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Centralised and decentralised control of active distribution systems: models, algorithms and applications.

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A Mamma, Papà e Valeria.

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Contents

List of Figures

List of Abbreviations

AD	Active Demand
ADN	Active Distribution Network
AEEG	Autorità Per l’Energia Elettrica Ed Il Gas
CHP	Combined Heat And Power
DER	Distributed Energy Resources
DES	Distributed Energy Storage
DG	Distributed Generation
DMS	Distribution Management System
DNO	Distribution Network Operator
DSE	Distribution State Estimation
DSI	Demand Side Integration
DSM	Demand Side Management
DSO	Distribution System Operator
DSSE	Distribution System State Estimators
EU	European Union
EV	Electric Vehicle
ICE	Internal Combustion Engine
ICT	Information Communication Technology
IPEX	Italian Power Exchange
JRC	Joint Research Centre
LP	Linear Programming
MAS	Multi Agent System
MO	Multi Objective
OPEX	Operational Expenditure
OPF	Optimal Power Flow
OTC	Over The Counter
PLL	Phase-Locked Loop
PMU	Phasor Measurement Units

PQ	Power Quality
RES	Renewable Energy Sources
SCADA	Supervisory Control And Data Acquisition
SOC	State Of Charge
TSO	Transmission System Operator
VPPs	Virtual Power Plants

Introduction

Power system were traditionally planned and designed by assuming unidirectional power flows from power stations to loads. Nowadays, several factors (e.g., liberalization of the electricity market, need of increased reliability, and environmental issues) lead to a situation where electricity is produced also downstream the transmission level. Connecting generators to the distribution networks could provide several benefits to the whole system, but also technical and safety problems that must be faced.

On the other hand, the loads are changing: new loads like electric vehicles and electric pumps are appearing in the network and they are going to modify the electricity consumption; while traditional loads (white appliances, electronic devices) are designed in order to be more efficient, but with additional functions or special features that require more energy.

For all these reasons, the approach to planning, design and operation of distribution networks is changing, taking advantages of the recent changes and development of information and communication technologies that allow the coordination of the resources, facilitating a number of advanced applications.

As a result, since about 2005, there has been an increasing interest in the Smart Grid, a grid that "incorporates information and communications technology into every aspect of electricity generation, delivery and consumption in order to minimize environmental impact, enhance markets, improve reliability and service, and reduce costs and improve efficiency". Many national governments are encouraging Smart Grid initiatives as a cost-effective way to modernize their power system infrastructure while enabling the integration of low-carbon energy resources.

In the last years, the European Union incentives research, development, and demonstration projects focused on development of the Smart Grids through funding programs created by the European Commission to support and foster research in the European Research Area.

In this context, the thesis presents different techniques implemented to control, operate and thereby integrate distributed energy resources (DER) into the distribution network. The first technique designed is a centralised control, characterised by a central controller (Distribution Management System) that gathers information like the measures of the main electric parameters, energy price and indicates to DERs (Active Loads, Generators, Energy Storage) the optimal set points. The main goal of the DMS is the minimization of system cost, subject to technical and economical constraints. The DMS model has been developed in the ATLANTIDE project, funded by the Italian Ministry of Economic Development under the framework of the Italian Research Fund for the Power System development.

The second technique developed is a decentralised control using Multi Agent Systems (MAS). This type of control has been designed and developed for the direct control of active demand and plug-in electric vehicles, managed by the Aggregator, which is entrusted by the end users to change their consumption habits according to their needs. Moreover, the proposed decentralised MAS, with the active participation of small consumers in the electricity system, support the integration of the Electric Vehicles in the LV distribution network and reduce its harmful impact on voltage regulation.

The techniques and the algorithms proposed by the author will be analysed and applied in representative Italian Distribution networks, by taking into account the development of the distribution system according to the load profile evolution, providing several examples to underline the importance of the Active Management for deferring the reinforcement of the existing grid infrastructures, increasing the hosting capacity of the network.

The structure of the Thesis is as follows.

Chapter 1 describes the evolution of the Power System, from the traditional/ hierarchical model to the modern power system, Smart Grid, underlining the main novelties in the Distribution Network and the problems that need to be faced.

In Chapter 2, the Active Distribution Networks will be described, analysing the revolution in the planning and management of distribution Networks.

Then in Chapter 3, a centralised control of Active Distribution Network is described. The optimization algorithm is analysed and several application in the Italian reference networks will be provided in order to show the effectiveness of the algorithm.

In Chapter 4 a decentralised control, developed through Multi Agent system Technology, for the management of LV systems characterised by many small customers with information flow is proposed.

Finally, Section 6 reports some concluding remarks.

In the Appendix, a brief overview on the most important projects on Smart Grid will be presented. The main European projects and the early smart grid initiatives will be briefly described.

CHAPTER I

1 The Evolution of Power System

1.1 Introduction

Power systems were traditionally planned and designed by assuming unidirectional power flows from power stations to loads. Nowadays, several factors (e.g., liberalization of the electricity market, need of reliability, and environmental issues) led to situation where the generation of electricity is executed also downstream at distribution level. Connecting generators to the distribution networks could provide several benefits to the whole system, but also technical and safety problems that must be faced.

At the same time, also the loads are changing: they are designed in order to be more efficient, but with additional functions or special features that require more energy. Moreover, new loads like electric vehicles and electric pumps are appearing in the network and they will modify the electricity consumption. For all these reasons since 2005, there has been increasing interest in the Smart Grid, an electricity network, with computer-based remote control and automation that allow the communication among all the users connected to it (generators, consumers) in order to efficiently deliver sustainable, economic and secure electricity. The Smart Grid concept combines a number of technologies, end-user solutions and addresses a number of policy and regulatory drivers and is an important economic/commercial opportunity to develop new products and services.

1.2 Traditional Power Systems

A power system is a structure constituted by electric equipment (e.g., generators, transformers, transmission lines, cables and switchgear) used to supply the consumers with electric energy. The power system is a hierarchical system mainly divided into three parts: the generation system, the transmission system, and the distribution system (Figure 1) [1].

In the *generation system,* the electricity is produced in 3-phase Alternate Current (AC) at the generation voltage level in power plants owned by an electric utility or an independent supplier. The voltage is increased by using step - up power transformers.

In 2012, the 28 European Member States (EU-28) produced 3.13 million GWh net electricity (that is the electricity measured at the outlet of the main transformers minus the consumption of power

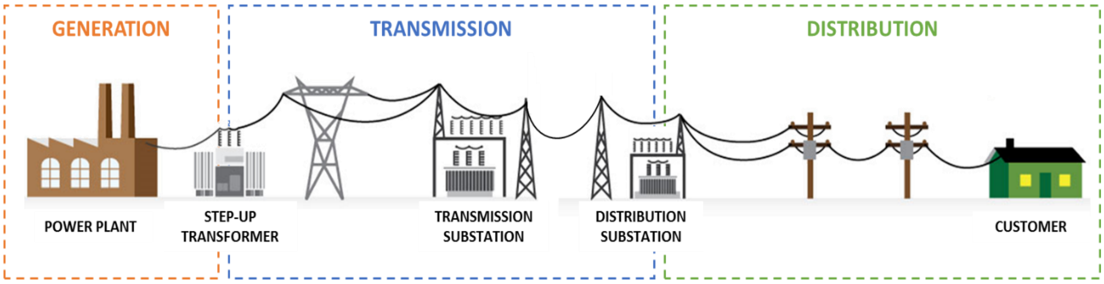


Figure 1: Structure of the Power system with one-directional power flow.

stations auxiliary services). This was the first year of relatively stable output after three years of historically quite large changes: a 5.0% fall in electricity generation in 2009 at the height of the financial and economic crisis, a 4.7% rebound the year after, followed by a further reduction of 2.2% in 2011. As such, the level of net electricity generation in 2012 remained 2.8% below its peak level of 2008 (3.22 million GWh) [2].

The generated power is transmitted over long distances under the most economical conditions, through the *transmission system* that is responsible for the delivery of power to load centres through transmission lines (overhead, underground, and seabed). For long-distance transmission, High-Voltage Direct Current (HVDC) systems may be less expensive and suffer lower electrical losses.

In Italy, the transmission system transfers electricity at 220-380-132-150 kV voltage levels through 63.500 kilometres of lines. The transmission lines, centrally controlled by the Transmission System Operator (TSO), feed the Primary Substations (PS), where the voltage is stepped down to 15-20 kV to supply the MV distribution network.

The transmission grid has good communication links to ensure its effective operation, to enable market transactions, to maintain the security of the system, and to facilitate the integrated operation of the generators and the transmission circuits. This part of the power system has some automatic control systems that could be limited to local, discrete functions to ensure predictable behaviour by the generators and the transmission network during major disturbances [3].

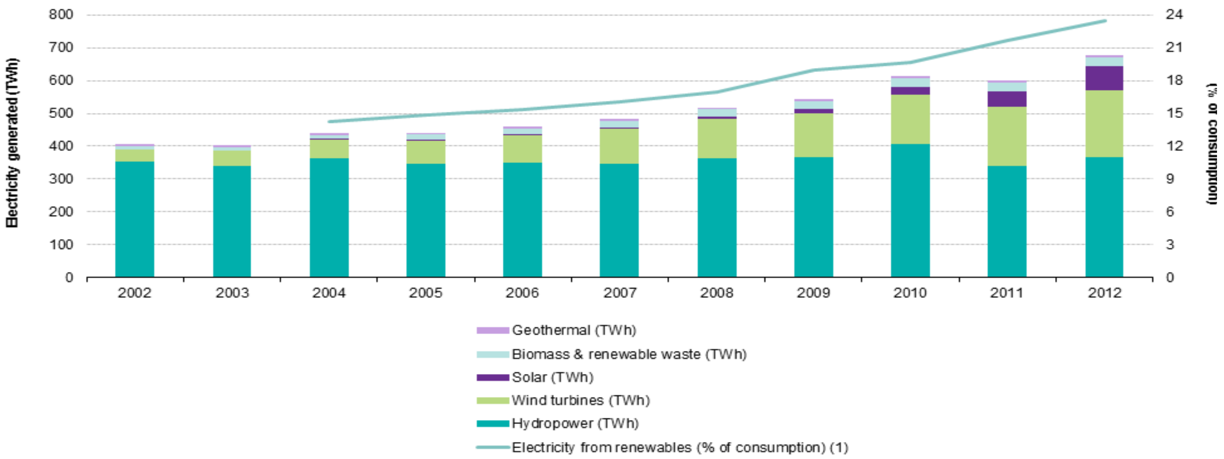
In the *distribution system*, the power is transferred through the distribution lines (or cables) to the local secondary substations (with distribution transformers) where the voltage is reduced to the consumer level (400 V) and the power lines of the local utility or distribution company delivery electricity to the final users (homes, commercial establishment, small industries).

The distribution system is very extensive but is almost entirely passive with little communication and only limited local controls. There is very little interaction between the loads and the power system other than the supply of load energy whenever it is demanded [3].

1.3 Main changes in the distribution networks

Nowadays the traditional division of the electrical power system is no longer representative because political drives (e.g., liberalization of the electricity market), need of reliability, and environmental issues (man-made greenhouse gases are leading to dangerous climate change) determined a situation in which significant volumes of small-to-medium scale renewable generation capacity have been already connected to the distribution networks (known as distributed generation, DG), resulting in bi-directional power flows.

In Europe, the growth in electricity generated from renewable energy sources during the period from 2002 to 2012 (see Figure 2) is characterised by an expansion in wind turbines, solar power and biomass. Although hydropower remained the single largest source for renewable electricity generation in the EU-28 in 2012 (54.1% of the total), the amount of electricity generated in this way in 2012 was relatively similar to that a decade earlier, rising by just 3.9% overall. By contrast, the quantity of electricity generated from biomass (including renewable waste) more than doubled, while that from wind turbines increased more than fivefold between 2002 and 2012. The relative shares of wind turbines and biomass in the total quantity of electricity generated from renewable energy sources rose to 30.4% and 4.1% respectively in 2012. The growth in electricity from solar power was even more intense, rising from just 0.3 TWh in 2002 to overtake geothermal energy in 2008 and biomass and renewable waste in 2011 to reach a level of 71.0 TWh in 2012, some 252 times as high as 10 years earlier. Over this 10-years period, the contribution of solar power to all



(1) 2002 and 2003: not available.
Source: Eurostat (online data codes: nrg_105a and tsdcc330)

Figure 2: Electricity generated from renewable energy sources, in the EU-28, 2002–12. [4]

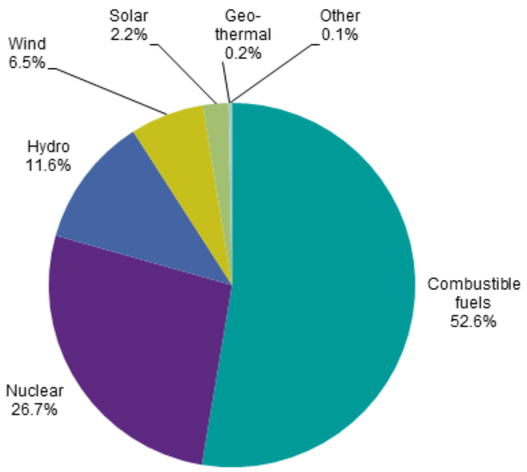
electricity generated from renewable energy sources rose from 0.1% to 10.5%. Tide, wave and ocean power contributed just 0.07% of the total electricity generated from renewable energy sources in the EU-28 in 2012 [4].

Indeed, as regards the structure of electricity production in 2012 (Figure 3): more than one half (52.6%) of the net electricity generated in the EU-28 in 2012 came from power stations using combustible fuels (such as natural gas, coal and oil) while almost a quarter came from nuclear power plants (26.7%). Among the renewable energy sources shown in Figure 3, the highest share of net electricity generation in 2012 was from hydropower plants (11.6%), followed by wind turbines (6.5%) and solar power (2.2%).

Consequently, in order to integrate, at reasonable costs, the DG into distribution networks without jeopardizing the existing quality of service, it is fundamental to have an active/smart approach. This aspect will be better analysed in the next chapter.

1.3.1 Distributed Generation

As a result of these trends, distribution system customers started to produce electricity using their own generation sources and sell it in the electricity market but also with the goal of feeding their loads or as backup sources to feed critical loads in case of emergency and utility outage (becoming prosumers). These distributed sources are defined as *distributed generation* in North American terms and embedded generation in European terms [1].



(1) Figures do not sum to 100 % due to rounding.
Source: Eurostat (online data code: nrg_105a)

Figure 3: Net electricity generation, EU-28, 2012 [4]

Several definitions of DG in Literature give more details on the main characteristics.

The International Energy Agency (IEA) defines DG as a generating plant serving a customer on-site, or providing support to a distribution network, and connected to the grid at distribution level voltages.

CIGRE recognizes to the DG the following characteristic: not centrally planned and not centrally dispatched, usually connected to the distribution network, smaller than 50 or 100 MW [5].

DG is defined as the development of a set of sources of electric power connected to the distribution network or the customer side of the meter [6].

All the above-mentioned definitions identify three same characteristics:

- Small scale generating technologies,
- Connection to the distribution network,
- Local employment.

Distributed generation technologies may be renewable or not; in fact, some distributed generation technologies could, if fully deployed, significantly contribute to present air pollution problems. Distributed generation should not to be confused with renewable generation. Renewable technologies include solar, photovoltaic or thermal, wind, biomass and geothermal. Non-renewable technologies include internal combustion engine (ICE), combined heat and power (CHP), micro turbines, fuel cell [6].

DG can provide several benefits to the owners and the power system [7] - [10]. Table I briefly summarizes technical and economic benefits of DG.

Table I – Technical and Economic benefits of DG.

Technical benefits	Economic benefits
reduced line losses (if DG optimally located);	deferred investments for upgrades of facilities;
voltage profile improvement;	reduced operations and maintenance costs of some DG technologies
reduced emissions of pollutants;	enhanced productivity;
increased overall energy efficiency;	reduced health care costs due to improved environment;
enhanced system reliability and security;	reduced fuel costs due to increased overall efficiency;

improved power quality;	reduced reserve requirements and the associated costs;
contribution to primary frequency regulation	lower operating costs due to peak shaving;
relieved congestion in Transmission and Distribution system.	increased security for critical loads.

However, the benefits of DG are highly dependent on the characteristics of each installation and the characteristics of the local power system. DG may create technical and security problems: increase fault currents, cause voltage oscillations, interfere with voltage-control processes, diminish or increase losses, etc. Several studies investigated the technical impact associated with connecting distributed generation to distribution networks [1], [11]-[14].

Here, a brief overview of the new DG related issues is presented.

- **Bidirectional power flow**

The main change in distribution systems is the *bidirectional power flow* caused by the power injection. In fact the distribution system has been designed to operate assuming a unidirectional power flow feed (radial feed) and technical and economic problems need to be faced with reverse power flows (e.g., some on - load tap changer transformers are not designed to reverse the power flow; the fault level increases; nuisance tripping of some healthy parts in distribution systems).

- **Protection**

Moreover, DG flows can reduce the effectiveness of *protection equipment*: protection of the generation equipment from internal faults; protection of the faulted distribution network from fault currents supplied by the DG; anti-islanding or loss-of-mains protection (islanded operation of DG will be possible in future as penetration of DG increases) and impact of DG on existing distribution system protection.

- **Voltage Profile**

Another problem is the *voltage rise,* mostly in rural networks that are characterised by long overhead lines with relatively high and comparable values of line resistance and inductive reactance (high X/R ratio), low demand and increasing RES generation.

- **Power quality**

The increased penetration of non-conventional types of electricity generators, often connected through power electronic interface, can cause transient voltage variations and harmonic distortion of the network voltage. These could determine thermal stress (due to the increased losses, if the DG placement is not optimal, and the presence of the triple harmonics in neutral current, even for a balanced source), insulation stress (that leads to reduced life time of the insulators). Another issue is the load disruption, which usually occurs with sensitive loads that are designed to operate under nearly pure sinusoidal voltage, or with the loads that depend on the zero crossing of the wave (e.g., communication equipment and the electronic clocks). Finally, the harmonics presence in the networks can cause telephone interference (high harmonic orders in particular), mal-operation of protection devices and switchgears, problems in the metering and instrumentation, and damage of capacitors and cables under resonance conditions [14].

1.3.2 New loads

Environmental concerns, the uncontrollable oil prices together with the fast technological development in the automotive sector, not only have triggered the appearance of DG, but they also led to changes in the load design, increasing the energy efficiency, and to new kinds of loads (e.g., heat pumps, electric vehicles) that will influence the electricity consumption [15].

1.3.2.1 Electricity consumption change

In the EU-27, electricity consumption both in the tertiary sector and in the residential sector is still rising (respectively 41.72% and 31.92% in twenty years).

In the tertiary sector, the largest electricity consumers are lighting in buildings (20.78% and 25.46% together with street lighting), electric space and water heating systems (19.22%), ventilation (12.47%) and commercial refrigeration (8.57%).

In the residential sector although many appliances are getting more efficient, their number is rising, most of them are used more often and for longer periods, or have more functions or special features that require more energy [16].

1.3.2.2 Residential consumption

For instance, the consumption of residential lighting and white appliances (i.e., refrigerators and freezers, washing machines, dishwashers and dryers) is decreasing, due to EU successful energy efficiency policies. Moreover, the air-conditioning market in the EU has seen a positive transformation into a more efficient one with the introduction of the energy label.

On the contrary, the market for television is growing and changing rapidly. Despite an increase in energy efficiency, total consumption of television sets has been increasing over the last years due to bigger screen sizes, flat panel displays, digital television broadcasting and high-resolution television (HD). Between 2007 and 2009 the increase in consumption is estimated some 2-3%, reaching 56 TWh in 2009.

1.3.2.3 Heat pump

The growth of heat pump load poses a challenge for distribution engineers. Heat pumps are seen as a promising technology for load management in the built environment because they can be coupled with Thermal Energy Storage (TES) systems to shift electrical loads from high-peak to off-peak hours, thus serving as a powerful tool in Demand-Side Management (DSM) [15], [17]. At the same time, a heat pump has an induction motor that could depress feeder voltage, especially if several such loads are connected to the same feeder (typically, 10 kW heat pump has a 2.5 kW compressor motor). Moreover, even with a soft-starter, heat pump motors are characterised by a starting current around twice the normal running current, that could cause switching transients and under voltages [18].

1.3.2.4 Electronic Devices

In the residential and tertiary sector, electronic devices (personal computer, smartphones, and tablets) are among the fastest growing electricity end-use. In the last decade, computers have become ubiquitous and their role will continue to be more and more important due to their impacts on productivity, education, society, and personal lives.

In the next chapter, the possible management of the loads will be better analysed.

1.3.3 Electric Vehicles

At the end of 2012, total worldwide electric vehicle stock numbered over 180,000. The spreading of electric vehicles will depend on a large variety of factors such as the performance and costs of batteries, the access to the distribution grid and its efficiency, the type of business model implemented to supply the consumer with reliable batteries and electricity, the acceptance by the consumer of new vehicle types and possible implied driving habits.

The diversity of these factors makes any market projection extremely difficult and impossible to define one single scenario about the penetration of electric vehicles. For these reasons, due to several sets of assumptions that can be made on the above-mentioned aspects, different

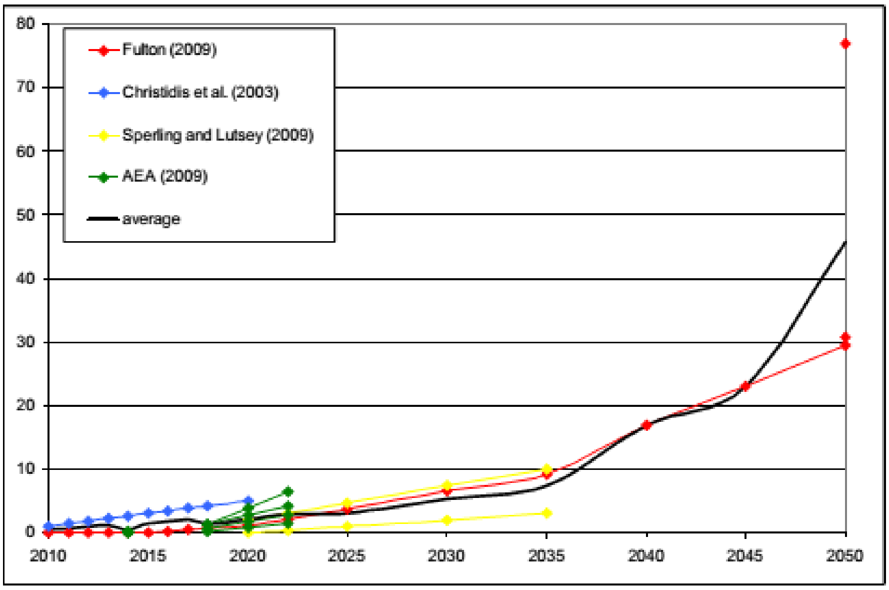


Figure 4: Scenarios about the market penetration of Battery Electric Vehicles (share in new car registration) [19].

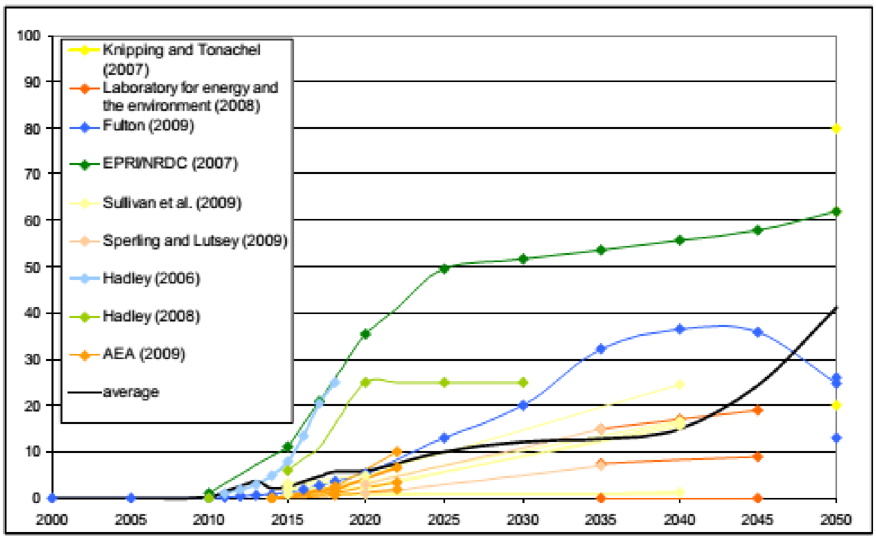


Figure 5: Scenarios about the market penetration of Plug-In Hybrid Electric Vehicles (share in new car registration) [19].

expectations on the market penetration of electric cars can be found in Literature. Figure 4 and Figure 5 illustrate the diversity of scenarios found on Battery Electric Vehicles (BEVs) and Plug-In Hybrid Electric Vehicles (PHEVs) respectively [19].

EV can be classified into four main types:

1. PHEVs equipped with an Internal Combustion Engine (ICE) in addition to their battery to provide traction or charge the battery;
2. Full EVs or Battery Electric Vehicles (BEVs);

3. Hybrid Electric Vehicles (powered by an ICE and by an electric motor that uses energy stored in a battery, charged through regenerative braking and by the ICE).
4. Fuel Cell Electric Vehicles (combines hydrogen gas with oxygen from the air to produce electricity, which drives an electric motor).

PHEVs and BEVs require the use of batteries with high-energy storage capacity and with charging infrastructure connected to the electrical networks. Hybrid Electric Vehicles (HEVs) and Fuel Cell Vehicles (FCV) are not considered in this thesis because these technologies do not represent a load for the power system. In the present thesis, the term Electric Vehicles (EVs) only refers to PHEVs and BEVs.

The EV batteries can be recharged either in a car park, corporate or public, or at home. Public charging infrastructure could include opportunities for rapid recharging, either via fast recharge systems (with compatible batteries) or via battery swapping stations that allow quick replacement of discharged battery packs with charged ones.

1.3.3.1 Main challenges related to EVs

The EV will determine several challenges (related to the customers, to the network and to the EV) that must be handled.

From the *customer* point of view, the main barrier to the market penetration of EVs is related to batteries, because of their cost (which determines the EV more expensive than similar cars), durability, energy capacity (EVs are characterised by shorter driving ranges per charge than conventional vehicles have per tank of gasoline), time for recharge, and technology maturity.

To cope with this consumer risk perception, various business models are being explored and tested, involving the automotive industry and new emerging business companies that are investing in the area.

This theme includes [19]:

- **Battery leasing**: it allows selling the car to the consumer and leasing the battery, covering maintenance, insurance and replacement of the battery, reducing the upfront cost and financial risks. Batteries are expected to be replaced every 5-6 years. When the renewal takes place, the latest battery technology will be implemented, which may have improved performance and range.
- **Vehicle leasing**: it is already applied for the conventional car market, especially when business cars are concerned. This is a more extended version of battery

leasing. It reduces the up-front costs but it has a higher monthly fee (some 600 euros/month).

- **Car sharing**: this model already operates in some cities in Europe with conventional cars, but still in a limited scale. Consumers can pay to rent a car on an hourly, daily or weekly basis as and when they need it. Cars are reserved in advance and collected from a local parking space.
- **Mobile phone style subscription service**: in this model the company owns both the battery and charging network and proposes different subscription pricing packages under which the consumer accesses to the network of charging points and battery stations. This model can also cover the electricity used to charge the battery. This service also covers battery swapping.

From the *distribution network point of view*, EVs will absorb and store energy, when parked and plugged to the electric grid. EV battery charging will increase the load demand, mostly in the peak hours, when the owners come back home from work (*peak on peak* phenomenon). This behaviour (called “dumb charging”), will cause thermal overloading of distribution transformers and cables, voltage excursions mostly in the LV part of the distribution network and power line losses. In order to show the peak-on-peak effect, in [20] the load demand of a MV semi-urban distribution network with 10% conventional vehicles replaced by EV is compared with the load demand without EV [20].

Moreover, the uncertainty related to when and where EVs will charge is a critical issue that needs to be considered to guarantee an efficient and robust operation of the electricity networks. The stored energy could also deliver back to the grid during the parking hours or outage, giving various potential benefits (provision of several ancillary services like peak power and spinning reserves), allowing the vehicle-to-grid (V2G) concept. In [21], the authors stated “The basic concept of vehicle-to-grid power is that EVs provide power to the grid while parked. The EV can be a battery–electric vehicle, fuel cell vehicle, or a plug-in hybrid. Battery EVs can charge during low demand times and discharge when power is needed.” Figure 6 schematically illustrates connections between vehicles and the electric power grid. Electricity flows from generators through the grid to electricity users (LV customers, EV charging station and so on) and flows back to the grid from EVs, or with battery EVs. In [21], the control signal from the grid operator (TSO, Transmission System Operator) is also depicted. Each vehicle must have three required elements: (1) a connection to the grid for electrical energy flow, (2) control or logical connection necessary for communication with the grid operator, and (3) controls and metering on-board the vehicle [21].

