The coordinated approach could be considered in the future regulatory framework.

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ABSTRACT

Nowadays, a significant number of distribution systems are facing problems to accommodate more photovoltaic (PV) capacity, namely due to the overvoltages during the daylight periods. This has an impact on the private investments in distributed energy resources (DER), since it occurs exactly when the PV prices are becoming attractive, and the opportunity to an energy transition based on solar technologies is being wasted. In particular, this limitation of the networks is a barrier for larger consumers, such as commercial and public buildings, aiming at investing in PV capacity and start operating as microgrids connected to the MV network. To address this challenge, this paper presents a coordinated approach to the microgrid investment and planning problem, where the system operator and the microgrid owner collaborate to improve the voltage control capabilities of the distribution network, increasing the PV potential. The results prove that this collaboration has the benefit of increasing the value of the microgrid investments while improving the quality of service of the system and it should be considered in the future regulatory framework.

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1. Introduction

The number of photovoltaic (PV) installations have exponentially increased over the last decades and a more accelerated growth, pulled by the emerging economies, is expected by 2020 [1]. This trend is driven by the falling prices of PV modules, e.g. between 2010 and 2020 the reduction of the average price of the PV systems is projected to be 75% [2]. Moreover, policy and regulatory measures have been incentivizing photovoltaic investments, such as Feed-in Tariffs (FiT) [3], which is a well-established policy to accelerate the renewable energy deployment into the grid. Authors in [4] outline the available FiT payment plans *i.e., Percentage FiT, Fixed Price FiT* and *Premium FiT*. Examples of FiT schemes in Europe are shown in [5] and in [6]. Other measures are capital subsidies for equipment purchase [7] as well as financial incentives and remuneration compensation schemes, such as self-consumption [8], net-metering [9] and net-billing [10].

In addition, in order to maximize the on-site DER penetration it is a common practice to apply Demand Response (DR) procedures to decrease the load in peak hour conditions, demand curtailment and rescheduling in response to real-time market prices. A survey of DR potentials and benefits in smart grids is shown in [11] and in [12], where real industrial case studies and research projects are presented. In [13] a review is conducted focusing on real time market architectures and incentive policies for integrating DER (e.g., PV and wind energy) and DR in electricity markets of the North America, Australia and Europe. Authors claim that in the future such market architectures that integrate DER and DR will facilitate the

* Corresponding author.
E-mail address: mikel@kth.se (M. Armendáriz).

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asset utilization and thus they will contribute to maintain the security and the reliability of power systems.

This massive growth of DER installations, in particular PV, has brought new challenges to the operation of distribution systems. This is noticeable especially in Medium Voltage (MV) and Low Voltage (LV) networks, which are more vulnerable to the variations of the distributed generation. Several examples of the consequences brought by the large PV penetration in the distribution systems can be found in the literature [14–17]: voltage variations and unbalance, power congestion at the substation feeders, reverse power flows that can trip the protection relays affecting the grid reliability and islanding protection, etc.

A traditional solution to deal with these challenges is the active curtailment of the PV generation whenever it causes problems to the grid operation [18]. However, this procedure has been discouraged under the recent regulatory frameworks with the argument that curtailment is a threat to the investment in renewables and to the accomplishment of emission targets [19]. Thus, the alternative solutions to PV curtailment are either regulatory or technical. On the regulatory side, self-consumption legislation has been approved in a significant number of countries [20]. Self-consumption policies aim at redesigning the PV remuneration tariffs to incentivize an adequate sizing of the PV installations and to promote the investment in behind-the-meter storage technologies [6], reducing the PV injection into the grid. On the technical side, several solutions to improve the supervision and control of the distribution grid to avoid the contingencies caused by the excess of PV generation have been proposed. An example of a supervision tool can be found in [21], where a probabilistic load flow method to quantify the over-voltages in a residential distribution network with high penetration of PV is presented. Also, a variety of design and control strategies to achieve operational security of distribution networks under scenarios of large PV penetration: grid-scale battery storage system design method to overcome voltage variations is presented in [22], an optimization method based on VAR compensation assisted with a communication infrastructure is proposed in [23], the coordination between static-VAR compensation and On Load Tap Changer (OLTC) are explored in [24] and the benefits of using Static Synchronous Compensator (STATCOM) for dynamic voltage regulation to avoid PV curtailments in peak situations is shown in [25].

These technical approaches to improve grid controllability proved to be very efficient in increasing the capabilities of distribution systems to host more PV capacity. However, they entail investment and operational costs to the distribution system operators (DSO) and, especially in scenarios of unbundling electricity sectors, DSOs have no interest in making those investments and bearing those costs. In fact, they have no motivation to enable more PV capacity, since their remuneration depends on electricity consumption and the challenges of solar integration are mostly peak power related [19]. Moreover, the installation of photovoltaic units has the practical effect of reducing the net consumption of the prosumers, which decreases the income of the DSOs.

The difficulties of the system to accommodate more solar power persist in most distribution networks, especially those that already have a considerable number of photovoltaic installations connected to the LV network. This is a particular barrier for larger consumers, such as commercial and public buildings, aiming at investing in PV capacity and start operating as microgrids connected to the MV network (e.g., [26,27]). Three main reasons explain the limitations imposed by the distribution grids to the microgrids investment and planning process: (1) microgrids require a significant amount of PV to justify the investments and, since all the capacity is concentrated in the same node, it increases the risk for the system; (2) self-consumption policies are not an effective solution for typical commercial and public buildings microgrids, due to the severe variability of the load (e.g., consumption decreases dramatically during the weekends in office buildings or during the entire summer in schools), which requires unbearable investments in storage to avoid PV feed-in for several days in a row; (3) as discussed further on this paper, microgrids investment and planning is a complex process encompassing multiple energy vectors and technologies, which means that a constraint imposed to a technology (in this case to the PV) can dramatically change the energy mix, increasing the overall investment and operation costs.

Summarily, microgrid owners are interested in making significant investments in PV to decrease their energy costs, but this large amount of PV cannot be accommodated by the distribution system, unless new investments are made by DSOs, which have no economic inventive to make them. Thus, this paper aims to respond to this impasse, by presenting an investment approach to the microgrids investment and planning process, where DSO and microgrid owners collaborate to improve the voltage control capabilities of the grid and increase the PV potential. An example of PV investments in a school, operated as a microgrid and connected to the MV network, is shown to illustrate the approach.

The contributions of this paper are the following: first, we propose a concerted approach, where the system operator and the microgrid owner cooperate in the investment process to increase the amount of PV capacity installed by the microgrid, without causing voltage problems to the distribution network; second, we demonstrate the advantages of involving the system operator in the microgrid investment and planning process in comparison with the standard isolated investment approach; third, we test and compare three voltage control strategies that increase the PV potential of the distribution network.

This paper is divided as follows: Section 2 presents the conceptual approach towards a collaboration between the system operator and the microgrid owner in the investment and planning process and it discusses the main advantages and limitations; Section 3 proposes technical solutions to enhance grid controllability so that the optimal solutions from the investment and planning process can be applied; Section 4 presents a case study involving a realistic distribution network with a microgrid investment and finally Section 5 presents the main conclusions of the paper.

2. Microgrid investment and planning: a coordinate approach

2.1. Microgrid investment and planning problem

Microgrid investment and planning is a complex problem that considers different energy generation and storage technologies and multiple energy vectors to supply energy loads, typically while trying to minimize both capital and operational costs. Several tools can be found in literature to address this problem, such as REopt [28], RETScreen [29], SAM [30], HOMER [31] and DER-CAM (Distributed Energy Resources Customer Adoption Model) [32]. A comprehensive comparative study of tools for distributed generation projects is conducted in [33], where authors categorize the tools based on the type of use and capabilities, the addressed sector and the type of analysis (e.g., economic, energy-related or environmental analysis). These tools vary in data granularity (both in space and time), detail (linear vs non-linear), and solution method (optimization vs simulation). A discussion on the strengths and weaknesses found in each model type can be found in [34]. This work is supported by the use of DER-CAM, which addresses the electricity sector and fits the purpose of the study because it is valid to conduct economic and energetic analysis. The generic formulation of DER-CAM is described in (1)–(4).

$$min.C = \sum_t InvC_t \cdot Ann_t + \sum_h \left(\sum_t UtilC_h + FOM_{t,h} + LMC_h - SR_h \right) \quad (1)$$

s.t.

$$GS_{t,h} + U_h - S_h = L_h + Sc_{t,h} + LM_h \quad (2)$$

$$\underline{GS_{t,h}} \leqslant GS_{t,h} \leqslant \overline{GS_{t,h}} \quad (3)$$

$$F_h \leqslant \overline{F_h} \quad (4)$$

The objective function defined by C, considers DER investment costs given by $InvC_t \cdot Ann_t$, where Ann_t is an annuity rate to account for annual ownership costs and allow comparing t technologies with different lifetimes. Additionally, different operational costs are considered in the objective function, such as utility costs, $UtilC_h$, fuel and maintenance expenses associated with different DER, $FOM_{t,h}$, as well as costs related to load management decisions such as curtailments and DR events, LMC_h, and potential revenue from power exports, SR_h.

The key constraints are hourly (h) energy balances (2), generically stating that utility purchases (U_h), the dispatch of local generation and storage units ($GS_{t,h}$), and power exports (S_h), must balance energy loads (L_h), charging of storage units ($Sc_{t,h}$), and load management events (LM_h). Other key constrains include the operational boundaries of DER, generically represented in equation (3), or the $\overline{F_h}$ feed-in limit (4), which defines the maximum reverse electric power flow from the microgrid to the main distribution network. A detailed mathematical formulation of DER-CAM is presented in [35].

2.2. A coordinated approach for the microgrid investment and planning problem

Microgrids investment and planning optimization tools aim at supporting the investment decisions to be made exclusively by the microgrid owner. The solution that results from this optimization problem is a combination of technology investments and hourly dispatches that minimize the total costs of the microgrid owner. In non-isolated microgrids, the dispatch leads an hourly energy flow between the microgrid and the distribution network at the Point of Common Coupling (PCC). If significant investments in local generation are made by the microgrid owner, this flow can change the direction in some periods, becoming positive when the microgrid has a surplus of generation and power is fed into the grid. Therefore, in larger microgrid infrastructures where a more dramatic fluctuation is expected at the PCC power profile, a technical steady-state validation of the investments should be performed by the DSO, in order to ensure that the network can host the PCC profile without violating the normal operation of the distribution system. If the PCC profile generated by the optimal dispatch entails any risk to the distribution network operation, the microgrid investment solution is not feasible, since the dispatch and the investment problem cannot be separated. Therefore, the microgrid planning problem has to be solved again, narrowing the feed-in limit constraint (4) that limits the power at PCC. This process is repeated until a feasible PCC power profile is found, as shown in Fig. 1a.

Obviously, after some iterations of this process, the technology mix found is a sub-optimal solution. In fact, the successive reductions of the PCC limits lead to higher costs and/or lower remuneration from the PV feed-in in comparison with the original infeasible solution. Also, it is important to stress that this loss of value is more severe when the distribution network already has a considerable number of photovoltaic installations and the voltages are near the upper limits, which reduces the new PV capacity to be installed by the microgrid.

Part of this limitation imposed by the distribution system to the microgrid planning problem can be solved with some investments on the network side, namely equipment that enhances the controllability and correct voltage violations when the PV injection is higher. However, from a regulatory perspective, this requires transforming the DSO in a participant agent in the microgrid investment and planning problem. Instead of simply accepting or rejecting the PCC power profile, the system operator may also evaluate some investments in new assets to enhance the controllability of the network, decreasing the constraints of the microgrid planning problem. These new assets will leverage the PV investments and increase the microgrid economic gains.

Thus, the rationale behind the approach presented in this paper, where a coordination of the investments between DSO and microgrid owner, is based on the assumption that the economic value of removing part of the grid constraints to the microgrid planning problem is higher that the costs of the investments in these new assets. Therefore, the Capital Expenditures (CAPEX) and Operational Expenditures (OPEX) associated with these new assets can be totally or partially allocated to the microgrid owner, e.g. by reducing the feed-in prices or by including an annual fee that covers the lifecycle cost of the investments, as shown in Fig. 1b. This cost is defined in (5).

$$Cost_{Ann.\ DSO\ investment} = Cost_{Annual\ ctrl.\ OPEX} + Cost_{Annualized\ ctrl.\ CAPEX} \quad (5)$$

Although this approach is valid for any kind of DSO investments that increase the capabilities of hosting more PV, in this paper we are exploring the investment and operation costs of OLTC both in MV/LV and MV/LV transformers, using the optimal strategies presented in Section 3. Hence, CAPEX captures the expenses required

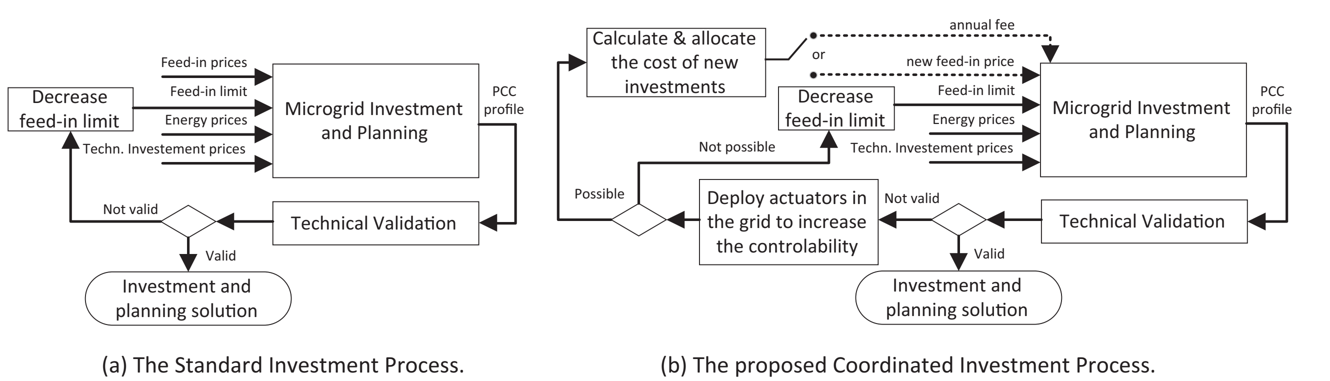

Fig. 1. (a) The standard investment process. (b) The proposed coordinated investment process.

for acquiring or upgrading the OLTC actuators to perform voltage control and the OPEX captures the running costs such as maintenance and OLTC operation. In this paper we assign the OPEX to be dependent of the tap change operations where each tap change corresponds to 4.81 cents $/tap-change [36].

3. Proposed technical solutions to enhance grid controllability

Under the coordinated approach presented above, the DSO should evaluate potential investments in new assets that can increase the PV hosting capacity and, consequently, the remuneration of the microgrid. In this paper, investments in OLTC assets are considered to enhance the controllability of the distribution network. Three voltage control strategies, encompassing the investment and operation of OLTC equipment by the DSO, are presented. In addition, a passive strategy based on the PV capacity curtailment is also tested for comparison purposes. The voltage control strategies considered in this study follow a hands-off policy that is aligned with the electricity unbundling in EU. Thus, in this study, we assume not to be dependent of 3rd parties to operate the distribution grid as it could be to interact with the end customer to perform inverter control in all its varieties, e.g. PF(P), Q (V). Therefore, only assets own and controllable by the utility are considered, more specifically OLTCs at MV and LV substations.

3.1. Description of the control strategies

The first control strategy corresponds to the business as usual and it is named as *CS-A*. It is the most common situation and it consists of manipulating only the OLTC connected to the power transformer at the MV substation. This strategy assumes no OLTC actuators connected to the transformers at the LV substations that spread out from the MV substation. Therefore, there is only one variable to be manipulated in this control strategy: the tap position at the MV substation. The second control strategy corresponds to the problematic feeder control, named as *CS-B*, which consists of manipulating the OLTC actuator deployed at the LV substations that experience overvoltages. The third strategy corresponds to the compensation strategy, named as *CS-C*, which consists of manipulating two types of actuators: first, the OLTC at the MV substation, as in *CS-A*. Second, the OLTC actuator deployed at the LV substations that do not experience overvoltages and can experience undervoltages as a side effect of manipulating the OLTC at the MV substation.

The control strategies are formulated as a Model Predictive Control (MPC), since it allows controlling both the voltage quality and the OLTC switching operations by employing simple linear models of the electrical grid. For the sake of result comparison, these control strategies are also compared to the PV capacity curtailment.

3.2. MPC architecture

The MPC architecture is shown in Fig 2. The controlled plant corresponds to the MV-LV distribution grid, which is formed by an n number of LV Secondary Substations (SS) that are connected to a primary MV distribution substation (HV/MV) following a radial topology. Similarly, each of the LV secondary substations is spread out on a radial topology providing electricity to a group of households.

The bus voltage reference trajectories are defined by the vector $\vec{r}$ and are set to *1pu*. These reference trajectories can be dynamically imposed by a Supervisory Control and Data Acquisition - Distribution Management System (SCADA-DMS) that operates the M B_u V-LV grid. The measurements correspond to the controlled signals of the physical process and represent the bus

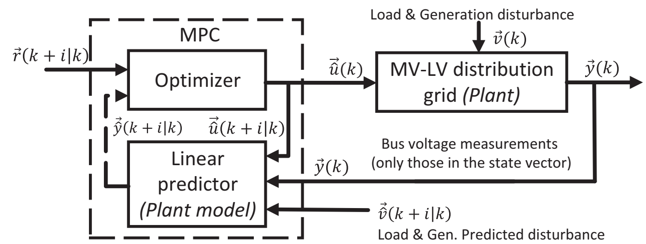

Fig. 2. MPC-based control architecture.

voltages at the LV distribution network; these are defined by the vector $\vec{y}$ and are assumed to be obtained by the Automatic Meter Reading (AMR) infrastructure. The objective of the control architecture is to obtain a sequence for the tap positions (*i.e.,* the manipulated variables) defined by the $\vec{u}$ vector so that the $\vec{y}$ vector follows the $\vec{r}$ vector.

The state-space representation of the plant's model is defined in (6) and the details of how to obtain the A, and B_v matrices can be found in previous works presented in [37] and in [38].

$$\hat{\vec{x}}(k+i+1) = A \cdot \hat{\vec{x}}(k+i) + B_u \cdot \hat{\vec{u}}(k+i) + B_v \cdot \hat{\vec{v}}(k+i) \tag{6a}$$

$$\hat{\vec{y}}(k+i) = \hat{\vec{x}}(k+i) \tag{6b}$$

$$\hat{\vec{x}}(k) = \hat{\vec{x}}(k|k) = \vec{y}(k) \tag{6c}$$

The disturbance applied to the controlled plant is defined by the $\vec{v}$ vector and it represents the active and reactive power increments in the LV grid caused by the load and the PV generation units. The estimated measured disturbance represents the predicted values for $\vec{v}$ and it is defined by the $\hat{\vec{v}}$ vector. These predictions can be obtained from a load and a PV generation forecaster that yields the prediction values for a p-prediction horizon using weather data such as outdoor temperature, solar radiation and wind speed, as presented in [39]. The optimization problem is formulated as a receding horizon-based Mixed Integer Quadratic Programming (MIQP) model [40], where the objective is to minimize the cost function defined by $J(\vec{z}_k)$ over a period of 24 h, as defined in (7). Subject to the constraints defined in (8) and (9), which set the requirements for the voltage level and the OLTC's tap operations. The decision vector $\vec{z}_k$ is defined in (10).

$$\begin{aligned} min J(\vec{z}_k) = & \sum_{j=1}^{n_y}\sum_{i=1}^{p}\{w_{i,j}^{y}[r_j(k+i|k) - \hat{y}_j(k+i|k)]\}^2 \\ & + \sum_{j=1}^{n_u}\sum_{i=0}^{p-1}\{w_{i,j}^{\Delta u}[\hat{u}_j(k+i|k) - \hat{u}_j(k+i-1|k)]\}^2 + \rho_\varepsilon \varepsilon_k^2 \end{aligned} \tag{7}$$

s.t.

$$\underline{y_j}(i) - \varepsilon_k \cdot \underline{V_j^y}(i) \leqslant \hat{y}_j(k+i|k), \ i = 1:p, j = 1:n_y \tag{8a}$$

$$\overline{y_j}(i) + \varepsilon_k \cdot \overline{V_j^y}(i) \geqslant \hat{y}_j(k+i|k), \ i = 1:p, j = 1:n_y \tag{8b}$$

$$\overline{u_j}(i) \leqslant \hat{u}_j(k+i-1|r_j(k+i|k)k) \leqslant \overline{u_j}(i), \ i = 1:p, j = 1:n_u \tag{9a}$$

$$\underline{\Delta u_j}(i) \leqslant \Delta\hat{u}_j(k+i-1|k) \leqslant \overline{\Delta u_j}(i), \ i = 1:p, j = 1:n_u \tag{9b}$$

$$\sum_{i=1}^{p}|\Delta\hat{u}_j(k)| \leqslant \text{MADSON}, \ j = 1:n_u \tag{9c}$$

where the decision vector is:

$$\vec{z}_k = [\hat{u}(k|k)\hat{u}(k+1|k)\cdots\hat{u}(k+p-1|k)\varepsilon_k]^T \quad (10)$$

k is the current interval; p is the prediction horizon; ε_k is the slack variable at control interval k; ρ_ε is the constraint violation penalty weight; n_y is the number of output variables; n_u is the number of manipulated variables; is the reference for j^{th} plant's controlled signal at i^{th} prediction horizon step; $\hat{y}_j(k+i|k)$ is the prediction of j^{th} plant's controlled signal at i^{th} prediction horizon step; $w^y_{i,j}$ is the penalty weight for j^{th} plant's controlled signal at i^{th} prediction horizon step; $w^{\Delta u}_{i,j}$ is the penalty weight for j^{th} manipulated variable increment at i^{th} prediction horizon step; $\underline{y_j}(i)$ *and* $\overline{y_j}(i)$ are the lower and the upper bounds for j^{th} plant's controlled signal at i^{th} prediction horizon step; $\underline{u_j}(i)$ *and* $\overline{u_j}(i)$ are the lower and the upper bounds for jth plant's manipulated variable at ith prediction horizon step; $\underline{\Delta u_j}(i)$ *and* $\overline{\Delta u_j}(i)$ are the lower and the upper bounds for j^{th} plant's manipulated variable increment at i^{th} prediction horizon step; $\underline{V^y_j}(i)$ and $\overline{V^y_j}(i)$ are the lower and the upper bounds for soft constraints tuning factor; MADSON is the Maximum Allowable Daily Switching OperatioNs.

4. The benefits of a coordinated approach: case study

This chapter presents a realistic case study to illustrate the coordinated microgrid investment approach discussed above. The PV investments in a school, with average dimensions in terms of load consumption, operating as a microgrid and connected to the distribution network, are analyzed. Two investment approaches are used in this analysis in addition to the reference case:

- *References case*: The situation before the DER investments in the school.
- *Standard investment approach:* The DER investment in the school using the standard microgrid investment and planning tool, where the role of the DSO consists of accepting or rejecting the profile at PCC.
- *Coordinated investment approach:* The DER investments in the school using the approach proposed in this paper, where the DSO actively participates in the process by evaluating new possibilities of enhancing the distribution grid controllability, allowing more PV capacity in the school.

At the end, the costs associated with each investment approach are quantified in order to evaluate the economic performance of the collaborative investment approach presented in this study. In addition, the technical performance of each investment approach is also assessed.

4.1. Case Setup and Input data

The electric network considered in this case study, shown in Fig. 3, is a typical MV-LV distribution grid composed by two long feeders connected to a HV/MV distribution substation. The node SS1 is a heavily loaded substation consuming 5GWh/year and with a peak power of 1457 kW in winter periods. The nodes SS2 and SS3 are two secondary substations feeding two residential neighborhoods, whose topology is based on the IEEE European LV Test Feeder [41]. The residential area under SS3 is composed by 55 modern buildings equipped with rooftop PV systems, causing reverse power flows at noon, especially in the summer when the reverse power flow peak is 190 kW. In contrast, no significant photovoltaic penetration exists in the old buildings of SS2, where the peak electricity consumption, 180 kW, occurs during the winter. Lastly, a school serving this area is connected to the SS4 secondary substation. Here is where a private microgrid is deployed and the PV investments are made.

4.2. Reference case

In the reference case, the PCC profile at node SS4 corresponds to the school load before the DER investments. The school has a consumption of 600MWh/year with 220 kW of peak happening in winter. A time-of-use (ToU) tariff based on three periods (peak, shoulder and off-peak) is applied to the electricity consumption of the school. Table 1 presents the electricity prices in each period that are based on the PG&E E-19V tariff [42]. These prices lead to a total annual energy costs of 149.1 k$ and this is considered as the reference case for the analysis of this case study.

In the reference case, the PCC profile of the school does not cause any voltage problem to the distribution network. However, due to the significant PV already installed in the residential neighborhood connected to SS3, this LV node is close to reach the upper voltage limit. Fig. 4 shows the 24 h voltage profile during weekdays and weekends in the four seasons of the year. As shown in the figure, the voltage increases during daylight hours, especially in spring where the peak occurs. The voltage in weekends is higher than in weekdays, due to the consumption decrease in the school, located in a close node (SS4).

4.3. Standard investment approach

In the *standard investment approach* we assume that PV generation and storage capacity are added to the school microgrid, located in node SS4, due to the investments done by the microgrid owner. The microgrid design is performed by the DER-CAM optimization model. This solution is obtained by solving a MILP, where the objective is to maximize the economic savings by installing the mix of DER technologies: PV and battery capacity. This DER configuration represents an unrestricted, or ideal, microgrid design, because the resulting feed-in power into the grid is disregarded. The rationale on adding the PV generation and battery installations is that in this new situation part of the generated surplus energy from the PV panels can be stored in the battery and be used later on when the school's consumption demand turns higher that the onsite generated energy production. This way the microgrid can reduce the energy import from the grid. Moreover, a FiT mechanism is assumed, which incentivizes energy exports into the distribution grid depending on the load profile, the generated power profile and the available energy in the battery. In this investment approach, the optimal unrestricted DER capacity values are reduced so that the feed-in power profile at the PCC does not generate overvoltages in the grid and therefore, does not jeopardize the distribution network operations.

The investment cost is defined by (11) and the PV system and battery data regarding variable cost, fixed maintenance and the assumed lifetime of the PV system are shown in Table 2. This information is very relevant because together with the feed-in price, which is assumed uniform in this study (0.1 $/kW h), they determine the viability and the installed PV generation and battery storage capacities.

$$Cost_{Inv.} = Cost_{Fixed} + Cost_{Variable} \quad (11)$$

The considered investment period corresponds to 20 years, the maximum payback period is limited to 10 years and an interest rate of 5% was assumed. The optimal investment solution resulting from these conditions can generate a feed-in peak power of 506kWp and the resulting PCC profile has an impact on the voltage of the critical feeder (i.e., the end node of SS3 as it is the part in the grid where the highest overvoltages are observed). Fig. 5 shows the 24 h voltage

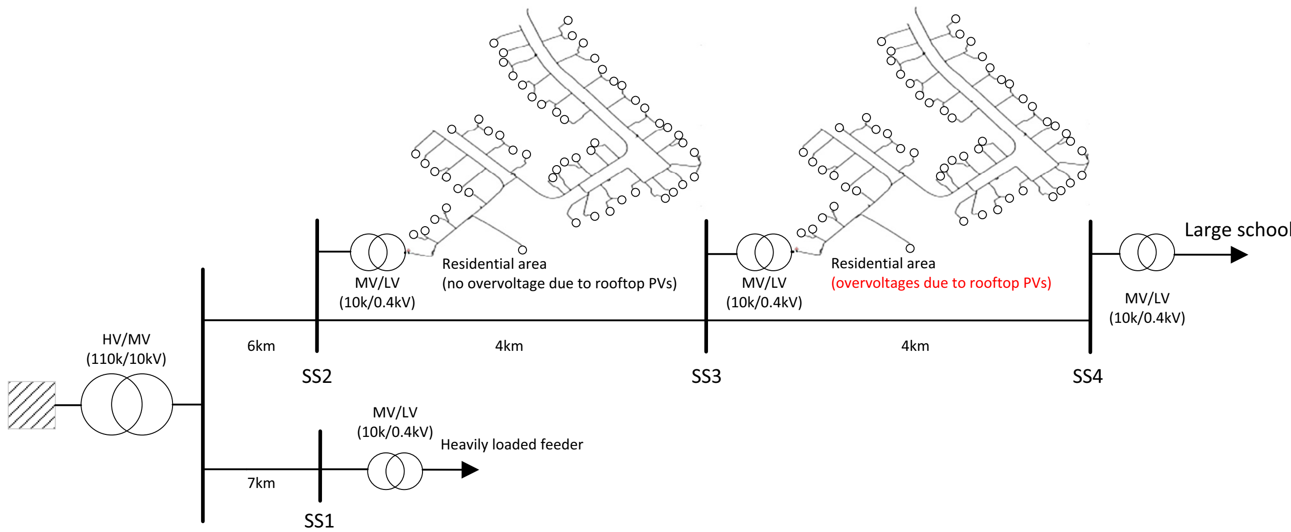

Fig. 3. The single-line diagram of the electric distribution grid case study.

Table 1
Electricity rates [$/kW h].

Peak	Shoulder	Off-peak
0.16	0.10	0.08

Table 2
Photovoltaic and battery data.

Technology	Variable cost ($/kW or $/kWh)	Fixed maintenance ($/kW per month)	Lifetime (years)
PV	2800	0.25	30
Battery	400	0	10

profile at the end of SS3 for different seasons and type of days. It can be seen that overvoltages occur during spring and summer periods, which results in this DER investment solution obtained by the *unrestricted design* not being feasible.

Therefore, under the standard microgrid investment approach, the feed-in power of the school should be successively narrowed until a feasible investment solution is found. The result of this iterative process of constraining the microgrid investment and planning is a significant decrease of the PV capacity of the school and a small increase of the battery size, which allow the feed-in power to reduce from 506 kWp to 101 kWp and keep the system stable. However, this restricted solution has a lower economic value for the school owner: the energy savings decrease and annualized energy cost increase in comparison with the ideal (unrestricted) investment solution. Table 3 summarizes the solutions for the unrestricted and restricted microgrid designs.

4.4. Coordinated investment approach

In the proposed coordinated investment approach besides the DER investments in the school by the microgrid owner, the DSO also evaluates new investments in OLTCs to upgrade the grid controllability. This controllability improvement avoids the overvoltages caused by the unrestricted microgrid design. If these costs are assumed by the microgrid owner, the total coordinated design cost results in (12). Instead, if the costs are covered by the system operator, the total cost for the microgrid owner remains as in the *standard investment approach - unrestricted design.*

$$Cost_{\substack{\text{Coordinated design}\\(\text{Ctrl. cost by }\mu\text{Grid})}} = Cost_{\text{Standard investment-unrest. design}} + Cost_{\text{Ann. ctrl. inv.}} \quad (12)$$

In Table 4 the design costs for the microgrid owner are compared. It can be seen that the design with highest costs corresponds to the standard design, which requires curtailment of installation capacity, followed by the coordinated design with the controllability upgrading costs covered by the microgrid owner. Finally, the lowest costs correspond to the coordinated design with the controllability upgrading costs covered by the DSO. From this table one can see the potential savings that can be obtained if there is collaboration between the system operator and the microgrid owner. Besides,

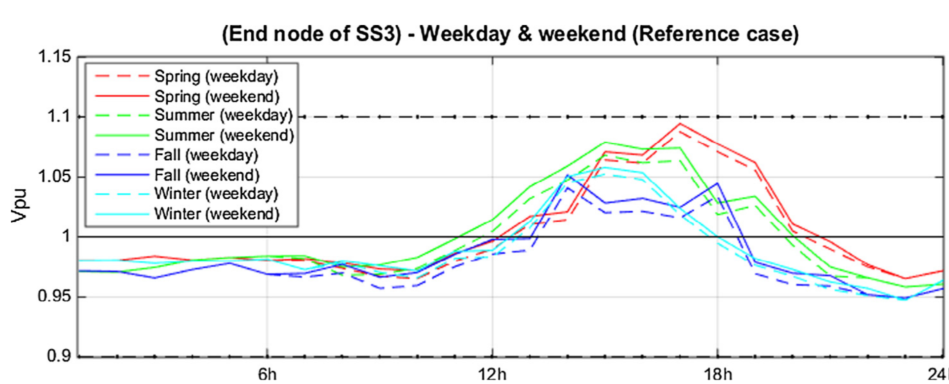

Fig. 4. Voltage profiles at the critical feeder in the reference case. The voltage limits are set to 1.1 pu and 0.9 pu, which correspond to $\boldsymbol{U_n} \pm 10\%$, with $\boldsymbol{U_n} = 230\boldsymbol{V}$.

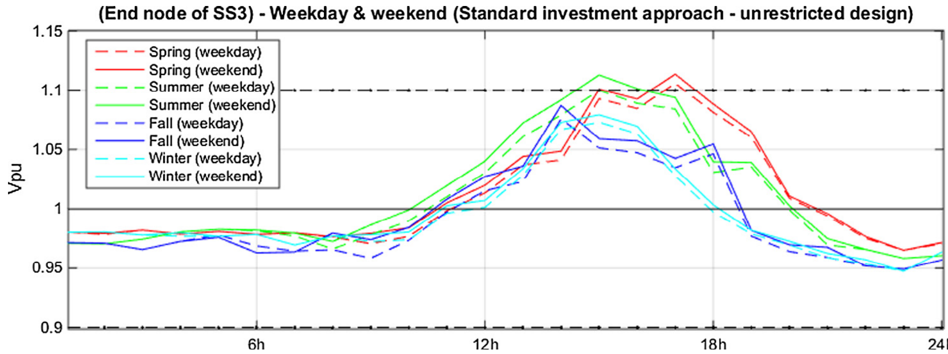

Fig. 5. 24 h voltage profile at the end of SS3 for different seasons and type of days for the *standard investment approach* – unrestricted design.

Table 3
Optimal PV and battery capacity solution corresponding to the standard microgrid designs.

Standard microgrid design type	PV capacity (kW)	Size of PV (m^2)	Battery capacity (kW h)	PV export (kWp)	Energy cost (k$/year)	Energy savings (k$/year)
Unrestricted	610	3993	268	506	92.9	56.2 (37.7%)
Restricted	343	2241	320	101	106.6	42.5 (28.5%)

Table 4
Microgrid investment cost comparison.

Microgrid investment	Energy cost (k$/year)	Controllability cost		Total cost (k$/year)	Energy savings (%)
		CAPEX (k$/20 year)	OPEX (k$/year)		
Reference case	149.10	–	–	149.10	–
Standard investment approach (restricted)	106.60	–	–	106.60	28.50
Coordinated investment approach: controllability cost by microgrid owner					
CS-A	96.00	0.6	0.21	96.81	35.07
CS-B	92.90	0.3	0.07	93.27	37.45
CS-C	92.90	0.9	0.35	94.15	36.86
Coordinated investment approach: controllability cost by DSO					
CS-A	96.00	–	–	96.00	35.60
CS-B	92.90	–	–	92.90	37.70
CS-C	92.90	–	–	92.90	37.70

from the microgrid owner point of view, the deployment and operation of the required controllability technology is economically motivated regardless who covers the expenses. Anyhow, if the DSO covers these costs the energy savings are obviously larger. The reason here is that the feed-in remuneration can cover the controllability costs and that remuneration turns larger with the coordinated design than with the standard design. The *CS-A* control strategy only allows the 70% of the feed-in peak power (354 kWp) obtained by the unrestricted design without forcing overvoltages in the grid. This requires reducing the installed generation and storage capacity to 579 kW and 363 kW h respectively. And consequently, the resulting savings turn smaller than the obtained by applying the *CS-B* or the *CS-C*. Yet, *CS-A* achieves bigger savings than the standard investment approach.

In any case, the microgrid owner would be benefited from the deployment of assets because it would still reach energy savings even though it paid part of the controllability costs. Nevertheless, assuming the facts that additional PV installations are installed on the feeder and that the network is already close to the voltage limits, the controllability costs could be prorated among these installations. The reason is that it is not only the responsibility of the marginal new PV installation to cover all the costs because the other installations will also contribute to the overvoltages.

In order to maximize the energy savings, the microgrid owner would be in favor of the lowest cost control strategy to be deployed and that would be the CS-B. Similarly, that would also be the control strategy that looks best in terms of costs if the DSO covered part of the deployment charges. However, as it will be shown next in Section 4.5, this asset deployment strategy simply fits the purpose of allowing the microgrid to be integrated into the grid but it does not provide voltage profile improvement support.

4.5. Voltage quality improvement of the distribution grid

In this section the performance of the microgrid designs are evaluated in terms of the voltage quality improvement of the distribution grid. This metric represents how well the controllability upgrade contributes to the voltage profile flattening of the rest of the nodes that form the distribution grid. This indicator is defined by (13) and (14) and it indicates the root-mean-square error between each of the measured bus voltages and its reference voltage for a period of 24 h. This calculation is performed for all the control strategies and it is normalized to the $RMSE_{grid}$ obtained when the reference case is applied. Thus, the RMSE% reduction is computed as defined by (15). The results are summarized in Table 5.

$$RMSE_{bus} = \sqrt{\frac{\sum_{k=0}^{23}(1 - voltage(k))^2}{24}} \tag{13}$$

Table 5
Voltage quality vs. controllability cost for each microgrid design.

Microgrid investment	RMSE (%) reduction in 24 h (avg. year)	Location of OLTCs	Controllability cost total (k$/year)
Reference case – no control	0	–	–
Standard investment approach			
Unrestricted design – no control	−12	–	–
Restricted design – Curtailment	0	–	–
Coordinated investment approach			
CS-A	15	HV/MV	0.81
CS-B	−2	SS3	0.37
CS-C	16	HV/MV, SS1	1.25

$$RMSE_{grid} = mean(RMSE_{bus}) \quad (14)$$

$$RMSE\ \%\ reduction = \frac{RMSE_{grid:\ reference\ case} - RMSE_{grid:\ CS-A/B/C}}{RMSE_{grid:\ reference\ case}} \cdot 100 \quad (15)$$

The strategy that achieves the best RMSE% reduction considering the entire network corresponds to the *CS-C*, followed by the *CS-A* and then by the *CS-B*. The reason is that both *CS-C* and *CS-A* use the OLTC at the HV/MV transformer, thus affecting the full network. Besides, *CS-C* reaches better quality results due to the combination of HV/MV and MV/LV OLTC control, the former to remove the overvoltages and to improve the voltage quality, and the latter to compensate the undervoltages forced by the former. The *CS-B* shows small negative RMSE% reduction even though the control is applied and the overvoltages are removed. This is due to the penetration of PV increases the voltage level at adjacent nodes of the network and the *CS-B* only focuses on the problematic feeder disregarding the rest of the network. All in all, it is important to analyze the fact that it is possible to remove the overvoltages only by focusing on the problematic feeder. However, if in addition to removing the overvoltages we also expect to improve the voltage profile of the rest of the network, the studied solutions require adding extra OLTCs with the corresponding costs. Fig. 6 shows that the tested control strategies can remove the overvoltages and especially the *CS-C* and the *CS-B* outperform the rest in terms of voltage profile flattening at the problematic node.

Therefore, if the DSO covered part of the costs it seems a better option to choose the CS-C because it would allow maximizing the microgrid's energy savings in addition to improving the voltage profile and thus preventing future overvoltage problems in other parts of the grid.