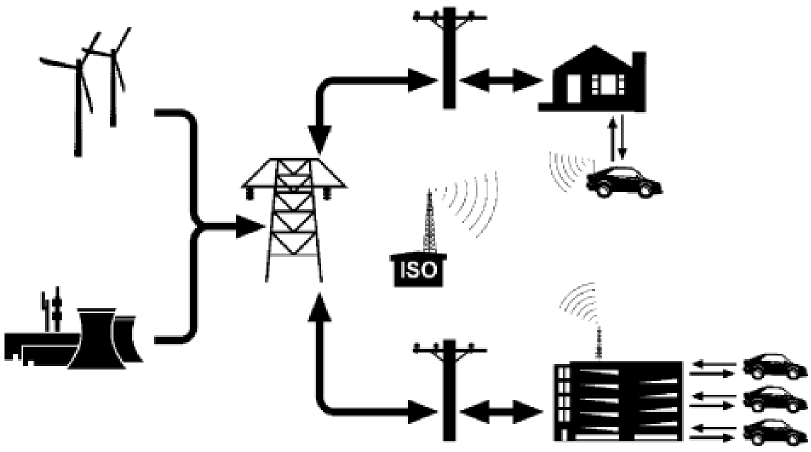


Figure 6: Illustrative schematic of proposed power line and wireless control connections between EVs and the electric power grid [21].

It is clear that a large deployment of EVs will involve:

- evaluation of the impacts that battery charging may have in system operation;
- identification of adequate operational management and control strategies regarding batteries' charging periods;
- identification of the best strategies to be adopted in order to use preferentially RES to charge EVs;
- assessment of the EV potential to participate in the provision of power systems services, including reserves provision and power delivery, within a V2G concept.

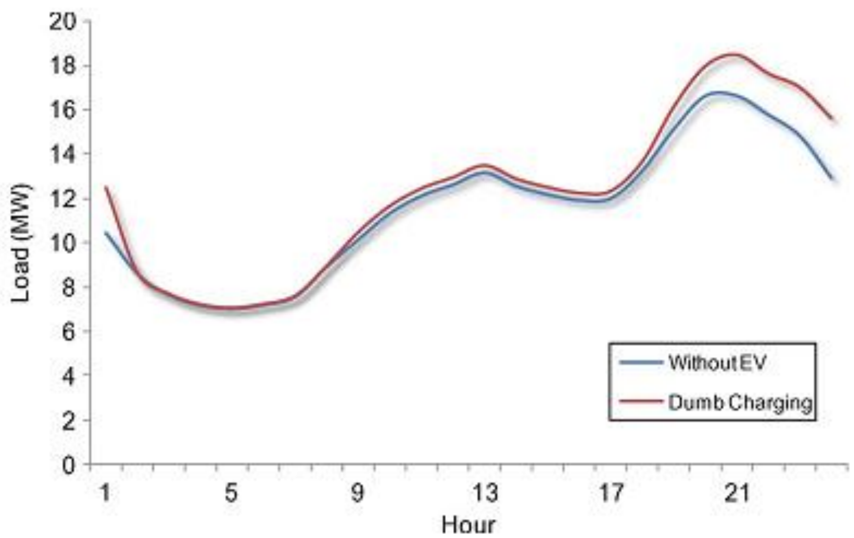


Figure 7: MV grid load diagram with 10% EV [20].

The last challenge is related to vehicles' limits [21]:

1. The current-carrying capacity of the wires and other circuitry connecting the vehicle through the building to the grid, related to the place where the battery is recharged (public car park or at home, that could include opportunities for rapid recharging).
2. The stored energy in the vehicle, that is the on-board energy storage less energy used and needed for planned travel, times the efficiency of converting stored energy to grid power, all divided by the duration of time the energy is dispatched. This is calculated in equation (1):

$$P_{EV}=\frac{\left(E_s\text{-}E_{pl}\right)\cdot\eta_{inv}}{t_{disp}} \tag{1}$$

   Where P_{EV} is the maximum power available, E_s the stored energy available to the inverter, E_{pl} is energy needed for planned travel (directly proportional to the distance to travel and inversely proportional to the vehicle driving efficiency), η_{inv} the electrical conversion efficiency of the DC to AC inverter (dimensionless), and t_{disp} is time the vehicle's stored energy is dispatched (related to the electricity market).
3. The rated maximum power of the vehicle's power electronics.

The third limit is generally much lower than those related to the current-carrying capacity of the wires and the stored energy (limit 1 and 2), so the energy limit is given by the lower of the first two limits.

In the Literature, there are several studies and different research projects founded by the European Union, related to the technical impact of EV. While there are some similarities across these studies, each of them considers a different approach in terms of the electric system, analysis method, EV uptake and charging scenarios analysed [22].

In [20], Lopes et al. present a conceptual framework to integrate electric vehicles into electric power systems. The proposed framework (based on a combination of a centralised hierarchical management and control structure and a local control located at the EV grid interface) covers two different domains: the grid technical operation and the electricity market. In the paper, the differences between advanced control EV charging strategies and uncontrolled charging approaches are analysed, evaluating the impacts of EVs in an MV network, as well as the benefits for the DSO arising from the adoption of a smart charging approach and the impacts of EVs in the dynamic behaviour of a small LV grid and of a larger MV grid, both operated in islanded manner.

In [22] the impact of EVs on British distribution networks has been studied, underlining the importance of the EV owners' behaviour. In the paper, both a deterministic and a probabilistic approach were employed, in order to evaluate the impact of EV battery charging on: thermal loadings of distribution transformers and cables, voltage of distribution network nodes and power line losses.

1.4 The Smart Grid paradigm

Since 2005, there has been increasing interest in the Smart Grid [3]. The Smart Grid concept combines a number of technologies, end-user solutions and addresses a number of policy and regulatory drivers. It does not have a single clear definition [3].

EPRI (Electric Power Research Institute) defines the Smart Grid as a grid that "incorporates information and communications technology into every aspect of electricity generation, delivery and consumption in order to minimize environmental impact, enhance markets, improve reliability and service, and reduce costs and improve efficiency [23].

The European Technology Platform [24] defines the Smart Grid as "an electricity network that can intelligently integrate the actions of all users connected to it – generators, consumers and those that do both – in order to efficiently deliver sustainable, economic and secure electricity supplies."

The Smart Grid is required to be self-healing and resilient to system anomalies. To allow pervasive control and monitoring, the smart grid is emerging as a convergence of information

Figure 8: representation of a Smart Grid [26].

technology and communication technology with power system engineering. Table II depicts the salient features of the smart grid in comparison with the existing grid [25].

Table II – The smart grid compared with the existing grid [25]

Existing Grid	Intelligent Grid
Electromechanical	Digital
One-way Communication	Two-way Communication
Centralised Generation	Distributed Generation
Hierarchical	Network
Few sensors	Sensors Throughout
Blind	Self-Monitoring
Manual Restoration	Self-Healing
Failures and blackouts	Adaptive and Islanding
Manual check/Test	Remote Check/Test
Limited Control	Pervasive Control
Few Customer Choices	Many Customer Choices

Many national governments are encouraging Smart Grid initiatives as a cost-effective way to modernize their power system infrastructure while enabling the integration of low-carbon energy resources. Development of the Smart Grid is also seen in many countries as an important economic/commercial opportunity to develop new products and services. In the European Union, the Smart Grids Technology Platform states that is vital that Europe's electricity networks are able to integrate all low carbon generation technologies as well as to encourage the demand to play an active part in the supply chain [28]. This must be done by upgrading and evolving the networks efficiently and economically. In order to facilitate the integration of the low-carbon technologies, the use of a more *active* approach of managing distribution networks (including both network elements and participants) will be analysed.

1.4.1 Technologies for Smart Grids

1.4.1.1 Information Communication and Technology

As seen in Table II, the current distribution system has little communication, with very little interaction between the loads and the power system other than the supply of load energy whenever it is demanded. ICTs and the Internet will allow countries to manage growing amounts of electricity produced from renewable energies, new modes of transport and living as well as other structural shifts in electricity supply and demand. Technologies and the use of data enable improved and more accurate information about the availability, price and environmental impacts of energy, thereby empowering producers and consumers to make more informed energy conservation choices. The Internet especially gives rise to a new generation of businesses providing services around electricity, adding further value and innovation to the energy sector value chain.

In order to allow an easy communication, avoiding expensive upstream assets, the utility companies have introduced various levels of command-and-control functions (for instance Supervisory Control And Data Acquisition, SCADA), but the distribution network remains outside their real-time control. In North America, less than a quarter of the distribution network is equipped with information and communications systems, and the distribution automation penetration at the system feeder level is estimated to be only 15% to 20% [25]. Italy has an advanced Quality of Service (QoS) for all customers, due to the implementation of advanced grid automation systems for Fault Location Isolation and Service Restoration (FLISR), which significantly improve the continuity of supply of active distribution networks.

ICT for Smart Grids includes [3]:

- two-way communication technologies to provide connectivity between different components in the power system and loads;
- open architectures for plug-and-play of home appliances; electric vehicles and micro-generation;
- communications, and the necessary software and hardware to provide customers with greater information, enable customers to trade in energy markets and enable customers to provide demand-side response;
- software to ensure and maintain the security of information and standards to provide scalability and interoperability of information and communication systems.

In Figure 9, the elements involved in the SG, the communication systems and the different protocols available are depicted.

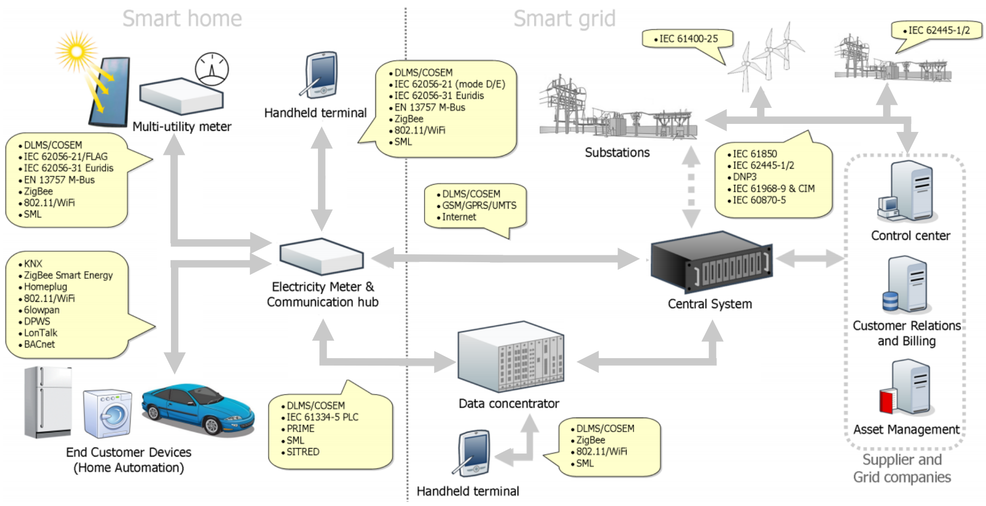


Figure 9: Smart grid system architecture [26].

1.4.1.2 Sensing, measurement, control and automation technologies

These include [3]:

- Intelligent Electronic Devices (IED) to provide advanced protective relaying, measurements, fault records and event records for the power system;
- Phasor Measurement Units (PMU) and Wide Area Monitoring, Protection and Control (WAMPAC) to ensure the security of the power system [27];
- Integrated sensors, measurements, control and automation systems to provide rapid diagnosis and timely response to any event in the power system. These will support enhanced asset management and efficient operation of power system components, to help relieve congestion in transmission and distribution circuits and to prevent or minimize potential outages and enable working autonomously when conditions require quick resolution.
- Smart appliances, communication, controls and monitors to maximize safety, comfort, convenience, and energy savings of homes;
- Smart meters, communication, displays and associated software to allow customers to have greater choice and control over electricity and gas use. They will provide consumers with accurate bills, along with faster and easier supplier switching, to give consumers accurate real-time information on their electricity and gas use and other related information and to enable demand management and demand side participation. Moreover, smart meters will also help Distribution Network

Operators (DNOs) to collect actual load profiles from every node, helping in the planning studies (this aspect will be better analysed in the next chapters).

1.5 Liberalization of the electricity market

The European Union has determined a comprehensive European energy policy in order to limit the EU's external vulnerability to gas and oil imports, combat climate change and promote jobs and growth, encouraging competition in electricity generation, sale and purchase, under criteria of neutrality, transparency and objectivity, through the creation of a marketplace.

The electricity sector liberalization process began on 19 December 1996, with the Directive 96/92/EC [29] of the European Parliament and of the Council concerning common rules for the internal market in electricity. This Directive establishes common rules for the generation, transmission and distribution of electricity. It lays down rules on the organization and conduct of electricity, market access, criteria and procedures applicable to tendering, licensing and exploitation of networks.

In 2003, with the Directive 2003/54/EC [30], the second package for the liberalization of electricity market was introduced. It underlines that fair and impartial access to network is needed as far as the appropriate transmission and distribution systems (vertically integrated enterprises with a distinct legal personality). Additionally, the directive points out the importance to ensure the independence of transmission system operators and distribution over the producers and suppliers.

The third package for liberalization of the electricity market consists of the Directive 2009/72/EC [31], the Regulation 714/2009 on conditions network access for cross-border exchanges in electricity and Regulation 713/2009 establishing the Organization for Cooperation of Energy Regulatory Authorities. This Directive repealed the previous Directive 2003/54/EC.

1.5.1 The European market for electricity

The market that emerged from the EU energy sector liberalisation is predominantly an “energy-only” model, in which generators’ revenues depend solely on the electricity they can sell to the market without receiving any additional income for their installed capacity. In this way, electricity could be treated as any other commodity, with price determined purely by supply and demand. Thus, price signals will establish the optimum level of generation capacity by creating the incentives for all participants to either invest in new power plants or voluntarily curtail their demand in times of scarcity [32].

The participants to the market are both large and small generators (using a variety of technologies), transmission operators, suppliers, retailers, aggregators, ESCOs and customers.

1.5.1.1 The evolution of DNOs towards DSOs

After the liberalization of the electricity market, European DNOs are facing new challenges. Besides their traditional mission to operate, maintain and develop an efficient electricity distribution system, they are asked to fulfil a new role: to facilitate effective and well-functioning retail markets.

According to the European Union directive 2003/54/EC, "Distribution System Operator means a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the distribution system in a given area and, where applicable, its interconnections with other systems and for ensuring the long term ability of the system to meet reasonable demands for the distribution of electricity". That means that DNO should manage the networks as the TSOs do for transmission systems, so becoming Distribution System Operators (DSOs).

DSOs have the responsibility to deliver energy of suppliers to end-users and to maintain the distribution networks. They are hence particularly important in ensuring faultless delivery of electrical power to the end users. In addition, the distribution companies together with suppliers must identify practicable solutions for information exchange on large numbers of customers, in order to simplify and support the choice of the supplier in the competitive market (also because overall European DSOs remain key players in the activity of metering the electricity flow to customers). Accordingly, DSOs' role is to facilitate the market, not participate in it. This is especially valid when managing metering, providing information to market participants and smoothing the process of changing supplier [33].

1.5.1.2 European Market structure

There are two main markets where trade takes place: the *wholesale market* where the bulk of electricity is sold and purchased between suppliers, generators, non-physical traders and large end users; and the *retail market* where electricity is finally sold to the end consumer.

Trading electricity takes place either via *bilateral agreements* or via a *commercial power exchange*. Bilateral contracts represent the greatest volume of electricity traded in most countries. Bilateral trading comprises mostly so-called Over The Counter (OTC) contracts, in which a broker anonymously facilitates transactions between two counterparties, or the counterparties contact each other directly. Contracts can trade energy months or even years before delivery.

Power exchanges often trade lower volumes of electricity compared to what is traded bilaterally. This is done through auctions, where bids and offers are gathered and a market clearing price is struck according to the principles of supply and demand. Therefore, the energy price in power exchanges is particularly relevant as it serves as a reference point or bilateral trading. Power exchanges are generally used for trading medium (months) to short term supply (up to the day prior to delivery or even a few hours before real time).

The electricity market is developed across different time scales:

- **Day-ahead,** when the parties (generators, traders, and end users) can submit bids and offers to buy or sell energy for delivery on the following day.
- **Intraday**, when the adjustments needed after day-ahead gate closure can be made much more economically and efficiently in intraday markets; this allows renewable producers to adjust their positions close to real time and reduce their imbalance (difference between scheduled production and real production), and related costs.
- **Real-time balancing,** when the TSO takes full control of the power system and corrects any imbalance created by the difference between supply and demand in real-time.

During real-time operation specifically, the reserves are dispatched via a balancing mechanism managed by the TSO in which market participants can place bids for up- or downward balancing power. Such a balancing market is the last opportunity for commercial transactions in the system and as such, normally trades at higher energy prices than forward, day-ahead and intraday markets. TSOs incur costs for procuring reserves as well as for energy used to cover imbalances. Therefore, an imbalance mechanism is applied to recover all associated costs from the market participants that deviate from their submitted schedules. The TSO determines these costs either by the marginal price or by the average price of all accepted offers during the balancing period. In addition to this cost, the TSO could charge imbalances differently depending on whether they are positive (more production than forecast) or negative (less production than forecast). It could even add penalties as disincentives for future imbalances.

The design of the imbalance mechanism has important consequences on the interactions between balancing and day-ahead markets. A single price imbalance mechanism applies the penalty only when generators deliver less energy than the one contracted day-ahead. A dual price mechanism applies when generators deliver more and less energy than contracted. A dual imbalance price mechanism is supposed to give stronger incentives to deliver schedules as submitted, but it could also incentivise strategic gaming behaviour and may excessively penalise wind energy generators, as wind forecasting can deviate up or down. Such balancing provisions put them at a disadvantage compared to conventional generators as their forecasts become more accurate closer to electricity delivery, but they have few or no opportunities to use them in real time operation.

1.5.2 Italian Power Exchange (IPEX)

In 1999, the Italian Electricity Market arises from Legislative Decree no. 79 of 16 March 1999 (Legislative Decree 79/99), which transposed the European Directive on the internal market in electricity into the national legislation.

The Italian Energy Market is managed by Gestore dei Mercati Energetici (GME). GME is wholly owned by the company *Gestore dei Servizi energetici* (GSE), which is in turn entirely owned by the Ministry of economy and finance. GSE has also full control of the companies *Ricerca sul Sistema energetico* (RSE) and *Acquirente Unico* (AU) (company that buys electricity, on the power exchange or on OTC basis, in the market at the most favourable terms and sell it to distributors or standard offer retailers for supply small customers who do not purchase in the open market).

Unlike other European energy markets, GME's market is not a merely financial market, where prices and volumes only are determined, but a real physical market, where physical injection and withdrawal schedules are defined [34].

The Italian Electricity Market consists of:

- **Spot Electricity Market**
- **Forward Electricity Market with physical delivery obligation**; it is the venue where forward electricity contracts with delivery and withdrawal obligation are traded.
- Platform for physical delivery of financial contracts concluded on IDEX (Italian Derivatives Energy Exchange, is the derivatives segment of the Italian Market exchange, where financial electricity derivatives are traded).

In Figure 10, the organization of the electricity market is summarized.

1.5.2.1 Spot Electricity Market

The Spot electricity Market consists of three submarkets:

- **Day-Ahead Market**, where producers, wholesalers and eligible final customers may sell/buy electricity for the next day;

- **Intra-Day Market**, which replaced the existing Adjustment Market; in this market, producers, wholesalers and eligible final customers may change the injection/withdrawal schedules determined in the Day-Ahead Market.
- **Ancillary services Market**, where the TSO procures the ancillary services needed to manage, operate, monitor and control the power system; this market consists of an ex-ante session, during which services for congestion relief and reserve capacity are bought; and a second intra-day session, during which the same bids/offers are accepted for balancing purposes.

1.5.2.2 The Day-Ahead Market

The Day-Ahead Market is a wholesale electricity market, where hourly blocks of electricity are negotiated for the next day and where prices, volumes and also injection and withdrawal schedules are defined for the next day. It is based on an implicit-auction model and hosts most of the transactions of purchase and sale of electricity.

Before the sitting of the Day-Ahead Market, GME provides market participants with information about the expected electricity requirements for each hour and each zone and the maximum admissible transmission limits between neighbouring zones for each hour and each pair of zones.

For each hour and each zone, GME also specifies the conventional reference price, i.e. the price that GME conventionally applies to demand bids without a price limit in order to assess their adequacy with respect to the available amount of the market participant’s financial guarantees.

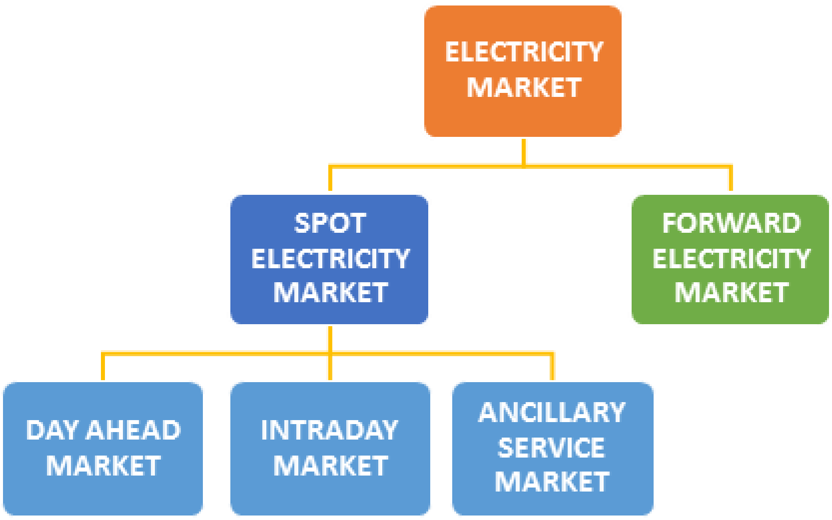


Figure 10: Organization of the Electricity Market.

The accepted demand bids pertaining to consuming units belonging to Italian geographical zones are valued at the "Prezzo Unico Nazionale" (PUN – national single price); this price is equal to the average of the prices of geographical zones, weighted for the quantities purchased in these zones.

1.5.2.3 The Intra-Day Market

The Intra-Day Market enable participants to update their demand bids and supply offers, as well as their commercial positions, with a frequency similar to the one of continuous trading, taking into account variations of information about the status of power plants and consumption requirements, defined in the Day Ahead Market by submitting additional supply offers or demand bids. Continuous trading is a mechanism of trading based on automatic matching of demand bids and supply offers and continuous entry of new bids/offers during the trading sessions.

The sessions of the Intra-Day Market are based on price-setting rules that are consistent with those of the Day Ahead Market. Nevertheless, unlike in the Day-Ahead Market, the PUN is not calculated and all purchases and sales are valued at the zonal price. Upon the closing of each session of the Intra-Day Market, GME (as done at the end of the Day-Ahead Market) notifies the TSO of the results that are relevant for dispatching: flows and updated injection and withdrawal schedules. If there are other market sessions after the one to which GME's results refer, these results are required by the TSO to determine preliminary information about residual transmission capacities between zones for subsequent market sessions.

1.5.2.4 The Ancillary Services Market

The Ancillary Services Market is the venue where the TSO procures the resources that it requires for managing, operating, monitoring and controlling the power system (relief of intra-zonal congestions, creation of energy reserve, real-time balancing). In this market, the TSO acts as a central counterparty and accepted bids/offers are valued at the offered price (pay-as-bid).

In Figure 11, the organisation of the Electricity Market in Italy it is represented.

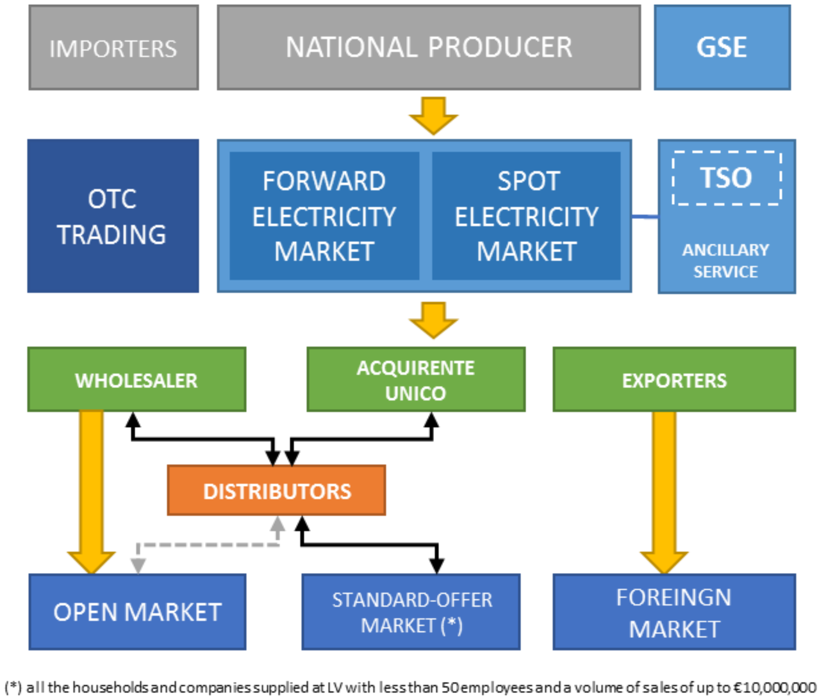


Figure 11: Schematic representation of the Italian Electricity Market.

CHAPTER II

2 Modern Distribution Networks

2.1 Introduction

The increasing quantities of Distributed Energy Resources (DERs), often based on Renewable Energy Source (RES), but also the ageing infrastructure, the increasing consciousness of environmental issues, the rising energy costs, the regulatory pressure, the growing demand of energy and the rapid innovations in technology are both drivers and challenges for the distribution business. Therefore, a Smart Grid is fundamental for a sustainable energy future, because it is capable of addressing all the challenges previously mentioned. An important step towards this new electric system model is the concept of the Active Distribution Networks (ADNs).

The above-mentioned revolution in the power system, that is the increasing quantities of DER (RES, batteries and loads), but also the ageing assets and lack of circuit capacity (that requires high capital costs for replacement/reinforcement), but also the limitation previously stated before require more active approach of planning and managing distribution networks.

2.2 Active Distribution Network

The possibility to better integrate the RES in the Distribution Network is given by the ADN. ADN would be considered by most to be under the Smart Grids umbrella term, but instead of the term Smart Grid, widely used in the industry associated with the development of different applications around a newly integrated information technologies layer to the power system, applied to both transmission and distribution networks, ADN is totally related to distribution networks.

A shared global definition of active distribution networks was developed by CIGRE Working Group C6.11 in [35]:

"Active distribution networks have systems in place to control a combination of distributed energy resources (DERs), defined as generators, loads and storage. Distribution system operators have the possibility of managing the electricity flows using a flexible network topology. DERs take some degree of responsibility for system support, which will depend on a suitable regulatory environment and connection agreement".

In Figure 12, the general schematic of an ADN with many of these technologies is presented.

There are several ways to implement ADNs. They range from the innovative standalone operation of a single network element (e.g., On-Load Tap Changer, OLTC, on the transformer or voltage regulator relay) without the need of remote communications to the extensive use of the latter (i.e., ICT infrastructure), in order to manage network elements and participants/actors altogether, according to the corresponding application of the scheme [3].

Depending on the schemes in place, it can be said that ADNs follow a similar philosophy to that used in transmission systems: preventive and/or corrective control actions due to the occurrence of events such as faults, contingencies, violation of network constraints, etc. are applied. The active network management system – the core of ADN - will provide alternative ways to solve the most common technical issues (*no-network* solutions) typically faced with business as usual *network* solutions (e.g. line/transformer refurbishment). Table III presents some examples of how these issues could be solved by either of the two approaches. It is worth noting that traditional investments will be always needed at some point in the planning horizon, but it is evident that no-network planning alternatives have the potential to cope with many network issues in the short to mid-terms [36].

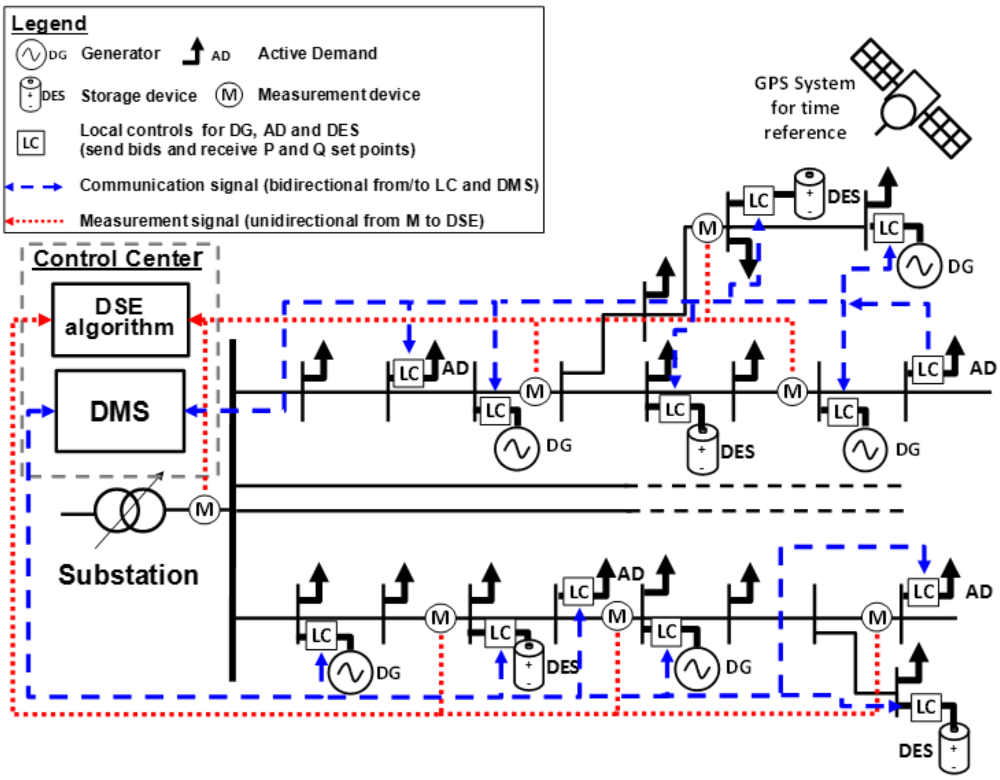


Figure 12: General schematic of ADNs [36].

Table III – Business As Usual and ADN approaches to Tackle Technical Issues [35]

ISSUE	NETWORK SOLUTIONS	NO-NETWORK SOLUTIONS
Voltage rise/drop	Network reinforcement Generation tripping Capacitor banks Limits/bands for demand and generation	Coordinated Volt/VAR control Coordinated dispatch of DER Storage On-line reconfiguration
Hosting Capacity	Network reinforcement	Coordinated dispatch of DER Storage On-line reconfiguration
Reactive Power Support	Transmission network Capacitor banks Limits/bands for demand and generation	Coordinated Volt/VAR control Storage Coordinated reactive power dispatch of DER
Protection	Protection settings tuning New protection elements	On-line reconfiguration Dynamic protection settings
Ageing	Strict network designs specifications based on tech./econ. analyses	Asset condition monitoring

2.2.1 Distributed Energy Resources

Distributed Energy Resources are all the elements that make the distribution network “active”.

Furthermore, the full integration of stationary energy storage devices, plug-in electric vehicles and active demand through communication facilities has the ambition to change the way the power system is operated, by partly abandoning the classical “load following” paradigm to adopt the new “load shaping” paradigm.

DERs are parallel and stand-alone electric generation units located within the electric distribution system at or near the end user that could be beneficial to both electricity consumers and the power systems provide that the integration is properly engineered. Even if the centralised electric power plants will remain the major source of electric power supply for the future, installing DER at or near the end user can also in some cases benefit the electric utility [37], [38].

DERs in the distribution network are:

- **Distributed Generators** (analysed in the previous chapter) small scale generating technologies (renewable, Renewable Energy Resources, or not) connected to the MV-

LV level. DG may determines technical and economic benefits (relieve contingencies, deferred investments for upgrades of facilities, reduced emissions of pollutants) but also create technical and safety problems like increasing fault currents, cause voltage oscillations

- **Distributed Energy Storage (DES)**. The rapid advances in energy storage technology and the growing interest of the industrial world and the scientific community have permitted such devices of reasonable size to be designed and commissioned successfully aiming at balancing any instantaneous mismatch in active power during abnormal operation of the power grid. This pressure to the diffusion of DES clashes with the lack of a clear regulatory environment that defines who can possess these devices, which operation constraints can be imposed, which mechanisms of grants (like the feed-in tariff for renewable energy) can be exploited by the investors. All these issues are very important because the costs of the technologies used for the storage devices in the distribution networks are still high and can weight on the investment's profitability [39].
- **Electric Vehicles** belong to non-conventional loads. They will have a great impact on the distribution network because of their charging pattern. For this reason, it is important to find a suitable charging strategy in order to avoid the problems and maximize the benefits, giving support to the network.
- **Loads**, that means the participation of customers to Active Demand (AD) programs for the management of the network. AD customer is paid for the requested changes in active power production/absorption with respect to the scheduling pattern and for the support to the network.

2.3 Planning Distribution Network

Distribution networks were designed to cope with the worst-case scenario (mainly in terms of loads and voltage drops, and certain security constraints) of a given load forecast and in order to require minimum or no operation. This approach, called fit-and-forget, is carried out by assuming certain that the worst case will happen (deterministic approach). The design of the system must cope with the worst scenario.

The traditional planning process starts defining a planning study, with several alternatives to be examined. These are then technically assessed taking into account of the load demand forecasts for the corresponding planning horizon. If a planning alternative is not technically feasible (particularly for the design of feeders), then network reinforcement/expansion plans (e.g., new conductor sizes, transformers. feeders, etc.) are applied. Otherwise, the next step is to evaluate the corresponding cost. The most cost-effective solution is finally the planning alternative likely to be adopted. Figure 13 presents a generic flow chart that resembles this common practice. In fact, the WG C.19 proposed the flowchart to several DSOs, and more than 90% of respondents confirmed that they follow the traditional steps of the typical distribution network planning process.

The fit-and-forget approach has been also applied when distributed generation has to be connected, considering a maximum generation-minimum demand scenario that, for renewable sources, does not occur frequently. While in some cases, the current design of networks has been adapted to cater for distributed generation, this passive way of planning and operating the distribution networks has proven cost-effective in the last decades, it might in the future become a barrier for increasing penetrations of DG and non-conventional loads (as described in the previous chapter).

DNOs will commonly provide *firm capacity access* to *medium-scale DG plants* (i.e., ability to produce up to the registered capacity at any time with a defined range of power factor capability) provided there is minor or no impact on the network (otherwise reinforcements will need to be paid for according to national rules). This means that with each subsequent connection, the hosting capacity of the network will be reduced, reaching its *fit-and-forget* limit soon. Some DNOs, in order to facilitate further penetrations (aligned with local, regional or government targets), have also

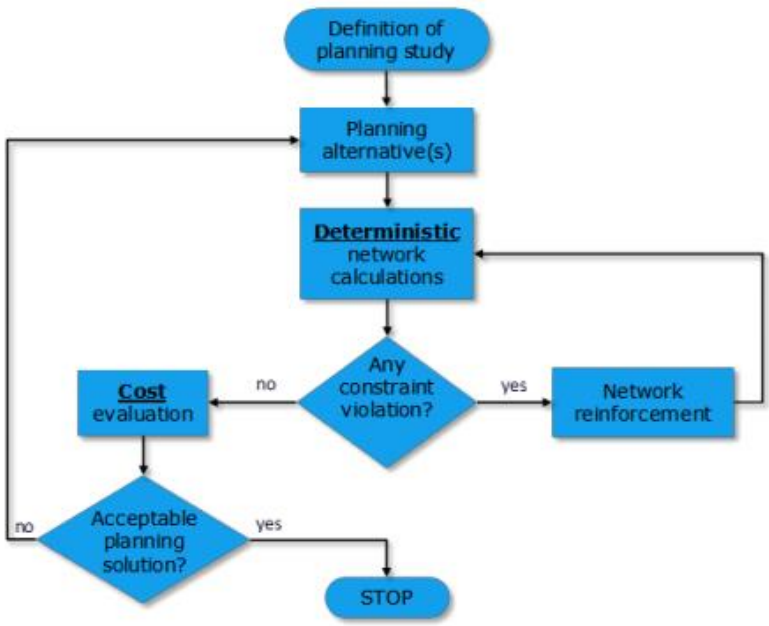


Figure 13: General Planning Framework for Passive Networks [35].

adopted *non-firm connections* where generators are tripped automatically (in a last-in-first-out basis) after a network constraint is violated. While *non-firm connections*, applied in a few countries (e.g., UK and Italy), do increase the hosting capacity of distribution networks for medium-scale DG, this approach can also reach its limits relatively soon, either due to technical constraints or economic factors (for the DG developers) [35].

Connections of *small-scale distributed generation*, commonly in the form of photovoltaic panels or micro CHP, have -in general- different rules. Such installations will basically need to comply with minimum standards (according to the region/country) and register the connection (as part of, for example, a feed-in-tariff scheme). Broadly speaking, this means that the DNO has little or no control over the penetration of this type of connections. Therefore, high penetrations of small-scale DG can quickly and more easily lead low-voltage circuits to have technical issues similar to those found upstream [35].

2.3.1 The evolution of planning: from a passive approach to an active approach

The "Copernican revolution" from the current passive distribution network to the future Smart Grid paradigm aims at applying at distribution level (improved and tailored) techniques and solutions that have been used for decades in transmission systems.

The advent of more advanced distribution networks is progressively changing distribution planning objectives: increasing the hosting capacity at minimum cost in order to accept all the connection requests received without jeopardizing the network security and the quality of supply So a maximum exploitation of existing assets and infrastructure will become a priority, and their operation will be much closer to their physical limits than in the past. Moreover, the majority of this new generation is no programmable and dispatchable (RES), and increasing levels of uncertainty are now faced by DNO/DSO.

Therefore, the *fit-and-forget* approach, due to the high and not necessary expenditures caused by its application, is no longer suitable for modern distribution networks. Indeed, the future philosophy of distribution network planning will consider less traditional network investments instead of cost-effective Active Distribution Network solutions such as generator dispatch, demand side integration, control of transformer taps, etc. (see previous Table III) in order to manage network issues [35].

Active Distribution Network Planning starts with the definition of the planning study (identification of which options have an effective impact on the planning analyses and need to be represented). The second step is the customer's data modelling. In fact, a wrong load forecast could pre-date investments and cause equipment over-sizing (in case of over-estimation), or, in case of under-estimation could provoke early degradation of the quality of service due untimely upgrades. So, the model is no longer based on a snapshot of the operating conditions (e.g., max generation/min demand, min generation/max demand), but adopting time-series (or time dependent) models in order to capture the operational aspects of different network elements.

Two possible ways to represent the hourly variability of demand and generation are [36]:

1. The characterisation and clustering of demand-generation states in a year, considering time series profiles of annual power consumption and generation. This solution allows to recognize different operating conditions and to cluster them in order to decrease the computational burden of the planning calculations (Figure 14). The analysis has to be extended to several years of historic data, in order to have a better estimation of the probability of occurrence of each state [40]. It is worth noting that the amount of historic data available may not be enough to properly extend this methodology, due to the relatively recent introduction of RES generation and the lack of widespread measurement systems [36].
2. The identification of distinctive daily profiles to be used seasonally or for the whole year by choosing from the time-series annual profiles some typical days that could be assumed as sufficiently representative of the behaviour of loads. These representative days are then divided into elementary intervals (1 hour) and the network calculations are repeated sequentially for each of them (Figure 15). In this case, to capture the corresponding uncertainties, loads and generation have to be modelled with suitable probabilistic density functions (e.g., normal, beta, etc.) [41].

To cope with the several uncertainties that mark the electrical distribution system, two actions are performed:

- a *probabilistic network calculation* (i.e., probabilistic load flow calculation) to represent the typical planning data and the existing correlations (among loads, among generators, and between loads and generators) and
- *the use of the risk concept* in the choice of the best planning alternatives.

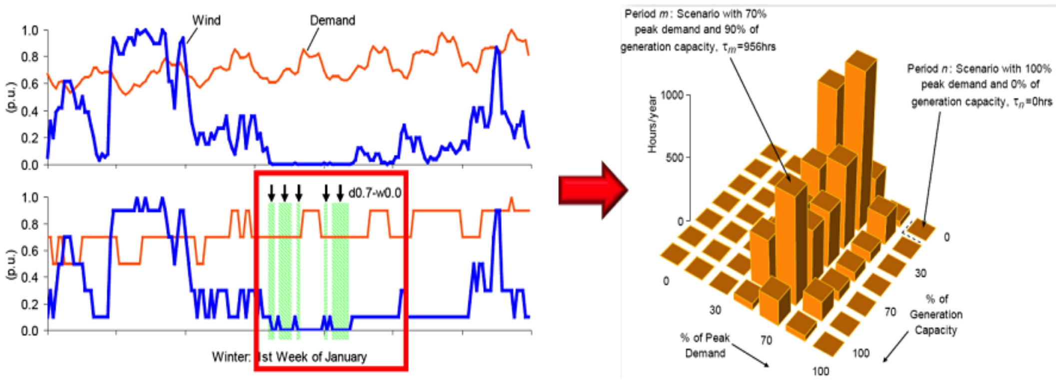


Figure 14: Characterization and clustering of demand and generation variability [40].

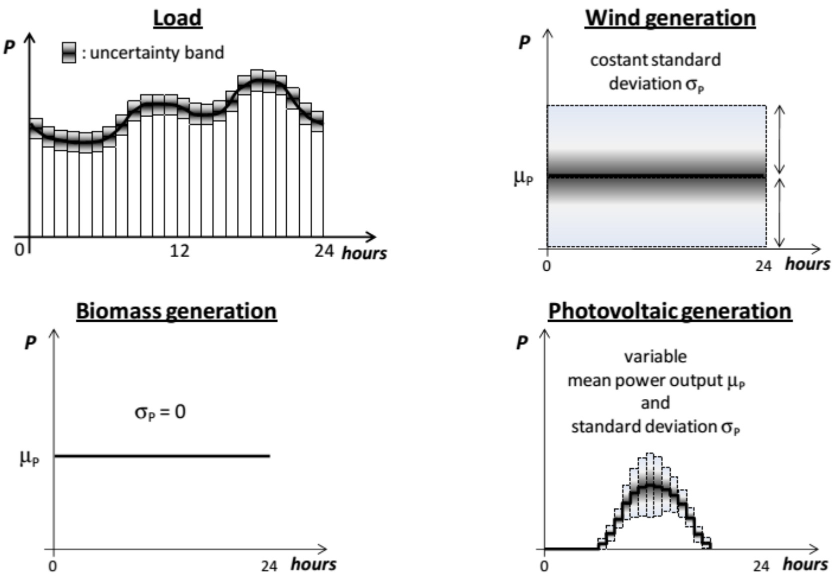


Figure 15: Example of daily profile representation [41].

If the risk of constraint violations is acceptable, it is possible to integrate the no-network actions given by the Active Management; if not, multi-objective programming is recognized to be the most effective way for planning transparently and objectively the system evolution taking into account the multiple needs of different stakeholders.

The new General Framework for ADN Planning is depicted in Figure 16.

2.3.2 Probabilistic approach

One of the main sources of uncertainty in MV distribution network calculations is the renewable generation, due to the unpredictability of the primary energy sources (wind speed, solar radiation, and water flow). In addition, the load manifests natural random variations that can increase in presence of residential photovoltaic installations and uncontrolled recharge of EVs. These uncertainties can be modelled by suitable probability density functions (*pdf)*, if the probabilistic data for the input variables are available. Depending on the stochastic distributions assumed (i.e., Gaussian, Beta, Rayleigh, etc.), network calculation can be performed with specific probabilistic load flow algorithms or with the most general Monte Carlo simulation approach. Instead, when the probabilistic data are unknown, the planner can draw out possible scenarios based on experience and knowledge or, for instance, by using fuzzy set theory. The results of these calculations are the stochastic representation of the nodal voltage and branch current variables, through which the technical constraints can be verified with a relative confidence (acceptable risk of violation) [42].

By so doing, cheaper planning schemes (in respect to the ones obtained with the *fit-and-forget* approach) may be adopted being aware of the (low) risk accepted.

2.3.3 Multi-Objective approach

The liberalization of the electricity market has broken the monopoly of the players involved in the power system, adding to the electric utilities (committed to network management and

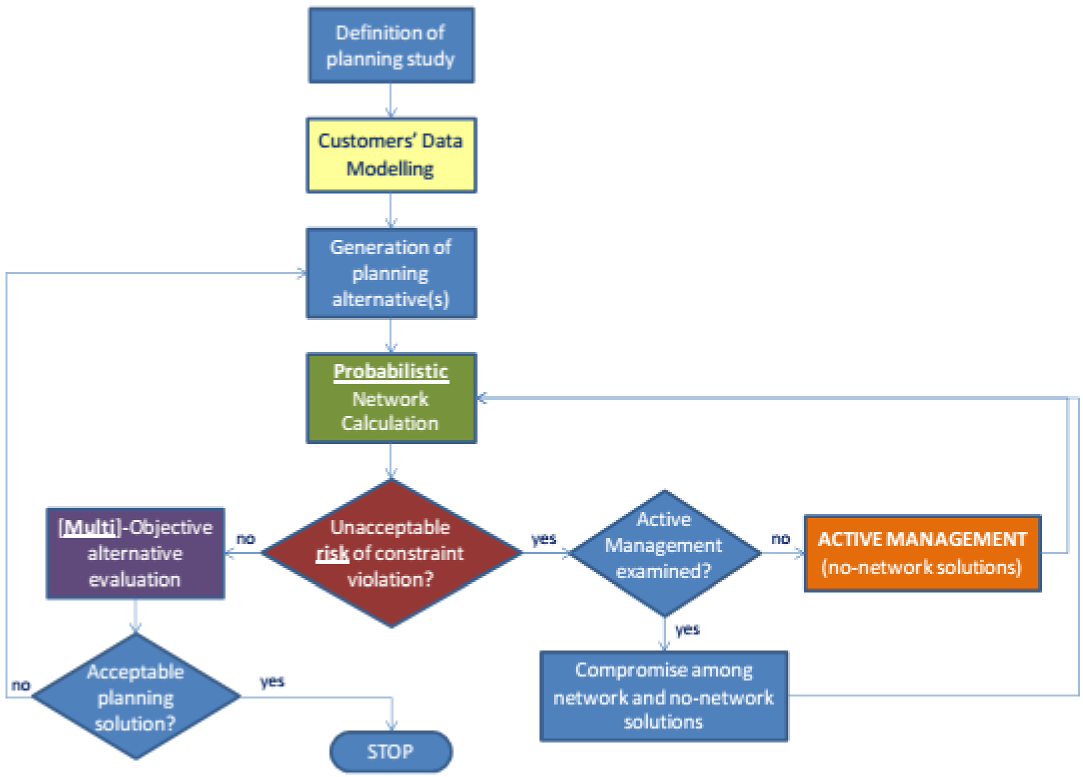


Figure 16: General Framework for ADN Planning [35].

expansion at minimum cost) new players and stakeholders with different needs. For instance, the Regulator, which represents the interest of the civil society and wants to favourite the integration of RES at reasonable costs, the generators' owners that wish to maximize the profits of their investments, but also aggregators of active demand and small generation [35].

The need to find compromise solutions for the conflicting goals of the system stakeholders, and the difficulty of defining a unique objective function, lead to Multi-Objective (MO) approaches. In fact, by using MO programming, trade-off solutions in a set of acceptable solutions (Pareto set) can be identified by applying suitable decision making techniques (Multi-Criteria Decision Making, MCDM, and Multiple-criteria decision analysis, MCDA) which may lead the planner to better decisions and minimize risks in uncertain scenarios [35],[43].

In Figure 17, a set of acceptable solutions is depicted. A solution belongs to the Pareto set (red line) if no improvement is possible in one objective without worsening in any other objective. It is crucial that in the absence of preference information all non-dominated solutions are considered equivalent. Thus, a multi-objective analysis provides very useful information not only by finding single particular solutions that are non-dominated, but also by deciphering the shape, extension and correlation of the trade-offs between objectives.

In the Literature, the multi-objective methods are divided into two main groups:

- classical approach to multi-objective optimization,
- multi-objective optimization methods based on Evolutionary Algorithms.

The first group makes use of *single-objective technique and a priori information*. By changing the master objective function several solutions of the Pareto set are identified. This classical approach asks the user to perform an a priori decision making, by assigning preferences to the objectives under consideration, such that the final-product is the solution that best matches those

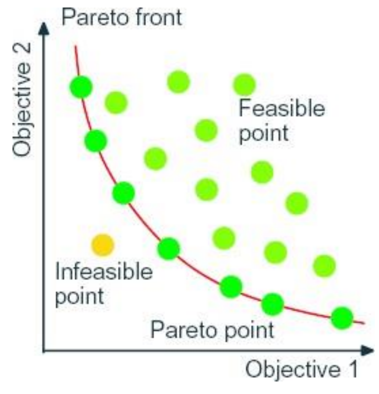


Figure 17: Set of acceptable solutions (Pareto set).

specifications. The weighted-sum and the ε-constrained methods are the most widely used methods in this category and provide a single least-cost solution. One 'master' objective is optimised while the other functions are considered as constraints, or alternatively, all objectives are aggregated into a single objective function that is optimised. Deep knowledge of the problem is required in order to define adequate master objectives and constraint levels or aggregation method and weights, respectively. These procedures can be very useful to find single solutions when information is known a priori. On the other hand, several solutions of the Pareto set can be found by changing the aggregation function or the master objective iteratively. These methods have their limitations: the weighted-sum method may require a long operating time with a large number of objectives and the solutions found strongly depends on the shape of the Pareto frontier. Similarly, the ε-constrained method requires strong a priori knowledge of the problem and it is not suitable with a large number of objectives. ε-constrained methods can be very time-consuming and the solutions depend on the shape of the Pareto frontier and the aggregation method.

The complexity of current distribution system, with possible multiple players sharing the responsibility of operation, suggests the use of "true" multi-objective algorithms that produce a set of Pareto optimal solutions without the use of subjective weights. These algorithms fall in the group of multi-objective optimization methods based on Evolutionary Algorithms (EA). EA manage sets of possible solutions simultaneously, and permit identification of several solutions of the Pareto front at once. During the past twenty years a large number of Multi-objective Evolutionary Algorithms (MOEA) has been developed. The main classification of these algorithms is in first generation or second-generation MOEA. The second generation of MOEA is characterised by the use of elitism. At present, two of the most used second generation algorithms are the Non Sorting Genetic Algorithm II (NSGA-II), and the Strength Pareto Evolutionary Algorithm 2 (SPEA2). These algorithms allow finding an accurate, diverse and well-spread Pareto front and they guarantee to produce useful information for the subsequent decision-making process. Even though with specific formulation and modifications, many authors have proposed MO approaches for the DER planning optimization problem [35].

Recent MO frameworks presented the integration of stochastic and controllable DER in the distribution grid. They take in due account the inherent time-varying behaviour of demand and distributed generation (particularly when RES are used), the fact that load models can significantly affect the optimal location and sizing of DER in distribution systems, and strategies to achieve an integration of DG units in LV and MV distribution grids while optimising several relevant objectives.

Nevertheless in Literature a host of pioneering studies into multi-objective DER planning has been pursued, each lacks important features of contemporary optimization theory. Most of all, they do not offer a suitable tool to lead the DER planner in the formalization of a new optimization problem [35].

2.4 Active Management of Active Distribution Network

The operation influences the planning stage of the modern distribution system and more attention has already been paid to operation strategies that allow the transition from passive networks to active/smart networks. Active management enables the DSO to maximize the use of the existing circuits by taking full advantage of generator dispatch, demand side integration, control of transformer taps, reactive power management, and system reconfiguration in an integrated manner. All these ways to control and integrate DERs affect the system operation, but they also have a significant role even in the optimal development of the system or, in other terms, the active network operation significantly contaminates the planning stage. For instance, the generation curtailment of renewable generators and/or the load shedding of responsive loads can help relief network congestions and therefore they are valuable planning alternatives to the classical network reinforcements. For these reasons, it is crucial that the planning tools for the ADNs integrate network operation practices (Table III) in the set of feasible planning alternatives, in order to identify the best technical and economic balance between the innovative active management (that tends to maximize the utilization of existing assets in distribution system) and the traditional network expansion. Obviously, for an accurate comparison of the planning options, the costs of the active management implementation should be defined. CAPEX and OPEX depend on the ICT and on the Regulatory environment (policy for refunding investments, obligation to serve or remuneration of the ancillary services).

2.4.1 Active management system model

In Active Distribution Networks, DERs are involved in the network operation. By exploiting the active and reactive power dispatching of DG, the use of storage devices, and the active demand, the DSO may reduce technical barriers to renewable integration and increase the hosting capacity of the network. The DSO may also have the opportunity to manage electricity flows by using flexible network topologies (i.e., network reconfiguration) [44].

The core of the active management is the *Distribution Management System* (DMS). The DMS (Figure 18) supervises the network operation by gathering measures of the main electric parameters, executing the state estimation and, if necessary, modifying the set points of DERs (e.g., generators, storage devices, and responsive loads).

The DMS is developed using a Central Processing Unit that collects all the measurement and decides next actions. It is the first control realized, because it is easier to implement in the planning studies. It allows to have a comprehensive vision of the ADN, and to control all the elements. On the other hand, it needs an expensive data communication infrastructure to handle a large amount of information.

The main features that must be implemented in the future DMS are:

- Weather forecasting;
- Load and generation forecasting;
- State Estimation:
  - Active/reactive power from Loads,
  - Scheduled power from generators,
  - State of Charge (SoC) of DES,
  - Status of the sectionalizing switching devices,
  - Tap position of on-load tap changers transformers;
- Bid aggregation of DER (Active Load, EVs, DES) and Constraints and contracts;

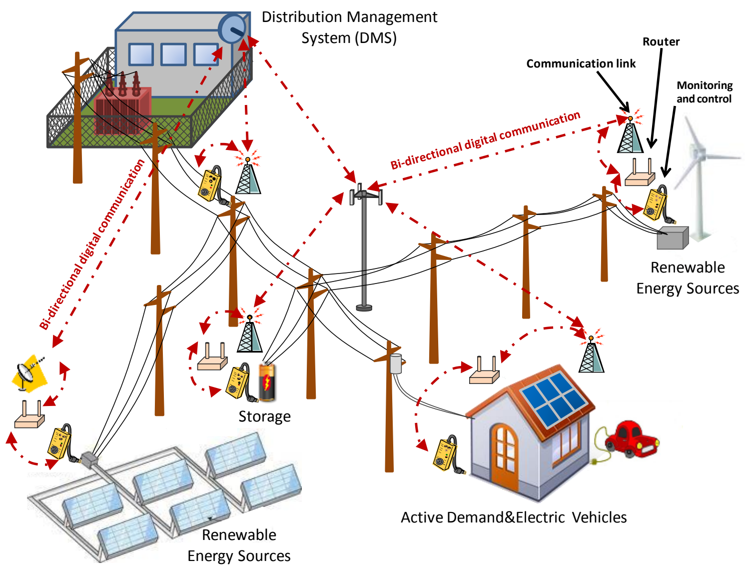


Figure 18: Scheme of active distribution network with the DMS.

- Day ahead;
- Communication system
- Operation conditions.

In Figure 19 the DMS architecture is shown.

The DMS communicates with the novel Intelligent Electronic Devices (IEDs) that will be widely deployed across the distribution network with protection and operation purposes. IEDs need a communication network, that, in order to avoid possible blackouts caused by unexpected failures, must be highly reliable, scalable, secure, and robust [45].

2.4.2 The role of the DSO

DSOs have to operate networks to ensure a secure, high quality supply of electricity and to facilitate access to new consumers and participants. However, this operation has traditionally been limited to network elements (e.g., on-load tap changers, capacitor banks, etc.). As described in the previous subsection, certain applications of ADNs require also the control of network participants (demand and generation). Consequently, the full deployment of ADNs, i.e., more observable and controllable networks, DSOs will allow the widespread use of new services such as those from demand and generation aggregators to help managing not only distribution but also transmission networks, as well as balancing demand and generation.

By developing new business activities, thereby diversifying the business model, and by transforming operational philosophies from passive into active network management, DSOs can

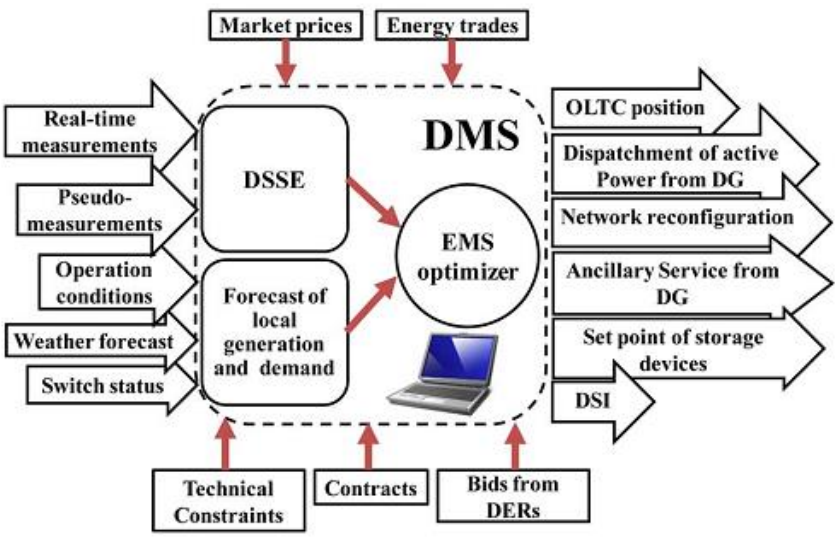


Figure 19: DMS Architecture.

overcome the challenges that arise from the increasing penetration of DG, incentive regulation, regulated connection charges, and unbundling. Regulation, however, should stimulate a competitive market environment allowing DSOs to have access to a wider range of options and incentives available in choosing the most efficient ways to run their businesses [35].

Depending on the regulatory framework, these flows of information could contribute to the competitiveness of electricity, promoting the role of low-carbon technologies while ensuring a safe and secure operation of the network. With a much more controllable infrastructure, DSOs will allow the widespread use of new services such as those from demand and generation aggregators to help managing not only distribution but also transmission networks, as well as balancing demand and generation [35].