5. Conclusion

In this paper we propose a concerted microgrid investment approach where the system operator and microgrid owner cooperate in order to increase the amount of PV capacity installed by microgrid without causing voltage problems to the distribution network. The common regulatory rules only require the DSO to accept or to reject the PV installations. However, the microgrid owner would be in favor of collaborating with the DSO by deploying assets to increase the controllability and to allow larger PV capacity installations, so that the disturbances caused by the photovoltaic injection can be handled. Thus, the energy savings can be increased without violating the normal operation of the distribution system. Therefore, the microgrid owner is incentivized to pay the deployment because it will still achieve energy savings. This collaboration is illustrated by a case study, where the coordinated and the standard microgrid investments are compared. The results show that the coordinated planning process is economic viable for the microgrid owner and that the voltage profile is improved with its corresponding increased hosting capacity for the distribution grid. Therefore, we can conclude that even if all the costs were allocated to the microgrid (worst case scenario); the coordinated process would still be a better solution than the current situation (passive role of DSO) for both actors: microgrid owner and DSO.

We highlight the fact that the activities related to upgrading the grid controllability are performed by the system operator and these could be financed by the microgrid owner or even by prorating the costs among the additional PV installations that are installed on the feeder.

From a regulatory perspective, two approaches can be used to allow this collaboration: either by incrementing the energy tariff considering the annualized lifecycle cost of the investments or by applying a reduction to the PV feed-in price remuneration.

Finally, the controllability assets can be deployed to simply remove the overvoltages only by acting on the problematic feeder that hosts the problems. Or additionally, extra assets can be deployed, so that the voltage quality of the rest of the network can be improved. Hence, according to the obtained results the *CS-C* or compensation strategy seems to be the strategy that fits best the microgrid's and the grid operator's objectives, energy savings and voltage profile improvement in the distribution grid.

Further research work will focus on developing and proposing methods to share the costs among the prosumers responsible for the network violations.

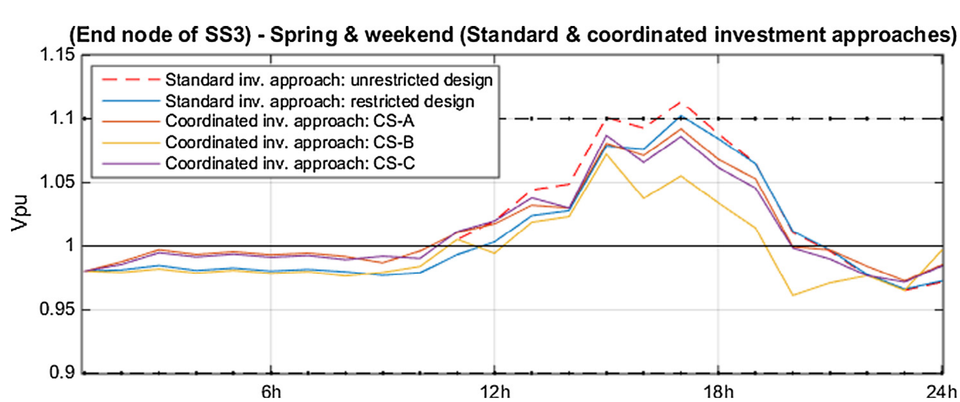

Fig. 6. 24 h voltage profile at the end of SS3 for the *standard* and *coordinated investments approaches.*

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Paper IV

Comparative Study of Optimal Controller Placement Considering Uncertainty in PV Growth and Distribution Grid Expansion

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Comparative study of optimal controller placement considering uncertainty in PV growth and distribution grid expansion

M. Armendáriz[a,*], K. Paridari[a], E. Wallin[b], L. Nordström[a]

[a] KTH Royal Institute of Technology, Osquldas väg 10, 7 tr, Stockholm, Sweden
[b] Vattenfall Research & Development, Evenemangsgatan 13, Solna, Sweden

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ABSTRACT

Distributed generation (DG) and especially grid-connected residential photovoltaic (PV) systems are emerging and high penetration levels of these can have an adverse impact on several low voltage (LV) distribution grids in terms of power quality and reliability. In order to reduce that effect in a cost-effective manner, the traditional distribution grid planning process is being reengineered by incorporating the grid control operations and considering the uncertainties *e.g.*, DG power, demand and urban/rural expansion plans. One of the challenges is to determine if the required technology deployment to operate the grids can provide a better solution in terms of quality and cost than the traditional approach, which is principally based on cable reinforcement and change of transformers. In addition, if controllers were to be deployed, it would be important to determine where they should be placed and at what stage of the expansion planning, especially when the planning is assumed to be non-deterministic.

Therefore, following this situation, in this paper we propose an optimal way to deploy and to operate utility's controllable resources at the distribution grid and additionally we consider the uncertainties related to PV growth and distribution grid expansion. Thus, we include the non-deterministic multistage perspective to the controller placement problem. Furthermore, we perform a techno-economic analysis of the results and we show that an optimal controller placement allows removing the overvoltage problems arising in the LV grid in a more cost-effective way compared to a typical traditional grid reinforcement approach.

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1. Introduction

The number of photovoltaic (PV) installations have exponentially increased over the last decades and an accelerated growth is expected by 2020 [1]. This trend is driven by the falling prices of PV modules, available financial incentives, remuneration compensation schemes and capital subsidies for equipment purchase [2–4].

The advantages of PV and renewable distributed generation (DG) in general is that they can contribute to the power system with a series of benefits *e.g.*, peak shaving, electricity loss reduction along transmission and distribution lines, increased reliability and overall decrease of greenhouse gas emissions. On the contrary, new challenges arise, especially in medium voltage (MV) and low voltage (LV) grids, which are more vulnerable to the unpredictable fluctuations of the distributed generation *e.g.*, PV systems can produce voltage rise, overloading of the components, higher harmonic content, reverse power flows and increase energy losses at LV grids [5,6].

Historically, as a consequence of the DG being insignificant these later phenomena have not been a problem and very low degree of flexibility has been added to the LV distribution lines. Thus, most of MV/LV secondary substations have been at most equipped with off-load tap changers. At this stage, it is mainly pilot demonstration projects which are testing On-Load Tap Changer's (OLTC) capabilities at LV grids (for pilot examples see Refs. [7,8]). Actually, the traditional distribution grid planning process is carried out in a relatively passive way and a reliable supply of electricity is guaranteed by designing and planning a robust grid with minimum level of operations. In addition, this planning process is required to cope with the worst-case set of scenarios (*e.g.*, voltage drops, overloading of components and congestion) even though these generally occur only a few hours a year [9]. And for the cases in the planning horizon when grid reinforcements are needed, the traditional solution involves refurbishing the cable and/or transformers.

* Corresponding author.
E-mail address: mikel@kth.se (M. Armendáriz).

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For this reason, the traditional planning process has the potential of being redefined and carried out in a more efficient way. In fact, the DSOs are nowadays going through an innovative process in which they are studying how to adopt a more active role by incorporating grid operations into the distribution grid planning. As explained in Refs. [10,11], the reason is that if the existing assets and infrastructure are operated much closer to their physical limits than in the past a better balance between Operational Expenditures (OPEX) and Capital Expenditures (CAPEX) can be achieved in the long-term. This can be achieved by including a flexible utilization of Distributed Energy Resources (DER), loads and controllable assets to support grid operations.

The largest part of the related literature focuses primarily on the operational aspects of the Volt-VAR Optimization (VVO) problem and on how to integrate, combine and coordinate the Supervisory Control and Data Acquisition/Distribution Management Systems (SCADA/DMS) with the available set of DSO‘s actuators (*e.g.*, OLTCs and capacitor banks) and the control of DER and electric vehicles [12–14]. Recently, additional publications that take into account the operational aspects in the LV planning process are starting to emerge. Some examples are: Ref. [15], where authors show that OLTC can be used to defer grid investments for situations with long, rural or sub-urban feeders where a scenario of high growth of PV is anticipated. In Ref. [11] authors compare the traditional reinforcement to a more modern one where they consider integrating the future grid operation practices (*e.g.*, distributed energy storage) in the set of feasible planning alternatives. In Ref. [16] the optimal long-term planning of battery location, capacity and power rating is based on the short-term optimal power flow considering the wind power generation uncertainties. And in Ref. [10] authors provide a comprehensive overview of active distribution grid planning where they propose a multi-dimensional framework for optimal active distribution grid planning to integrate the operations into the planning.

Thus, in addition to operating the assets effectively, the decision regarding what type of controllers to use and where to place them in the grid is also a key problem, because it has direct implications on the investment costs. A classic example corresponds to the capacitor and voltage regulator placement problem, which corresponds to a combinatorial optimization problem that due to the large solution space, most of the cases use metaheuristic searching algorithms [17,18]. Most of the works provide solutions to the asset (capacitor and voltage controller) placement problem without considering the grid expansion planning [18–21]. Generally, those that consider the expansion planning have been conducted assuming deterministic expansion models and disregarding the planning uncertainties [22]. However, there are some works such as Refs. [23,24] that consider non-deterministic multistage long-term expansion planning for determining the optimal place to locate the assets *e.g.*, capacitor banks, voltage regulators, DG, etc. In these examples, the optimal location, type, capacity of the investments and the most appropriate time to make such investments is studied. Hence, this paper also studies the operational aspects in addition to the various distribution grid multistage expansion alternatives, considering the uncertainties related to the PV and the demand growth. Thus this paper yields the following contributions:

- First, we formulate and propose an optimal controller placement in MV/LV grids considering the temporal aspects of the distribution grid planning and the uncertainty in PV growth and distribution grid expansion. Thus, we include grid operations into the planning process.
- Second, we perform a comparative study in which we show that an optimal controller placement can defer the CAPEX and provide operational flexibility and efficiency in contrast to the traditional grid reinforcement approach.

The rest of the paper is divided as follows: Section 2 presents the problem description. Section 3 presents the proposed optimal controller placement problem. Section 4 formulates the proposed technical solution to enhance grid controllability. Section 5 presents a case study where we perform a techno-economical comparison of the optimal actuator placement versus the traditional reinforcement and finally, Section 6 presents the main conclusions of the paper and future work.

2. Problem description

Currently the DSOs are evaluating the investments in new assets to enhance the controllability of the distribution grids and incorporate them to the planning process. This could improve the voltage quality and it would increase the PV hosting capacity in a cost-effective manner. This approach should consider the uncertainties related to PV growth and distribution grid expansion. We describe in Fig. 1 the proposed optimal controller placement problem considering the integration of the operations. The optimal controller placement considers the current, mid and long-term states of the distribution grid. These states are formed by combining the distribution grid expansion plans and the considered PV growth rate alternatives. The optimization problem is presented in Section 3 and it is solved by using the costs of the grid control operations, which purpose is to satisfy and improve the voltage quality requirements in a cost-effective manner. The enhanced controllability operations are presented in Section 4. These control operations use the distribution network model and the time-series predictions for the load & PV generation.

3. Optimal controller placement problem

3.1. Consideration regarding uncertainty in PV growth and distribution grid expansion

One of the biggest challenges in current distribution grid planning is how to cope with the different source of uncertainties that can appear in the planning period (*e.g.*, prediction of load, generation, grid expansion, policies and regulatory framework, etc.). Specially, it is important to incorporate the temporal aspects corresponding to the planning process because this can have economic implications in the long run. For instance, the best grid planning decision in a scenario with absence of DG penetration does not need to keep being the best one during the entire planning period, especially if for example the PV generation increases drastically and some lines need to be refurbished. That is addressed in this work by including a set of scenarios that describe the possible uncertainties related to grid expansion and PV growth rate for the planning period.

In this study the planning period is equivalent to a time span of 15 years and it is equally divided into three phases of 5 year each: the current stage, which is the period when the decisions are taken, the mid-term and the long-term. The estimated information for the mid-term and long-term is used during the current stage to perform the appropriate planning decisions.

In Fig. 2 the grid expansion tree is shown over the planning period, which is composed by four expansion alternatives in the long-term. This grid expansion tree is instantiated into four PV penetration annual growth rate alternatives (*i.e.* 1%, 2.5%, 5% and 7.5%.), resulting in sixteen different scenarios, where each scenario represents a combination of grid expansion paths and PV growth rate.

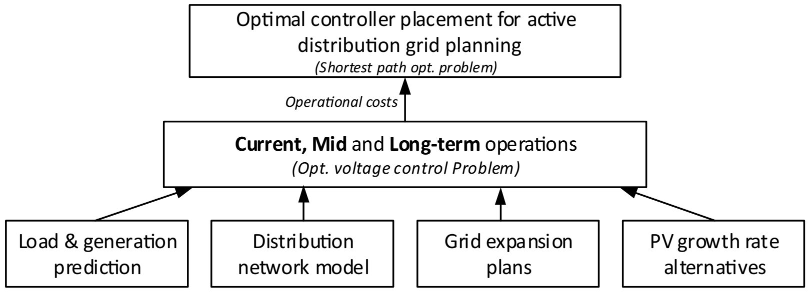

Fig. 1. Description of the planning problem considering the integration of the operations.

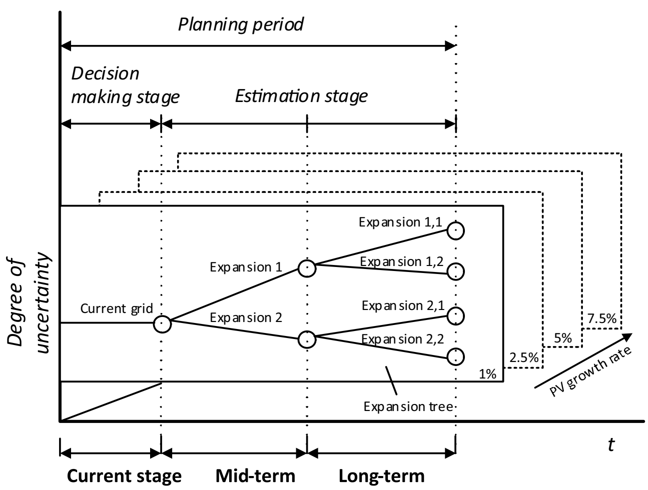

Fig. 2. Grid expansion scenario tree over the planning period for each PV growth rate.

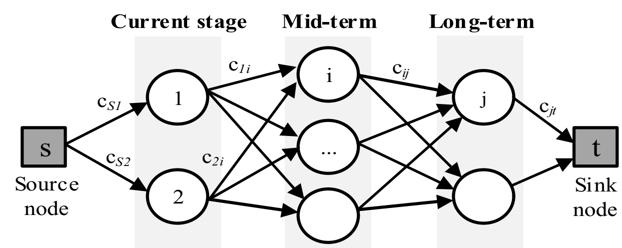

Fig. 3. Directed graph formed by the actuator placement alternatives.

Table 1
Actuator placement combinations for current stage, mid-term and long-term horizons. A "x/-" indicates which actuator(s) is/are placed/not placed for each node.

Actuator placement Node	Timeframe	Actuator 1	...	Actuator n
1	Current stage	...		...
2				
i	Mid-term		x/-	
...				
j	Long-term	...		...
...				

3.2. Motivation to deploy controllers in the grid

The DSOs typically perform *ex-post*-type of activities to improve the service voltage. These types of activities correspond to the traditional way to upgrade the grids (*e.g.*, replace cables, add parallel lines, change the network structure, etc.). However, an alternative to this can be to increase the controllability of the grid by deploying a number of actuators in certain locations in the grid, so that strategies like the one presented in Section 4 or in Refs. [18,25,26] can be incorporated. Thus, here we study a controller placement optimization problem in order to minimize the investment and operational costs of the controllers. These types of alternative activities lay within the regulatory recommendation under the European perspective to efficiently invest on active network management practices that enable the integration of DG and to postpone network reinforcements [27].

Thus, the controller placement can be a valid solution that operates the distribution lines closer to their physical limits, keeping the power quality within the standard limits [28] and without having to reinforce the weak lines. Hence, this approach facilitates to defer the grid reinforcements until the regulatory period is over. Afterwards, when the period is over or when the lines are amortized, these controllers can be placed in some other parts of the distribution grid, so that they can help to defer the CAPEX reinforcements of other lines.

3.3. Controller placement problem formulation

The controller placement problem is casted as a network optimization problem; specifically it belongs to the class of *Shortest Path Problems* [29]. The network representation of the problem is shown in Fig. 3 and it consists of finding the forward path from the *source node s* to the *sink node t* that shows the minimum cost. The nodes that form the network (*i.e.*, the directed graph) are divided into *current stage*, *mid-term* and *long-term* horizon-nodes. The arc costs are denoted by c_{ij} and represent the cost of transitioning from one stage to the next (*e.g.*, current stage → mid-term, mid-term → long-term) as it is explained later in this section.

In Table 1 the example of how to represent of all the possible actuator placement combinations for each of the planning horizons is shown. This structure is used later in the case-study.

The mathematical problem is formulated to solve the *Shortest Path Problem* and it is defined in Eqs. (1)–(6). The cost function in Eq. (1) corresponds to the function to be minimized and it represents all the forward paths from the *source to* the *sink node*. The constraints are defined in Refs. (2)–(6) and they are described next.

$$\min \sum_{(i,j)\in A} c_{ij} x_{ij} \tag{1}$$

s.t.

$$\sum_{(i,j)\in\delta^+(i)} x_{ij} - \sum_{(j,i)\in\delta^-(i)} x_{ji} = \begin{cases} 1, & \text{if } i = s \\ -1, & \text{if } i = t \\ 0, & \text{else} \end{cases} \quad \forall i \in V \tag{2}$$

$$\sum_{(i,j)\in\delta^+(i)} x_{ij} \le 1 \quad \forall i \in V \tag{3}$$

$$x_{ij} \in \{0, 1\} \quad \forall (i,j) \in A \tag{4}$$

$$c_{ij} = \begin{cases} NPC_i, & \textit{if overvoltages}_i = 0 \\ \infty, & \textit{if overvoltages}_i = 1 \quad \forall (i,j) \in A \\ \epsilon, & \textit{if } i = s \textit{ or } j = t \end{cases} \tag{5}$$

$$NPC_i = \sum_{k=1}^{m} \frac{C_k}{(1+r)^k} - I \quad \forall i \in V \tag{6}$$

V is the set of nodes, A is the set of arcs and $\delta^+(i)$ and $\delta^-(i)$ are the set of outgoing and incoming arcs of node i. Constraints (2) are flow conservation constraints and constraints (3) require that there can only be one outgoing valid arc from each node that belongs to the path. Constraints (4) specify that x_{ij} are binary arc variables and these take value *1* when the arc (i, j) belongs to the path. Constraints (5) define the arc costs ($c_{ij} \in \mathbb{R}^+$). They represent the required costs to remove the overvoltages in the grid for each of the actuator placement combination defined by *i* node and they corresponds to its deployment Net present Cost (NPC). NPC is defined in Eq. (6) and it is used to represent the life-cycle cost of a system. It consists of aggregating the cash outflows related to an investment project, in this case it corresponds to the required investments that improves the voltage quality and allows removing the overvoltages. The parameter I corresponds to the initial investment cost of the controllers and C_k represents the net cash outflow for the year k within m period of years*;* r is the discount rate. For the cases that the actuator placement combination defined by *i* node cannot remove the overvoltages, the arc is disabled by forcing its cost to be ∞. Lastly, the cost of outgoing arcs from the source node and the cost of incoming arcs form the sink node corresponds to ε, which is a small and positive number that enables the arcs and does not influence the minimum cost solution.

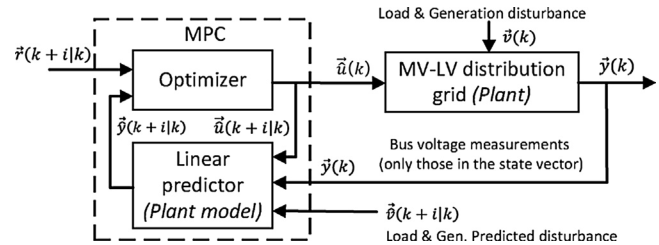

Fig. 4. MPC-based control architecture.

Two variants of the controller placement problem are considered:

- Temporary component placement

The cost of removing a controller is neglected and it is assumed that during each term the optimal controller combination could be deployed to defer the CAPEX reinforcements until the planning period is over.

- Permanent component placement

When an actuator is selected to be installed in a term *e.g.*, mid-term, it will also be used in the next term. This requires an adjustment in the optimization problem. To fix that, when a node is chosen in the current or in the mid-term, the following possible nodes than can be selected in the following terms must contain at least the same actuators that the first node had. We call *feasible* nodes to these nodes and *non-feasible* to the nodes that contain fewer actuators. That condition is added to the initial optimization problem by disabling the arcs that lead to *non-feasible* nodes.

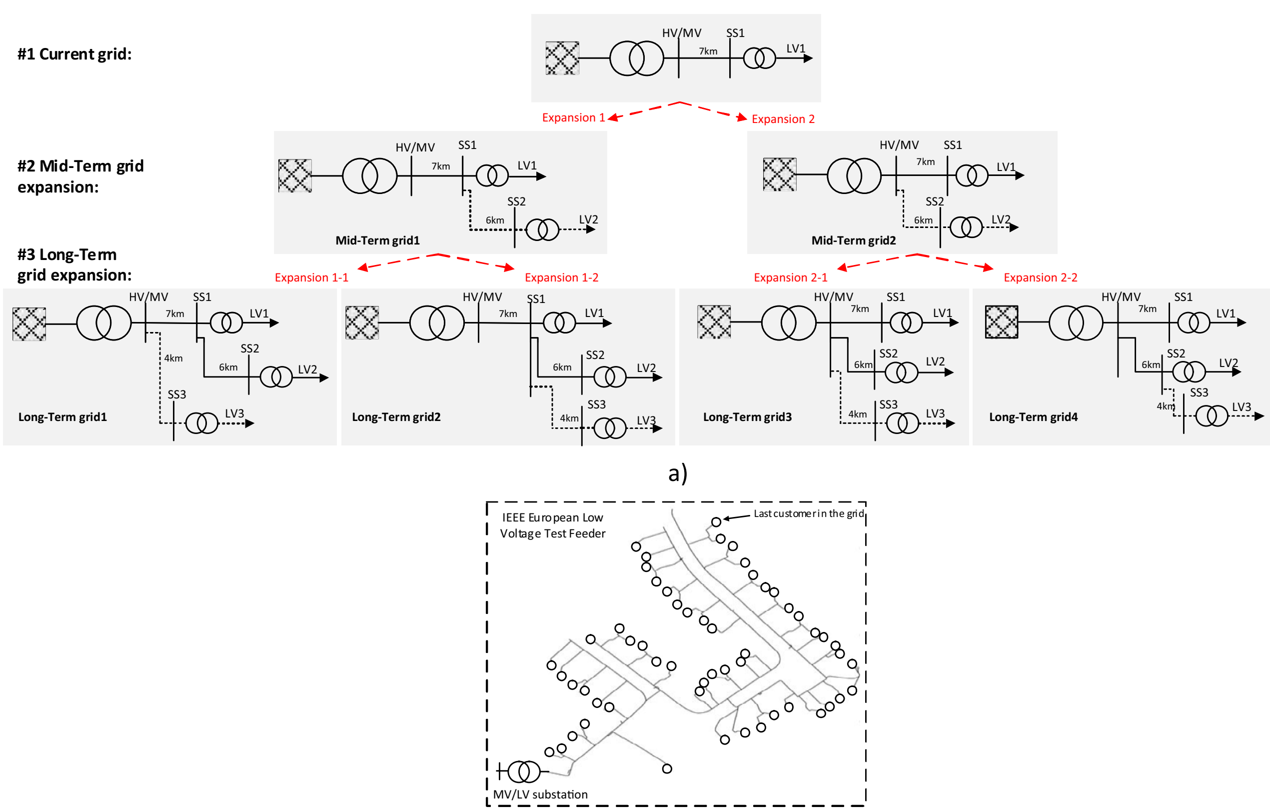

Fig. 5. a) One-line diagram of the MV grid expansion alternatives over time. b) One-line diagram of the IEEE European LV test feeder that corresponds to LV1, LV2 and LV3.

4. Voltage quality improvement by enhanced controllability

4.1. Proposed technical solutions

The DSOs can make investments in new assets in order to enhance the controllability of the distribution grid. Examples of these investments can be based on active management schemes such as reactive power compensation and coordinated OLTC voltage control.

In this paper, for simplicity reasons and in order to keep the number of the controlled signals low, the investments are restricted to OLTC technology. However, mechanically switched reactors, Static VAR compensator (SVC) or even LV-STATCOMs are additional technological alternatives that could serve as a complement to OLTCs. These could be utilized during the hours in the day when overvoltages are observed to consume the reactive power and to remove the overvoltages.

The considered voltage control strategies in this study follow a hands-off policy that is aligned with the electricity unbundling in EU [30]. Thus, we assume not to be dependent of 3rd parties to operate the distribution grid as it could be to interact with the end customer to perform inverter control in all its varieties, e.g. PF (P), Q (V). Therefore, only assets owned and controllable by the utility are considered, more specifically OLTCs at MV and LV substations.

4.2. Description of the control architecture

The control architecture that is considered in this paper is formulated as a Model Predictive Control (MPC), since it allows controlling both the voltage quality and the OLTC switching operations by employing simplified linear models of the electrical grid (*e.g.*, [31]). This control architecture has been introduced and applied in previous publications (see Refs. [32,33]) and it is shown in Fig. 4.

The controlled plant corresponds to the MV–LV distribution grid, which is formed by an n number of LV Secondary Substations (SS) that are connected to a primary MV distribution substation (HV/MV) following a radial topology. Similarly, each of the LV secondary substations is spread out on a radial topology providing electricity to a group of households.

The bus voltage reference trajectories are defined by the vector $\vec{r}$ and they are set to 1 pu. These reference trajectories can be dynamically imposed by a Supervisory Control and Data Acquisition — Distribution Management System (SCADA-DMS) that operates the MV-LV grid. The measurements correspond to the controlled signals of the physical process and represent the bus voltages at the LV distribution grid; these are defined by the vector $\vec{y}$ and are assumed to be obtained by the Automatic Meter Reading (AMR) infrastructure on hourly basis.

The state-space representation of the plant's model is defined in Eqs. (7)–(9) and the details of how to obtain the state-transition matrix (A), the input matrix (B_u) and the disturbance matrix (B_v) can be found in previous works presented in Refs. [31,32]. The state-equation is represented by Eq. (7), the output equation by Eq. (8) and the estimated state vector by Eq. (9).

$$\vec{\hat{x}}(k+i+1) = A\cdot\vec{\hat{x}}(k+i) + B_u\cdot\vec{\hat{u}}(k+i) + B_v\cdot\vec{\hat{v}}(k+i) \tag{7}$$

$$\vec{\hat{y}}(k+i) = \vec{\hat{x}}(k+i) \tag{8}$$

$$\vec{\hat{x}}(k) = \vec{\hat{x}}(k|k) = \vec{y}(k) \tag{9}$$

The disturbance applied to the controlled plant is defined by the $\vec{v}$ vector and it represents the active and reactive power variations in the LV grid caused by the load and the PV generation units. The estimated measured disturbance represents the predicted values for $\vec{v}$ and it is defined by the $\vec{\hat{v}}$ vector. These predictions can be obtained from a load and a PV generation forecaster that yields the prediction values for a p-prediction horizon using weather data such as outdoor temperature, solar radiation and wind speed, as presented in Ref. [34].

The objective of the control architecture is to obtain a sequence for the tap positions (*i.e.*, the manipulated variables) defined by the $\vec{u}$ vector so that the $\vec{y}$ vector follows the $\vec{r}$ vector. The optimization problem is formulated as a receding horizon-based Mixed Integer Quadratic Programming (MIQP) model [35], where the objective is to minimize the cost function defined by $J(\vec{z}_k)$ over a period of 24 h, as defined in Eq. (10). Subject to the constraints defined in Eqs. (9) and (15), which set the requirements for the voltage level and the OLTC's tap operations. The decision vector $\vec{z}_k$ is defined in Eq. (16).

$$\begin{aligned} J(\vec{z}_k) &= \sum_{j=1}^{n_y}\sum_{i=1}^{p}\{w_{i,j}^{y}[r_j(k+i|k) - \hat{y}_j(k+i|k)]\}^2 \\ &\quad + \sum_{j=1}^{n_u}\sum_{i=0}^{p-1}\{w_{i,j}^{\Delta u}[\hat{u}_j(k+i|k) - \hat{u}_j(k+i-1|k)]\}^2 + \rho_\varepsilon \varepsilon_k^2 \end{aligned} \tag{10}$$

s.t.

$$\underline{y_j}(i) - \varepsilon_k\cdot \underline{V_j^y}(i) \le \hat{y}_j(k+i|k), \quad i=1:p, \quad j=1:n_y \tag{11}$$

$$\overline{y_j}(i) + \varepsilon_k\cdot \overline{V_j^y}(i) \ge \hat{y}_j(k+i|k) \quad i=1:p, \quad j=1:n_y \tag{12}$$

$$\underline{u_j}(i) \le \hat{u}_j(k+i-1|k) \le \overline{u_j}(i), \quad i=1:p, \quad j=1:n_u \tag{13}$$

$$\underline{\Delta u_j}(i) \le \Delta\hat{u}_j(k+i-1|k) \le \overline{\Delta u_j}(i), \quad i=1:p, \quad j=1:n_u \tag{14}$$

$$\Sigma_{i=1}^{p}|\Delta\hat{u}_j(k)| \le \text{MADSON}, \quad j=1:n_u \tag{15}$$

$$\vec{z}_k = [\hat{u}(k|k)\hat{u}(k+1|k)\cdots\hat{u}(k+p-1|k)\varepsilon_k]^T. \tag{16}$$

k is the current interval; p is the prediction horizon; ε_k is the slack variable at control interval k; ρ_ε is the constraint violation penalty weight; n_y is the number of output variables; n_u is the number of manipulated variables; $r_j(k+i|k)$ is the reference for jth plant's controlled signal at ith prediction horizon step; $\hat{y}_j(k+i|k)$ is the prediction of jth plant's controlled signal at ith prediction horizon step; $w_{i,j}^{y}$ is the penalty weight for jth plant's controlled signal at ith prediction horizon step; $w_{i,j}^{\Delta u}$ is the penalty weight for jth manipulated variable increment at ith prediction horizon step; $\underline{y_j}(i)$ *and* $\bar{y}_j(i)$ are the lower and the upper bounds for jth plant's controlled signal at ith prediction horizon step; $\underline{u_j}(i)$ *and* $\bar{u}_j(i)$ are the lower and the upper bounds for jth plant's manipulated variable at ith prediction horizon step; $\underline{\Delta u_j}(i)$ *and* $\overline{\Delta u_j}(i)$ are the lower and the upper bounds for jth plant's manipulated variable increment at ith prediction horizon step; $\underline{V_j^y}(i)$ and $\bar{V}_j^y(i)$ are the lower and the upper bounds for soft constraints tuning factor; MADSON is the Maximum Allowable Daily Switching OperatioNs.

5. Optimal actuator placement vs. traditional reinforcement: case study

5.1. Case setup and input data

The arbitrary 10 kV MV radial distribution grid is used as an example and its expansion alternatives over time are shown in Fig. 5a). This grid in its current grid structure serves electricity to a single secondary substation denoted as SS1. In the mid-term the grid can be expanded into two alternatives named as *Expansion 1* and *Expansion 2* that serve electricity to SS2 substation. Then, in the

Table 2
The set of simulated scenarios consisting of the combination of four grid expansion alternatives and four PV growth rates.

Scenario	PV growth rate	Grid expansion
01:	1.0%	*Expansion 1 → Expansion 1-1*
02:		*Expansion 1 → Expansion 1-2*
03:		*Expansion 2 → Expansion 2-1*
04:		*Expansion 2 → Expansion 2-2*
05:	2.5%	*Expansion 1 → Expansion 1-1*
06:		*Expansion 1 → Expansion 1-2*
07:		*Expansion 2 → Expansion 2-1*
08:		*Expansion 2 → Expansion 2-2*
09:	5.0%	*Expansion 1 → Expansion 1-1*
10:		*Expansion 1 → Expansion 1-2*
11:		*Expansion 2 → Expansion 2-1*
12:		*Expansion 2 → Expansion 2-2*
13:	7.5%	*Expansion 1 → Expansion 1-1*
14:		*Expansion 1 → Expansion 1-2*
15:		*Expansion 2 → Expansion 2-1*
16:		*Expansion 2 → Expansion 2-2*

long-term, the grid can be expanded from the mid-term expansions into four alternatives that will include the SS3 substation. These grid expansions are named as *Expansion 1-1, Expansion 1-2, Expansion 2-1* and *Expansion 2-2,* respectively. The MV grid is formed by overhead lines and the phase impedance corresponds to: $Z = 0.202 + 0.122\,j\,[\Omega/\text{km}]$. The corresponding line distances are shown in Fig. 5a). For simplicity reasons, all the LV grids connected to each of the MV/LV secondary substations are modeled as a residential neighborhood consisting of 55 customers served by the 0.4 kV grid, whose topology is based on the IEEE European LV Test Feeder as shown in Fig. 5b). The characteristics of the LV network (*e.g.*, distances, physical characteristics of the cables, transformers, etc.) are available in Ref. [36].

In order to test how the service voltage could vary during the several stages that form the planning period four PV penetration annual growth rates are tested. The set of scenarios that is formed by combining the grid expansion alternatives and the PV growth rates is depicted in Table 2. It is assumed that the annual power growth rate for the load corresponds to 1%. The PV growth rate can be explained by new PV systems being connected to the residential neighborhood and by replacing degraded PV systems (*i.e.* PV panels and inverters) by newer and more effective ones [37].

The evolution of the aggregated PV power at the MV/LV secondary substations for each PV growth rate is shown in Fig. 6. Consequently, if there are variations in the PV generation, these will affect the voltage service level. The performed simulations correspond to the worst case scenario, because the purpose is to find in what situation the overvoltages could emerge if no control mechanisms were deployed.

Hence, after analyzing the voltage level of the current grid for four seasons and weekday/weekend combinations, it is found that it is spring — weekend the time of the year that is more critical in terms of voltage rises. Thus, a 24 h time period in *spring — weekend* conditions is used to predict the overvoltages for each of the

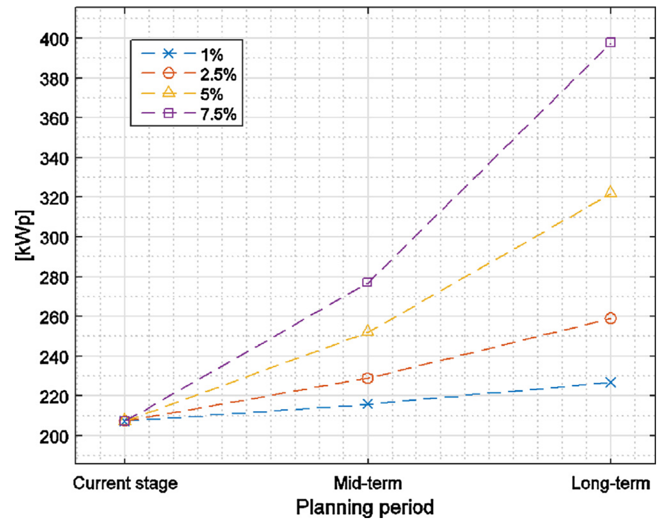

Fig. 6. The evolution of the aggregated PV peak power for the LV grid over the planning period for the assumed four growth rates.

grid expansion alternatives caused by the tested PV growths. In this study a voltage level above +1.1 pu is identified as an overvoltage. 28 simulations are performed considering the PV growth rate and the grids at each expansion: 4×1 simulations correspond to the current grid, 4×2 simulations correspond to the mid-term grids and 4×4 simulations correspond to the long-term grids. The results are presented in Table 3 and they show that the overvoltages start to emerge when the PV growth rate reaches the 2.5%. The voltage level status of the current grid is omitted in this table because overvoltages are not expected at this time of the planning period. Thus, the results for 24 simulations are shown in this table.

In order to improve the quality of supply in terms of service voltage along the LV grids and to remove the anticipated overvoltage situations that can emerge due to PV penetration, the following strategies are compared:

- Optimal deployment of controllers that enhance the grid controllability:
  - ○ Permanent component placement.
  - ○ Temporary component placement.
- LV cable reinforcement: This solution can be considered as the business as usual approach to reduce the potential impact of PV systems in LV grids. This traditional reinforcement practice consists of replacing the conductors for thicker ones to supply the load by solving the voltage problems. The reason is that a cable with wider diameter will have lower impedance and therefore will produce smaller voltage variations (drop or rise). This solution is also the typical one to supply the load without violating the thermal ratings.

Table 3
The status of the overvoltages in the grid for the simulated grid expansions and PV growth rates. (x = predicted overvoltages in the grid).

PV growth rate	Mid-term expansion				Long-term expansion											
	1		2		1-1			1-2			2-1			2-2		
	LV1	LV2	LV1	LV2	LV1	LV2	LV3	LV1	LV2	LV3	LV1	LV2	LV3	LV1	LV2	LV3
1.0%	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
2.5%	–	–	–	–	x	x	–	x	x	x	–	–	–	–	–	x
5.0%	–	–	–	–	x	x	x	x	x	x	x	x	x	x	x	x
7.5%	x	x	–	x	x	x	x	x	x	x	x	x	x	x	x	x

Table 4
The actuator placement combinations for the current stage.

Actuator placement Node	Timeframe	HV/MV	SS1	SS2	SS3
1	Current stage	–	–	–	–
2		–	x	–	–
3		x	–	–	–
4		x	x	–	–

Table 5
The actuator placement combinations for the mid-term horizon.

Actuator placement Node	Timeframe	HV/MV	SS1	SS2	SS3
5	Mid-term horizon	–	–	–	–
6		–	–	x	–
7		–	x	–	–
8		–	x	x	–
9		x	–	–	–
10		x	–	x	–
11		x	x	–	–
12		x	x	x	–

5.2. Optimal actuator placement versus traditional reinforcement

As shown in Table 3, overvoltages are not found in scenarios 1–4 (PV growth of 1%), which means that neither line reinforcements nor actuator deployments are considered to be applied. The same situation occurs with scenario 7 (PV growth of 2.5% for *Expansion 2* and then *Expansion 2-1*). Therefore, the most interesting scenarios to compare in terms of alternatives to remove the overvoltages are the scenarios 5–16 (PV growth of 2.5%, 5%, and 7.5%). The actuator placement configuration for each of the nodes is depicted in Tables 4–6, for the current stage, mid-term horizon, and long-term horizons respectively.

The optimal controller placement problem presented in section 3 is applied to each scenario and the results that show the shortest path from source to sink node (*i.e,* the minimum cost for the entire planning period) are shown in Table 7. These results determine whether at any substation (primary or secondary) an OLTC should be deployed permanently or temporary. In this study, we disregard the required refurbishment cost that would be applied to the LV lines that are expanded in the subsequent term and are predicted to have overvoltages. The reason is that these lines would be properly dimensioned to cope with the new situation, because the constructions works would have to be performed nevertheless. Therefore, line reinforcement cost only applies when overvoltages arise in a previously deployed LV line and when the overvoltages

Table 6
The actuator placement combinations for the long-term horizon.

Actuator placement Node	Timeframe	HV/MV	SS1	SS2	SS3
13	Long-term horizon	–	–	–	–
14		–	–	–	x
15		–	–	x	–
16		–	–	x	x
17		–	x	–	–
18		–	x	–	x
19		–	x	x	–
20		–	x	x	x
21		x	–	–	–
22		x	–	–	x
23		x	–	x	–
24		x	–	x	x
25		x	x	–	–
26		x	x	–	x
27		x	x	x	–
28		x	x	x	x

are caused by the newly expanded LV line. This situation applies from Mid-term to Long-term and it is illustrated by the scenarios 5, 6, 9–12, 15 and 16. Consequently, in the rest of the scenarios: 8, 13 and 14 (excluding 1–4 and 7 because these do not show grid problems) only the actuator placement solution is considered. The line reinforcement results for each scenario are also shown in Table 7.