2.5 The importance of customer in the management of the network

Demand Side Integration (DSI) programs by increasing the flexibility of demand allow making a better use of network capacity and managing the inherent not programmability of RES. DSI programs reduce the variance of the RES production from the DSO/TSO point of view and are a viable alternative to network reinforcement (i.e. no-network solutions in planning) [46].

In Literature, the participation of customers in the active management of the network is identified with different names: *Demand Side Management*, *Demand Side Response* and *Demand Side Integration*. The term Demand Side Management is used to reflect a customer-managed environment driven by the electric utility industry. On the contrary, with the onset of electric power industry restructuring world-wide, many customers are not subject to an environment of centralised management, so the term Demand Side Response reflect the market driven aspect of demand-side behaviour, such as demand response to market conditions. Finally, the term Demand Side Integration, as recognized by the CIGRE WG C6.09 and CIGRE WG C6.19, better represent the overall technical area focused on the demand-side and its potential as a source of supply [35],[36], [46],[47].

2.5.1 Forms of Demand Side Integration

Demand Side Integration actions are:

- Demand Response (DR),
- Energy Efficiency (EE) and
- Strategic Load Growth (SLG).

DR includes all intentional electricity consumption pattern modifications by end-use customers that are intended to alter the timing, level of instantaneous demand, or total electricity consumption by transmitting changes in prices, load control signals or other incentives to end-users to reflect existing production and delivery costs [48]. These activities are commonly known as peak clipping, valley filling, load shifting and Dynamic Energy Management. Energy efficiency programs, are designed to reduce electricity consumption while maintaining a comparable level of service and/or user comfort. While Strategic load growth activities, are designed to increase load level in a strategic fashion, such as shifting between one type of supply to another with more favourable characteristics (e.g., environmental impact).

Figure 20 summarizes the DSI programs described.

2.5.1.1 Programs to involve customers in the Demand Side Integration

Several programs can be used for load contribution in system management and control as pointed out by a series of international initiatives. These programs can be based on incentives (Incentive-Based Programs, IBP) or on Price (Price-Based Programs, PBP) [49]. In Figure 21, a classification of DR programs is shown.

The first group can be divided into *classical programs*, where participating customers receive participation payments (a bill credit or discount rate) for their participation in the programs and *market based programs* where customers are rewarded with money for their performance, depending on the amount of load reduction during critical conditions.

Classical IBP include Direct Load Control programs (in which utilities have the ability to remotely shut down participant equipment, air conditioners and water heaters, on a short notice) and Interruptible/Curtailable Load programs (where participants are asked to reduce their load to predefined values and receive upfront incentive payments or penalties if they do not respond).

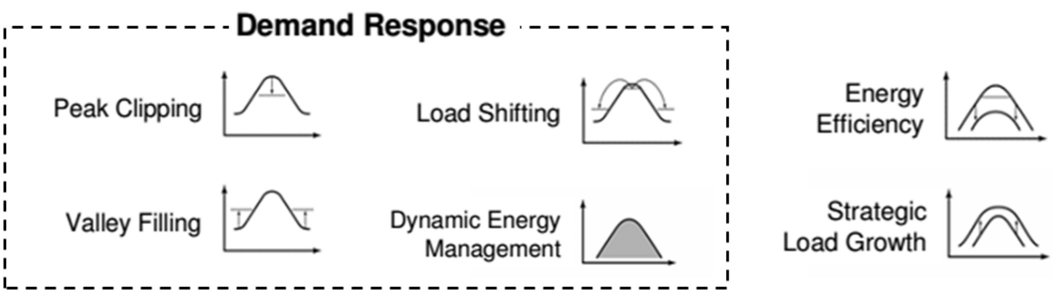


Figure 20: DSI programs.

Market based IBP include Emergency DR Programs, Demand Bidding, Capacity Market, and the Ancillary services market. In Emergency DR Programs, participating customers are paid incentives for measured load reductions during emergency conditions; while in Demand Bidding (also called Buyback) consumers bid on specific load reductions in the electricity wholesale market. A bid is accepted if it is less than the market price and the customer must curtail his load by the amount specified in the bid or face penalties [49].

Furthermore, Capacity Market Programs are offered to customers who can commit to providing pre-specified (usually a day ahead) load reductions when system contingencies arise. Participants are penalized if they do not respond to calls for load reduction. Ancillary services market programs allow customers to bid on load curtailment in the spot market as operating reserve. When bids are accepted, participants are paid the spot market price for committing to be on standby and are paid spot market energy price if load curtailment is required [49].

2.5.2 Active Demand

The concept of Active Demand, introduced in the context of the European project ADDRESS (see Appendix) is based on the idea that end users should play an active role in the electricity distribution process, adjusting their consumption patterns depending on the dynamics of the energy markets

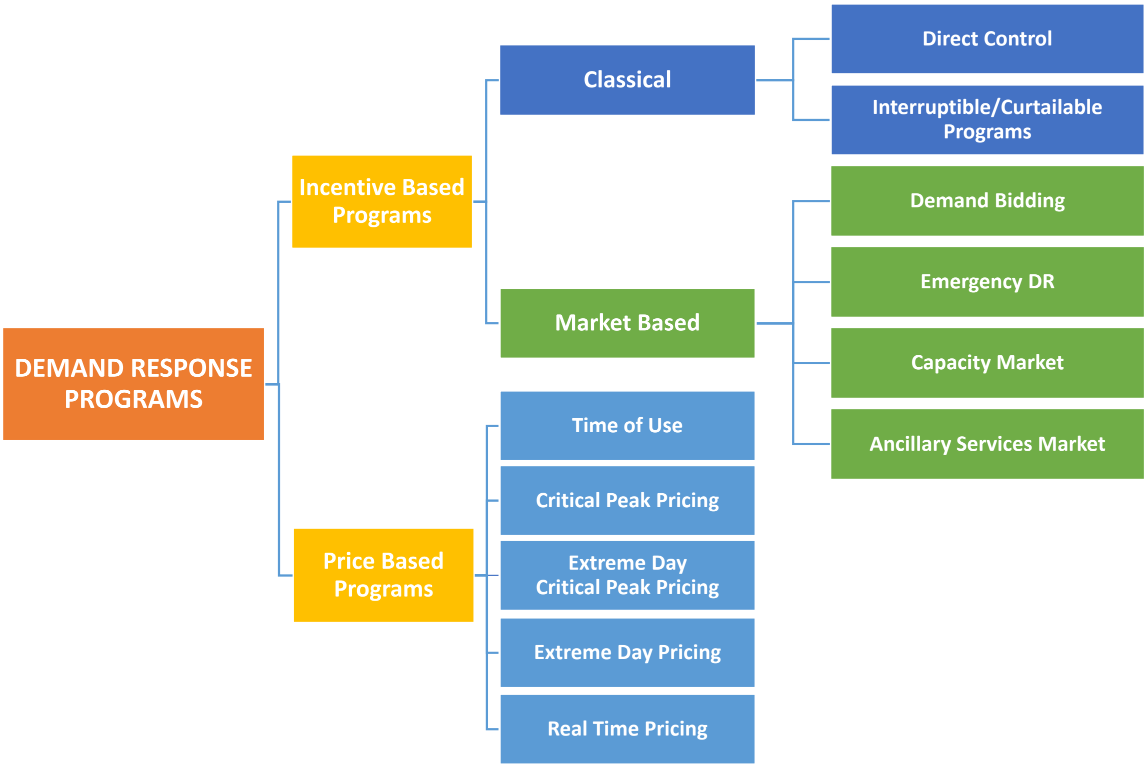


Figure 21: Classification of demand response programs [49]

[50]. The demand elasticity offered by end-users allows deferring the reinforcement of the existing grid infrastructures caused by new load profiles and distributed generation. DSI provides the means to modify the consumer's load to meet the network constraints. These load profile modifications can spontaneously be implemented by the end users themselves, typically driven by price signals, or be managed by an entity, called Aggregator, which is entrusted by the end users to change their consumption habits according to its needs (i.e., Remote Management).

2.5.2.1 The Aggregator

The figure of the Aggregator is not a new figure in the electricity market, and it has been analysed in several studies [51] - [54]. In [51] and [52] the authors analyse the operation of a domestic heat load aggregator on the Swedish island of Gotland, with the aim to minimize the losses on the HVDC connection to the Mainland, matching local wind generation and load. In the ADDRESS project, a demand aggregator as a mediator between consumers and markets has been hypothesised. The aggregator acquires the flexibilities and the contributions provided by consumers to form AD-based services to be offered to the DSO through local markets [50], [53]. In [54] the role of an aggregator agent for EVs has been analysed, as a commercial middleman between a system operator and the EVs. It is more elaborated than a simple load aggregator, because it can offer more services and technical flexibility. The EV Aggregator is able to manage and control its EV portfolio (e.g., charging of batteries), collecting a large amount of information like the driver's behaviour and electrical market prices.

In Chapter 4, an Aggregator, capable to manage both EVs smart recharge and customers participating to AD program, is described. Several examples will be provided in order to demonstrate the importance of DSI.

2.5.2.2 The Active Customer

The Active Customer can respond with three general actions [49]:

1. Customer *reduces* his consumption during peak periods when prices are high without changing its consumption pattern during other periods (involving a temporary loss of comfort). This response is achieved, for instance, when thermostat settings of heaters or air conditioners are temporarily changed.
2. Customers may respond to high electricity prices by *shifting* some of their peak demand operations to off-peak periods (for instance, shifting some household activities

dishwashers). The residential customer in this case will bear no loss and will incur no cost. However, this will not be the case if an industrial customer decides to reschedule some activities and rescheduling costs to make up for lost services are incurred.

3. Customer owned distributed generation may *use onsite generation*. Customers who generate their own power may experience no or very little change in their electricity usage pattern; however, from utility prospective, electricity use patterns will change significantly, and demand will appear to be smaller.

To improve the performance of the load model two elements have to be considered: the *level of participation* of the customer and the *payback effect.*

The acceptance model is necessary because every user is willing to modify the consumption profile in different ways. This depends on price signal, but also on available flexibility, willingness to reduce the comfort, etc. In particular the most important factor that influence customer's behaviour is the price signal. Indeed, the economic issues, related to tariff plans and the variable energy costs, significantly affect the degree of customer acceptance. So a profile of acceptance should be modelled. The acceptance profile should have the same characteristics of the consumption profile and the same chronological representation [36], [46]. For the operation of a distribution system (and for novel planning methodologies) the worth of DSI acceptance cannot be limited to an instantaneous analysis of effects. Indeed, many customers can accept to reduce energy consumption if the price signal is high but they will also try to recover part of the demand later. It is clear the risk from the DSO point of view to relieve critical instantaneous congestions by building the conditions of a new subsequent congestion.

This effect has often referred in the Literature as the *payback effect. Payback effect* must be optimally managed in operation. In order to do that a proper model has to used that takes into account the reaction of the customer to an active demand program (for example: an user for an appropriate signal price accepts to reduce the consumption for two time intervals; after the two intervals user needs the highest power in order to recreate the previous conditions). In Figure 22, the red line represents the active demand availability while the blue one shows the real user participation. The AD is expressed as the variation of the load demand in comparison with the reference load profile, which is the scheduled power without AD, and it is representative of the involvement of the customers. In fact, the load models must include some kind of mechanism describing how ad is "transformed" into ad^{true} [36],[46],[55].

2.5.2.3 AD mechanism

Having the Aggregator, the DSO and the consumers as the main electricity system actors, the AD mechanism can be described as follows.

The Aggregator builds an AD-based service by collecting the flexibilities of its pool of customers (provided in the form of modifications of the consumers' typical consumption profiles), in order to meet the needs of other electricity system participants and builds an appropriate AD-based product. An AD-based product is a specified power capacity to be delivered over a specific time horizon.

Therefore, an Aggregator is able to sell a deviation (load reduction/increase) from the scheduled demand, not a specific level of demand. Then, the Aggregator offers the AD-based product on the market: if the AD-based product is sold, the Aggregator submits it to the DSO for technical validation. Finally, when the validated AD-based product is received from the DSO (curtailment is possible), the Aggregator sends appropriate price volume signals to its consumers.

The demand elasticity offered by end-users allows deferring the reinforcement of the existing grid infrastructures caused by new load profiles and distributed generation.

Residential consumers are typically not disposed to characterise exactly in advance their flexibility. For this reason, the AD-based services are requested in the form of price and volume signals, and provided by the consumers on a voluntary and contractual basis [53].

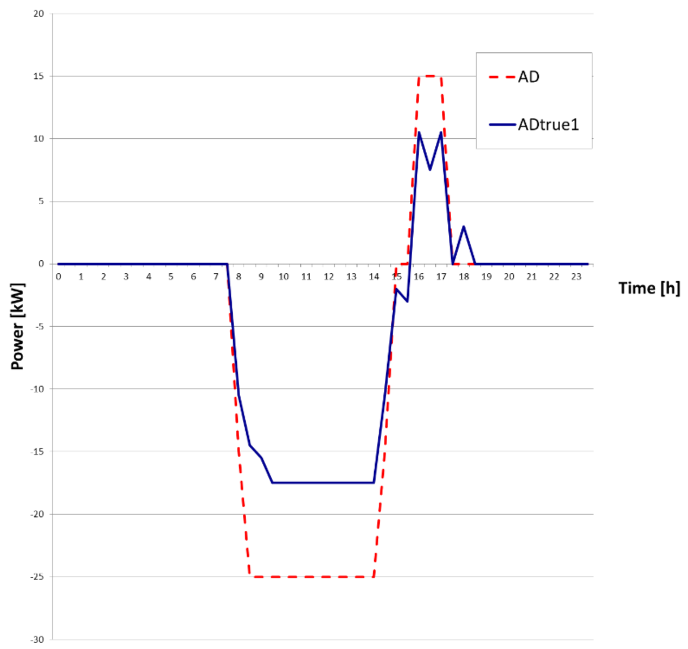


Figure 22: The payback effect.

2.5.3 EV role in DSI

As analysed in the previous chapter a large-scale adoption of EVs will require significant changes in power system operation procedures and practices. Considering a future scenario with EV integration in electrical distribution systems, it is necessary to assess the impact that results from the connection of these units with LV networks.

DSI policies based on EV lead to several benefits: increasing the flexibility of the electrical distribution system operation, but also (in customer side) improving the reliability of the distribution system, providing extra economic benefits to the vehicle owners, and reducing the home or building electricity purchase cost. Especially, when renewable energy resources, such as wind or solar, are integrated in smart grid, the batteries in EVs can function as energy storage system to reduce the influence of weather conditions.

In order to involve the EVs owners in the active management of the network, different EV charging schemes are considered:

- **Multiple tariff policy**, with the aim to foster EV charging at Valley Hours: during off-peak hours. This type of recharging is used to simulate the target of a multiple tariff policy. It could be obtained with new appropriate Multi-Tariff incentive schemes, and with technological solutions such as smart meters and timers in the cars.
- **Smart Charging**: EV start charging at the selected hour s to “fill the valley” of the overall aggregated profile, considering demand and distributed generation. Local issues were not taken into account to design this type of charging, so it only fills the valley from an aggregated point of view. This recharging system is expected to require controls system and communication systems.

Moreover, in order to involve the EVs owners in the operation, large business entities (e.g., universities, shopping centre, industrial parks, commercial and public garages) could offer parking spaces for EVs owners. Thus, the Smart Garage may provide the base for an aggregated service to act as an electric power source or storage, becoming a G2V operation, and/or an energy support service for nearby buildings through the electricity power network, which may become a Vehicle to Building (V2B) operation [56],[57].

The control and communication capabilities between electric vehicles and power grid are essential to enable advanced interactions but may also be important for mitigating the impacts of very large numbers of EV charging from the grid. As increasing numbers of EVs are sold, local grid to vehicle communications broadcasting will be useful for emissions and price signalling. Two-way communications that transmit the present and desired state-of-charge (SOC), power flow, and other parameters will be useful in enabling our demand side management approach. Individual communication interface modules that support the many potential standards such as ZigBee M, 802.11 WiFITM, WiMaxTM, cell phone, or Power Line Communication (PLC) which could be selected based on regional needs, terrain, cost, or utility preferences [58].

CHAPTER III

3 Centralised Control System for Active Distribution network

3.1 Introduction

By managing DG active and reactive power dispatch, storage devices and active demand, DSO may reduce technical barriers to renewable energy sources integration and increase the hosting capacity of the network. All these actions could be exploited by a central controller or DMS, able to find (with a real-time status of the network) an optimal solution that allows avoiding the possible contingencies, reducing the operational cost related to the active management taking into account technical and economical constraints. In the following, a centralised control system for the management of MV distribution network, developed during the research activity is described.

3.2 Distribution Management System

The DMS is the core of ADNs optimal operation, where all the control decisions are taken. The term DMS means solutions with very different complexity levels: from energy management (also with advanced functionality for offline studies of small entities) up to full real-time management of the distribution network (including the underlying SCADA). When generators are involved in the operation of the distribution system, the DMS reproduces the Energy Management System (EMS) functions commonly used at transmission level.

The DMS essential elements to optimise the network operation, avoiding contingencies and finding the economically optimal operations point of the networks, are the measurement system, the distribution system state estimator (DSSE), and the EMS. The DSSE provides to the EMS the status of the network, by exploiting the measures from the field. Real-time intra-day optimization is then performed by the EMS to avoid contingencies and to find the economically optimal operation points of the network. Nevertheless, in order to exploit the above mentioned functions, a reliable and fast communication system is necessary [44].

However, nowadays a fast communication networks could be implemented both via physical connection through Ethernet cables or optic fibres, and via radio or wireless technologies.

Obviously, the centralised control must be coordinated and synchronized with the local control systems of DERs. Grid synchronization can be made by means of different methods, e.g. the common PLL (Phase-Locked Loop) technique [58]. The local controls are generally constituted by several devices, grid and generator side (e.g. interface and generator protections and power electronic control systems). They may have a high level of complexity and may even use DSP (Digital Signal Processor) to interface to the grid or to develop ad hoc algorithms to control the power electronic [44].

The EMS solves the optimization problem running in real-time in a dedicated DSP or in industrial computers that can be sited in a control centre in the primary substation. Once the time horizon (typically one day) and the time interval (e.g. Δt = 1 hour, but even shorter) are defined, at the beginning of the time interval the DMS receives the status of the network, the technical constraints, as well as the market prices and information on energy trades. If the DSE function is integrated in the DMS the status of the network is assessed running a suitable estimation algorithm gathering data directly from field measurements (i.e. by the measurement signals). Furthermore, the DMS collects bids from DERs for the next time interval.

3.3 The EMS optimization algorithm

The main goal of active distribution network operation is the minimization of system cost, subject to technical and economical constraints. From a mathematical point of view, the minimization can be formulated as a classical OPF problem [59]. In Literature, the OPF has been solved through several techniques as non-linear programming (NLP), linear programming (LP) or mixed-integer linear programming (MILP) [59] - [61].

An EMS algorithm for real scale applications requires speed, reliability and ability to handle many different operating constraints, thus in the proposed application the revised simplex method is used to solve the sparse LP problem. This method is computationally efficient, accurate, and particularly suited to large and sparse LP problems [62]. Moreover, NLP calculations risk being too heavy from computational point of view and too slow in convergence for real-time application [59].

3.3.1 Objective Function

The Objective Function (OF) to be minimized by the network operator is the sum of the costs of active management alternatives C_i, (2) i.e., the cost for changing the scheduled DG active power production, generally cost for curtailment (C_{P_DG}), the cost of reactive support (C_{VAR}), the cost of demand side integration (C_{AD}), the cost of energy storage operation (C_{DES}). Furthermore, the cost of energy losses minimization C_{losses} can be included in the OF if the improvement of the efficiency of power delivery is a task that DSOs have to pursue.

$$\min J = \left\{ \sum_i C_i = C_{losses} + C_{P\_DG} + C_{VAR} + C_{AD} + C_{DES} \right\} \tag{2}$$

The cost function J is subject to power flow equations, technical and commercial constraints that can be formulated either as equality or inequality constraints. The technical constraints concern node voltages and branch power flows during normal and emergency conditions, the maximum and minimum active and reactive power from DG, the operation of the storage devices, etc. The economical constraints regard regulation, connection rules, obligations, contracts, etc. The minimization can be expressed also as a linear combination (see equation (3)) of the Power Losses (P^{losses}) [63], the Power from DG (P^{DG}), the reactive power Q^{Var}, the power from load (P^{AD}), the active and reactive power exchanged with DES (P^{DES},Q^{DES})[44].

$$\begin{aligned}\min J = \min \Bigg\{ & \sum_{i=1}^{N_{br}} \alpha_i P_i^{losses} + \sum_{i=1}^{N_{DG\_GC}} \beta_i P_i^{GD} + \sum_{i=1}^{N_{DG\_VAR}} \gamma_i Q_i^{Var} + \sum_{i=1}^{N_{AD}} \delta_i P_i^{AD} + \sum_{i=1}^{N_{DES}} \kappa_i P_i^{DES} + \cdots \\ & + \sum_{i=1}^{N_{DES}} \lambda_i Q_i^{DES} + \cdots \Bigg\}\end{aligned} \tag{3}$$

In the following, the terms of equation (2) and (3) will be analysed. It is worth to consider that in order to use LP with variables, which could assume positive and negative value (e.g. reactive power from DG), two different non-negative variables have been used. This is the case of the reactive power that can be exchanged in the network (inductive), the active power of DG (which could increase or decrease compared to the scheduled one), or the reactive power (inductive or capacitive) from DG.

For instance, the variable that represents the power exchanged from DES with the network, is expressed by means of two terms: X_{Pi}^{DES} and Y_{Pi}^{DES}: if the storage is giving power to the network (discharge), the variable X_{Pi}^{DES} assumes a nonzero value, while Y_{Pi}^{DES} will be null. At the same time, if the storage is charging, the X_{Pi}^{DES} will equal to zero and Y_{Pi}^{DES} assumes a nonzero value [44].

3.3.1.1 Evaluation of the energy Losses

C_{losses} is directly related to the energy power losses (P^{losses}), through a coefficient, α, as stated in equation (3). The losses in the *i-th* branch the network can be summarized as showed in equation (4):

$$P_i^{losses} \cong \frac{r_i}{r_{max}} \cdot |F_i| \tag{4}$$

Where:

F_i is the active power flow through the *i-th* branch of the analysed network, characterised by the resistance r_i; r_{max} is the maximum resistance between all the branches of the network.

The idea of this approximation, since it is not fundamental in the proposed DMS to know the exact value of the power losses, is to optimise the power flows by penalising paths with high resistance and favouring those that have small resistance [64]

Using a coefficient ρ (that is proportional to r_i), equation (5) gives the approximated value of the cost of energy losses, C_{losses}.

$$C_{losses} = \sum_{i=1}^{N_{br}} \alpha_i P_i^{losses} \cong \sum_{i=1}^{N_{br}} c_i^{losses} \cdot \Delta t \cdot \frac{r_i}{r_{max}} \cdot |F_i| = \sum_{i=1}^{N_{br}} \rho_i \cdot |F_i| \tag{5}$$

where c_i^{loss} is the unitary cost of the energy lost (expressed in monetary unit per kWh), and Δt is the time interval between two successive DMS runs.

3.3.1.2 Cost related to Active power

C_{P_GD} is the cost that takes into account the cost paid to DG owners to modify the generated power from the scheduled pattern, to change the power flows in the network in case of contingencies (e.g., overcurrents/overvoltages, caused by the not simultaneity of generation and demand), or, if the cost of losses becomes greater than the cost due to the DG owner for the curtailed power.

The cost for increase / decrease the generated power from DG (C_{P_DG}) can be expressed as in equation (6) :

$$C_{P\_DG} = \sum_{i=1}^{N_{DG\_GC}} \beta_i P_i^{DG} = \sum_{i=1}^{N_{DG\_GC}} c_i^{P\_DG} \cdot \Delta t \cdot P_i^{DG} \tag{6}$$

Where:

- $C_i^{P\_DG}$ is the cost for cutting 1kWh of the i-th generator,
- Δt time between two successive real-time network calculations,

- N_{DG_CG} is the number of controllable generators, connected to the distribution network,
- P_i^{DG} is the variation of power in reference of the power offered by the owners at the same time interval; also additional generation of power is considered, paying attention to not exceed the maximum power that the selected generator can produce. In this case, the cost could change due to agreements between the DSO and the DG owner. Then P_i^{DG} can assume positive values if the DMS asks for more power, vice versa, if a power curtailment is demanded.

3.3.1.3 *Cost related to Ancillary services*

In order to manage the network DERs can also provide ancillary services (e.g., voltage regulation, reserve, black start, etc.) [65].

The reactive power exchange in the network by DG is evaluated as in equation (7):

$$C_{Var} = \sum_{i=1}^{N_{DG\_VAR}} \gamma_i Q_i^{Var} = \sum_{i=1}^{N_{DG\_VAR}} c_i^{Var} \cdot \Delta t \cdot Q_i^{Var} \tag{7}$$

Where:

- c_i^{VAR} is the cost for 1 kVARh given by the i-th generator (GD),
- Δt is the interval between two successive real-time network calculations,
- N^{DG_VAR} is the number of generators that provide reactive power for the active management of the distribution network.

3.3.1.4 *Cost related to Active demand*

The term C_{AD} takes into account the cost for shifting or curtailing the power absorbed by the Active Load. The approach is similar to the one related to DG: the LP minimizes the cost for the clients that participate to the AD program.

According to [50], the AD is expressed as a variation of load with respect to a reference profile representing the load without any participation to demand side any integration [52]. The model introduces the concept of flexibility that is the power an active user makes available to a DMS expressed as a power reserve provision (downward or upward) related to a specific price/volume bid.

The cost C_{AD}, as C_{P_GD} in (5), is stated as in equation (8):

$$C_{AD} = \sum_{i=1}^{N_{AD}} \delta_i P_i^{AD} = \sum_{i=1}^{N_{AD}} c_i^{AD} \cdot \Delta t \cdot P_i^{AD} \tag{8}$$

Where:

- P_i^{AD} represents the unknown shed power from the i-th Active Customer,
- N_{AD} is the number of the responsive loads,
- Δt is the interval between two successive real-time network calculations,
- δi is the cost for cutting (or increasing) the load power for 1kWh.

3.3.1.4.1 Payback effect

For a given area, basing on the concept of flexibility, the DMS or the aggregator sends the request of AD to the final customers expressed in terms of power, AD^{req}. Usually, the response of the loads involved in AD, AD^{true}, does not perfectly match the request because customers have to be free to decide if and how much contribute to the operation of the distribution system. For these reasons, in the presence of AD, at a certain time interval *k*, the load energy consumption will be the summation of the base load, *b(k)* and the effective contribution to demand side management, AD^{true}, (9).

$$y(k) = b(k) + AD^{true}(k) \tag{9}$$

The simplest way to model AD^{true} is with Finite Impulse Response (FIR) filter, as showed in (10).

$$AD^{true}(k) = \sum_{i=0}^{2} f^i \cdot AD^{req}(k-1) + n(k) \tag{10}$$

The weights f^0, f^1, and f^2 are the model parameters, which take into account the customer's level of willingness to accept the request to curtail the consumption (f^0), but also the effect of precedent curtailments (f^1, and f^2) that can reduce the amplitude of the true action (*payback*). The term *n(k)* is white noise with null mean value. Examples of AD profiles are shown in Figure 23, where the red line represents the active demand availability while the blue and the green one show two possible real user participation, due to the fact that a demand modification may be followed by an opposite sign modification.

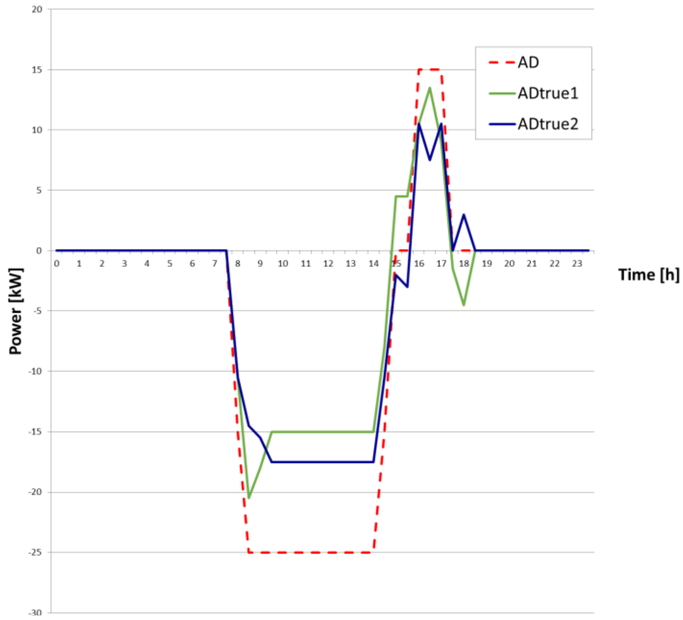


Figure 23: Comparison between the AD^{req} (dashed red) and the two possible AD^{true} (green and blu lines).

3.3.1.5 Cost related to DES management

DES model is a simplified one, without taking into account the time constant of the storage system. The model has a power electronic converter for network connection, in order to provide independent real and reactive power exchange with the grid [66].