5.3. Economic evaluation

In order to compare the scenarios from an economic perspective the NPC indicator is used, as presented in Section 3.3. The initial investment cost of the controllers and the net cash outflow for each of the 15 years that form the planning period are computed using the CAPEX and OPEX values. In this study the assumed CAPEX for HV/MV and MV/LV OLTC's correspond to 12 and 6 k$ respectively. We assign the OPEX to be dependent of the tap change operations, where each tap change corresponds to 4.81 cents $/tap-change [38]. Besides, a discount rate of 5% is used for all the scenarios.

The calculated NPC of the three the presented strategies are shown in Fig. 7 for each of the simulated scenarios. The results indicate that the scenarios 1–4 and 7 do not require grid reinforcement nor actuator deployment investments, obviously due to the fact that none of these scenarios show voltage problems. In addition, the traditional grid reinforcement costs are not applicable either to the scenarios 8, 13, and 14, because as it was explained in Section 5.2, the grid problems in these scenarios must be removed by dimensioning and installing the new lines accordingly. Thus, the

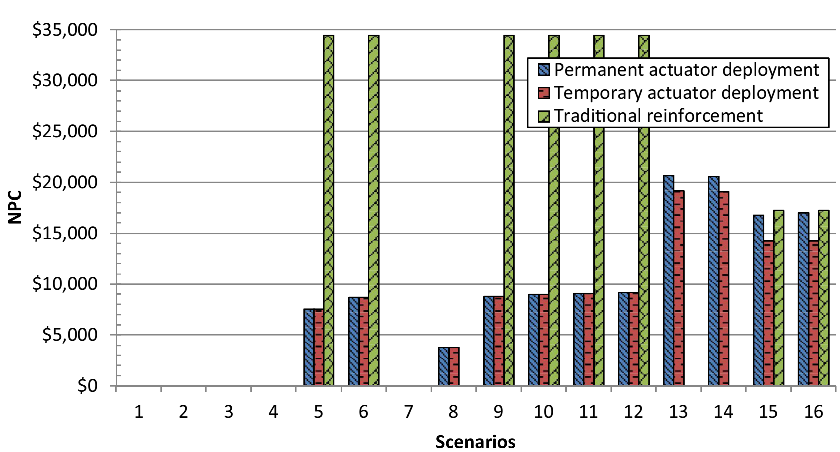

Fig. 7. Economic evaluation: NPC of the presented strategies vs. scenario.

Table 7
The traditional cable reinforcement and optimal actuator configuration deployment for each scenario (x = reinforcement at LV line, p/t = permanent/temporary actuator deployment).

Sxcenario	LV line reinforcement			OLTC placement configuration						
	Mid-term → Long-term			Mid-term extension			Long-term extension			
	LV1	LV2	LV3	HV/MV	SS1	SS2	HV/MV	SS1	SS2	SS3
01:	–	–	–	–	–	–	–	–	–	–
02:	–	–	–	–	–	–	–	–	–	–
03:	–	–	–	–	–	–	–	–	–	–
04:	–	–	–	–	–	–	–	–	–	–
05:	x	x	–	–	–	–	–	p/t	p/t	–
06:	x	x	–	–	–	–	p/t	–	–	–
07:	–	–	–	–	–	–	–	–	–	–
08:	–	–	–	–	–	–	–	–	–	p/t
09:	x	x	–	–	–	–	p/t	–	–	–
10:	x	x	–	–	–	–	p/t	–	–	–
11:	x	x	–	–	–	–	p/t	–	–	–
12:	x	x	–	–	–	–	p/t	–	–	–
13:	–	–	–	p	t	t	p/t	–	–	–
14:	–	–	–	p	t	t	p/t	–	–	–
15:	x	–	–	–	–	p/t	t	p	p	p
16:	x	–	–	–	–	p/t	t	p	p	p

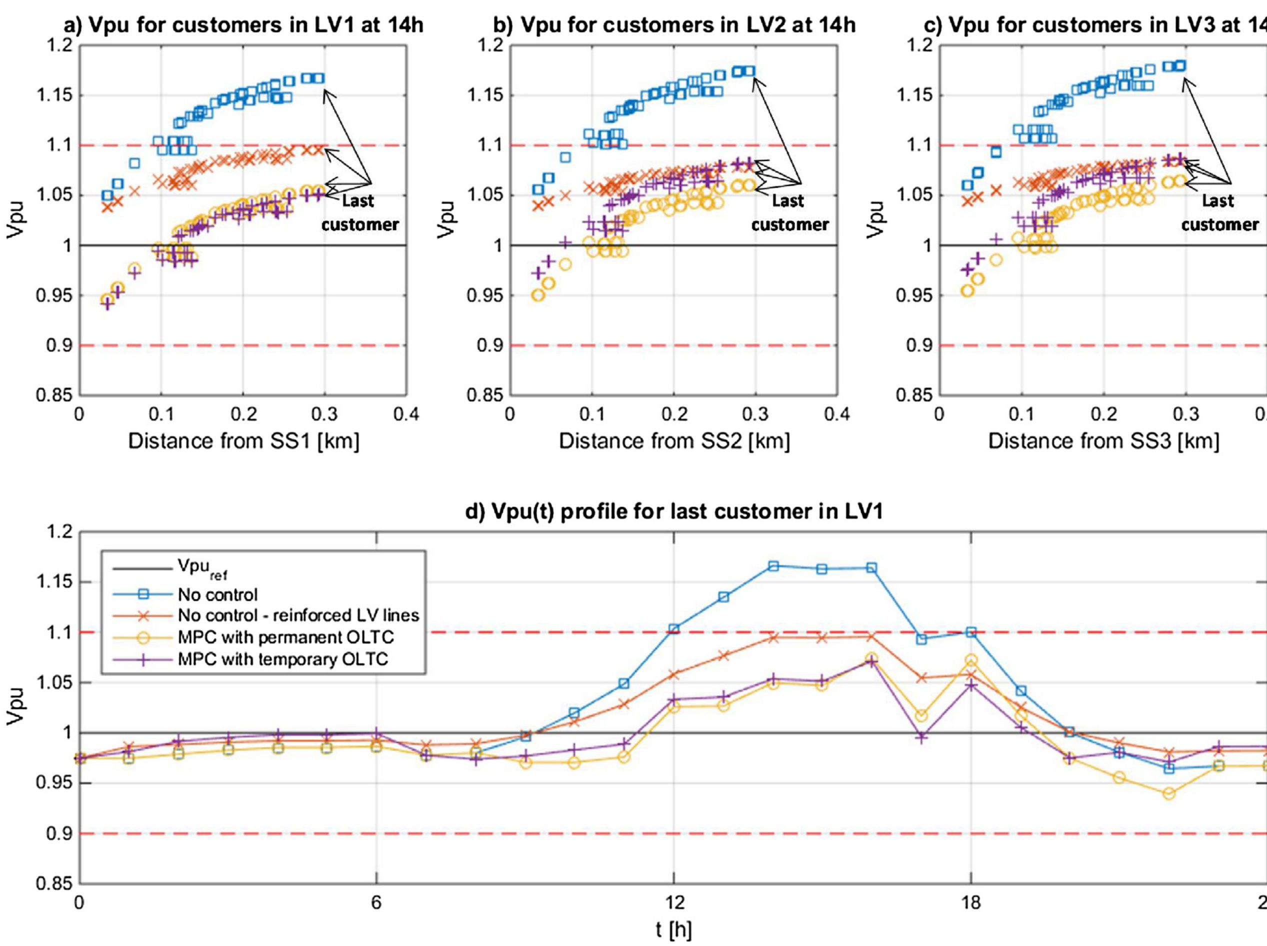

Fig. 8. Simulation results at 14 h (peak hour) for the scenario no. 16 showing the power quality analysis: a) *Vpu* for customers in LV1 vs the distance to the SS1, b) *Vpu* for customers in LV2 vs the distance to the SS2, c) *Vpu* for customers in LV3 vs the distance to the SS3, d) 24 h profile of *Vpu* for the last customer in LV1 grid.

calculated actuator-deployment costs for these three scenarios can similarly be avoided (both for permanent and temporary solutions).

Hence, the scenarios that are interesting to compare are the 5, 6, 9–12, 15 and 16. From these results we can infer that the optimal actuator placement is more economical than the traditional grid reinforcement solution because it shows lower NPC values in all the scenarios. Furthermore, by comparing the two actuator placement alternatives (*i.e.,* permanent vs. temporary), the results show that the temporary deployment solution can be even less costly than the permanent deployment solution. The reason is that the temporary approach provides more flexibility by giving the possibility to deploy and remove the assets when necessary. For instance, in scenario 15 and in scenario 16 an OLTC is deployed in SS2 in the mid-term to remove an specific voltage grid problem in LV2. Then, later in the long-term the grid problems arise in LV1 and LV2. Hence, the OLTC at SS2 is removed and an OLTC is placed at the HV/MV transformer, which is sufficient to remove the long-term grid problems in LV1, LV2 and in LV3. This solution shows lower cost than the permanent solution that consists of keeping the OLTC at SS2 and deploying another two OLTCs, one at SS1 and another one at SS3.

5.4. Power quality analysis

As presented in Refs. [32,33] the proposed actuator control strategy based on MPC is a valid solution to remove the overvoltages and in overall to improve the quality of supply in terms of voltage service level in the long-term. In Fig. 8 we illustrate the voltage level for the simulation results at 14 h (peak hour) for the scenario 16 (*i.e.,* Expansion 2-2 and PV growth rate of 7.5%). This scenario is selected for illustration purposes because it clearly stresses the grids and it helps to shows the overvoltages. Specifically, in Fig. 8a)–c) the voltage service level are plotted for the customers at the LV1, LV2 and LV3 grids, respectively. It can be seen that if no control mechanisms are applied, overvoltages emerge in the three LV grids. It can be seen that the voltage rise is positively correlated with the distance to the secondary substation and the customers located furthest see the highest overvoltage levels. However, if the lines are reinforced or if the actuators (*e.g.* OLTCs) are deployed, the voltage service level is kept within the 1 ± 0.1 pu acceptable threshold. In Fig. 8d) the 24 h voltage service profile is shown for the last customer located in LV1 for *spring — weekend* conditions. In this scenario, the difference in voltage service level between permanent and temporary OLTCs deployment corresponds to the number of actuators needed and to how well these can improve the voltage profile. In this case the permanent solution requires three OLTCs, one at each of the LV grids. In contrast, the temporary solution only deploys one OLTC at the HV/MV substation, which is sufficient to remove the overvoltages but not improve the voltage profile as much as the permanent solution.

The model is automated in Matlab and the simulations, which consider all the combinations that form the case-study, are solved in 385 min. For that, the power flow simulations are performed in OpenDSS [39] and the MIQP is solved using IBM ILOG CPLEX Optimizer's solver [40]. The system integration is performed by using the GridPV Toolbox for Matlab developed at Sandia National Laboratories [41].

6. Conclusion and future work

In this paper we perform an optimal controller placement that allows removing the overvoltage problems arisen in the grid caused by the PV penetration in LV grids. We assume that the controllers are utility's controllable resources such as OLTCs that can be deployed at HV/MV or MV/LV substations. The optimization problem also considers the uncertainties related to PV growth and distribution grid expansion.

In order to illustrate the performance of the optimal controller placement, we conduct a case study in which we compare the optimal controller placement with the traditional grid reinforcement practices. The uncertainty in PV growth and in the distribution grid expansion for the next 15 years is considered by creating a set of sixteen scenarios. We compare both the economic and voltage quality-related results for the scenarios. The results show that the optimal controller placement allows a more economical steady state operation of the distribution system that satisfies the voltage quality requirements than the traditional grid reinforcement practices. However, there are also some cases in which grid problems can be avoided by dimensioning and installing the new lines accordingly, thus the need for controller deployment can be avoided.

Future research work will focus on incorporating probabilistic aspects to the source of uncertainties and the optimal controller placement will be redefined as a stochastic shortest path problem. Furthermore, the control strategy will be upgraded by incorporating thermal rating constraints. This improvement will allow analyzing not only rural and sub-urban residential distribution grids, but also urban grids, which have higher component overloading problems.

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Paper V

Multiagent-Based Distribution Automation Solution for Self-Healing Grids

Multiagent-Based Distribution Automation Solution for Self-Healing Grids

Markus Eriksson, Mikel Armendariz, *Student Member, IEEE*, Oleg O. Vasilenko, Arshad Saleem, *Member, IEEE*, and Lars Nordström, *Senior Member, IEEE*

***Abstract*—A multiagent-based distribution automation solution is proposed to be used in the distribution of self-healing grids to solve the service restoration part of the Fault Location, Isolation and Service Restoration (FLISR) task. The solution reduces the grid topology to an undirected weighted graph and executes a distributed implementation of Prim's minimum spanning tree algorithm to solve the problem. The solution is compliant with state-of-the-art standards within smart grids, including but not limited to IEC61850. To test the performance of the algorithm, a testbed is assembled consisting of a physical dc grid model and several Arduino microcontrollers and Raspberry Pi computers. The test results show that the proposed algorithm can handle complex FLISR scenarios.**

***Index Terms*—Distribution automation, Fault Location, Isolation and Service Restoration (FLISR), IEC 61850, minimum spanning tree, multiagent systems (MASs), Prim's algorithm.**

I. Introduction

NEW trends in the electricity sector are demanding distribution system operators (DSOs) to improve the reliability of the electrical network by renovating its infrastructure and functionalities. This renovation process is driven by needs such as penetration of renewables, distributed generation, and increasing demand for electricity, which forces the electric power system to evolve from the traditional unidirectional power flow to a newer paradigm where power flows bidirectionally [1].

Fortunately, in parallel to the mentioned renovation process, the Information and Communication Technologies (ICT) have significantly matured and are nowadays available at an affordable cost, assisting DSOs to improve situation awareness. This will facilitate the design of applications in accordance with the new operational paradigm and market models incorporating more actors and to use more flexible and powerful control methods such as distributed control and multiagent systems (MAS; see [2] and [3]).

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M. Eriksson, M. Armendariz, A. Saleem, and L. Nordström are with Industrial Information and Control Systems, Royal Institute of Technology, 10044 Stockholm, Sweden (e-mail: markue@kth.se; mikel@kth.se; arshads@kth.se; larsno@kth.se).

O. O. Vasilenko is with Ericsson Innovations Russia, Moscow 127083, Russia (e-mail: oleg.vasilenko@ericsson.com).

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Moreover, support for constructs, such as ontologies and speech, enables the MAS architecture to be compatible with standardization work in data models and communication for distribution automation such as IEC 61850 (see [4] and [5]).

In particular, distributed control attracts the attention of the industry experts as a promising distribution automation technology for higher grid reliability due to its robustness, scalability, and efficiency (see [6] and [7]). In contrast to the legacy automatic transfer switching schemes that assume each substation implements a preprogrammed local power restoration plan, the more advanced distributed control approaches propose that the affected substations can cooperatively develop and enforce adapted power restoration plans in order to achieve higher reliability and better postfault conditions in the grid. For this reason, a MAS-based distribution automation solution is studied to solve the Fault Location, Isolation and Service Restoration (FLISR) problem in the context of complex scenarios of self-healing grids. The solution applies the monitoring and control functionalities provided by the MAS system, and it implements an ICT infrastructure that is optimized for efficient operation.

A. Power System Reliability

The electric power system aims at providing electricity to customers in the most efficient way, assuring continuity, power quality, and reliability (see [8]–[10]). The literature shows that the most common indexes that permit evaluating power system reliability are: SAIFI (*System average interruption frequency index*), SAIDI (*System average interruption duration index*), CAIFI (*Customer average interruption frequency index*), and CAIDI (*Customer average interruption duration index*) [10]–[12].

The migration of automation intelligence in MAS-based control from the center to the grid periphery helps improve the indexes by shortening system response times as it avoids the scenario where a central control system spends much time on extensive requesting and collection of measurement and state information from different substations before the power supply restoration begins.

B. Communication for Distributed Control

As far as the communication is concerned, the proposed MAS-based control strategy suggests using the computing capacity of the substations to quickly analyze the situation. Therefore, primarily, only succinct data containing analysis results

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and action requests have to be sent over the communication network, similar to [13]. Likewise, the substation equipment does not need to interact in real time with the control centers to get orders on how to act when the situation changes.

Since the MAS-based control is more tolerant to the communication network parameters, the control system devices can use different kinds of communication networks, e.g., 3G and 4G, which offer a communication bandwidth with acceptable quality of service (QoS) package at a reasonable price. In addition, the implementation of decentralized control in distribution automation improves the scalability of the distribution grids because the agent-based control approach requires only that the agents maintain consistent and up-to-date information about their local area and not the entire grid. This supports a gradual rollout of the new control devices.

C. Related Work

The evolution in methods and technologies in FLISR is described in the *Power and Energy Magazine* [14], from 70s when service restoration was manually done to nowadays, when the FLISR process is automatically done.

An important phase in the FLISR process is the location of the fault, which can be done by applying different techniques such as apparent impedance measurement [15], direct three-phase circuit analysis [16], superimposed components [17], traveling waves [18], power quality monitoring data [19], and artificial intelligence [20]. In the FLISR process, service restoration is a key element, and it can be generalized as a multiobjective and multiconstraint optimization problem. There are multiple available techniques in the literature to solve the service restoration part, which can be implemented following either a centralized or a decentralized approach (e.g., heuristic algorithms [21], [22], mathematical programming [23], fuzzy reasoning [24], knowledge-based expert systems [25], etc.).

Traditional centralized distribution automation architectures are becoming less popular to apply FLISR applications due to the dynamic change in network topologies and because it requires a single decision-making software component to process all the data [26]. Therefore, significant effort is being made to implement FLISR following a decentralized architecture. The following literature shows relevant developments in the research community using a multiagent approach: In [27], Ling and Liu proposed a distributed topology computation for a distributed FLISR algorithm considering switch and communication failures. In [28], Solanki *et al.* proposed a MAS approach to solve system restoration assuming maximization of the power supply for as many loads as possible and prioritizing critical/vital loads. In [29], Lim implemented a solution that restores the grid for different outage situations in advance, where the restoration plans are delivered to terminal agents that control the distribution grid switches and act in parallel in case of outages. In [7], Chowdhury and Koval analyzed how traditional IEC 61850 substation automation functions can support real-time performance of multiagent control. In [30], Chouhan *et al.* proposed a hybrid MAS that uses a distributed multiagent control to detect faults and a centralized control agent to reconfigure the grid, following a graph-theoretic framework to solve the grid reconfiguration. In [31], Parikh *et al.* proposed a technique to solve FLISR using the IEC 61850 GOOSE substation automation standard, considering feeder, switch, and transformer capability limits. In [32], Lin *et al.* proposed a MAS approach to achieve FLISR assuming priority indexes. In [33], an IEC 61850 model expansion toward distributed FLIRS was proposed. In [34], Buse and Wu proposed to use mobile agents for remote access to intelligent electronic devices (IEDs). In [35], Lim presented a MAS approach with a central agent and terminal agents and tested it in code-division multiple-access and Ethernet communication environments, showing better restoration times using Ethernet.

Additionally, commercial FLISR products based on multiagents and decentralized architectures are being developed. An example is S&C IntelliTEAM II [36] that is implemented at ENMAX, a DSO in Alberta, Canada.

Further to the works referred above, we propose an efficient MAS-based FLISR solution that does not select a particular type of line (e.g., tie lines) and is applicable to different kinds of grid topologies, including those with bidirectional energy flows. Thus, a composition of the MAS with a minimum number of agents and agent types with clear roles is proposed. The important feature of the solution under consideration is that it assures that a power restoration plan will be found after only a few rounds of negotiations between the substations. The number of rounds cannot exceed the number of the affected substations.

D. Delimitations

This paper only considers grid topologies consisting of circuit breakers and disregarding other types of switches, such as sectionalizers or tie switches. This simplification does not affect the performance of the system restoration part of the algorithm because the switching is carried out in the isolation and reconfiguration phases. For the sake of simplicity, active power line losses (1) are disregarded in the problem formulation and will be considered in the following studies.

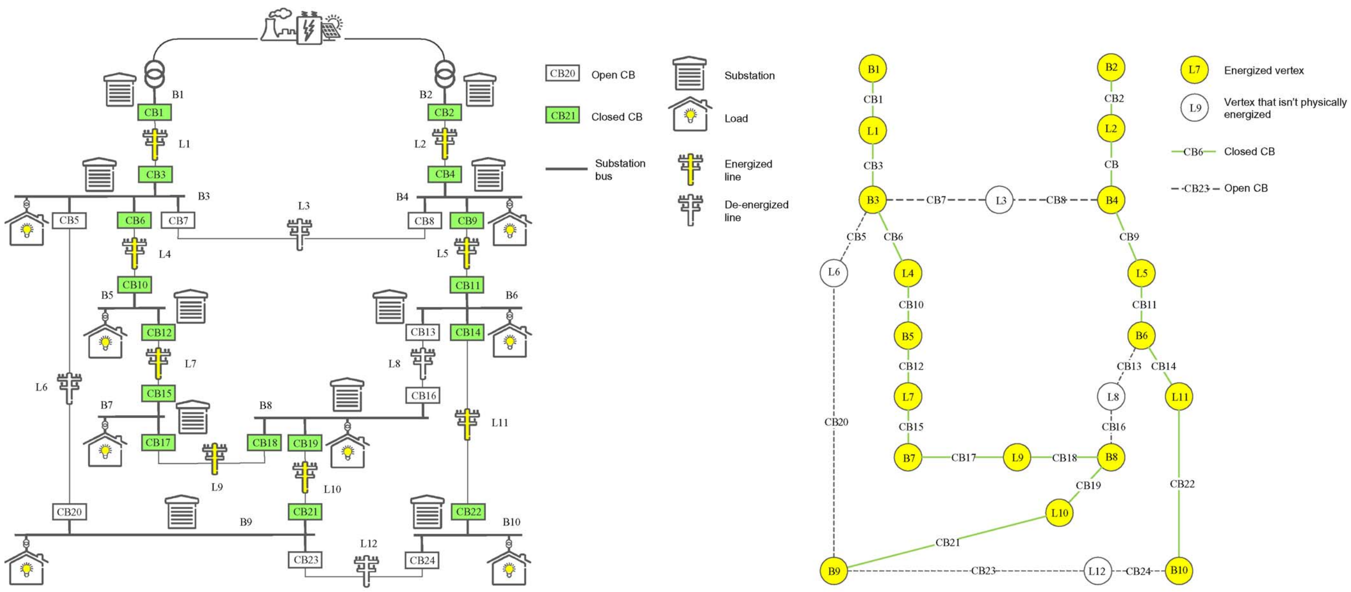
II. Solution to the FLISR Problem

In the following section, the solution to the FLISR task is presented following a decentralized and distributed approach.

A. Overview of the Solution

The distribution automation FLISR solution is based on a MAS consisting of three types of agents: substation control agent (SCA), load control agent (LCA), and restoration agent (RA). All these three types of agents perform protection and control functions that can be mapped to the IEC 61850 standard. The agents can be implemented on an IEC 61850-compatible IEDs or other platform that supports communication interfaces and can control primary substation equipment (e.g., breakers).

The proposed solution uses a distributed implementation of Prim's minimum spanning tree algorithm to solve the *Service Restoration* part of the FLISR task. Prim's algorithm is a greedy



(a) (b)

Fig. 1. (a) Testbed grid and (b) its graph representation. Note that there is one RA responsible for each individual vertex.

algorithm made for mathematical graphs that iteratively builds up a minimum spanning tree from a set of nodes (vertices) and undirected weighted edges [37]. To enable the MAS to use Prim's algorithm, a graph representation of the grid topology is used where the graph's edges (see Fig. 1) are mapped to circuit breakers, and the graph's nodes are mapped to the areas enclosed by two or more circuit breakers, i.e., lines and buses. The power grid capacity constraints are represented by the graph's edge weights.

B. Mathematical Formulation of Service Restoration Problem

The *Service Restoration* step in FLISR can be formulated as the following graph-theoretic problem.

Let $G = (V, E)$ be an undirected connected weighted graph consisting of the set of nodes V and a set of edges E. Furthermore, let the set of nodes V consist of two subsets: $V = (V_f \cup V_r)$, where V_f is the set of all feeder nodes (see *B1 and B2* in Fig. 1), and V_r is the set of regular nodes. This set of regular nodes is further divided into energized nodes (V_e) and de-energized nodes (V_d), $V_r = (V_e \cup V_d)$.

Assuming a radial network topology, each tree, $T_1, T_2, \ldots, T_N$, in the grid will be acyclic and consist of one and only one feeder node, $V_f^n \in V_f$, and any number of energized nodes, $T_n = (V_n, E_n)$, where $V_n = (V_f^n, V_e^n)$, and $V_e^n = (V_{e_1}^n, \ldots, V_{e_m}^n)$. This means that two trees cannot have the same feeder node, that is: $V_f^i \neq V_f^j \forall\, i, j \in 1, 2, \ldots, N$ and $i \neq j$. The number of trees in the graph, i.e., N, is therefore equal to the number of feeder nodes: $V_f = (V_f^1 \cup V_f^2 \cup \ldots V_f^N)$.

The MAS seeks a solution where the set of de-energized nodes V_d is divided among the trees: $T_1, T_2, \ldots, T_N$, such that: $T_n = (V_n, E_n)$, where the set of nodes in the tree $V_n = (V_f^n, V_e^n, V_d^n)$ and $V_d = V_d^1 \cup V_d^2 \cup \ldots \cup V_d^N$, with the constraint: $L_{V_f^n} \leq L_{max}^n, \forall\, n = 1, 2, \ldots, N$. $L_{V_f^n}$ and L_{max}^n are the current load and the maximum capacity of the feeder node V_f^n, respectively. Furthermore, let $L_{V_{r_i^n}}$ be the load of a regular node $V_{r_i^n}$. The load of feeder node V_f^n is then

$$L_{V_f^n} = \left(\sum_{\text{all} V_{r_i}^n \in V_r^n} L_{V_{r_i}^n} \right) + \text{losses}. \tag{1}$$

To ensure that the constraint is fulfilled, the weight of adding one vertex V_{d_i} to a tree T_j is set to be

$$w_{ij} = \frac{L_{V_f^j} + L_{V_{d_i}}}{L_{max}^j} \tag{2}$$

and a new connection will be possible only if $w_{ij} \leq 1$.

A distributed implementation of Prim's algorithm is used to provide a solution for the *Service Restoration* problem in its graph form.

C. Distributed Adaptation of Prim's Algorithm

A radial power grid consists of multiple separate trees. Prim's algorithm creates one minimum spanning tree from a set of nodes and edges by growing the tree one node at a time. On the contrary, in this new distributed approach, all separate trees need to grow in parallel until the set of de-energized nodes becomes empty or the trees reach a point where they are unable to connect more nodes due to capacity constraints and/or no more connections are possible due to the graph being disjoint or blocking between the trees. The distributed adaptation of Prim's algorithm implemented by MAS follows the given steps.

1. Let $T_1, T_2, \ldots, T_N$ be the trees to which the de-energized nodes are added.
2. Let $e_1, e_2, \ldots, e_N$ be the sets of edges such that $e_n = (e_n^1, e_n^2, \ldots)$ connects all adjacent nodes V_i and V_j such that $V_i \in T_n$ and $V_j \in V_d$, $(n = 1, 2, \ldots, N)$. Let $C_m = \varnothing$ be the set of connections for node $V_{d_m} \in V_d$, where $m = 1, 2, \ldots, M$.

3. For each set of edges e_n, select the edge that has the minimum weight ($\mathrm{E}_{\mathrm{n}}^{\min} \in \mathrm{e}_{\mathrm{n}}$) as defined in (2). Then, let $\mathrm{V}_{\mathrm{d_m}}$ be connected to T_{n} through the edge with minimum weight ($\mathrm{E}_{\mathrm{n}}^{\min}$) and store the possible connection for $\mathrm{V}_{\mathrm{d_m}}$, $\mathrm{c_n} = (\mathrm{T_n}, \mathrm{E}_{\mathrm{n}}^{\min}, \mathrm{w}_{\mathrm{E}_{\mathrm{n}}^{\min}})$ and $\mathrm{C_m} = \mathrm{C_m} \cup \mathrm{c_n}$.
4. For each de-energized node $\mathrm{V}_{\mathrm{d_m}}, \mathrm{C_m}! = \varnothing$, select among all edges the one that has the minimum weight and add the node to the tree, $\mathrm{T_n}$ matching that connection, $\mathrm{V_n} = \mathrm{V_n} \cup \mathrm{V}_{\mathrm{d_m}}$. The load of the tree is increased with the load of the added node: $\mathrm{L}_{\mathrm{V_f^n}} = \mathrm{L}_{\mathrm{V_f^n}} + \mathrm{L}_{\mathrm{V_{d_m}}}$. Remove $\mathrm{V}_{\mathrm{d_m}}$ from the set of de-energized nodes, $\mathrm{V_d} = \mathrm{V_d} \setminus \mathrm{V}_{\mathrm{d_m}}$.
5. Go to step 2.

   If the remaining capacities of the trees are higher than the combined load of all de-energized nodes, then

$$\mathrm{L}_{\max}^{\mathrm{n}} - \mathrm{L}_{\mathrm{V_f^n}} > \mathrm{L_d} \forall\ \mathrm{n} = 1, 2, \ldots, \mathrm{N} \tag{3}$$

   where $\mathrm{L_d}$ is given by

$$\mathrm{L_d} = \sum_{\text{all } \mathrm{V_{d_i}} \in \mathrm{V_d}} \mathrm{L}_{\mathrm{V}_{\mathrm{r_i}}^{\mathrm{n}}}. \tag{4}$$

   Then, assuming a connected graph, the distributed Prim's algorithm will always result in $\mathrm{V_d} = \varnothing$, which means that all de-energized nodes will be added to the trees.

D. Description of the MAS

The distributed adaptation of Prim's algorithm is implemented in a MAS consisting of the following three types of agents.

- *SCA*: It is responsible for controlling one substation's equipment. It informs affected restoration agents of events and status changes in the grid, and if a fault occurs, the SCAs cooperate to locate it by comparing the measurements. If an agent (or grid operator) wants to change the state of a device (e.g., close a circuit breaker), it sends a request to the specific SCA that controls the targeted equipment.
- *RA*: It is responsible for one node, $\mathrm{V_i} \in \mathrm{V}$, in the grid topology graph, and its task is to ensure that the node is energized. A node is energized if it belongs to a tree $\mathrm{T_n}$ $(\mathrm{n} = 1, 2, \ldots, \mathrm{N})$ and has a power supplier, i.e., if it is either a feeder node, $\mathrm{V_i} \in \mathrm{V_f}$, or if it has been granted power access through another energized node.
- *LCA*: It is responsible for one tree, $\mathrm{T_n}$ $(\mathrm{n} = 1, 2, \ldots, \mathrm{N})$, in the grid topology graph. It monitors the tree's feeder, $\mathrm{V_f^n}$, to ensure that its used capacity does not exceed its limits, $\mathrm{L}_{\mathrm{V_f^n}} \leq \mathrm{L}_{\max}^{\mathrm{n}}$.

The RAs and LCAs together create a system behavior that matches the distributed version of Prim's algorithm to solve FLISR. The role of these agents and the mapping to the algorithm are explained as follows.

1. *Fault localization*: Right after the automatic protection triggers, the SCA agents in control of the affected region compare measurements and determine the faulted node.
2. *Isolation*: The faulted node is isolated both physically and virtually, which means that its adjacent edges (circuit breakers) are opened and removed from the grid topology graph. All RAs that had the faulted node as their power supplier are now de-energized, which means that they no longer belong to a tree. These agents are added to the set of de-energized nodes and inform their power receivers that they are de-energized. This process of sharing the power fault information starts from the faulted vertex and is spread out downstream to the bottom of the de-energized branch.
3. *Power restoration negotiation*: The following steps describe the distributed adaptation of Prim's algorithm. The RA will be responsible for the de-energized node $\mathrm{V_{d_i}}$ and the LCA will be responsible for the tree $\mathrm{T_n}$.
   1. Each de-energized RA requests power restoration from its adjacent RA nodes. Its load is attached to the request. It starts a timer that is used as a trigger in case one or more responses are lost due to communication faults, such as packet losses.
   2. If an RA is energized and receives a request for power restoration, it forwards the request to its tree's LCA. If it is de-energized, it responds with a power denial.
   3. Each LCA that receives a unique forwarded request calculates the weight of the connection and (re)starts a timer, which is used to trigger the LCA to move to the next step. The weight is calculated as follows:

$$\mathrm{w_{ij}} = \frac{\mathrm{L}_{\mathrm{V_f^j}} + \mathrm{L}_{\mathrm{V_{d_i}}} + \mathrm{L}_{\mathrm{V_f^j reserved}}}{\mathrm{L}_{\max}^{\mathrm{j}}}. \tag{5}$$

   4. When an LCA's timer triggers, it selects the power restoration request with lowest weight $(\mathrm{w_{ij}} \leq 1)$, and it sends a connection proposal to the RA that made the request. All other requests are denied. It also updates the reserved capacity load with the requested load, i.e.,

$$\mathrm{L}_{\mathrm{V_f^j reserved}} = \mathrm{L}_{\mathrm{V_f^j reserved}} + \mathrm{L}_{\mathrm{V_{d_i}}}. \tag{6}$$

      The load reservation enables the LCA to continue operating without having to wait for a reply to the connection proposal.
   5. When a de-energized RA receives a response, it restarts its timer, stores the response, and matches it with the corresponding sent request.
   6. When a de-energized RA receives a response to all sent requests or its timer triggers, it accepts the connection proposal from the LCA that provides the lowest weight. If the RA does not receive a connection proposal, it goes back to step 1. The RA is now energized and proceeds to the reconfiguration phase.
   7. An LCA that receives a connection acceptance from node $\mathrm{V_i}$ updates the used capacity load and the reserved capacity load, i.e.,

$$\mathrm{L}_{\mathrm{V_f^j}} = \mathrm{L}_{\mathrm{V_f^j}} + \mathrm{L}_{\mathrm{V_i}} \tag{7}$$

$$\mathrm{L}_{\mathrm{V_f^j reserved}} = \mathrm{L}_{\mathrm{V_f^j reserved}} - \mathrm{L}_{\mathrm{V_i}}. \tag{8}$$

      If it receives a connection denial, it removes the matching load reservation and decreases the reserved load, as in (8).

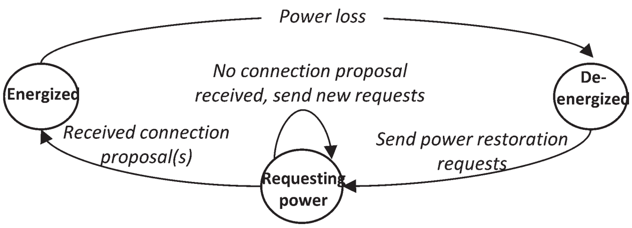


Fig. 2. State machine representation for the RA in phases 3 and 4.

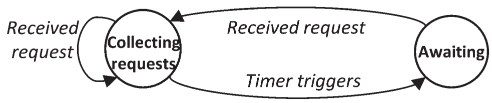


Fig. 3. State machine representation for the LCA in phase 3.

TABLE I
UPON EVENT POWERLOSS

Set state to: deenergized; Isolate;
For each power receiver: send PowerLoss(power receiver);
Set LCA and Power supplier to None; Set state to requesting power;
For each *neighbor*, $V' \sim V_{d_i}$ *: Send Request(* V', $L_{V_{d_i}}$ *);*

TABLE II
UPON EVENT CONNECTIONPROPOSAL

Set $c_i^{best} = \left(T_{best}, E_{best}^{min}, w_{E_{best}^{min}}\right) = \min_w (C_i) = \min_w (c_{i_1}, c_{i_2, \ldots})$;
Set LCA = T_{best};
Set Power supplier = V_p ; *//where* V_{d_m} *is connected to* V_p *via* E_{best}^{min}.
Send: ConnectionAcceptance(T_{best}); *Send: ConnectionAcceptance(*V_p);
For each *connection proposal*, $c_k = (T_k, E_k^{min}, w_{E_k^{min}}) \in C_k$, $c_k \neq c_i^{best}$
Send: ConnectionDenial(T_k); Then *set state to energized*;

8. An RA that receives a connection acceptance adds the accepting RA to its list of power receivers and proceeds to the reconfiguration phase.

   Steps 1–2 can be mapped to step 2 in the distributed adaptation of Prim's algorithm, steps 3–5 to step 3, and steps 6–8 to step 4.

4. *Reconfiguration*: If an energized RA is not physically energized and it or one of its power receivers has a nonzero load, it ensures that it is physically isolated and asks the SCA to close the circuit breaker between itself and its power supplier. The RA is now physically energized.

E. State Machine Representation and Pseudocode for the Restoration Agent and Load Control Agent in Phases 3 and 4

Figs. 2 and 3 show the state machine representation for the RA and LCA along with the required pseudocode to implement the state transitions (see Tables I–IV).

Note that the details are omitted for the sake of brevity.

1) Restoration Agent

   Tables I and II show the pseudocode for the RA (responsible for the node V_{d_i}).

2) Load Control Agent

   Tables III and IV show the pseudocode for the LCA, which is responsible for the tree T_n.

TABLE III
UPON EVENT POWERRESTORATIONREQUEST

Set: $w_{ij} = \dfrac{L_{V_f^j} + L_{V_f^j\,reserved} + L_{V_{d_i}}}{L_{max}^j}$;
if $\left(V_{d_i}, L_{V_{d_i}}, w_{ij}\right) \notin$ *requests* and $w_{ij} \leq 1$
Set state to collectingRequests;
Set requests = requests $\cup \left(V_{d_i}, L_{V_{d_i}}, w_{ij}\right)$, *Start: Timer;*
else *Send ConnectionDenial(*V_{d_i});

TABLE IV
TIMER TIMEOUT

Set $\left(V_{d_{best}}, L_{V_{d_i}}, w_{best}\right) = \min_w$ (*requests*);
Set reservations = reservations $\cup \left(V_{d_{best}}, L_{V_{d_i}}, w_{best}\right)$;
Set $L_{V_f^j\,reserved} = L_{V_f^j\,reserved} + L_{V_{d_i}}$;
Send: ConnectionProposal($V_{d_{best}}, w_{best}$);
For each *request*, $\left(V_{d_i}, L_{V_{d_i}}, w_{ij}\right) \neq \left(V_{d_{best}}, L_{V_{d_i}}, w_{best}\right)$;
Send ConnectionDenial(V_{d_i});
Set requests = $\emptyset$; *state to waiting;*

F. Discussion on Complexity and Optimality

A way to evaluate the time complexity of Prim's algorithm is to assess the way adjacent vertices are stored. Centralized algorithms that store adjacent vertices using adjacent lists show $O(V^2 \log_2 V)$ complexity, and if a matrix representation is applied, the complexity reduces to $O(V^2)$. The presented distributed algorithm stores adjacent vertices using adjacent lists, and the worst-case scenario shows $O(V)$ complexity since the functional feeder will add one node per iteration until the capacity limit is reached or there is no more possible connections to make.

The power restoration optimality criterion that the presented algorithm follows corresponds to energizing as many nodes (e.g., secondary substation loads) as possible while not exceeding capacity constraints. That is represented by the currently used weighing system (2).

The algorithm is not guaranteed to find an optimal solution, as trees with lower remaining capacity could block other trees with higher remaining capacity, effectively leaving nodes stranded. An example graph that illustrates the suboptimal behavior is shown in Fig. 4(a). There are two trees T_1 and T_2 containing nodes A1 and A2, respectively, and three de-energized nodes V1, V2, and V3. The optimal solution would be to connect all de-energized vertices to A2, but the algorithm would not be able to come up with this solution unless dynamics such as packet loss or delays were introduced.

The algorithm will find that the best connection for T_1 is to connect to V2 as that node has the lowest weight of the possible choices (V2 and V3) and the weight, $w_{v2} = 0.4$, is less than or equal to 1. In the same way, it will find that the best choice for T_2 would be to connect to V1 as that node has the lowest weight, $w_{v1} = 0.067$, of the adjacent vertices.