In the EMS model, DES belong to the DSO, and use them to relieving contingencies, to minimizing the cost of charge due to DG owners and AD customers or to minimizing the energy losses. Thus, for DSO the cost for recharging DES is equal to the hour energy price, whereas the discharge cost to the DSO is assumed almost for free and only depending on the depreciation of the storage devices due to their use (e.g., 10% of the energy price). These assumptions avoid that the DSO follows any arbitrage practice, actually not permitted, for instance, by the Italian regulatory environment. The cost related to DES, in equation (1) takes into account:

1) Charge

DSOs pay for charging the battery. The cost is considered related to P^{DES}, the power taken from the network as showed in (11)

$$C_{DES(charging)} = \sum_{i=1}^{N_{DES}} k_i \cdot P_i^{DES} \; k_i = c_j^{DES(ch)} \tag{11}$$

Where $c_j^{DES(ch)}$ is the cost to charge 1 kWh the j-th DES, Δt is the interval between two successive real-time network calculations, N_{DES} is the number of DES connected to the distribution network.

2) Discharge

The cost of discharge is formally similar to equation (11), as stated in equation

$$C_{DES(\text{discharging})} = \sum_{i=1}^{N_{DES}} k_i^{'} \cdot P_i^{DES}; \qquad k_i^{'} = c_i^{DES(disch)} \cdot \Delta t \tag{12}$$

Where: $c_j^{DES(disch)}$ is the cost for the j-th DES to exchange 1 kWh with the network (it takes into account also the reduction of the life of DES), Δt is the interval between two successive real-time network calculations, N_{DES} is the number of DES connected to the distribution network.

3) Reactive support:

DES can also exchange reactive power (inductive or capacitive) with the network, thus, the cost is directly related with kVARh exchanged, as stated in:

$$C_{Q\_DES} = \sum_{i=1}^{N_{DES}} \lambda_i \cdot Q_i^{DES}; \qquad \lambda_i = c_i^{Q\_DES} \cdot \Delta t \tag{13}$$

Where: $c_i^{Q\_DES}$ is the cost to inject 1 kVARh Δt is the interval between two successive real-time network calculations, N_{DES} is the number of DES connected to the distribution network the give reactive support.

3.3.2 Constraints

The constraints of the minimization include:

- 2 N_{bus} equality equations, representing the balance of powers, active and reactive respectively. They are based on the Kirchhoff's current law at each node of the network;
- $2 \cdot N_{bus}$ inequality equations, corresponding to the voltage limits in the nodes.
- $2 \cdot N_{seg\_DG}$ inequality constraints, representing the capability curve for each generator (N_{seg_DG} is the number of straight lines used to approximate the generator capability curve approximated with a piecewise linear to maintain the linear formulation). Equation (14) gives a general formulation of the constraints in the equality form (the equations are $2 \cdot N_{seg\_DG}$ in order to take into account both inductive and capacitive reactive power Q^g).

$$P_i^g + m_{ji}^g \cdot Q_i^g \leq q_{ji}^g \tag{14}$$

$$P_i^g + m_{ji}^g \cdot Q_i^g \geq q_{ji}^g$$
$$j = 1 \ldots . N_{seg\_DG} \; i = 1 \ldots . N^{DG}$$

where P_i^g and Q_i^g are the active and reactive power from DG, that define the operation point, m^g_{ji} and q^g_{ji} are the slope and the intercept of the j-th line used to approximate the capability curve of the i-th generator.

- N_{seg_Br} inequality equations, representing the constraints caused by the thermal limit of the lines, a similar approach used to take into account the capability constraints of the generators is used for the lines: a piecewise linearized circle that has the rated apparent power of such line as radius represents the feasible area for the operation point.
- 4 N_{seg_DES} inequality equations, representing the DES technical constraints; the implementation is similar to the approach used for the generators and the lines: a linearized circle that has the rated apparent power of such line as radius represents the feasible area for the operation point.

To linearize the relationship between voltages and control variables, the voltage *sensitivity coefficients* are used. The sensitivity matrix is calculated once at the beginning of the time interval starting from Jacobian matrix [60],[67],[68]. This assumption is reasonable because hopefully the variations of scheduled power production have been kept as low as possible by the DMS, and, on the other side, the continuous calculation of sensitivity coefficients is a time consuming process that increases with the number of DERs in the network.

Starting from the sensitivity indexes, the constraints on voltage can be expressed as in (15).

$$s_j^{P_{GD}} = \frac{dv_i}{dP_j^{GD}} \; ; \; s_k^{VAr} = \frac{dv_i}{dQ_k^{VAr}} \; ; \; s_I^{P_{AD}} = \frac{dv_i}{dP_I^{AD}} \; ; \; s_I^{Q_{AD}} = \frac{dv_i}{dQ_I^{AD}} \; ; \; s_{es}^{P_{DES}} = \frac{dv_i}{dP_{es}^{DES}} \; ; \; s_{es}^{Q_{DES}} = \frac{dv_i}{dQ_{es}^{DES}}$$

$$\begin{gathered}
\sum_{j=1}^{N_{GD}} s_j^{P_{GD}} P_j^{GD} + \sum_{k=1}^{N_{DG_VAr}} s_k^{VAr} Q_k^{VAr} + \sum_{I=1}^{N_{AD}} \left(s_I^{P_{AD}} + s_I^{Q_{AD}} tg\varphi_I\right) P_I^{AD} \\
+ \sum_{es=1}^{N_{DES}} s_{es}^{P_{DES}} P_{es}^{DES} + \sum_{es=1}^{N_{DES}} s_{es}^{Q_{DES}} Q_{es}^{DES} \leq \Delta V_{lim,i}^{over} \\
\sum_{j=1}^{N_{GD}} s_j^{P_{GD}} P_j^{GD} + \sum_{k=1}^{N_{DG_VAr}} s_k^{VAr} Q_k^{VAr} + \sum_{I=1}^{N_{AD}} \left(s_I^{P_{AD}} + s_I^{Q_{AD}} tg\varphi_I\right) P_I^{AD} \\
+ \sum_{es=1}^{N_{DES}} s_{es}^{P_{DES}} P_{es}^{DES} + \sum_{es=1}^{N_{DES}} s_{es}^{Q_{DES}} Q_{es}^{DES} \geq \Delta V_{lim,i}^{under}
\end{gathered} \tag{15}$$

where i=1…Nbus, and $\Delta V_{\lim,i}^{over}=V_{ref}^{over}-V_i$, and $\Delta V_{\lim,i}^{under}=V_{ref}^{under}-V_i$ are the maximum allowable deviations of the i-th bus voltage Vi, with V_{ref}^{over} =1.05 p.u. and V_{ref}^{under} =0.95 p.u..

Equation (16) gives the matrix form of the mentioned constraints.

$$\begin{bmatrix} A_1 & 0 & B_g & 0 & B_{AD} & B_{DES} & 0 \\ 0 & A_1 & 0 & B_g & tg\varphi_I B_{AD} & 0 & B_{DES} \end{bmatrix} \cdot [X] = \begin{bmatrix} P_{bus} \\ Q_{bus} \end{bmatrix}$$

$$\begin{bmatrix} 0 & 0 & s^{P_{GD}} & s^{VAr} & \left(s^{P_{AD}}+s^{Q_{AD}}tg\varphi_I\right) & s^{P_{DES}} & s^{Q_{DES}} \end{bmatrix} \cdot [X] \le \left[\Delta V_{lim}^{over}\right]$$
$$\begin{bmatrix} 0 & 0 & s^{P_{GD}} & s^{VAr} & \left(s^{P_{AD}}+s^{Q_{AD}}tg\varphi_I\right) & s^{P_{DES}} & s^{Q_{DES}} \end{bmatrix} \cdot [X] \ge \left[\Delta V_{lim}^{under}\right]$$

$$\begin{bmatrix} I & m^{Br} & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & I & m^g & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & I & m^{DES} \end{bmatrix} \cdot [X] \le \begin{bmatrix} q^{Br} \\ q^g \\ q^{DES} \end{bmatrix} \qquad (16)$$

$$[X] = \begin{bmatrix} F^P \\ F^Q \\ P^{GD} \\ Q^{VAr} \\ P^{AD} \\ P^{DES} \\ Q^{DES} \end{bmatrix}$$

where:

- A_1 is the node to branch incidence matrix,
- I is the identity matrix,
- B_g, B_{AD} and B_{DES} are binary matrixes introduced to include the active and reactive power from DES into power flow equations,
- s^{PDG} and s^{VAR} are the voltage sensitivity indexes with respect active and reactive powers from DG, respectively,
- s^{PAD}, and s^{QAD} are the voltage sensitivity indexes with respect to the active and reactive powers shed by Active Customers, respectively,
- s^{PDES} and s^{QDES} are the voltage sensitivity indexes with respect active and reactive powers from DES, respectively,
- P^{AD} is the vector of the unknown shed powers (output of optimization)
- P^{GD} is the vector of the unknown curtailed powers (output of optimization),

- P^{DES} and Q^{DES} are the vectors of the unknown reactive power flows from DES, respectively (output of optimization),
- P_{bus} e Q_{bus} are the are the nodal powers,
- m^g and q^g are the slope and the intercept used to approximate the capability curve of the generators,
- m^{BR} and q^{BR} are the slope and the intercept used to approximate the thermal limit constraint of the lines,
- m^{DES} and q^{DES} are the slope and the intercept used to approximate the capability curve of the DES.

Besides the mentioned constraints, the minimization problem is subject to non-negative constraints and upper and lower bounds of the unknown variables (X and Y) as in (17).

$$
\begin{aligned}
&-P_{max,j}^{GC} \leq P_j^{GC} \leq P_{max,j}^{DIS}\ j = 1 \dots N_{GD} \\
&-Q_{max,k}^{VAR} \leq Q_k^{VAR} \leq Q_{max,k}^{VAR}\ k = 1 \dots N_{GD\_VAr} \\
&0 \leq P_I^{AD} \leq P_{max,I}^{AD}\ I = 1 \dots N_{AD} - P_{max,es}^{DES} \leq P_{es}^{DES} \leq P_{max,es}^{DES}\ es = 1 \dots N_{DES} \\
&-Q_{max,es}^{DES} \leq Q_{es}^{DES} \leq Q_{max,es}^{DES}\ es = 1 \dots N_{DES}
\end{aligned}
\tag{17}
$$

where it is assumed that DMS can curtail or increase the *j^th^* generator power production of $P_{max,j}^{GC}$ e $P_{max,j}^{DIS}$, respectively, commit the reactive power exchange from the *k^th^* generator $Q_{max,k}^{VAR}$, or shed the *l^th^* RL of $P_{\max,l}^{RL}$ at maximum, exchange active and reactive power with the *es-th* DES of $P_{max,es}^{DES}$ e $Q_{max,es}^{DES}$, respectively. P_j^{GC} , Q_k^{VAR} , P_{es}^{DES} , Q_{es}^{DES} e e P_l^{AD} are unknown.

In order to take into account the operation of DES in the optimization, in [66] the authors proposed to include a window on future time. Indeed, the optimal usage of storage depends not only on the operation in the current time interval, but also on the previous and future operation decisions.

Once the time horizon (typically a day) and the time interval (e.g., 1 hour, but even shorter) are defined, at the beginning of each time interval the DMS receives not only the current status of the network and the energy market prices, but also forecasts for the subsequent incoming time intervals. Actual and predicted input data are used to make, at each time interval, decisions that are optimal because are based on the analysis of a complete time horizon as it is normally done in the classical unit commitment applied to power system. Since the algorithm has been conceived for real time applications, at each time interval the optimization is run again using the current state of charge of storage as starting value. The OPF takes into account what is going to happen in the incoming time intervals to find the optimal profile of ES operation by optimizing the most convenient time intervals to charge or discharge the storage [66].

The equation in (2) is changed, in order to take into account also the subsequent incoming time intervals as showed in equation (18):

$$\min J = \left\{ \sum_{h=h_{cur}}^{h_n} \sum_{i} C_i^h \right\} \tag{18}$$

Where h_{cur} e h_n are the current time interval and the last interval, respectively.

To explain the process, let us suppose that the time horizon h_n is equal to 3 hours and the time interval is one hour. At the first time interval (h_{cur}= 1), the DMS receives the initial state of the network (load demand, scheduled production by DG, SoC from the DES, status of switches, current tap of OLTC, etc.), energy market prices for the current time interval and the forecast of the same quantities for the next time intervals (h= 2 and h= 3). The minimization in (18) at h_{cur}= 1 foresees all the 3 intervals in advance until the final time (h_n= 3) and it is subject to the constraint equations ***(19)***. The star values **Var***(h_{cur}= 1) are the output solution at h_{cur}.

At the second interval (h_{cur}= 2), the optimization takes into account also the last third interval, with the constraint equations ***(20)***. Finally, when h_{cur} is equal to the time horizon *(h_{cur}= 3=h_n), the cost of only current time interval is minimized (there are not intervals in advance) and the minimization has been reduced to the original formulation (one set of constraint equations).

$$\begin{bmatrix} \mathbf{A\,(h_{cur})} & \mathbf{0} & \mathbf{0} \\ \mathbf{0} & \mathbf{A\,(h+1)} & \mathbf{0} \\ \mathbf{0} & \mathbf{0} & \mathbf{A\,(h_n)} \end{bmatrix} \cdot \begin{bmatrix} \mathbf{Var(h_{act})} \\ \mathbf{Var(h+1)} \\ \mathbf{Var(h_n)} \end{bmatrix} \begin{smallmatrix} = \\ \le \\ \ge \end{smallmatrix} \begin{bmatrix} \mathbf{B(h_{cur})} \\ \mathbf{B(h+1)} \\ \mathbf{B(h_n)} \end{bmatrix} \Rightarrow \mathbf{Var^*\,(h_{cur}=1)} \tag{19}$$

$$\begin{bmatrix} \mathbf{A\,(h_{cur})} & \mathbf{0} \\ \mathbf{0} & \mathbf{A\,(h_n)} \end{bmatrix} \cdot \begin{bmatrix} \mathbf{Var(h_{cur})} \\ \mathbf{Var(h_n)} \end{bmatrix} \begin{smallmatrix} = \\ \le \\ \ge \end{smallmatrix} \begin{bmatrix} \mathbf{B(h_{cur})} \\ \mathbf{B(h_n)} \end{bmatrix} \Rightarrow \mathbf{Var^*\,(h_{cur}=2)} \tag{20}$$

$$\begin{bmatrix} \mathbf{A\,(h_{cur})} \end{bmatrix} \cdot \begin{bmatrix} \mathbf{Var(h_{cur})} \end{bmatrix} \begin{smallmatrix} = \\ \le \\ \ge \end{smallmatrix} \begin{bmatrix} \mathbf{B(h_{cur})} \end{bmatrix} \Rightarrow \mathbf{Var^*\,(h_{cur}=3=h_n)} \tag{21}$$

In this way, the proposed algorithm is able to take advantage by the DES operation. In fact the operating margin of DES depends on the SoC in a given time interval and thus it is influenced by the previous operation decisions but it should be also based on the knowledge of the future.

The OPF takes into account what is going to happen in the incoming time intervals to find the optimal profile of DES operation by optimizing the most convenient time intervals to charge or discharge the storage.

3.4 Centralised Control Implementation in the ATLANTIDE project

The model of the centralised DMS previously described has been used in the ATLANTIDE project (see Appendix) and has been applied to the reference networks together with the hypothesized evolutionary scenarios developed in the project, in order to provide a useful benchmark for testing and comparing different distribution schemes and operation strategies [69] - [73].

As stated before, the DMS belongs to a bigger framework, the Active Distribution System (ADS), where the centralised DMS is constituted by a suitable OPF used by an Energy Management Systems (EMS), as showed in Figure 24. The model of the network (nodal voltage and branch current), which could be also estimated through a DSE, the set point and bids from DERs involved in the optimization are acquired by the DMS. The DMS also gathers non-technical inputs (i.e., regulation, connection rules, law, license, obligations) and weather forecast (e.g., wind prediction), demand and generation forecast, and Distribution System State Estimators (DSSEs). Then an OPF is executed and operation signals are sent to the local controllers of generators, storage devices, and flexible loads. The model of the network and the evaluation of the optimal set point are evaluated with a Load Flow calculation with MATLAB®, OpenDSS (Open-Source Distribution System Simulator developed by EPRI [74], [75]) or Digsilent.

In the ATLANTIDE DMS model, the flexibility of the algorithm allows the active management alternatives can be user-defined to fit with the specific features of different types of networks, like rural, industrial and urban networks (the reference network of the different typologies have been created in the same project [69] - [73].

Rural networks are characterised by long overhead lines, with relatively high and comparable values of line resistance and inductive reactance (high X/R ratio), low demand and increasing RES generation. The main issue in these networks is voltage regulation (i.e., typically over-voltages caused by excessive power production from RES).

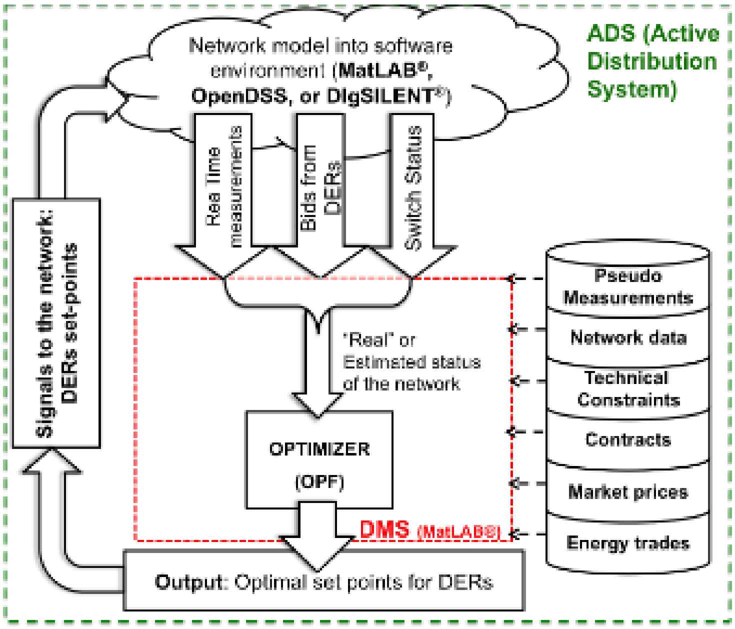


Figure 24: Scheme of Active Distribution System tool [69].

In this context, generators could participate to the Volt/VAr regulation, giving a valid opportunity that might be effective to reduce the curtailment of the renewable power production, avoiding solutions based on excessive injections of reactive power may lead to an undesirable energy efficiency worsening. For this reason, it is fundamental including the energy losses minimization cost in the objective function optimised by the DMS. In fact, depending on the value given to the improvement of energy efficiency, the active management can lead to different solutions. If energy losses are highly valued, it is preferable curtailing active power instead of increasing losses by producing capacitive reactive power. If the energy losses have a reasonable value, the curtailment may be not as much as the one necessary without the DG involved in Volt/VAR regulation. Furthermore, in rural networks an optimised ES operation can reduce the problems due to the low load coincidence factor and the poor homotheticity between demand and local generation. The amount of energy to be curtailed can be reduced and ES may contribute to the reduction of Joule losses by minimizing both operation costs and externalities. For these reasons the EMS for rural networks minimizes an OF that includes all the active management alternatives (i.e., general formulation, as in equation (2)) [68], [72].

Industrial networks are smaller than the rural ones, with prevalence of underground cables and bigger cross sections. In industrial areas the generators are programmable and often their power production is driven by the thermal need of the industrial facility they serve. Thus, the DMS to estimate the real energy demand has to consider not only the electric demand, but also the thermal one. In fact, in case of curtailment of those generators that are “thermal need followers”, the DG owner must produce the extra thermal energy (that one that is not generated with CHPs) by resorting to auxiliary boilers fuelled by conventional fuels. This in general causes an increase of CO2, and, depending on the regulatory environment, economic compensation to those power plants whose production has been curtailed or stopped. Simply speaking, it may happen that the Society pays more to have a low carbon world giving incentives to RES and the final result may be a greater carbon emission. Suitably managed ES, coordinated with thermal storage units, allow increasing the hosting capacity in the area and reducing the pollution. Therefore, the DMS for industrial networks does highly benefit from the inherent storage capabilities of industrial sites by integrating its usage with other no-network solutions (e.g., distributed network regulation) [72].

Short cable lines and high load density with a considerable portion of LV loads supplied by a high number of MV/LV stations characterise urban networks. These networks are less affected by voltage regulation problems than the rural networks. The DMS has to manage high-energy demand that can cause network congestions (mostly at LV level). Under-voltages may be caused by the simultaneous charging of the EVs at given hours of the day (e.g., when the workers come back to home) if the diffusion of EVs will reach the hypothesized level. Unfortunately these problems could not be solved by the injection of reactive power from DG because of the use of buried cables and the significant number of LV circuits. Load shaping is the most promising action in this kind of network. Urban final users and EV owners, by participating to active demand programs, can contribute to load levelling and peak shaving. The DMS optimization function allows increasing the hosting capacity of the system with less capital expenditures (e.g., deferment of investments for the addition of a second transformer in the substation) by exploiting the opportunities from demand side integration. In addition, the DMS would relieve contingencies by changing the network topology. Finally, even though many authors envisages the benefit of small storage (community storage), the wide spread integration of storage at low voltage in the final customers premises was not considered and, as consequence, the DMS for urban networks will not exploit ES. For this reason the DMS will work only by considering one time interval at a time, considerably reducing the computational efforts. This aspect is very important because the DMS for urban networks has to execute OPF calculation for both MV and LV networks that may become very large in real size application [72].

3.5 Distribution System Estimation

In [76], the importance of increasing the accuracy of the state estimation and robust DSSE algorithms at the distribution level, in order to reduce operational extra-costs as well as the number of unsuccessful DMS actions has been investigated. In fact, the quality of the estimates can seriously affect the active operation of the system, and, in the worst cases, compromise the correct operation, with the risk of jeopardizing the reliability of the whole network. The proper work of DMS and OPF can, indeed, be affected by several issues related to DSSE (e.g., those related to measurement types, locations and number, and the redundancy to safeguard the results against the loss of measures, signals, or changes in network topology, the reliability of the communication system, etc.).

The task of defining objective criteria to evaluate the quality level obtainable by a given measurement system and the DSSE algorithm is truly challenging. It should take into account the compromise between the two opposite objectives of increasing the accuracy of the results and reducing the total costs. In particular, the total costs should consider not only the cost of the instrumentation, but also the costs caused by an induced active management. In fact, in case of a real contingency, (overvoltage caused by an excessive production from DG or under-voltage caused by high demand) the OPF tries to optimise the operation point by minimizing the active power to be curtailed and/or modifying the power factor of the local generators, or shedding the load demand of the “active” customers. Depending on the regulatory environment, these control actions imply a cost to pay to the DG owners and the AD customers for changes the scheduled pattern and support the network. It is clear that if the DSSE underestimates or overestimates the network state, the optimal operation point assessed by the DMS could not be adequate to solve the problem or, at least, may lead the DSO to extra costs. In this case, the DSO may have to pay DG owners and/or AD customers for a service (active power curtailment, reactive support or load shedding) that could not be effective to solve the contingency. For this reason, in the DSSE total cost, the economic benefit of an improved state estimation has to be taken in due consideration.

For these reason, the DSSE algorithm has been embedded into the DMS (see Figure 25), as the OPF one, in order to co-simulate the two functions of DMS, estimation and OPF, with the final goal of comparing the costs of an incorrect network operation caused by a not sufficiently accurate state estimation with the cost necessary to improve the accuracy of the state estimation.

3.5.1 State Estimation

The State Estimation (SE) is based on mathematical relations between system state variables and measurements. The status of a system with a measurement device on each node is totally known, but, owing to the extension of electric distribution networks, this approach is economically unfeasible. Distribution networks are just partially monitored, thus the pseudo-measurements, obtained from a priori information, have to be added to the real-time measurements to make the system observable. A suitable DSSE is therefore necessary for evaluating the status of the system on the basis of few measurements. The DSSE has to provide a complete and consistent representation of the operating conditions and it is essential for the DMS operation.

The state variables are commonly related to node voltages or branch currents. The measurement model used for DSSE can be described as in equation (22):

$$\bar{z} = \bar{h}(\bar{x}) + \bar{e} \tag{22}$$

where $\bar{z}$ is the vector of the measurements and of the chosen pseudo-measurements; $\bar{h}$ is, in general, a non-linear measurement function (depending on the measurement model); $\bar{h}$ is the vector of state variables. $\bar{e}$ is the measurement noise vector and is usually assumed to be composed by independent zero mean Gaussian variables, with covariance matrix $\sum_{\bar{z}} = diag\{\sigma_{z_1}^2, \dots, \sigma_{z_N}^2\}$.

Measurements have low standard deviation σ, while pseudo-measurements are assigned with a higher σ due to their low confidence level.

The classical WLS (Weighted Least Squares) approach minimizes the sum of the squares of the residuals according to the equation (23):

$$\begin{aligned} \underline{\hat{x}} &= \arg\min_{\underline{x}} \left(J\left(\underline{x}\right)\right) = \arg\min_{\underline{x}} \sum_{i=1}^{N} w_i \left(z_i - h_i\left(\underline{x}\right)\right)^2 \\ &= \arg\min_{\underline{x}} \left[\underline{z} - \underline{h}\left(\underline{x}\right)\right]^{\mathrm{T}} \mathbf{W} \left[\underline{z} - \underline{h}\left(\underline{x}\right)\right] \end{aligned} \tag{23}$$

where w_i represents the weight associated with measurement z_i, while $W = diag\{w_1 \dots, w_N\} = \sum_{z}^{-1}$. An iterative Newton method is usually applied until convergence is obtained with a given tolerance. At each iteration, the following normal equations system is solved to compute the estimated state (24):

$$\mathrm{G}(\underline{\hat{x}}_k)(\underline{\hat{x}}_{k+1} - \underline{\hat{x}}_k) = [\mathrm{H}^{\mathrm{T}}(\underline{\hat{x}}_k)\mathrm{W}][\underline{z} - \underline{h}\left(\underline{\hat{x}}_k\right)] \tag{24}$$

Where is the gain matrix and is the Jacobian matrix of the measurement function vector at the k-th iteration.

Unavoidable uncertainties affect the estimates provided by DSSE:

- (Low) level of reliance on pseudo-measurements due to the stochastic behaviour of demand and generation (particularly relevant with high shares of RES in the systems).
- Inherent uncertainty derived from the measurements (accuracy of the instrumentation and decay of the metrological characteristics).
- Anomalies or faults in the measurement system (reliability of the measurement system).
- Insufficient redundancy.
- Deviations from their nominal value of network parameters (resistance, reactance of the lines, etc.).
- Changes in network topology.
- Reliability of communication system.

The DSSE, integrated in the DMS, assesses the status of the network starting from the recorded data (i.e., pseudo-measurements and network parameters) and the data directly gathered from the field (i.e., measurement signals). The OPF algorithm solves the optimization problem on the basis of the estimated status of the network derived from DSSE. Finally, the DMS sends the optimised control signals to the local controllers of DERs to apply the corrective operation actions. In this sense it may assume also the role of scheduling coordinator for DERs of Virtual Power Plants (VPPs) [77].

The field, or the "real" network, subjected to the DMS control has been modelled with the OpenDSS software package for power system simulation (Figure 25) [76].

An external code in MatLab®, able to communicate with the OpenDSS software environment, has been written to simulate the DMS. The procedure can then be split up into two blocks. The first block performs the DSSE and collects the data for the optimiser. The second block executes the optimization. With an interface routine DG, storage devices, and flexible loads set points are sent to their local controllers in the field and hold constant until the end of the considered time interval.

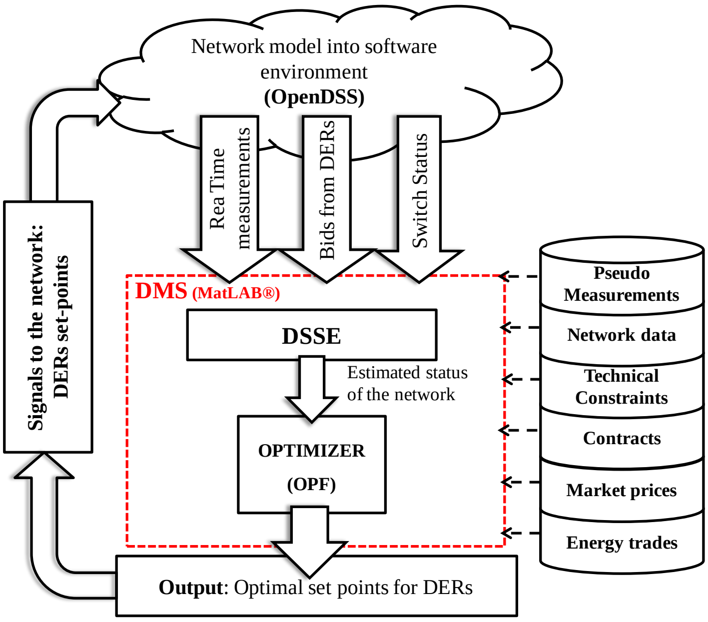


Figure 25: Implementation of the active operation chain. The data flow between the DMS and the simulated network is highlighted [76].

3.6 Case studies

In the following significant applications of the DMS are provided to show the effectiveness of the algorithm implemented.