The only possible tree for V3 to connect to is T_1, but T_1 does not provide sufficient capacity to connect to V3 as the edge

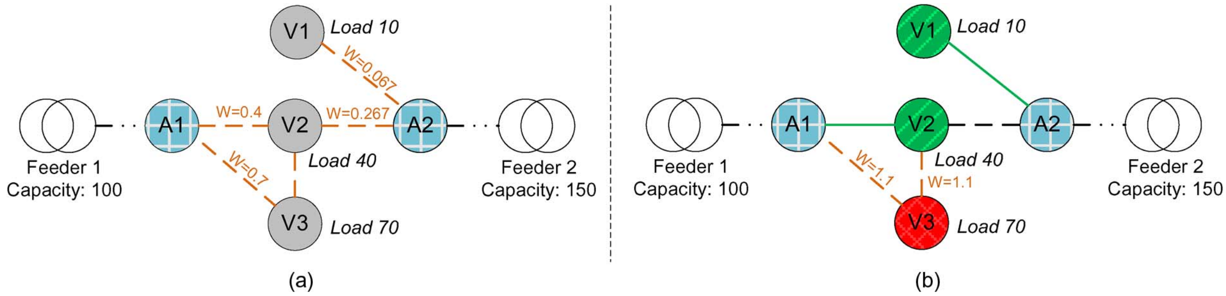


Fig. 4. (a) Example graph that illustrates the suboptimal behavior. (b) Example where the V3 vertex is left stranded.

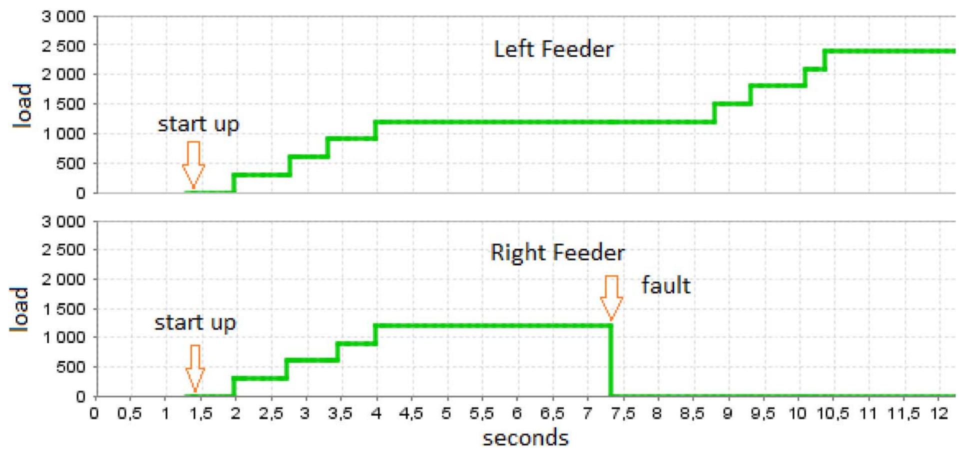


Fig. 5. Plots of the feeders' load with a single fault.

weight $w_{v_3} = (40 + 70/100) = 1.1$ is larger than 1. The result is that V3 is left stranded, as shown in Fig. 4(b).

Tree T_1: Feeder node: $V_f^1 = A1$; Energized node: $V_{e_1}^1 = V2$; De-energized node: $V_{d_1}^1 = V3$.

Tree T_2: Feeder node: $V_f^2 = A2$; Energized node: $V_{e_1}^2 = V1$.

To address this problem, the algorithm has the potential to be extended. In order to help stranded neighbors, the agents need to be aware of the stranded agent, and they have to be able to restart the power restoration. However, it is important to acknowledge the fact that the optimality criterion is determined by the capacity constraints through the graph's edge weights, and this solution might not be optimal from a practical point of view; a simple and reliable but suboptimal algorithm can be better in practice than a more advanced but intricate and resource-consuming one. Therefore, any improvement in this sense has to be weighed against the detrimental effects on the performance.

III. Testbed Design

The MAS is implemented using *Jack Intelligent Agent* (http://www.aosgrp.com) programming software, which is an event-based and agent-oriented framework built on Java. *Jack* provides Belief-Desire-Intention software model behavior, simplistic messaging between agents in different processes/computers, and metareasoning. The scope of multiagent-based control in this work covers the modeling of system-level control behavior and agent interactions in a near-real-time scenario. There are several platforms that can be used for that purpose, and in this case, Jack is selected because it provides explicit constructs for modeling system-level events, system actors as agents, system functionalities as plans, and capabilities. Moreover, Jack allows real-time integration of the multiagent-based control and the power systems simulation.

To test the MAS, a testbed consisting of ten Raspberry Pi (RPi) computers, ten Arduino single-board microcontrollers, and a physical dc electrical grid model is assembled. The agent software is hosted and executed on the RPis (i.e., smart devices installed in substations to provide them the agent capabilities), and the physical interconnection between the RPi and the electrical grid model is done by the Arduinos (i.e., IED). This latter element enables the MAS to acquire current measurements and operate the breakers. These devices are easy-to-use commercial off-the-shelf products that allow proving that the solution can be implemented by means of relatively low-cost equipment with moderate hardware capacity.

The complete MAS for the testbed grid topology, Fig. 1, consists of 34 agents (10 SCAs, 22 Ras, and 2 LCAs), which are distributed among the ten RPis. The timer the LCA uses is set to have a timeout delay of 200 ms, and for the RA a timeout of 400 ms. The system is configured such that the loads have a value of 300 and the capacities of the two feeders are set to 3000, which is larger than the combined load of the eight loads, i.e., 2400. This should enable each feeder to supply all loads in case the other is inaccessible due to fault(s).

A. Results of the Tests

The system is put to test in two scenarios.

1. Single fault in line L2 (see Fig. 5).
2. Recurring faults in lines L1 and L2 with a period of 6 s (see Fig. 6). The faults are cleared after 0.1 s.

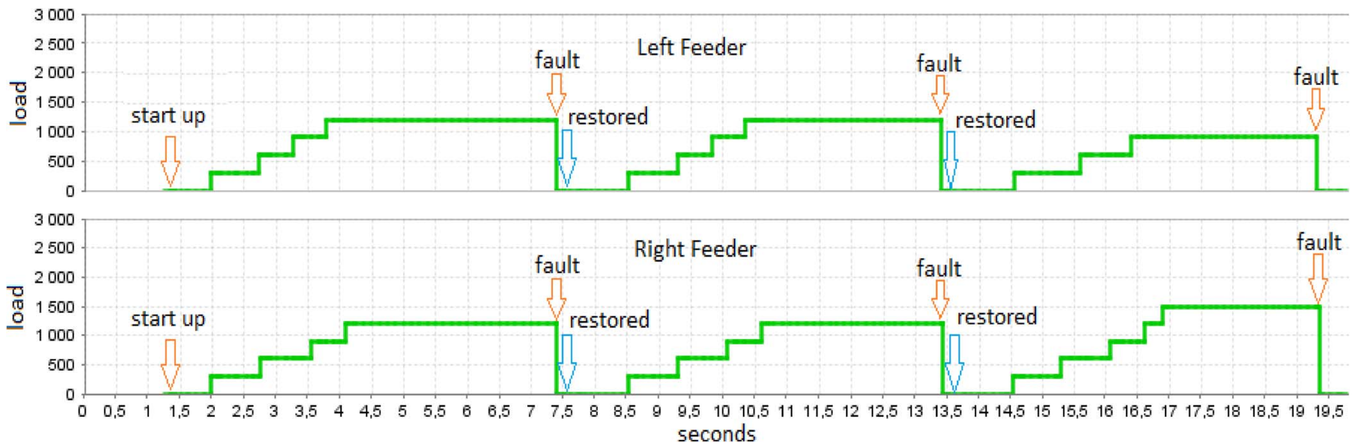


Fig. 6. Plots of the feeders' load with multiple recurring faults.

The results in Figs. 5 and 6 show that the system manages to provide a solution to both scenarios and that the system is stable; it can handle both simple blackouts with only a single fault and multiple simultaneous recurring faults combined with periods of complete blackout. Furthermore, the algorithm is applicable not only for the chosen testbed topology but also for all distribution grids that are reducible to a graph via the method presented in this paper. Additionally, it is seen that the system always strives to balance the feeders' loads and succeeds in all solutions apart from the last in Fig. 6, where one load has been moved from the left feeder to the right due to asynchrony and eventual packet loss.

In order to reconfigure the grid and restore the power supply after faults (or interruptions subject to substation loads and configuration options), the algorithm controls and coordinates the switching operations performed on the distributed grid sites (i.e., substations). The results are close to optimal grid configuration, in terms of the balanced substation loads and percentage of successful restorations.

B. Comparison With the Benchmark Solution

The regular automatic standby activation solution that can be used as a benchmark uses statically programmed switching logic and cannot coordinate switching among remote sites. Such solution does not take into account the dynamically changing loads; it uses fixed switching sequences with predefined timers and cannot provide flexibility of swiftly setting up different grid configurations. Likewise, the robustness and predictability of the operation results get worse when the grid changes due to the accession of new feeders or installation of new automatic standby activation instances.

Furthermore, in contrast to considerably longer manual outage management times that could last from one to several hours [38] (i.e., time for customers to report the outage + time for crew to travel to fix the problem + time for crew to locate the fault + time to perform the manual switching + time to repair the fault), the service restoration part of the FLISR procedure presented in this paper requires approximately 3 s to be executed. Thereby, due to shorter response times, it has the potential to significantly improve the performance indexes such as SAIDI and CAIDI (see Fig. 7).

C. Properties of the Algorithm

The main features of the proposed algorithm are as follows.

- Robustness against multiple distinct blackouts (also local communication blackouts) without any increased difficulty due to the fact that each blackout is locally managed.
- Scalability: Due to the fact that each blackout is locally managed, it allows plug-and-play operation and expansion.
- Instantaneous communication requirement only linearly dependent with blackout size as the RAs locally negotiate. The linear growth permits the system to avoid communication outage states even in large blackout areas.
- It strives to keep the relative load of feeders at the same level, which permits the algorithm to be applicable not only for the FLISR scenario but also for grid startup situations.
- The algorithm relies on the awareness of the grid topology, consisting of properly working substations and lines. Therefore, once a faulty line appears within the spanning tree, it gets isolated and excluded from the grid topology as the MAS acknowledges it.

D. Information and Communication Architecture

The testbed uses an ICT solution optimized to support the multiagent-based distribution automation systems. It covers four layers: multiagent cloud, telecommunication network, service enablement platform, and applications. This layered ICT architecture (shown in Fig. 8) follows the main statements of the so-called cyberphysical service enabler architecture.

The multiagent cloud consists of intelligent devices scattered across the distribution grid. These devices run the agent processes and support the required physical interfaces to control the sensors and actuators in the distribution grid.

The telecommunication network layer offers data communication services by means of wide area wireline or wireless network technologies. The mass penetration of the intelligent devices can be supported by the usage of the public cellular communication networks as the modern cellular network technologies, 4G in particular, allows prioritization of critical data traffic and provide levels of bandwidth and latency sufficient

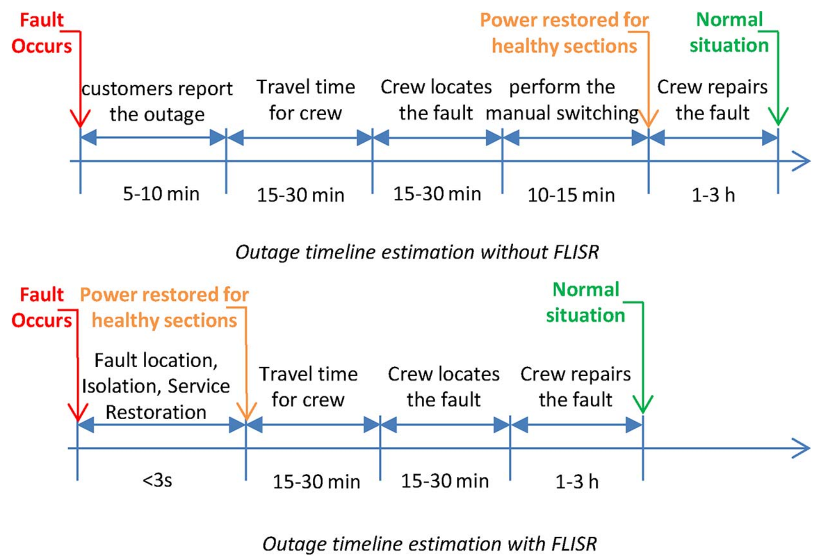


Fig. 7. Outage timelines with and without FLISR.

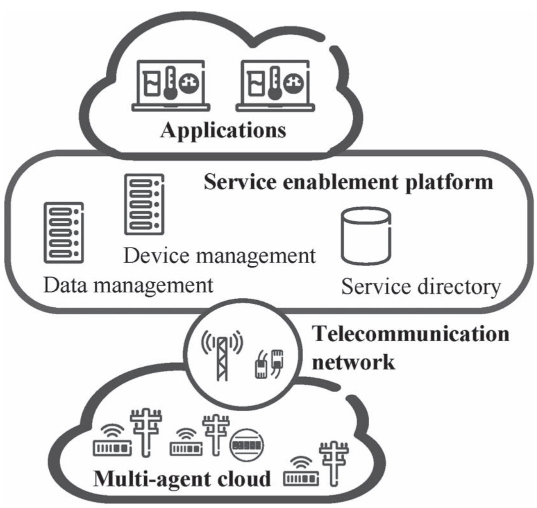


Fig. 8. ICT architecture diagram.

for most distribution automation applications implemented by MAS.

The service enablement platform provides a secure open interface between the MAS and applications. It consists of *device management, data management, and service directory parts*. The device management component enables remote configuration of the intelligent devices along with remote installation of the agent software. The data management functionality provides secure data transmission between the agents and the applications. It registers the addresses of the agents in the telecommunication network and translates service requests from the applications to MAS into the requests in the agent communication language. The service directory informs the applications about services and data provided by the MAS. It supports the ontology data by supplying a description of the MAS and describes the semantics of the service requests and data structures used by the agents.

The application layer accommodates different applications that use services provided by MAS. These can include legacy operator applications such as SCADA and DMS.

IV. Conclusion and Future Work

A multiagent-based distribution automation solution has been developed to restore the power supply in case of outages in a distribution network. The FLISR solution is based on Prim's algorithm, and a parallel ICT architecture is created that is optimized to support the implementation of MAS in smart grids. The tests have been carried out to show that the proposed algorithm can perform the FLISR process as quickly as within several seconds of computation time and that the system is stable and can handle complex scenarios such as multiple simultaneous faults. Future studies will consider load priorities, voltage/current limitations, losses, and stranded vertices. Further simulations will include the study of the alternative communication network design and technologies such as Ethernet and 3G/4G cellular networks, considering the actual geographical aspects of the network topology and the impact on the QoS, e.g., availability, reliability, and resilience.

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Markus Eriksson received the B.Sc. degree in engineering physics from the Royal Institute of Technology (KTH), Stockholm, Sweden, in 2013, where he is currently working toward the M.Sc. degree in systems, control, and robotics with a focus on networked control.

His research interest includes multiagent-based distributed control systems.

Mikel Armendariz (S'12) received the M.Sc. degree in automation and industrial electronics from the University of Mondragon, Mondragon, Spain, in 2008 and the M.Sc. degree in production engineering and management from the Royal Institute of Technology (KTH), Stockholm, Sweden, in 2010, where he is currently working toward the Ph.D. degree in electrical engineering in the Department of Industrial Information and Control Systems, School of Electrical Engineering.

His research interest lies in low-voltage distribution networks with a particular focus on monitoring and control.

Oleg O. Vasilenko was born in Voronezh, Russia, in 1972. He received the Diploma and Ph.D. degrees in communication and information systems from Voronezh Technical University, Voronezh, in 1994 and 1999, respectively.

He is currently a Senior Solution Architect with Ericsson Innovations Russia, Moscow, Russia. His major research field is multiagent-based distributed control systems and their applications.

Arshad Saleem (M'07) received the M.Sc. degree in distributed and intelligent systems from Blekinge Institute of Technology, Karlskrona, Sweden, in 2007 and the Ph.D. degree in electrical engineering from the Technical University of Denmark, Kongens Lyngby, Denmark, in 2011.

He is currently a Researcher with the School of Electrical Engineering, Royal Institute of Technology (KTH), Stockholm, Sweden. His research interests include the application of ICT, distributed control, and artificial intelligence in electric power systems. He is also actively involved with standardization work in electric power systems.

Lars Nordström (M'07–SM'12) received the M.Sc. degree in electrical engineering and the Ph.D. degree in industrial control systems from the Royal Institute of Technology (KTH), Stockholm, Sweden.

He is currently a Professor of information systems for power system management with the Department of Industrial Information and Control Systems. He leads the PSMIX research group at KTH. His research interests include methods and tools for analysis and design of reliable, interoperable, secure, and high-performing ICT systems for operation, control, and automation of power systems. He is engaged in a number of national, regional, and international projects on these topics.

Dr. Nordström is a personal member of CIRED and Cigre, serving, among other things, as a national representative for Cigre SC D2 "Information Systems and Telecommunication." He is also active in a number of standardization activities, including the IEC Strategic Group on Smartgrids as well as Chairman of the IEC TC57's Swedish mirror group.

Paper VI

Method for Reliability Analysis of Distribution Grid Communications Using PRMs-Monte Carlo Methods

Method for Reliability Analysis of Distribution Grid Communications Using PRMs-Monte Carlo Methods

M. Armendariz, R. Gonzalez, M. Korman, L. Nordström
Department of Electric Power and Energy Systems, KTH- Royal Institute of Technology, Stockholm, Sweden
e-mails: {mikel, rodrigog, korman, larsno}@kth.se

***Abstract*— This paper presents a method to perform reliability analysis of communication systems for distribution grids. The method uses probabilistic relational models to indicate the probabilistic dependencies between the components that form the communication system and it is implemented by Monte Carlo methods. This method can be used for performing reliability predictions of simulated communication systems and for evaluating the reliability of real systems. The paper contains a case study in which the proposed method is applied to evaluate the reliability of the communication systems that are required for monitoring the network components at low voltage levels using the smart metering infrastructure. This case study is taken from the EU FP7 DISCERN project. Finally, the results are presented in a quantitative way, showing the individual reliability of each component and the combined reliability of the entire system.**

Keywords—Communication systems for distribution grids, Monte Carlo, probabilistic relational models, reliability analysis.

I. INTRODUCTION

RECENTLY, the electric power system has been going through significant changes. Primarily, these changes are located at the distribution side of the power system, which was traditionally designed to deliver energy in one direction: from generation units to customers. Nowadays though, the power system is being required to cope with new challenges such as bi-directional energy flows caused by the combination of the new consumption patterns and the integration of intermittent renewable energy sources. Such challenges have great impact on the lifecycle of the physical elements that deliver the energy (e.g. lines, transformers, switches) and on the quality of service (e.g. voltage fluctuations, voltage imbalance, frequency deviations) [1]. Therefore, the grid needs to be refurbished with modern infrastructure that allows the deployment of suitable monitoring and control mechanisms to properly operate the grid complying with the required quality of service requirements. Such infrastructure must rely on two-way communication systems that allow the proper functioning of the applications that regulate the operations (e.g. supervisory control and data acquisition, energy management systems, remote protection systems). The technology that supports the later applications and form the communication system infrastructure spans from sensors and meters, Intelligent Electronic Devices (IEDs) and Remote Terminal Units (RTUs), to power line communication, fiber optics, phone lines, wireless-based solutions (e.g. WiMAX, cellular) and the corresponding information technology interfaces (e.g. routers, gateways, links, servers). These communication systems must fulfill several requirements covering security aspects regarding e.g., personal information for energy billing purposes, scalability aspects for hosting more devices and services [2]. Similarly, since systems are continuously being integrated (e.g. photovoltaic systems, measuring and control equipment) and each system follows a particular standard, it turns necessary to foster the use of interoperable standards so that the information can be easily shared among the systems. The reliability aspect of the communication systems is also critical for the proper functioning of the power system. It is very important that the communication systems are in an operative state performing as they should most of the time. It is therefore this quality which is analyzed in this paper: the reliability.

As the communication systems for distribution grids consist of the interconnection of several components and systems, if we were to express the systems' relationships following analytical expressions in a deterministic manner, it would be very difficult to model and to consider the effect of different combinations of values for different inputs, such as the observed availability of the components. Therefore, the reliability analysis is performed by following the Enterprise Architecture (EA) analysis discipline in terms of metamodeling and system analysis [3] and combining it with Monte Carlo (MC) methods that provide the probabilistic aspects of the study. By applying MC methods we add a stochastic characterization to the simulations by generating draws from a probability distribution.

This paper is a continuation of the work presented in the literature regarding reliability analysis of communications and control of power systems using probabilistic relational models (PRM). The PRM framework was presented in [4] and it was extended and applied in [5], [6]. The current work differs from previous contributions by extending the analysis framework by means of MC sampling and by integrating the Smart Grid Architecture Model (SGAM). The presented method can be used by power system simulations studies that require considering the influence of the communication systems' reliability as well as to analyze the reliability of real systems. It focuses on the communication infrastructure of the electrical distribution system and therefore we assume 100% availability for the rest of the systems and components *e.g.,* bus bars, lines, etc. Furthermore, the availability specifications for the different components such as routers and sensors are based on the datasheets provided by vendors.

II. RELIABILITY ANALYSIS

A. Methods for Reliability Analysis

Reliability, availability, and maintainability are three system attributes that are widely used in system analysis disciplines [7]. The reliability is the ability of a system (or component) to perform its required functions under stated conditions for a specified period of time. The availability corresponds to the ability of a system (or component) to perform its function when required; basically it represents the proportion of time for which the component is able to perform its function. These two attributes are related through the maintainability attribute, which represents the probability that a system can be repaired in a defined environment within a specified time frame. Increased maintainability implies shorter repair times and if we assume that maintainability remains constant, the availability percentage values fit the same rules as for reliability percentage values [7].

The communication systems that support power distribution grids offers a variety of functions, e.g. state estimation, voltage-control, etc., which are realized of both hardware and software components of different types with communication over large distances. The reliability analysis is a mature field of research that offers a very handful portfolio of analysis tools. Among others, the most well-known available methods to perform the reliability analysis of the communication systems are Fault Tree Analysis (FTA) [8], reliability block diagrams, Markov chains [9], Bayesian Networks (BNs) [10] and the qualitative method Failure Mode Effects Analysis (FMEA) [11]. Besides, FTAs can be translated into BNs, which are a subset of Probabilistic Relational Models (PRM) and use the probabilistic reasoning capabilities of these to perform probabilistic analysis (see II.C).

B. Reliability Analysis of Distribution Grid Communications

The main big actors and communication paths in the Smart Grid are identified by The National Institute of Standards and Technology (NIST) and these are: the generators of electricity, the carriers of bulk electricity, the network operator, the service providers and market operators, the electricity distributors and finally the end-users that may also generate and store electricity [12]. As far as the distribution domain is concerned, the communication systems serve as links to connect the actors in the distribution domain with the rest of the actors in the other domains. For example, the distribution domain is tightly connected to the Operations domain in real-time to manage the power flows. It is also connected to the transmission domain so that the substations are properly synchronized. And similarly, it is also interconnected with the Markets domain, because this one can trigger behavioral changes affecting both the generation and end-users, and in consequence affecting the distribution grid. In the same way, the communication systems serve as links to internally connect the distribution grid's actors (e.g. capacitor banks, sectionalizers, reclosers, protection relays, storage devices, and distributed generators) so that local functions can be executed, e.g. protection functions, etc. In either ways, the communication is carried out via IEDs, that perform local inter-device (peer-to-peer) communication, or via RTUs or similar devices for a more centralized communication. The power distribution system can be organized in many ways, for instance, the physical layout structure can be radial, looped or meshed. This structure, together with the actors involved in the entire power system and the communication and interaction among these actors influence the reliability of the power distribution grids.

Historically, the literature has been covering the physical power system reliability, with special emphasis on composite generation and transmission systems [13], applications to improve the reliability of radial/meshed distribution networks, [14] and substation and switching stations [15]. Besides, currently due to the Smart Grid concept additional publications that focus on the cyber-physical aspects for power systems reliability are emerging, covering both the inter- and intra-domain communication systems (see [16]-[18]).

C. Probabilistic Relational Model Analysis by MC Sampling

PRMs extend BNs with the concepts of objects, their properties, and relations between them, and can be used as a representation language for structured statistical models. They combine a logical representation (including entities, attributes and relationships) with probabilistic semantics based on BNs. A PRM specifies a template for probability distribution over an architecture model. This template describes a metamodel that includes a relational component (e.g. OR-gates to provide system redundancies, AND-gates to determine series dependencies) to designate the probabilistic dependencies between attributes of the architecture's objects. The main advantage is that it permits to model objects and their relations to each other in a manner similar to entity-relationship diagrams [19]. To be able to use the metamodel, an instance of that template is created and class *Function,* class *Device,* etc. (e.g. smart meter, data concentrator) are specified along with the values for each of their attributes, and the reference slots of the objects. For example, we may have a class *Function* with the reference slot *AssignedTo* whose range is the class *Device*. For each reference slot ρ we have an inverse reference slot ρ^{-1} that denotes the inverse relation. Following the previous example, the class *Device* has an inverse reference slot $AssignedTo^{-1}$to the class *Function (*see Figure 4). The probability distribution is specified as a BN consisting of a qualitative dependency structure and associated quantitative parameters. The *qualitative* dependency structure is defined by associating each attribute *A* of class *X* with a set of parents *Pa(X.A)*. *E.g.* the attribute *reliability* of class *Function* may have as parent *Function.AssignedTo.reliability*, indicating that the reliability of the class function depends on the reliability of

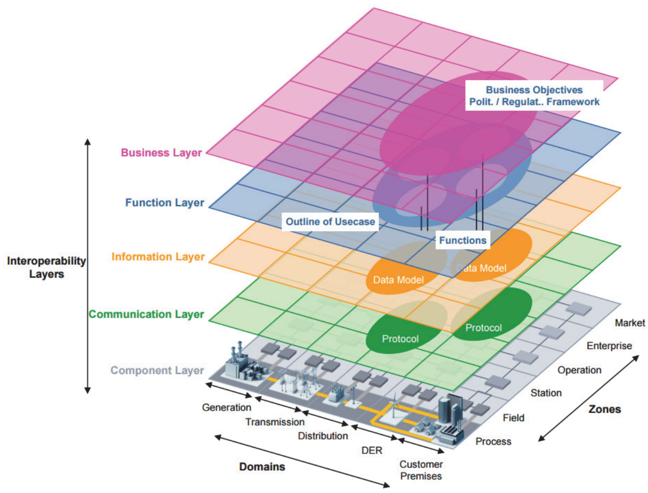

Figure 1. The SGAM framework. *(Courtesy: CEN – CENELEC - ETSI Smart Grid Coordination Group) [22].*

the class which it is assigned to. Regarding the *quantitative* part, given a set of parents for an attribute, a local probability model is defined by associating a *conditional probability distribution* between the attribute and the parents of the attribute. A PRM Π specifies a probability distribution over a set of instance I of the architecture consistent with a relational skeleton σ_r, as in (1). A detailed description of the PRM formalities can be consulted in [20]. This way, PRM constitutes the formal machinery for calculating the probabilities of various architecture instantiations. And this allows inferring the probability that a certain attribute (i.e. the reliability in this case) assumes a specific value. The PRM analysis can be extended by applying MC methods to enhance the study by including a probabilistic approach. MC methods are best suited when the problem has many variables which cannot be solved analytically and usually require large computational power. The input uncertainties such as the actual availability of a certain device are represented by probability distributions. The MC methods build models of possible results by replacing a probability distribution for any factor that has inherent uncertainty. Then, values are randomly sampled from the input probability distributions and the resulting outcome from each sample is recorded. This process is carried out repeatedly, each time using randomly sampled values. The sampling rate will thus determine the accuracy of a simulation. Finally, a large number of results are obtained based on stochastic input values. These results can be used to describe different attributes of the whole system as well as its components, such as reliability.

$$P(I|\sigma_r, \Pi) = \prod_{\mathrm{X}\in\sigma_r(X)} \prod_{\mathrm{A}\in\mathcal{A}(X)} P\big(\mathrm{X.A}\big|\mathrm{Pa(X.A)}\big) \quad (1)$$

III. Method to Perform the Reliability Analysis

This section describes the method and the framework to perform the probabilistic reliability analysis of communication systems for distribution grids. First, the communication system is designed following the SGAM template and then the data is formatted so that the probabilistic reliability analysis can be conducted by means of MC sampling. Finally, the results are presented in terms of mean (μ) and standard deviation (σ).

A. Communication System Design

The communication system architectures considered in this study are designed by following the DISCERN SGAM Visio Template, which is developed in Microsoft Visio and it exports the SGAM models in an XML format based on an extension of IEC 62559-3 data model [21]. The SGAM is spreading among the electricity sector to display system features of Smart Grids. This model is based on five interoperability layers that represent business processes and regulatory constraints, the required system functions, the exchanged information, the communication protocols and the necessary equipment and components. Each layer covers the Smart Grid plane, which is partitioned into five electrical domains (i.e., Bulk generation, Transmission, Distribution, DER and Customer Premise) and six information management zones (i.e., Market, Enterprise, Operation, Station, Field and Process), see Figure 1. The model can be used among other things to design architectures, analyze already installed architectures and to compare, benchmark and to map architectures. Figure 2 shows an example of a component layer design by the DISCERN SGAM Visio Template. It shows the required components for a specific use-case, as well as where in the Smart Grid plane (domains and zones) these components are located. Similarly, it shows from where the components fetch the data.

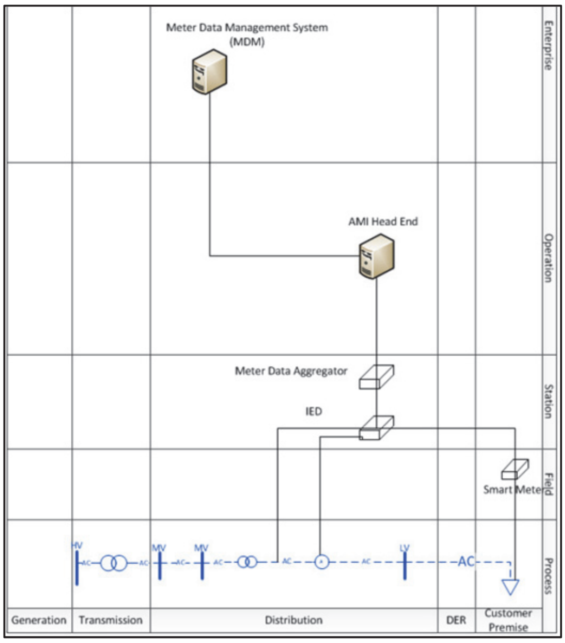

Figure 2. A SGAM component layer design showing the physical components required for a specific meter data collection process.

B. XML2EOM Format Converter

A translator is coded so that the SGAM architecture obtained from the DISCERN SGAM Visio Template in XML format is readable by the ArchiMate [23] metamodel through the tool-specific Enterprise Object Model (EOM) format files. ArchiMate is described as a modeling technique and a metamodel designed to support the practice of EA. Its primary focus is to support stakeholders addressing concerns regarding their business and the supporting ICT systems. ArchiMate is structured in three layers: the business layer, representing business processes, services, functions and events of business units; the application layer, representing software applications; and the technology layer, representing hardware and communication infrastructure. The format converter combines the five layers from the SGAM files into three layers according to the ArchiMate principle so that the Enterprise Architecture Analysis Tool (EAAT) [24] can perform the Monte Carlo simulations (see section III.C). The SGAM layers are combined in the following way: The business layer is conveniently named business layer in both structures, and the component layer and information layer are combined and converted into the technology layer. Similarly, the communication layer and function layer are combined and converted into the application layer.

C. EAAT Object Modeller and Monte Carlo simulations

The EAAT performs the PRM analysis, which is looped by MC simulations and it yields the availability values (see pseudo-code in TABLE I). Since we assume that the maintainability remains constant we can consequently infer the system's reliability values. The EAAT requires the EOM files obtained from the *XML2EOM* converter that contains the communication system architectures and together with the observed availability of each component (obtained from e.g. hardware vendors datasheets), the EAAT's object modeller can create the modelling templates that are required for running the simulations. Figure 4 shows an example of a modelling template (a framework instantiation of the EAAT model) to obtain the system's availability values. The infrastructure functions realize infrastructure services, while these provide meaningful information from the layer to the user. It is the user who adopts the business role, while the process represents the purpose of the application, thus forming a link to the IT system. The connections that are used within layers are realizing links. The objects that interconnect the layers correspond to infrastructure service to application function and application service to the business process. Devices are then connected to infrastructure functions while these are connected to the infrastructure services and the business role is connected to the business process. The non-cursive attributes within boxes in Figure 4 denote the observed availability specifications (e.g., obtained from datasheets provided by vendors); these correspond to sensors (e.g. current, voltage) and switch controls values and are used to obtain the results in the cursive attributes (e.g. availability attribute). If a value is missing or cannot be obtained by measurements, it is replaced by sampling a normal distribution $N(0.95, 0.01)$.

Finally, Figure 3 shows an example of the results that can be obtained by the study. In this example a histogram created by 1000 Monte Carlo iterations and its corresponding fitted normal distribution are shown. The results correspond to the availability used for reliability assessment of the meter data concentrator device that is present in the communication system architecture of Figure 4.

TABLE I
PSEUDO-CODE OF THE EXTENDED PRM ANALYSIS BY MC SAMPLING

for each sample *s* in *sampleSet* ***do***
Pseudo-randomly draw attribute values in the sample *s* for all attributes having a probability distribution defined.
Calculate all derived attributes using PRM technique in the sample.
Add the sample results to a collection of overall results.
for each attribute in the model ***do***
Summarize the results using the values obtained from each sample.
return Availability mean (μ) and standard deviation (σ) values.

IV. CASE-STUDY

This section describes the used case-study to evaluate the reliability of the communication systems in distribution grids. It focuses on enhanced monitoring and observability of network components at low voltage levels using the smart metering infrastructure. It is performed by collecting measurements, events and alarms that are created by the IEDs in the LV network. And its purpose is to use the information in the future for performing power quality analysis to improve LV network operations. Further details on this case-study *e.g.,* Key Performance Indicators (KPI), can be found in [25]. TABLE II shows the hardware that was used for this case-study as well as the obtained reliability values for each part and for the entire system after running MC simulations.

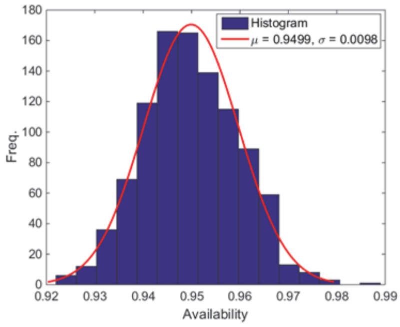

Figure 3. Histogram showing the availability used for reliability assessment of the meter data concentrator device.

TABLE II
RELIABILITY VALUES

Hardware/Section	(%)
LV Voltage sensor	99.9
LV Current sensor	99.9
Link between AMI Head End server and Meter Data Management System (MDMS) server	99.1
Link between MDMS, distribution operator and reporting KPI	99.1
Link between Current sensor and IED	98.1
Link between IED and Meter Data Aggregator	98.1
Link between Meter Data Aggregator & AMI Head End server	98.1
IED	96.1
Link between Voltage sensor and IED	95.1
Meter Data Concentrator	95.0
Smart Meter	94.1
Meter Data Management System server	94.1
Link between IED and Smart Meter	93.1
AMI Head End server	93.1
Total system reliability: from the sensors up to the operator.	**97.1**

V. DISCUSSION

The obtained results correspond to the availability attribute. Since the reliability and the availability are correlated by the maintainability attribute, we can infer that the reliability percentage values will be the same as the availability percentage values, provided that the maintainability of the elements that form the system remains constant. The results take observed availability specifications from datasheets provided by vendors; these correspond to sensors and switch controls. The rest of the components and links that form the system are characterized by a normal distribution $N(0.95, 0.01)$, although a Weibull distribution could also be a very good candidate for reliability modeling. Therefore, the more and the better the components and the links are characterized, the more accurate availability (and thus the reliability) values will be obtained by the EAAT. The availability (and thus the reliability) values are also affected by the component and system configuration. In a series configuration, a failure of any component results in the failure of the entire system and the more components in series the greater will be the availability (and reliability) drop. Besides, the least reliable component has the biggest effect on the reliability of the entire system. That is the situation in the studied case. However, if the components were combined in parallel configuration, the redundancy aspect would be included. This would mean that in the parallel configuration the most reliable component would have the biggest effect on that subsystem's reliability. Because the most reliable component will most likely keep the subsystem functioning upon a failure of an individual component in it.

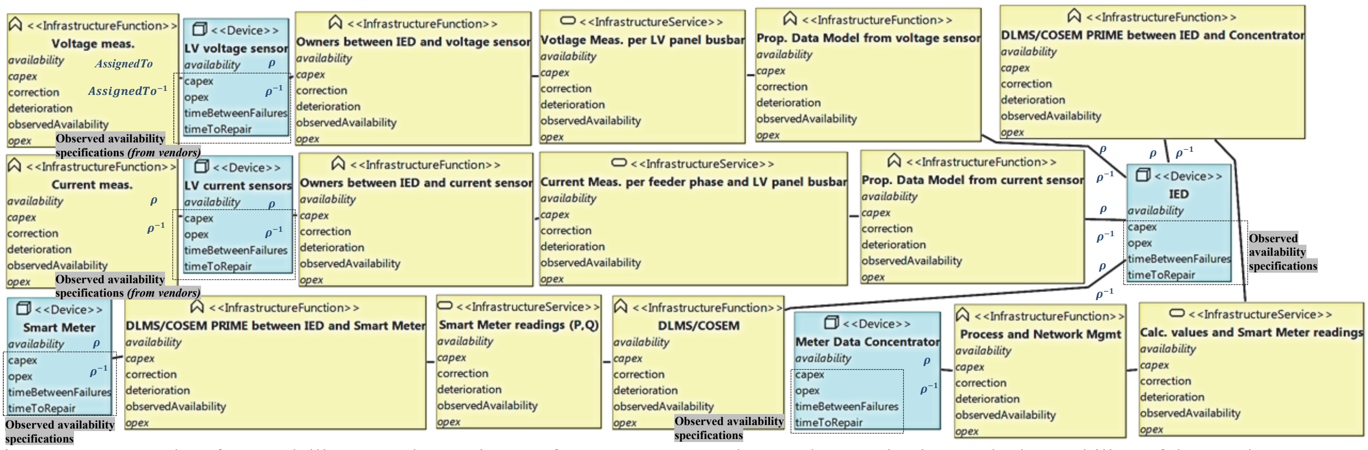

Figure 4. Example of a modelling template snippet of a use-case to enhance the monitoring and observability of low voltage network components. The template is created by EAAT's object modeler and shows the information model of the use-case.

VI. Conclusions

This paper investigates and discusses a probabilistic reliability analysis of communication systems for distribution grids. The analysis is performed by means of PRMs extended by MC methods that provide the stochastic characterization to the simulations. The simulations require including the observed availability specifications for each component that form the system architecture. However, if it is not possible to observe the availability of certain components, the PRM framework allows inferring the probability of these non-observed components by specifying a specific value from a normal distribution, provided that some evidence of the rest of the architecture instantiation is given. The SGAM templates are used to create the architectural design of the presented case-study, which are based on real utility data and their availability, and thus their reliability is calculated. This analysis can be used or embedded in other power system simulations studies that require considering the influence of the communication systems' availability or/and reliability.

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