3.6.1 Case 1: Centralised Control of Energy Storage and Distributed Generation

In [72] the DMS model has been applied to the ATLANTIDE rural network in order to avoid the contingencies that could arise in presence of renewable generators allowing the increase of the hosting capacity. The analysed network is constituted by seven feeders (mostly small cross sections overhead conductors for a total extension of about 160 km) with 103 MV nodes supplied by one HV/MV substation (Figure 26). Five PV plants are connected at MV level for a total of 7.7 MVA installed. The nominal load - a mix of agricultural, residential and small industrial customers - is about 18 MVA at the peak.

To emphasize the use of the DMS, simulations referring to a summer Wednesday in July 2020 are performed by considering the Business as Usual (BAU) scenario. The BAU scenario is based on the natural evolution of current trends without any new political action (e.g., no changes in the incentives for RES or no further promotion for energy efficiency improvement) and the trend for demand and production continues without discontinuities [70],[71].

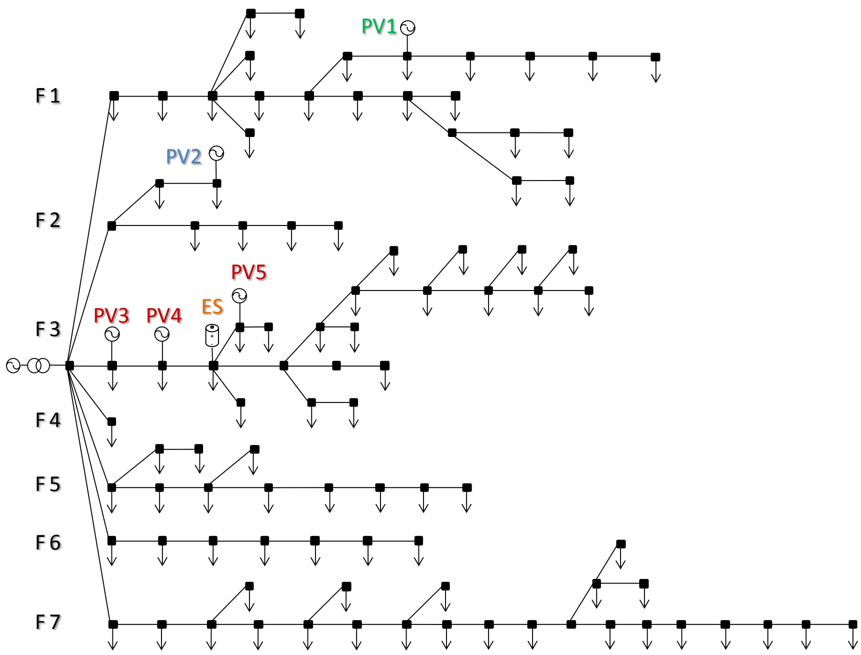


Figure 26: Schematic representation of the rural reference network [72].

The grow rates, for generation (for different sources) and Load demand (for different typologies of loads,) are summarized in Table IV.

Table IV – Load demand and generation annual growth rate in the ATLANTIDE BAU scenario

		BAU
Generation	Photovoltaic	10 %
	Mini & micro wind	5 %
	Bio-energy	2.7 %
	Mini-hydro	2 %
Load demand	Agricultural load	0.4 %
	Rural LV load	1.6 %
	Rural MV load	0.6 %

By using the hypothesized growth rates for load demand and generators in the BAU scenario, the nominal peak load demand reaches in 2020 about 20.23 MVA and the PV installed power will be about 20 MVA. Furthermore, in the 2020 has been evaluated the resort of energy storages for distribution in the network operation, by hypothesizing a 4 MW-2MWh REDOX battery installed in the feeder F3, as shown in Figure 26. In Figure 27, the load demand and the scheduled generation for the considered day in 2010 and 2020 are shown. The power production is always smaller than the total power demand, but between 11:30 a.m. and 2:00 p.m., some nodes in the feeders with the greater power production (F3 and F2) suffer for over-voltages beyond the maximum allowable threshold.

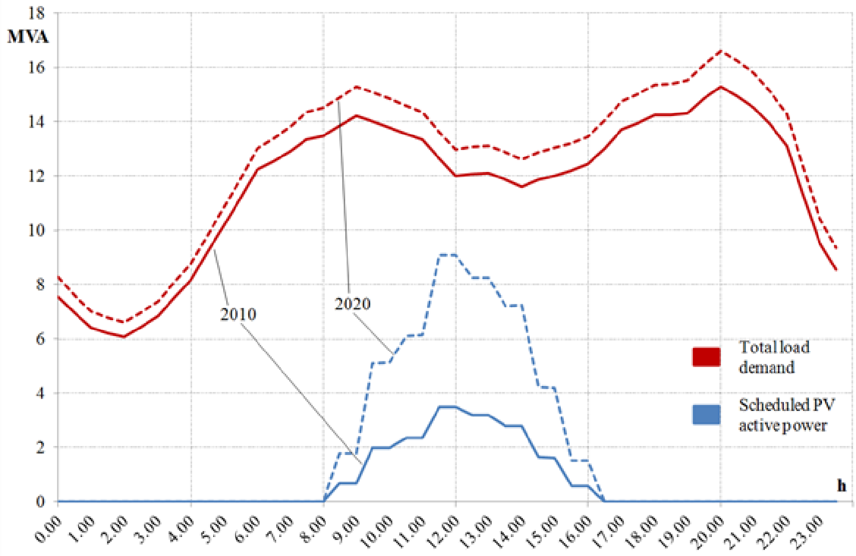


Figure 27: Total load demand and scheduled generation profile from PV in 2010 and 2020.

This happens because those feeders deliver to the final users less power than the one generated by the local PVs. Figure 28 shows the voltage profiles of the feeder with the greatest DG penetration level (F3) in a critical hour of the day.

In the selected day, the energy losses are equal to 4.484 MW in 2010 and arise to 5.374 MW in 2020 (corresponding respectively to 1.78 % and 2.13 % of the total energy demand).

It clearly emerges that the network is not capable to host the RES integration at the horizon year and actions must be taken to cope with this situation. Two possible solutions can be evaluated: a *network solution* (that is the traditional planning solution) or a *no-network solution*.

The first solution indicates to build new lines or upgrades the existing ones; while the second one, with the use of DMS will allow solving network issues with modern operation techniques:

1. exploit the curtailment of active power,
2. integrate in the volt/VAR regulation the DER,
3. integrate in the volt/VAR regulation the DER and the ES optimal operation.

From these different alternatives of active management, the system costs as well as the investments required to RES owners can be compared for an objective and transparent decision-making. Finally, the impact of energy efficiency on final decisions can be also assessed to avoid the risk of minimizing capital expenditures without obtaining required low carbon emissions.

Since in 2010 the voltage profile remains within the boundaries even in the most critical hours of the day, the DMS at the starting year can only perform the minimization of the Joule losses (GC is never necessary). The only possibility to improve the energy efficiency is resorting to the reactive

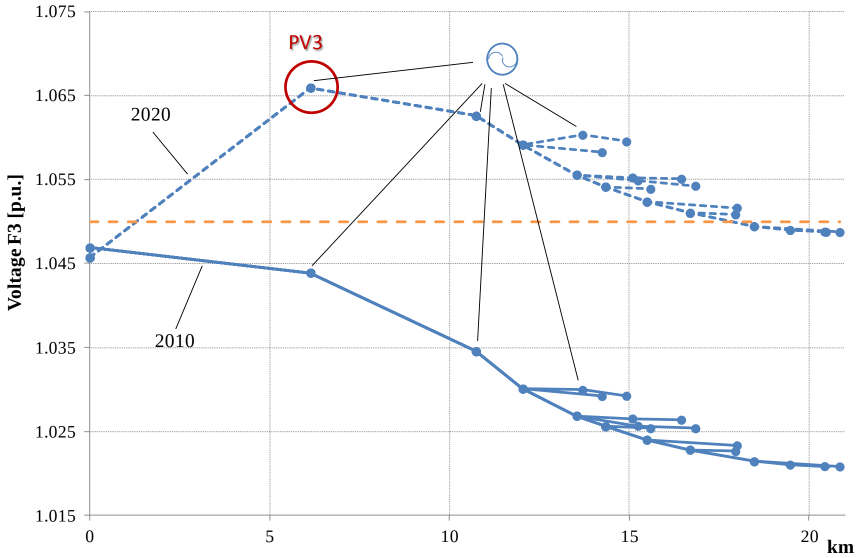


Figure 28: Voltage profile of the feeder F3 in a critical hour of the day (12:00 a.m.) in 2010 and in 2020

support from DG. To involve PV generators in the network operation it has been assumed that the interface power converters were oversized, with an extra cost for DG owners. In this case only if the DG owners are getting paid with fair tariffs for their reactive support, the cost sustained for the oversized converters will be recovered in a reasonable time. Suitable regulatory schemes are then necessary to remunerate DG investors for investments that are mainly for the distribution system, and then used by all the stakeholders beside themselves. The results of the simulations performed with these assumptions show three of the five generators required to inject inductive power into the network. The energy losses have been reduced to 4.066 MW (1.61%).

In 2020, the main problem is the voltage regulation but also the energy efficiency is pretty low for the DSO. In Italy, a flat remuneration mechanism compensates DSO for losses up to 2% of the energy delivered, thus, losses higher than 2% are a real cost for the DSO.

The simplest action to carry out is the curtailment of generation when the voltages is beyond the limits. If only the curtailment is applied and the generators do not participate to the Volt/VAr regulation, the DMS heavily curtails the active power generated by the five PV. The energy delivered by the DG during the examined day has been reduced from 43.325 MWh to 38.465 MWh in case the minimization of energy losses is disregarded, to 38.405 MWh if the improvement of energy efficiency is also taken into account. Despite the energy curtailed assumes almost the same values in the two simulations (only GC or both GC and losses minimization) the inclusion of the energy efficiency in the OF changes the generators that are called to reduce the production.

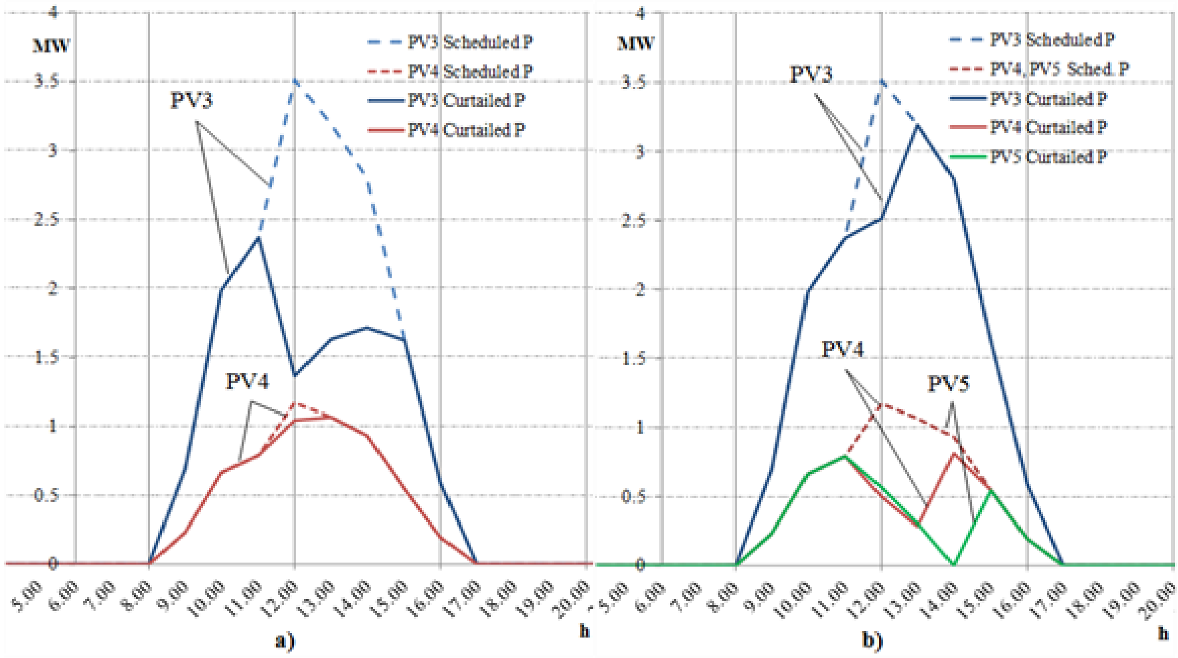
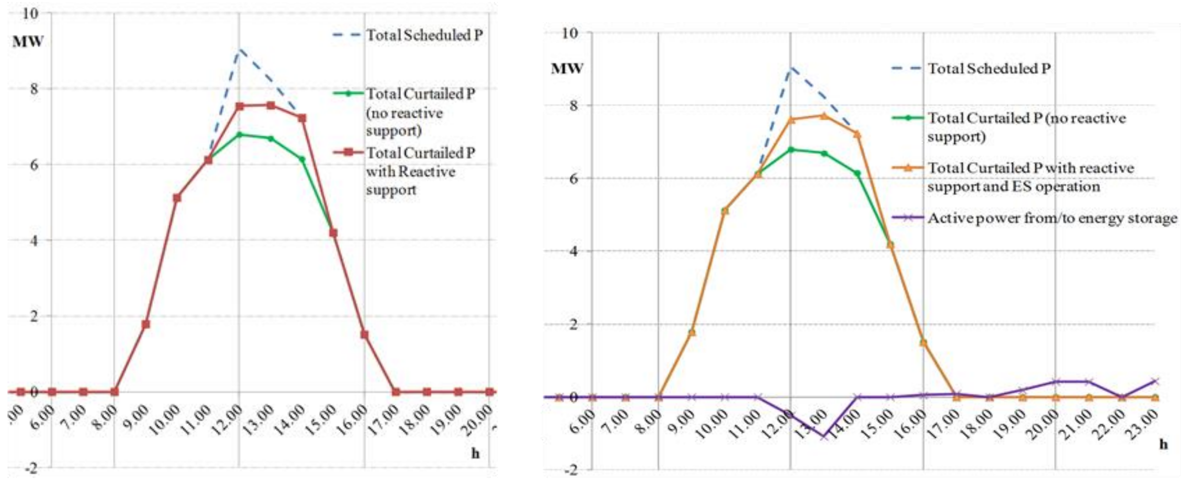


Figure 29: Scheduled and curtailed active power from DG connected to the feeder F3 when the GC alternative is selected: a) with losses minimization; b) losses minimization disregarded.

If the minimization of the energy losses is considered, only two generators in the F3 (PV3 and PV4 in Figure 26) are curtailed (Figure 29 a)), otherwise all generators in the critical feeder are involved (Figure 29 b). The use of DMS for allowing DG to participate to Volt/VAr regulation is a valid opportunity that might be effective, particularly in long overhead lines with high inductive reactance as in the rural test network. In this case, supposing that the power converters are sufficiently oversized to inject reactive power also when the PV are producing the rated active power, the production of reactive power can seldom limit the production of active power from DG.

In Figure 30 a) the total scheduled active power compared with the curtailed one with and without reactive support from DG is shown. In case of DG participation to the Volt/VAr regulation the total energy delivered during day by the PVs is about 41.115 MWh, corresponding to only 5.1% of curtailment, otherwise, if the PVs not are involved in this ancillary service the curtailment increases to the 11.5% of the scheduled active power.

The injection of capacitive reactive power in those hours when the voltage overcomes the limits helps to relieve the contingence with less active power curtailed. Furthermore, in the rest of the day, with the aim at improving the energy efficiency, the PVs are called to produce inductive reactive power. If the losses minimization is not taken into account the PVs inject only the capacitive reactive power during the critical hours of the day. Finally, if the ES operation is considered in the



a) b)

Figure 30: Total scheduled and curtailed active power with and without reactive support from DG.

optimization, the integration of RES is less challenging and, as a consequence, the hosting capacity of the network can be increased.

The optimal use of storage devices, strategically allocated in the network, allows DMS to find a good compromise between the need of minimize the operational costs and improve the overall efficiency of power delivery. Particularly, the ES can reduce the amount of energy to be curtailed and contribute to the reduction of Joule losses. In the proposed example, the PVs can deliver 41.354 MWh during the day, corresponding to a minimal percentage of curtailment (4.5% of the scheduled active power, Figure 30 a). The exam of the ES charge pattern shows that the recharge is simultaneous to the PV peak production even though at that time the energy price would not suggest to buy energy. This is a demonstration of the correct functioning of the proposed OPF algorithm that by using the information from forecast stops the charge of the ES until will be convenient for the system.

Furthermore, the reactive power production for voltage regulation from DG is slightly reduced, with the final result of reducing the total operation cost and improving the energy losses up to 1.92 % of the total energy demand. The voltage profiles for the feeder F3 during the same critical hour of the considered day in 2020 are also reported in Figure 33 to highlight the positive impact of ES on voltage regulation.

The study presented shows that the DMS is capable to find solutions that allow increasing the network hosting capacity and improving the efficiency of power delivery allowing the reduction of the power losses in the examined case, as summarized in Table V.

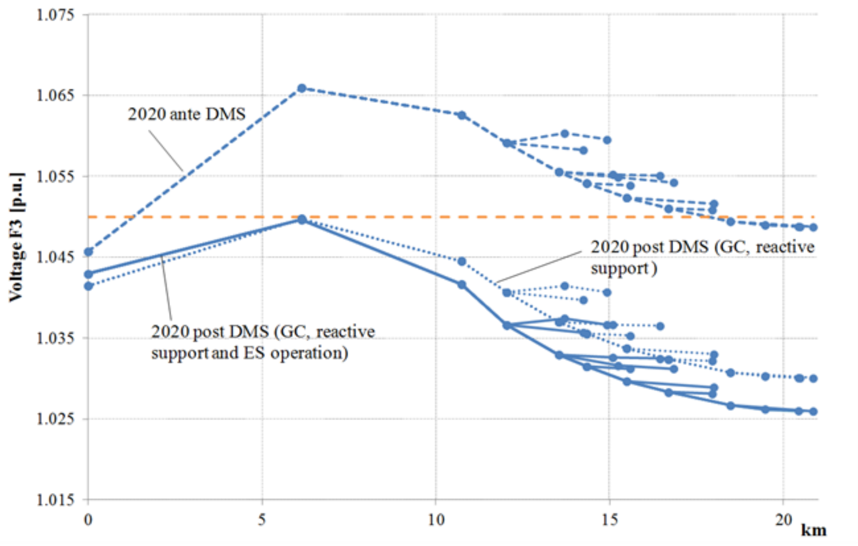


Figure 31: Voltage profiles of the feeder F3 in a critical hour of the day (12:00 a.m.) in 2020: the curves refer to the case without DMS operation, with the resort of GC and reactive support and with the addition of ES operation.

Table V – Losses in the network before and after the DMS

CASE ANALIZED	ANTE DMS	GC	WITH GC, REACTIVE SUPPORT	WITH GC, REACTIVE SUPPORT, ES OPERATION
PERCENTAGE OF LOSSES	2.13%	2.08%	1.94%	1.92%

3.6.2 Case 2: DER optimal coordination and Active Demand

In [73] the integration of AD in the Active Management of an urban distribution network has been proposed. The studied urban network (Figure 32) is constituted by five feeders with a low total loading (with a large amount of LV residential users) and 14.42 MVA of installed generating power (3 PV systems). Following the ATLANTIDE evolutionary scenario, it is assumed that in a future year (e.g., 2030), during critical hours of a typical summer day, the PV power production and the load demand cause over-voltages in feeder F_2 (the most active feeder) under voltages in and F_3 (the most loaded feeder). In Figure 33 a), the voltage profile of the F2 nodes closest to the PV generator (PV_231 in Figure 32) is showed, highlighting that the voltage arises beyond the technical limit (i.e.,

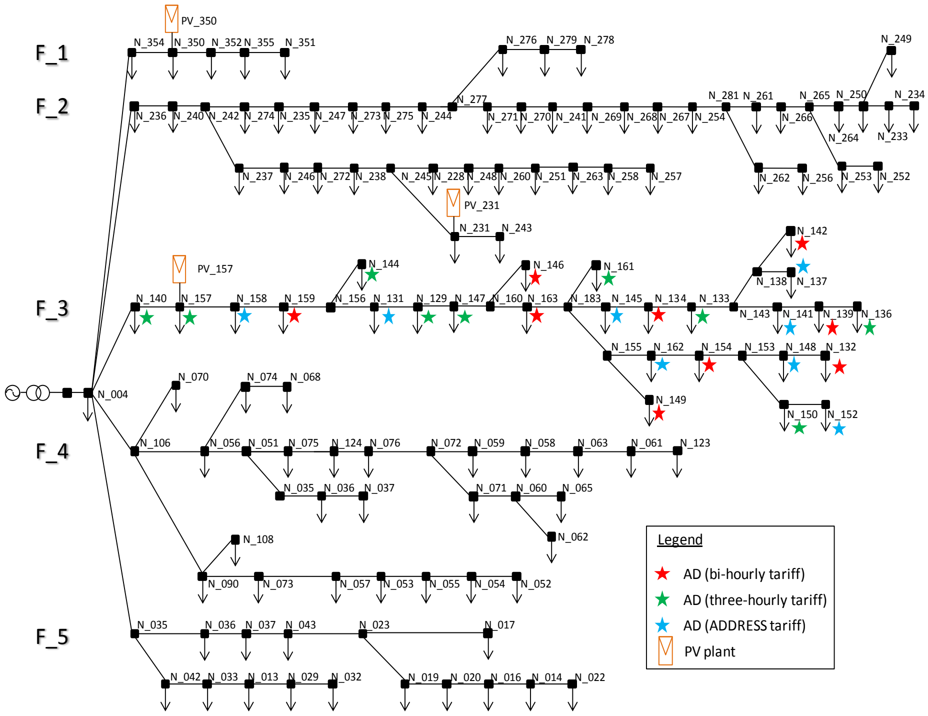


Figure 32: Schematic representation of the test urban network.

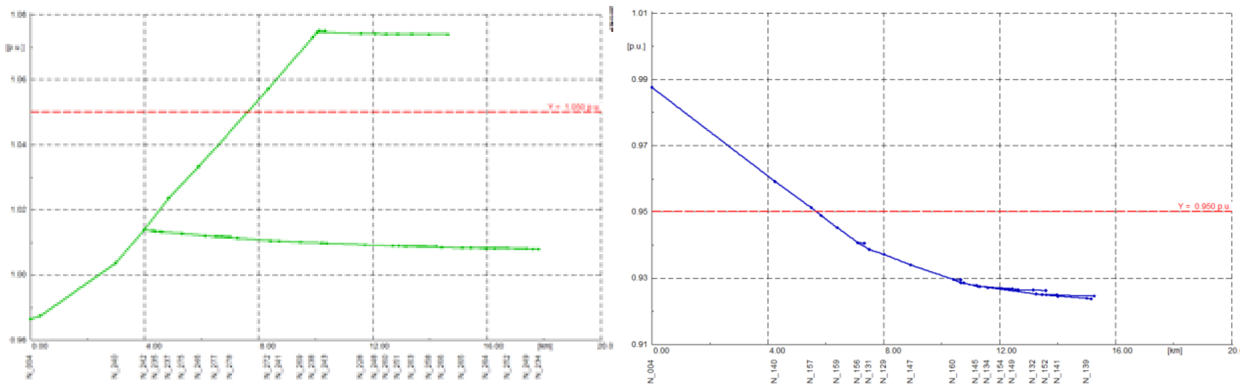
1.05 p.u.). The farthest nodes from the substation of the heavily loaded feeder F3 suffer to unsustainable under-voltages, as depicted in Figure 33 b).

In such situations, without operation in place, RES will be switched off, curtailing the active power during the overvoltage contingencies and capital expenditures to upgrade the network branches and cope the increased demand would be necessary. With the active management, including the customers in operation policies through the AD less or no upgrades are necessary and RES are not penalized.

In order to show such possible benefits to the system different active management policies have been simulated:

1. active and reactive power generation control for dispatchable generators;
2. AD is included the active management and integrated with DER optimal coordination;
3. DMS coordinates DER and AD but no reactive support from DG is available.

Assuming that the DSO pays DG owners and final users that participate to AD programs for their support to the network operation, the costs of the active management are supposed strictly related to the hourly energy price p(h) [€/MWh]. It is hypothesized that the energy price is subdivided into three time bands during the day to take into account the peak and off-peak hours. B1 and B2 are two off-peaks hour bands, with prices pB2 greater than pB1 and the B3 band represents the peak



a) b)

Figure 33: a) Voltage profile of MV nodes in F2 feeder at noon of a typical summer day; b) Voltage profile of MV nodes in F3 feeder at 7:00 pm of a typical summer day.

hour time band (pB3> pB2> pB1). Therefore, the price of AD support has been considered dependent on three tariff models named bi-hourly, three-hourly and ADDRESS tariff model (Figure 34). In order to discourage the resort to GC (in the network only RES is present) the price for varying the DG scheduled active power production has been assumed three times the energy price at the same hour of the day. On the contrary, to favourite their Volt/VAr support, the reactive power from DG is paid half the price of energy at the same hour.

Furthermore, the DG is supposed to give a total support to the DSOs (i.e., the generators offer the 100% of their active power production to be curtailed and the maximum reactive power that their inverters can exchange, during all the day). The active customers, depending on their contract

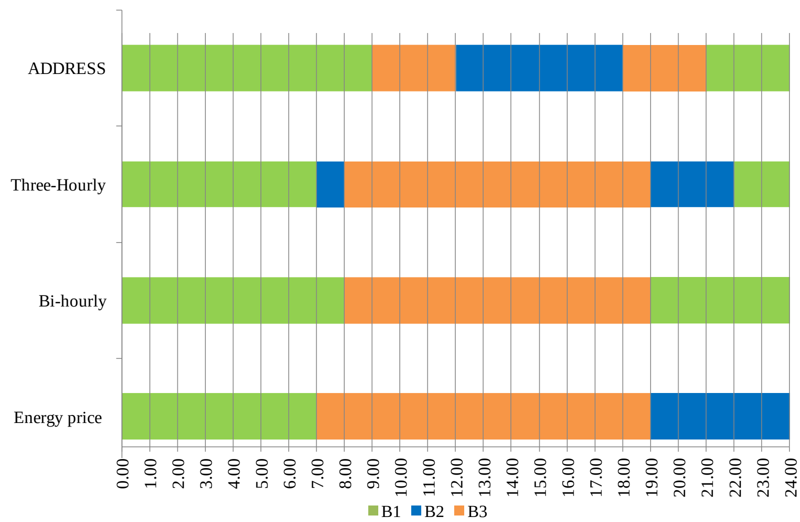


Figure 34: Hourly energy and AD tariff models bands.

and according with the tariff model in Figure 34, offer different percentages for varying their scheduled load demand (typically 10% in B1, 30% or 40% in B2, and 70% in B3).

During the examined day, the total scheduled energy produced by the three PV is equal to 50.11 MWh and the total energy delivered to the customers is equal to 130.57 MWh.

Over-voltage states

Between the 11.00 and 15:00 the total generation overcomes the total demand and in some nodes of feeder F2 over-voltages occur. The simplest action to take is the curtailment of the nearest generation (PV_231 in Figure 32) when the voltages is beyond the limits. If, as generation control, only the curtailment (GC) is applied and the generators do not participate to the Volt/VAR regulation, the DMS will curtail the active power generated by the PV_231. Whereas, if DG participates also to Volt/VAR regulation, the injection of reactive power in those hours when the voltage overcomes the limits will help to relieve the contingency with less active power curtailment. In Table VI, the energy produced by the PV_231 in the different examined cases is reported.

Table VI – Energy produced by the PV_231 generator

	Expected Energy [MWh]	GC Curtailed energy [MWh]	GC and Volt/VAR support Curtailed energy [MWh]
PV_231	30.13	27.18 (-9.76%)	28.25 (-6.21%)

It is worth noticing that in the test network only PV generators are installed. Even though generally the production of reactive power can seldom limit the production of active power from DG, it has been supposed that the power converters can inject reactive power also when the PV are producing the rated active power. To involve such type of generators in the network operation the interface power converters have to be oversized with an extra cost for DG owners that should be compensated by a fair regulatory mechanism.

- Under-voltages conditions

On the contrary, in the feeder F3 the main problems are the under-voltage conditions between 15:00 and 20:00 that occur in the farthest nodes from the primary substation. In order to relieve this contingency, the DMS can resort to the reactive power from the generator connected to the same feeder (PV_157 of Figure 32) and/or to AD. If the DMS can only dispatch the DG (no AD), the PV_157 will produce the (inductive) reactive power necessary to partially compensate the one requested by the loads. The total reactive energy delivered by the PV_157 during the considered day would be in this case equal to 9.28 MVAR. To investigate the impact of the AD in the active management, it has been then supposed that all F3 customers participate to AD programs, accordingly with the aforementioned tariff models.

Thus, the DMS shaves the peaks of the F3 load demand by minimizing the total cost of the active management. In this case, the resort to the reactive support from the generator is still useful but it is reduced more than the previous case (6.43 MVAr). Finally, if the PV generators are unavailable to participate to the Volt/VAR regulation, and AD will be the only option to reduce under-voltages, the load power curtailment will also increase, with extra operation costs. In Figure 35, the active power produced by the PV and the scheduled/modified power demand in the different examined cases are shown. The differences between the curtailed power curves (required and true) are related to the AD model. In fact, in real applications the behaviour of the customers that participates to AD programs, following a request from the aggregator to curtail their power, does not correspond perfectly to the request.

Thus, the power that will be effectively curtailed will be smaller than the required, as it is shown in the Figure 35. In addition, in Figure 36 the phenomenon of *payback* (PB) is represented, for instance, related to the load connected to the node N_139 of Figure 32, which is one of the nodes most involved in the active management. The PB effect leads to an increase in the load as a

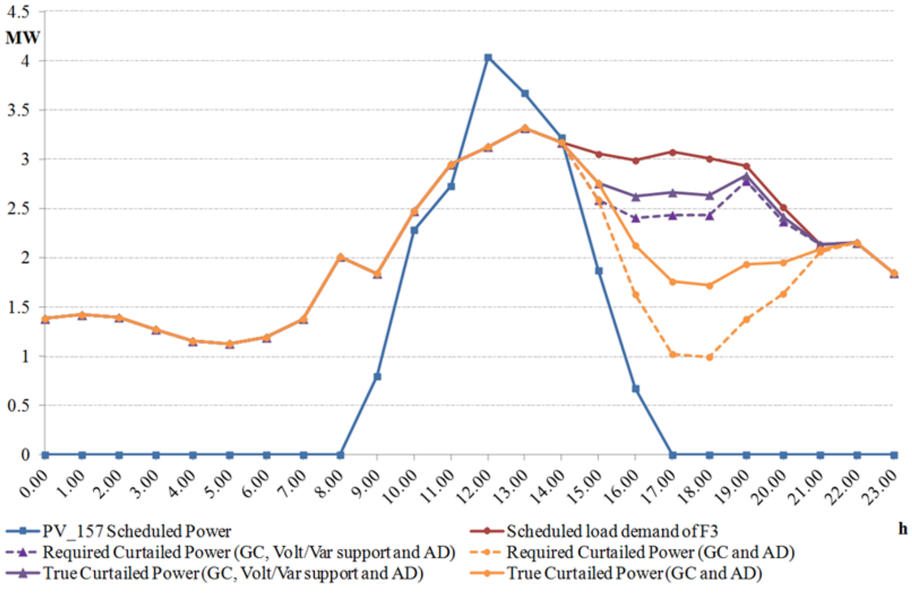


Figure 35: Power demand of the F3 loads: scheduled and curtailed (required and true) in the different examined cases.

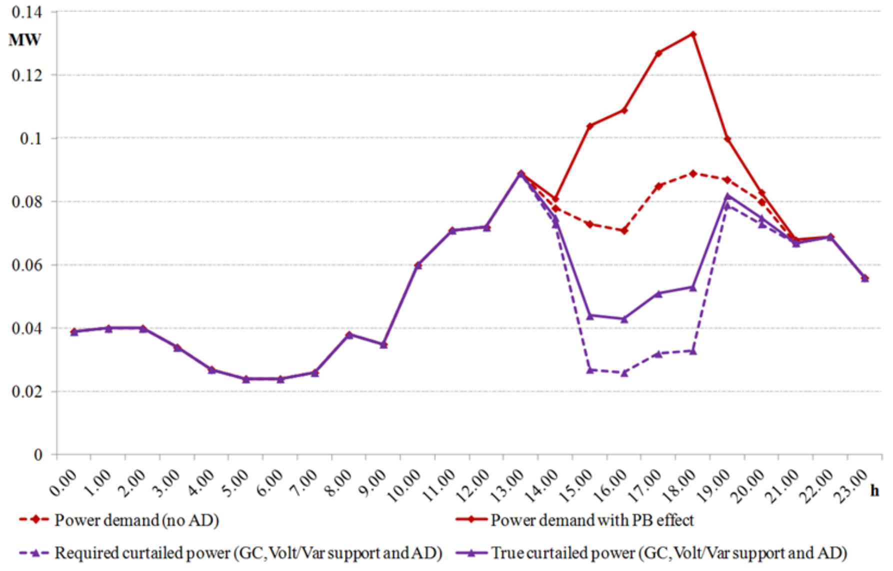


Figure 36: Load profile: scheduled, true (taking into account the PB effect) and curtailed, required and true, of the load connected in the N 139.

consequence of a previous reduction caused by a DMS request. The payback effect, in this particular example, is extremely emphasized to better explain the phenomenon (the solid line that represents the power demand taking into account the PB effect is definitely greater than the scheduled dotted one).

3.6.3 Case 3: Impact of State Estimation in the DMS operation

In The OPF algorithm is used to simulate the impact of DSSE on the active operation of distribution systems. The test network is the ATLANTIDE rural network, described in case study 1. The network is characterised by five PV plants, connected at MV level for a total of 20.07 MVA installed, while the overall nominal load (a mix of agricultural, residential and small industrial customers) is about 20.21 MVA at the peak, according to the 2020 BAU scenario (Figure 37).

The tests have been performed considering a typical summer week of 2020. In Figure 38 the profiles of the total demand and the generated power from the PV plants are shown for the considered summer week scenario.

The DMS can resort the GC and the Volt/VAr regulation to relieve the violations of technical constraints. The costs of active management are defined according to the regulatory scenario as described in the previous section.

The simulations are performed according to the following assumptions:

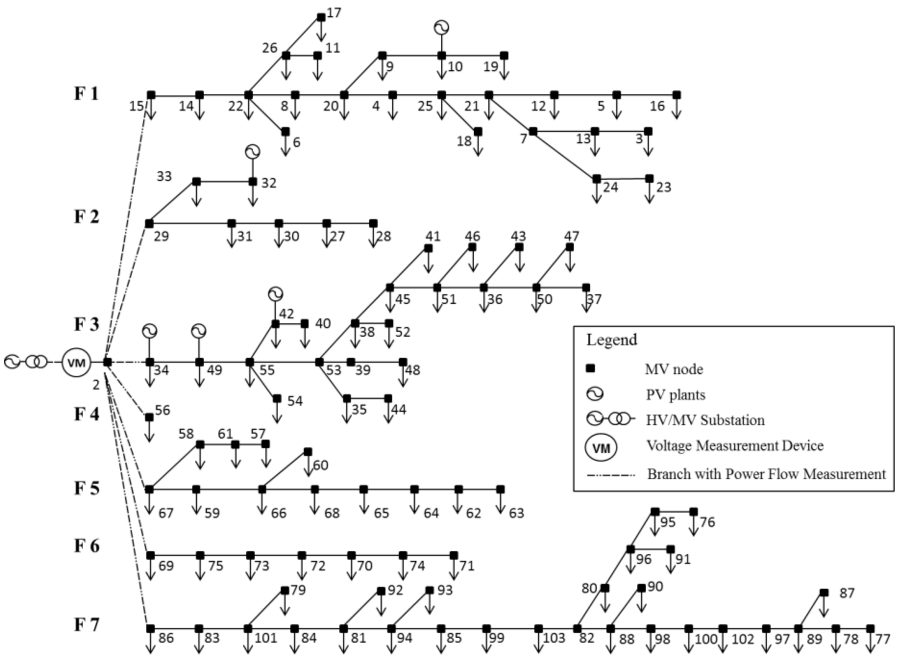


Figure 37: Rural network with the default measurement system highlighted.

– a maximum deviation of ±50% with respect to the nominal values for the active and reactive powers (Gaussian distribution) drawn by the loads;
– measurements are assumed to have a Gaussian distribution with a standard deviation equal to a third of the accuracy value;
– measurement accuracy equal to 1% for the magnitude of the voltage and equal to 3% for the power flow.

Such a high maximum deviation for the pseudo-measured powers is chosen to reflect the poor knowledge on the behaviour of the loads, whereas the accuracy assumed for the real measurements is commonly available in measurement devices installed in distribution networks.

The proposed procedure is assessed considering 336 operative conditions, corresponding to the half-hourly sampled week scenario. In each operative condition, the measurements are extracted from their probability distributions.

Several measurement configurations have been considered for the network, without applying any meter placement technique. Placing of the measurement devices can be optimised in order to guarantee a prefixed quality level of the estimates in a sufficient wide range of possible load and production variations and reduce the harmful effects of uncertainties and inaccuracies [27], [78]. The optimal placement of the instrumentation improves the reliability of the measurement system if a redundancy is a constraint of the optimization [79]. Furthermore, redundancy protects the DSSE

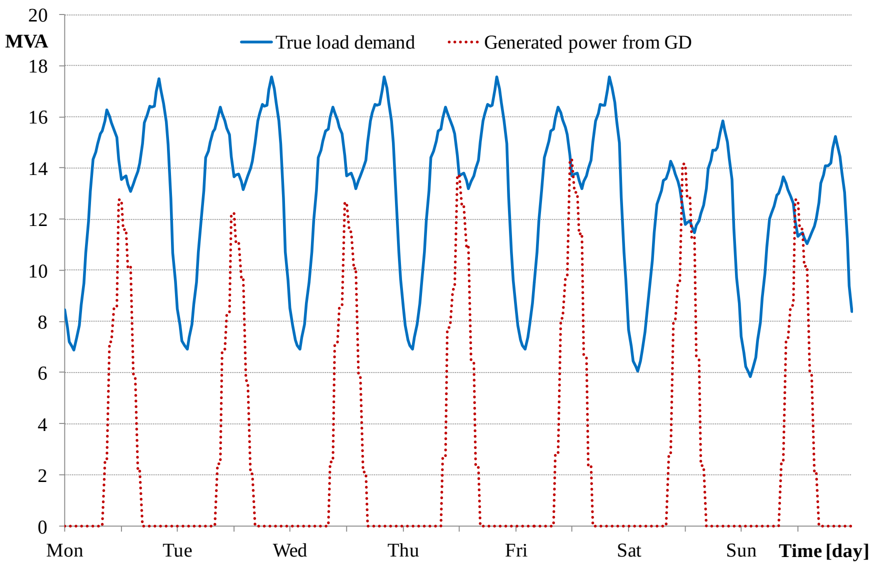


Figure 38: Total demand and generated power from the PV plants.

results against the variations in the network topology [80]. However, in the following tests, the focus was in particular on the impact of the DSSE accuracy on DMS operation and the measurement configurations are chosen to better illustrate such aspect.

- **Measurement point considered**

In all tests, the substation is monitored with a measurement point constituted by one voltage measure at the MV bus and by the power flow measurements in all the branches downstream (i.e., seven measured power flows, one for each feeder of the tested network). Furthermore, it has been assumed that the injected active power and the exchanged reactive power from DG are totally known (this assumption is reasonable, since all the DG plants participate to the network active management). Such base measurement system is referred to as "default measurement system" (see Figure 37). In the following, an example of "extended measurement system", chosen by geographical criteria to guarantee a prefixed (1%) accuracy level for voltage magnitude estimations, is also used (see Table VII).

Table VII – Extended measurement system: measurement devices added to the default system.

Node Voltage Measurements		Power Flow Measurements	
Nodes	10, 32, 34, 42, 49	Between nodes	10-19, 42-40, 15-14, 33-32, 49-55, 66-68, 85-99

In the Figure 39, the “true” apparent power of the most loaded node of the network (i.e., the number 27 in Figure 37) is compared with the estimated apparent power calculated by the DSSE algorithm based on default and extended measurement configurations: the difference between the “true” values and the estimated ones is smaller with the extended measurement system.

Table VIII reports further results concerning DMS co-simulations in the considered period: the number of nodes that suffer for overvoltage (N_OV) or under-voltage (N_UV) in the "true" operative conditions is reported as well as the amount of active power curtailed and the amount of reactive power exchange. The outcomes of the DMS action based on the “true” status and the status estimated by the DSSE relying on the two measurement configurations are compared. In particular, the total scheduled active energy was 442.2 MWh. It is possible to see that the energy is reduced of about 0.23 % in all the considered cases, both if the DMS receives the true network status or the one estimated by the default or by the extended measurement system (Table VII). The energy losses have been reduced after the DMS operation, but the DSSE underestimates their initial value (83.1 MWh or 85.5 MWh vs. 87.9 MWh of the “true” condition).

The most important results are related to the contingencies. In the central hours of the days, over-voltage conditions appear and OPF algorithm curtails active power from DG. In the evening hours, when the PV plants do not produce, under-voltage conditions appear due to the heavy load demand. In order to relieve such contingencies, the DMS exploits the reactive support from the DG (i.e., Volt/VAr regulation). The results show that the total exchanged reactive energy is rather increased with the default measurement system. With the extended measurement system the use of reactive power it is reduced thanks to the better working of DSSE.

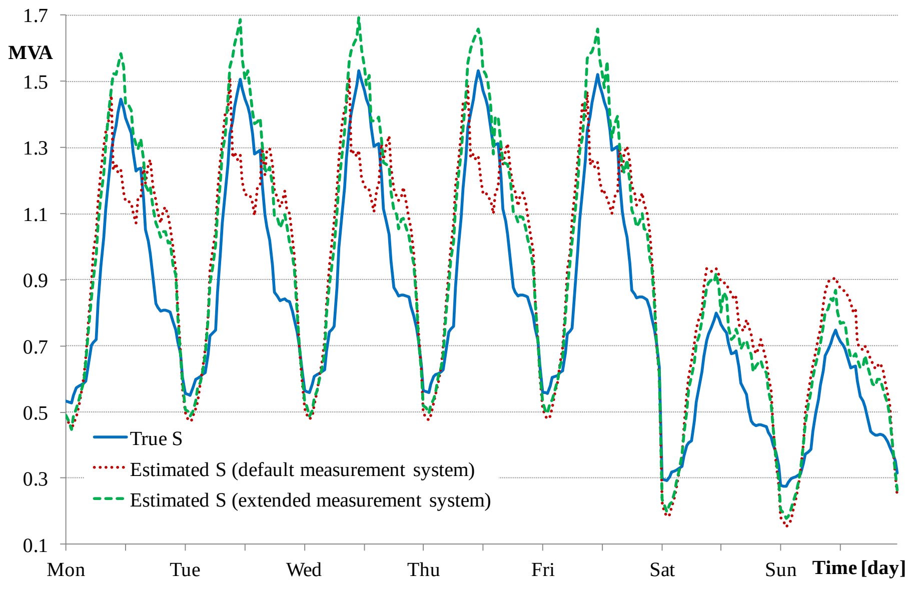


Figure 39: “True” and estimated apparent power (S) of the node 27 (Figure 37).

In Table VIII, the number of contingencies after DMS operation is reported in the three cases to highlight at what extent the accuracy of estimates impacts on the DMS effectiveness. The first remark is that the DMS reduces the number of network states that can determine the tripping of DG loss of mains relays even though the state estimation is not perfect. Anyway, if estimates are not accurate enough, a number of contingencies persist that may become unacceptable (i.e., 188 overvoltage conditions in the case of the default measurement system). This means that the OPF cannot relieve the contingencies and the voltage of several nodes remains out of the technical boundaries in many time intervals of the considered week. This fact causes further problems to both DG owner and DSO. For instance, if the DG loss of mains relay trips and commands the instantaneous disconnection of the generator, the DG owner will have an economic damage. Indeed, the new, not foreseen, network operation point might cause new contingencies that could be more difficult to relieve by the DMS. It is worth noting the impact of accuracy of both estimates and measures on the global quality of DMS. As it is showed in Table VIII, the better the quality of estimates the lower is the number of unsuccessful DMS actions. Particularly, the number of not successful actions reduces from 188 to 21. Finally, the total cost of the active management that is related to the OPF objective function (OF) values is greater in the case of estimated network status, but if the number of measurement devices increases and the state estimation reaches a greater level of accuracy, the operation cost is lower than in the case with the default measurement system.

Table VIII – Simulations results before and after the DMS operation.

Input to OPF	**P_DG [MWh]**	**Q_DG [MVArh]**	**Losses ante [MWh]**	**Losses Post [MWh]**	**N_UV ante**	**N_OV ante**	**N_UV post**	**N_OV post**	**OF**
”true” data	441.2	55.9	87.9	84.5	1828	199	0	0	2212
uncertain data (default measurement system)	441.1	77.0	83.1	79.8	2175	202	0	188	2877
uncertain data (added measurement devices - Table VII)	441.1	58.2	85.5	82.3	1889	218	0	21	2338

The results prove that by increasing the accuracy of the DSSE (i.e., adding measurement devices to the default measurement system) the operational extra-costs may be reduced as well as the number of unsuccessful DMS actions. The better the quality of state estimation the better performance of the DMS will be. Anyway, the general remark is that the DMS as well as the OPF algorithm have to be designed, taking into account the quality of state estimation, which is influenced by the measurement system. Lacking in properly considering the influence of uncertainties and inaccuracies in the DMS operation will dramatically reduce the usefulness of active management and jeopardize the reliability of distribution systems. Indeed, the design of active distribution networks requires the joint simulation of all DMS functions.

Although the described structure simulates a possible real active distribution network, it is worth noting that the communication delays between the real centralised DMS and DERs are not taken into account. In [81] an integrated software package for the cyber-physical simulation of DMS, that considers the accuracy of state estimation and measurements, has been developed and the effectiveness of a wireless Wi-Max communication system has been tested on the rural Italian representative network produced by the research project ATLANTIDE.

CHAPTER IV

4 Decentralised control system for Active Distribution Network

4.1 Introduction

When there are a lot of resources involved in the optimization and there is a huge amounts of information to handle, the centralised control system is not a suitable solution, because (as stated in the previous chapter) needs significant computational resources and communication infrastructures, becoming an expensive solution.

The problem arises in the management of LV systems characterised by many small customers with information flow from intelligent metering. Moreover, in LV systems, the presence of new additional loads (e.g., EV and their recharge systems), new high efficiency domestic appliances (e.g., heat pumps, induction cooking systems), and small generation (e.g., photovoltaic, CHP and small wind generators) are expected and will cause contingencies like voltage limits violation and power flow congestions. In order to solve these contingencies, there is the need of decentralised control systems, able to manage local optimization problems and to offer services to the DSO.

4.2 Decentralised control with Multi Agent System

Decentralised control systems can be developed basing on different methodologies. In the research activity, a Multi Agent System (MAS) has been designed and developed for the direct control of the active participation of small consumers in the electricity system, support the integration of the Electric Vehicles in the LV distribution network and reduce its harmful impact on voltage regulation. A multi Agent System is a system comprising two or more agents with local goals corresponding to subparts of the object designed.

According to Wooldridge [82], an agent is a software (or hardware), situated in some environment and is able to react autonomously to changes in that environment (Figure 40). Wooldridge states that the characteristics that make intelligent agent different from existing systems are:

1. *Reactivity*: that is the capacity to react to changes in its environment in a timely fashion, and taking actions based on those changes and the function it is designed to achieve.

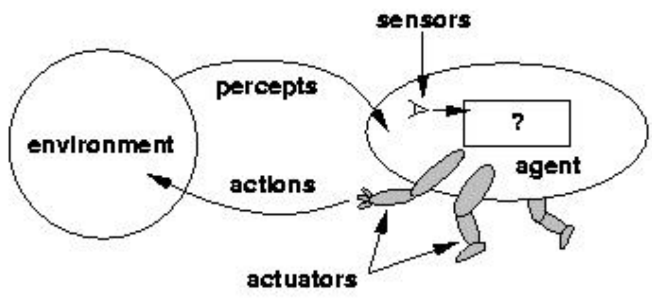


Figure 40: Representation of an Intelligent Agent.

2. *Pro-activeness*: is the behaviour to be goal-directed, because connotes that an agent will dynamically change its behaviour in order to achieve its goals. Wooldridge describes this pro-activeness as an agent's ability to "take the initiative".
3. *Social ability*: it is not only the simple passing of data between different software and hardware entities, but the ability to negotiate and interact in a cooperative manner. That ability is normally underpinned by an Agent Communication Language (ACL), which allows agents to converse rather than simply pass data.

4.3 MAS for the control of LV systems

The above mentioned characteristics of MAS make this system suitable for the operation of LV systems with distributed energy resources DER, developing a system that allow the direct control of customers for Demand Side Integration (DSI) policies. In this way it is possible to exploit existing LV assets (i.e., secondary substations, transformers, and circuits) without limiting the usage of electric energy and the activation of new markets open to final consumers, with is becoming more and more necessary.

MAS technology has been used for over a decade in several applications including diagnostics, power system restoration, market simulation, network control, and automation [83]. Moreover, the technology is maturing to the point where the first multi-agent systems are now being migrated from the laboratory to the utility, allowing industry to gain experience in the use of MAS and also to evaluate their effectiveness.

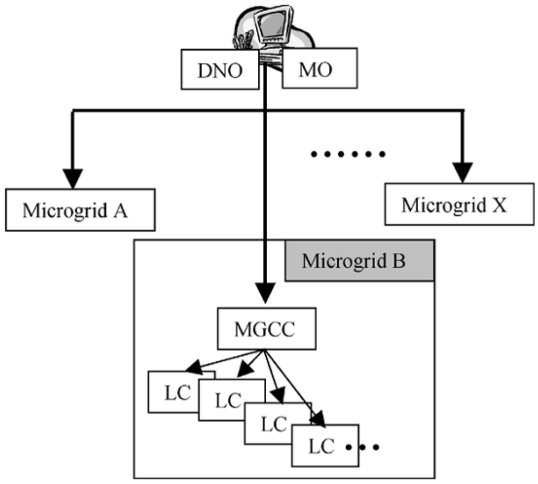


Figure 41: Control levels of the microgrid environment [84].

In the field of power system management, MAS are used for the control of Microgrid and developed in the project Microgrid and MoreMicrogrid (described in Appendix) MAS are used for the control of LV system, especially for scheduling EV charging in order to reduce its harmful impact on voltage regulation (Figure 41) [84].

In [85] it is developed a distributed, multi-agent EV charging control method based on the Nash Certainty Equivalence Principle that considers network impacts. The proposed EV management system satisfies the energy requirements of a large number of EVs considering their owner's preferences and ensuring the efficient operation of the network. In [86] MAS is used to optimally schedule EV charging, to fill the valleys in electric load profiles, but without providing other services to the network. In [87] two classes of EV charging coordination (the first based on classical quadratic programming and the second on market-based MAS), with the aim to reduce the peak load and the load variability in a distribution grid, are presented. Despite the comparison is based on power quality analysis the voltage profile is not optimised by the MAS. A MATLAB/JAVE/JADE MAS architecture for smart home energy management is proposed in [88] that takes into account customers' preferences and offers services to the distribution system. In [89] a MATLAB MAS for the DER management is developed; ZEUS is used to facilitate agent communications and allow negotiations for power exchange. The MAS uses a hierarchy of agents at different layers: a load management system, which is the decision maker agent, a zone agent that has the information about DG and controllable loads available in its zone, a load agent that has the information for all controllable load and DG agents that have information about the DG.

The proposed Multi Agent System realizes decentralised control systems with a Master-Slave interaction that allows finding a global optimum without a direct control of each resource. The general structure of the control is based on autonomous agents that exchange information about the state of the system to develop strategies that enable the achievement of both local targets and global objectives. In the proposed MAS control system, the Agents communicate directly with the Master Agent (MA), through a vertical communication. No information is exchanged among the agents in the current release.

The MA broadcasts the data necessary for Agents' local optimizations, gathers the results from local agents, and commands new local optimizations until a stable and optimal solution is achieved. In order to achieve an optimal DSI strategy by offering services like voltage regulation, each agent looks for the minimum of an OF that is based on local information and on the average behaviour of the other agents in the system. In other words, each Agent tries to maximize its benefits but in doing so it is limited by the other Agents that are looking for the same maximization too. This concept has been introduced in [90] for reducing the risk of dummy charging of EV during the peak hours, and improved in [91] with the MAS methodology enriched by a direct control of voltage profiles in LV networks.

4.3.1 Demand Side Integration with MAS

In chapter 2.5 the concept of DSI has been described, underlining the importance of the participation of the end users in the electricity distribution process, adjusting their consumption patterns, because they allows deferring the reinforcement of the existing grid infrastructures caused by new load profiles and distributed generation. The RM can be obtained with centralised systems that in LV applications require complex communication system with high bandwidth usage. The RM can also be realised with hierarchical/decentralised systems characterised by reduced communication between the aggregator and the customers with most of decisions made at customers' level.

4.3.2 The role of the Aggregator

The proposed model improves the MAS application for the control of LV networks with active loads and EV; the main contribution is represented by the modification of MAS algorithms for the RM of loads and EV (according to ADDRESS models) without a centralised optimization system as well as the definition of network constraints that allow following specific DSO requests. With the

RM the Aggregator is able to change the behaviour of customers in the portfolio (e.g. charging of batteries, change of the end-users' consumption patterns) [54]. In this framework, the Aggregator coordinates the behaviour of independent Agents so that the total load demand (EVs and loads) does not cause system issues (i.e. not exceeding a defined voltage limit or the cable rated capacity).

4.4 MAS implementation

The MAS control system is developed with JADE (Java Agent Development Framework), an open source software framework fully implemented in Java language, that allows the implementation of multi-agent systems through a middle-ware that complies with the FIPA specifications [92]-[94]. JADE provides three necessary elements in a multi-agent system: the Agent Management Services (AMS), the authority in the platform which provides the naming service; the Directory Facilitator (DF), that provides a yellow pages service and the Message Transport System, responsible for delivering messages among agents. JADE allows creating agent platform distributed across machines to simulate different agents located in different places. It supports an asynchronous agent-programming model, communication between agents. JADE also provides ontologies (vocabulary and semantics for the content of the messages exchanged between the agents) support.

Figure 42 shows the Agent Platform, with the Agents involved in the optimization and the AMS, the DF and the RMA. In the figure it is also possible to see message exchange between the Master Agent and the Agents through the Sniffer Agent.

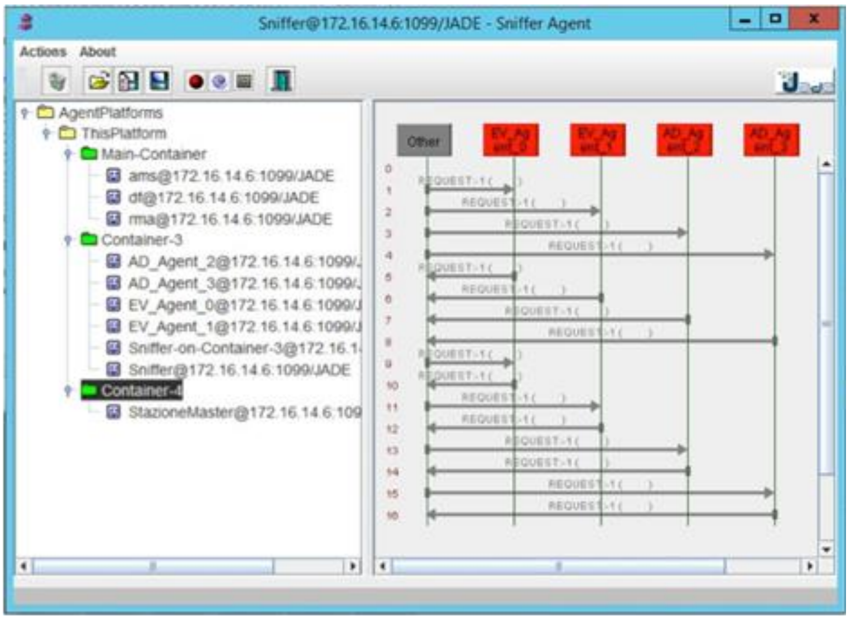


Figure 42: The Sniffer Agent for messages between Master and Slaves.

The structure of the control system is shown in Figure 43.

OpenDSS is used for load flow calculations [74], [75]; the JAVA compiler NetBeans is used to implement the multi-agent system in the JADE environment. JADE simulates the communication between Agents and the MA. Once the starting data are known and the initialization process is completed, the external iterative optimization process managed by the MA starts. The MA sends Agents a message to start local optimization and provides them the virtual price and the tracking parameter. Each Agent performs the mono-dimensional optimization process described by running a session of MATLAB. Once all Agents have completed the local optimization, the charging strategy and demand response of each agent is returned to the MA that decides whether to accept or reject the programs and to repeat the algorithm varying the load profile, according to the strategies presented.

4.4.1 The Optimization Algorithm

The optimization of MAS is performed with a weakly-coupled game approach. Agents know their own dynamics (i.e., maximum availability rate for the increase/reduction of load), the energy price and the average state of all other agents ("mass" behaviour). Therefore, each agent optimises the local OF by using local information about its state and global information, i.e., the pricing strategy, the average behaviour of the other agents and the technical constraints [95]. The DSI strategy is based on the virtual cost, $p(t, P_t)$, expressed by equation (25) [95]. The virtual cost is a linear function

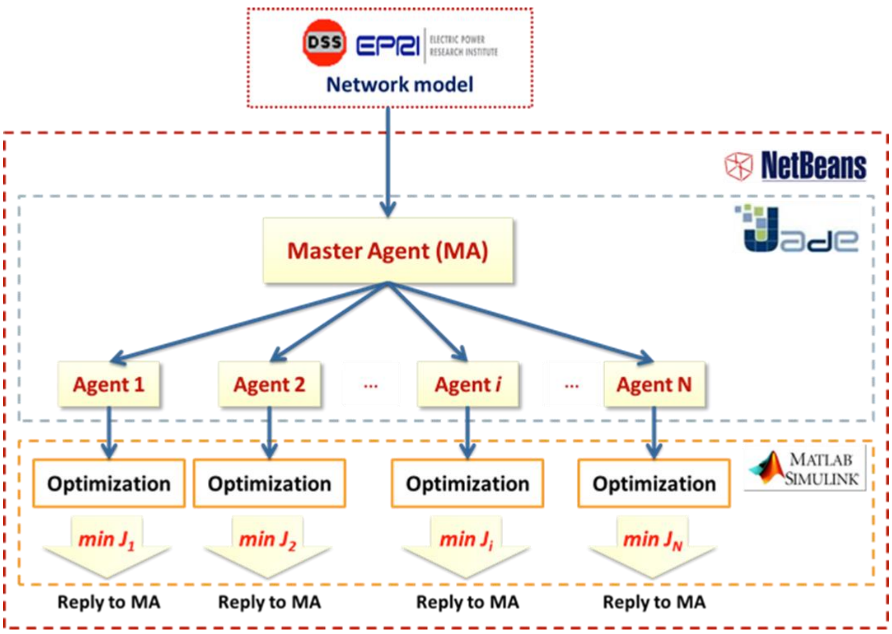


Figure 43: Structure of the control system proposed.

of the ratio between the total demand (the scheduled load demand and the demand of Electric Vehicles and the Active Customers) and the nominal power of the MV/LV transformer. Equation (25) shows that the highest virtual prices are expected at peak hours [90].

$$p(t, P_t) = f\left(\frac{D(t) + \sum_{i=1}^{N}(P_{EV,i}(t) + P_{AD,i}(t))}{P_{tr}}\right) \tag{25}$$

$$P_t(t) = \sum_{i=1}^{N} P_i(t) = \sum_{i=1}^{N}(P_{EV,i}(t) + P_{AD,i}(t)) \tag{26}$$

where:

- $D(t)$ is the forecasted non-EV demand of the MV/LV transformer at time t [kW];
- $P_{EV,i}(t)$ is the i-th EV charging power at time t [kW];
- $P_{AD,i}(t)$ is the i-th AD contribution (power reduction/increase) at time t [kW];
- $P_i(t)$ is the sum of the i-th EV charging power at time t and the i-th AD contribution (power reduction/increase) at time t [kW];
- P_t includes the total charging power of the EVs and the global AD contributions at time t [kW];
- P_{tr} is the nominal power of the MV/LV transformer [kW];
- t is the time interval (step of 1 hour);
- N is the effective number of Agents participating to the MAS control. It is the sum of the EVs involved in the charging control system and the loads included in the AD programs.

The MA evaluates (25) and (26) and sends the value of the virtual cost $p(t, Pt)$ and Pt(t) to Agents that execute the mono-dimensional constrained optimizations expressed in equation (27). This equation is constituted by two terms [95]. The first term is the virtual cost for purchasing energy from the system; the smaller is this cost the bigger is the distance from the peak hours. The second term takes into account the deviations between the Agent behaviour and mass behaviour of all Agents; this term avoids the risk that all Agents by moving far from the peak will form a new undesired peak in another hour. Indeed, each Agent tries to maximize its own benefits but the deviation from the mean behaviour is a cost that guides the global optimization to a real (system) minimum.

$$\min J_i(P_i, P_{-i}) = \sum_{t=0}^{T-1}\{p(t, P_t) \cdot P_i(t) + \delta[P_i(t) - avg(P_t)]^2\} \tag{27}$$

$$avg(P_t) = \frac{1}{N}\sum_{i=1}^{N} P_i(t) \tag{28}$$

subject to Agent specific technical constraints.

Where: P_i indicates the i-th agent power, P_{-i} the power of other agents (excluding i-th agent), $avg(P_t)$ is the average of the power controlled by Agents, t is the time at the beginning of each interval (step of 1 hour), T is the final time of the period (i.e., 0:00 a.m.) and δ is a tracking parameter with non-negative constant value [90]. The technical constraints are Agent specific and they are deeply described in the relevant sections; the constraints for all Agents are linear or linearized with reference to the control variables.

Equation (27) is a quadratic mono-dimensional constrained optimization problem and it is solved through a MatLab quadratic optimization function, called "Quadprog" [96]. This function is capable to solve large-scale and medium-scale quadratic optimization problems and it is appropriate to find the local minimum of the convex function (27). Due to the fact that each local minimum is not a global minimum for the system, a global optimization is necessary. This result is achieved through a single-objective, non-cooperative, dynamic game, which converges to Nash equilibrium under the condition of weakly coupled Agents. When all Agents have asynchronously performed local constrained optimizations, the feasible load profile is sent to the MA that recalculates (26) and (27). Equations (26) and (27) vary significantly in the first iterations and this is a measure of the distance from the global minimum. The smaller the changes between two subsequent iterations the closer is the global minimum. From a theoretical point of view this is the convergence to the unique Nash equilibrium. In fact, let us assume that p(r) is continuous on the variable r, where r is the ratio of total demand divided by the nominal power of the MV/LV transformer that corresponds to the variables in equation (26). Then, it can be proved that the Nash equilibrium exists if p(r) is continuously differentiable and strictly increasing on r, and the tracking parameter δ belongs to the interval defined by equation (29).

$$\frac{1}{2c}\max_{r\in[r\,min,r\,max]}\frac{dp(r)}{dr} \le \delta \le \frac{a}{c}\min_{r\in[r\,min,r\,max]}\frac{dp(r)}{dr} \tag{29}$$

Where r_{min} and r_{max} represent, respectively, the minimum and maximum *r* over the interval *T*, subject to the admissible control set, *c* is the total capacity of the secondary substation and *a* is a parameter in the range 0.5÷1. Equation *(29)* is a sufficient condition for the convergence, as demonstrated in [90],[91],[97],[98].

The proposed MAS algorithm flowchart is depicted in Figure 44. The MA receives the scheduled load and the voltage profile curves from the Aggregator that gathers this information from market and/or DSO in order to participate to service markets. After performing initialization, an iterative optimization process managed by the MA starts (“k” iteration loop).

The MA asks the Agents to optimise the energy profile on the basis of virtual price *p(t, Pt)*. Each agent performs the mono-dimensional optimization process in equation (27), taking into account the given constraints. The agent’s optimal pattern is given back to the MA that updates the requests once all Agents have completed the local optimization. Finally, the MA calculates the maximum load variation with respect to the previous iteration; if such variation is bigger than the acceptable threshold, the data are updated and a new optimization is run, otherwise the optimal schedule is found.

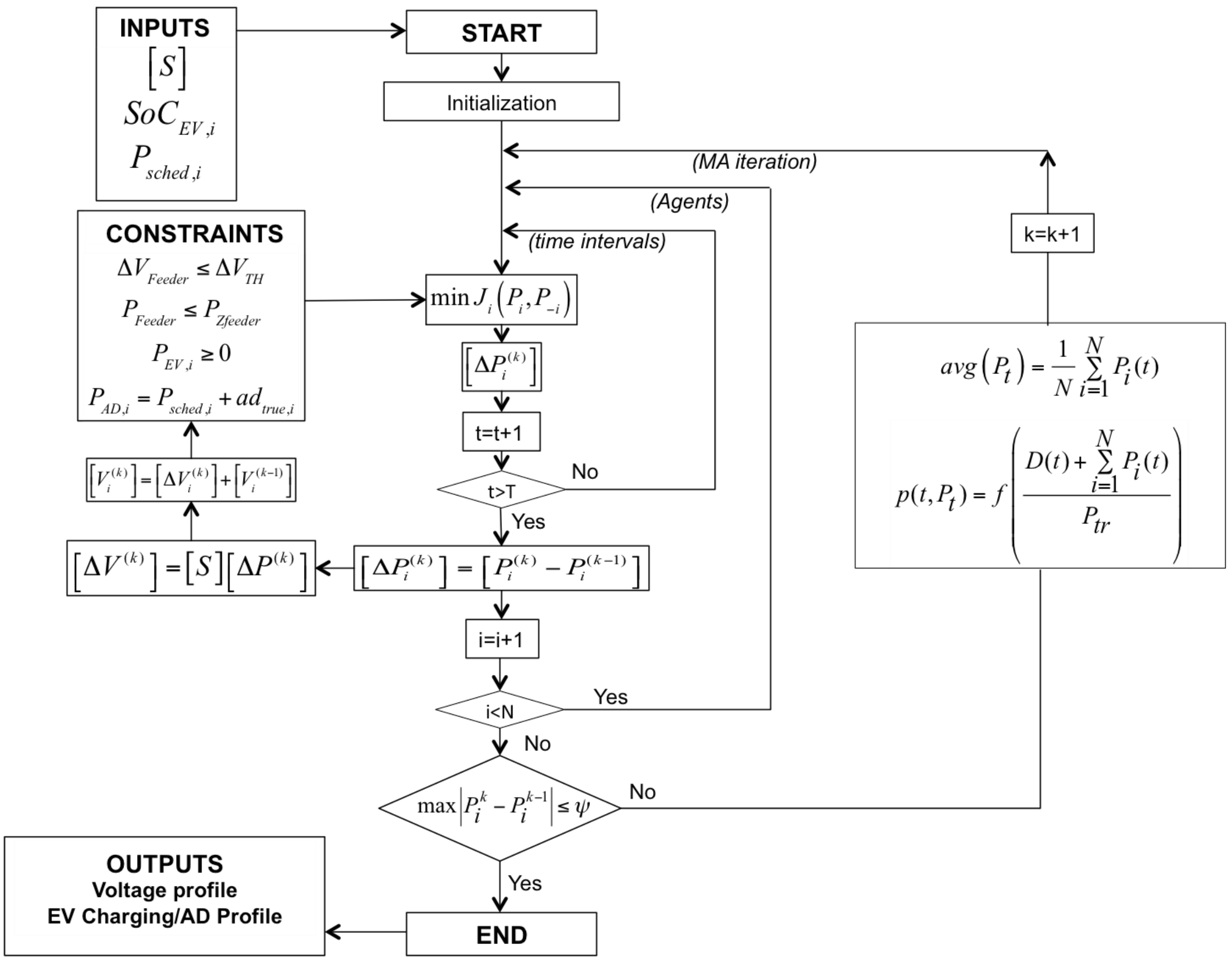


Figure 44: Flowchart of the proposed MAS optimization algorithm.

4.4.2 The EV charging station Agent

With the increasing of the EV penetration the practice of power demand management becomes more complex, due to the highly flexible spatial and temporal EVs exploitation. The arising of voltage limits violation is one of the possible consequences of a significant addition of EVs in distribution networks. The EV recharging process has to become more flexible to deal with the variation of costumers' consumption and RES production [100]. The flexibility will have an economic value that will be used to involve customers into DSI policies. Smart metering and ICT are the enabling technologies to offer market opportunities to the consumers, and to provide the DSO information regarding the behaviour of the prosumers. With the MAS proposed in the thesis, the EV Agent has to find the optimal recharging pattern subject to equations (30) - (32). With the proposed MAS control data on state of charge (SoC) and vehicle arrival and departure times are not sent to MA.

$$SOC_i(T-1) = 1 \tag{30}$$

$$\sum_{t=0}^{T-1} P_i(t) = (1 - SOC_i(t=0)) \cdot \frac{C_{bat}}{C_{eff}} \tag{31}$$

$$0 \leq P_i(t) \leq P_{plug} \tag{32}$$

SOCi(t) is the i-th EV battery state of charge at time t, T is the charging period, C_{bat} is the capacity of the EV battery, C_{eff} is the charging efficiency and P_{plug} is the maximum charging power of the charging infrastructure.

4.4.3 The Active Demand Agent

DSI provides the means to modify the consumer's load to meet the network constraints. Following the experiences made by other EU projects, the AD is expressed as a variation of load with respect to the scheduled profile, representing the load without any participation to demand side integration.

To improve the performance of the load model, Also for the Active Demand Agent, as in the model of the load in the centralised control (Section 3.4), the level of participation of the consumer and the payback effect have been considered:

- **level of participation of the consumer:** the acceptance model is necessary because every user is willing to modify the consumption profile in different ways. This depends on price signal, but also on available flexibility, willingness to reduce the comfort, etc. In particular the most important is the price signal that significantly affects the degree of customer acceptance.

- **payback effect:** is the reaction of the user to the active demand program (for example: an user for an appropriate signal price accepts to reduce the consumption for two time intervals; after the two intervals user needs the highest power in order to recreate the previous conditions).

4.4.4 Network Constraints

Customers and power system equipment have to operate within a range of voltage, usually ±5% of the nominal voltage. In the proposed methodology the MA uses demand flexibility to offer system services such as voltage regulation and congestion relieves. Each Agent has to optimise its load profile subject to the technical constraints expressed by (11) and (12).

Constraints on Voltage:

In order to guarantee that in each feeder the voltage deviation is within the maximum allowed threshold ΔV_{TH}, (in the flowchart in Figure 44 constraint $\Delta V_{Feeder} \leq \Delta V_{TH}$), in the optimization process the voltage constraint for the Agent *i* in the network is expressed by.

$$\frac{\sum_{m=1}^{n} V_m^{(k-1)} + \sum_{m=1}^{n} \frac{\delta V_m}{\delta P_i} \left(P_i^{(k)} - P_i^{(k-1)}\right) \cdot KC}{n} \geq (1 - \Delta V_{TH}) \cdot V_n \tag{33}$$

Where:

- *n* is the total number of Agents in the same feeder of the *i*-th Agent of the LV network;
- *m* is the internal iteration index (*m* = 1, 2, ..., *n*), considering the voltage contributions of the other agents in the same feeder of Agent *i*;
- *k* is the external iteration index (*k* = 1, 2, ..., *K*), managed by the Master Agent until the optimal EV/AD strategy for the network is reached, where *K* is the iteration in which the stopping criterion is reached;
- $\sum_{m=1}^{n} V_m^{(k-1)}$ is the sum of the voltage in the Agent buses [kV];
- $P_i^{(k)}$ is the contribution of the *i*-th Agent at the *k*-iteration [kW];
- $P_i^{(k-1)}$ is the contribution of the *i*-th Agent at the (*k*-1) iteration [kW];
- *KC* is a coefficient greater than 1;
- ΔV_{TH} is the average variation on voltage admitted by the DSO [kV];
- V_n is the reference value of the voltage [kV];

- $\frac{\partial V_m}{\partial P_i}$ is the coefficient of sensitivity of nodal voltage *m* with respect to the P_i injected power $\left[\frac{kV}{kW}\right]$.

Since the Aggregator does not know the network status it is assumed that DSO calculates these coefficients. The sensitivity coefficients are used in the algorithm, to linearize the relationship between the nodal voltages and the nodal power injections so that constraints remain linear [90].

The theory of the sensitivity is based on the Newton Raphson formulation of the load flow calculation to directly assume the voltage sensitivity coefficients as sub-matrices of the inverted Jacobian matrix. This relationship is represented by the following expression (34):

$$\begin{bmatrix}[\Delta P]\\ [\Delta Q]\end{bmatrix} = \begin{bmatrix}\left[\frac{\partial P}{\partial \vartheta}\right] & \left[\frac{\partial P}{\partial V}\right]\\ \left[\frac{\partial Q}{\partial \vartheta}\right] & \left[\frac{\partial Q}{\partial V}\right]\end{bmatrix} \cdot \begin{bmatrix}[\Delta \vartheta]\\ [\Delta V]\end{bmatrix} \tag{34}$$

where [ΔV] is the nodal voltages magnitudes and [Δϑ] is the nodal voltage phase variations corresponding to the nodal active or reactive power injections [ΔP] [ΔQ].

The matrix expression can be written as follows (35):

$$\begin{bmatrix}[\Delta P]\\ [\Delta Q]\end{bmatrix} = [J] \cdot \begin{bmatrix}[\Delta \vartheta]\\ [\Delta V]\end{bmatrix} \tag{35}$$

Where $[J] = \begin{bmatrix}\left[\frac{\partial P}{\partial \vartheta}\right] & \left[\frac{\partial P}{\partial V}\right]\\ \left[\frac{\partial Q}{\partial \vartheta}\right] & \left[\frac{\partial Q}{\partial V}\right]\end{bmatrix}$ is the Jacobian matrix.

The sub-matrix $\frac{\partial Q}{\partial V}$ is usually adopted to express voltage variations as a function of reactive power injections when the ratio of longitudinal line resistance versus reactance is negligible. This assumption is not applicable to distribution systems that require in addition to take into account active power injections.

In a distribution system, characterised by N buses, the relationship between the voltage variation and the power injections can be expressed with equation (36).

$$[\Delta V] = [S] \cdot [\Delta P] \rightarrow \begin{bmatrix}\Delta V_1\\ M\\ \Delta V_N\end{bmatrix} = \begin{bmatrix}\left[\frac{\partial V_1}{\partial P_1}\right] & K & \left[\frac{\partial V_1}{\partial P_N}\right]\\ M & 0 & M\\ \left[\frac{\partial V_N}{\partial P_1}\right] & K & \left[\frac{\partial V_N}{\partial P_N}\right]\end{bmatrix} \cdot \begin{bmatrix}\Delta P_1\\ M\\ \Delta P_N\end{bmatrix} \tag{36}$$

where *S* is the sensitivity matrix (NxN), ΔV is the vector of the Voltages variations, $\gamma = \frac{\delta V_m}{\delta P_k}$ is the sensitivity coefficient and ΔP is the vector of the variations of power injection [90].

The role of KC is fundamental since all loads in the network cause voltage variations but, when a single Agent performs the local mono-dimensional optimization, the unique control variable is represented by the Agents' controlled power, which might be not enough to improve voltage regulation. This is a clear interaction between the local Agent optimization and the global goal of the DSI direct control system. The idea is to ask each Agent to improve the voltage "pro quota", by assuming that each Agent can be responsible for its rated power capacity. With some algebraic manipulations of the linearized relationship between the Agent power and the nodal voltages this can be expressed with the coefficient *KC*, which in the simplest case of equal rated power for all Agents, is equal to the number of Agents in the feeder.

Constraints on cable overloading:

In order to use DSI for relieving power congestions, it has been assumed that the DSO passes the dynamic line rating of cables to the MA and Agents use it as a constraint in the local optimization. In the flowchart of Figure 44 the actual consumption of loads in each feeder P_{Feeder} must be within the rating of the feeder, $P_{Feeder} \leq P_{Zfeeder}$. The dynamic line rating considers the inelastic demand as well as the positive effect of AD.

Equation (37) formalises the constraint at the k-th iteration of the general optimization for the EV agent *i*.

$$P_{EV,i}^{(k)}(t) \leq \left(P_{zfeeder} - D_{feeder}(t) + \sum ad^{(k-1)}\right) \cdot \frac{P_{EVmax,i}}{\sum_{j=1}^{Nf} P_{EVmax,j}} \tag{37}$$

$P_{Zfeeder}$ is the dynamic line rating of the feeder, $D_{feeder}(t)$ is the non-EV demand of the feeder, $\sum ad^{(k-1)}$ is the contribution of the AD Agents to increase the available power capacity of the feeder, and the ratio $\frac{P_{EVmax,i}}{\sum_{j=1}^{Nf} P_{EVmax,j}}$ leaves to EV Agent the opportunity to use only a quota of the available capacity proportional to the maximum rated power, where *j* = 1, 2, ..., N_f is the sum index and N_f is the number of EV Agents in the feeder.

4.4.5 Stopping criterion

The optimal strategy for the network is reached when the global scheduling does not significantly change after two consecutive iterations. For this reason, the stopping criterion of the iterative process is based on a threshold in the maximum variation between the agent power in the last and in the previous iteration in Figure 44 as in *(38)*.

$$max|P_i^k - P_i^{k-1}| \leq \psi \tag{38}$$

Where P_i^k is the power of the *i*-th Agent at the *k*-iteration; P_i^{k-1} is the power of the *i*-th Agent at the (*k*-1) iteration; ψ is the threshold selected.

4.5 Case Studies

To show the effectiveness of the algorithm, in the following three significant applications of the DMS are provided.

4.5.1 Case 1: MAS to control a large penetration of EV

In [90] the decentralised control system described in the previous sections has been applied in a residential electrical distribution feeder with a large penetration of EV connected to the network.

The test network (depicted in Figure 45) is representative of LV urban Italian distribution networks. It is supplied by one MV/LV substation with a 15/0.4 kV 630 kVA transformer. It is constituted by six feeders, with 53 LV buses and 84 residential loads. Each feeder is characterised by 4 wires (neutral + 3 conductors) and the loads are both single-phase (70) and three-phase (14). The daily load curve models the urban load variations (without EV charging) in 24 hours (divided in 96 intervals, time interval = 15 minutes).

The average voltage threshold is required to be equal to 0.95 p.u., in order to satisfy the power quality service asked by DSO (ΔVTH =5%). The number of considered EVs in the test network is 100, placed randomly at the selected LV nodes in Fig 4, in order to highlight the significant benefits reached with charging regulation. For each EV the SOC_{in} equal to 30% and SOC_{out} 100% of the total charging capacity. In order to compare different case studies the arrival and departure time of the EVs have been considered fixed, with Tin equal to 6:00 p.m. and Tout equal to 7:00 a.m. However, the MAS control system can include different time needs, based on the EV owners preferences, or can set Tin and Tout randomly in each charging station.

The proposed methodology has been compared in different case studies:

1. Without EV charging regulation, called uncoordinated case or Dumb charging.
2. With EV charging regulation, but without the voltage charging control.
3. With EV charging and voltage droop charging control.

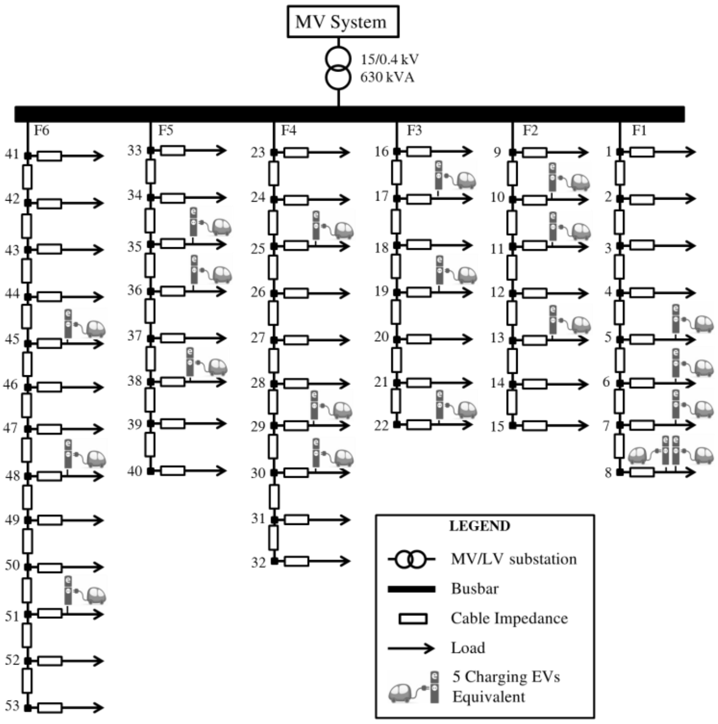


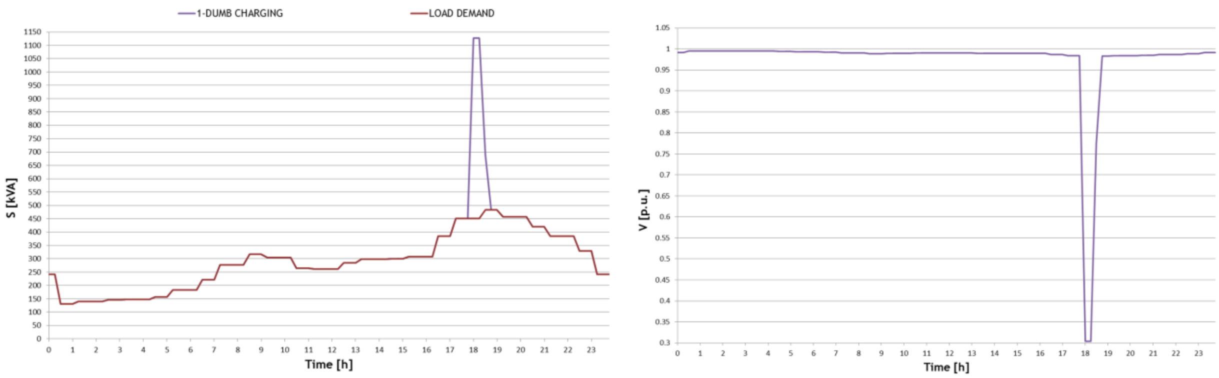
Figure 45: The LV network considered [90].

In this application, no contribution from AD is considered, so the Aggregator (MA agent) gathers only two types of information: Static (EV type, battery characteristics, and charging location characteristics); Dynamic (electricity market prices, EV status, signals from the system operator, preferences of the EV owner (e.g. charging Time, travel schedule), electrical energy consumed and injected by each EV).

In the first case, EVs charge as soon as connected to the grid, at the arrival time of 6:00 p.m. The coincidence of demand with EV recharging Figure 46 a) causes a peak in the load demand and, as a consequence, a deep voltage drop between 6:00 and 7:00 p.m. (Figure 46 b)) and line and transformer overloads.

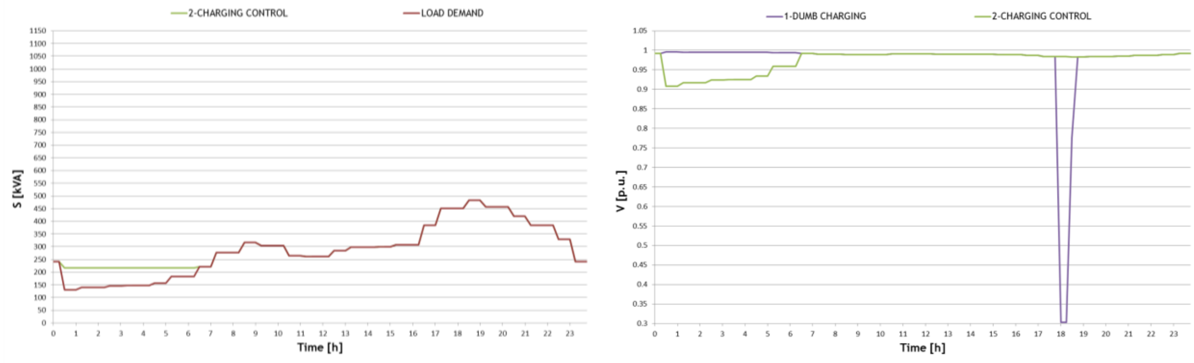
In the second case, with the MAS EV charging regulation but without voltage control a valley filling effect is obtained, that could be positive for the power system, but can pose the DSO in a difficult situation, being the voltage below the contractual limits (green line Figure 47 b)).

Finally, with both the controlled voltage and charging strategy, the agents can obtain the goal of recharging when the general price of energy is small and far away from the peak hours and, at the same time, voltage remains without the regulation band imposed (Figure 48 b)).



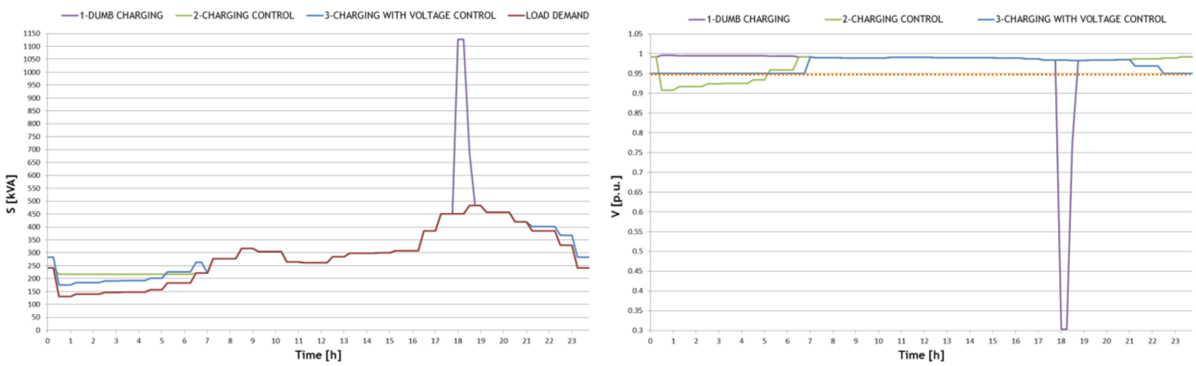
a) b)

Figure 46: a) the scheduled load demand and EV charging profile in the dumb charging (case 1)); b) the voltage profile in the network in case 1).



a) b)

Figure 47: a) the scheduled load demand and EV charging profile in case 2); b) comparison of the voltage profile in the network in case 1), with purple line, and in case 2) with green line.



a) b)

Figure 48: a) comparison of the load demand in case 1), case 2 and case 3); b) comparison of the voltage profile in the network in case 1), case 2 and case 3).

4.5.2 Case 2: MAS to control Active Demand

In [97] the AD Aggregator is used to coordinate the behaviour of independent agents so that the total load demand processed does not cause excessive voltage drops in the system (i.e. not exceeding a defined voltage limit).

The analysed network (depicted in Figure 49) is representative of urban Italian distribution networks [72]. The network is supplied by one MV/LV secondary substation with a 15/0.4 kV 400 kVA transformer. Three feeders, with 66 LV buses and 139 urban loads, constitute the network. Each feeder is constituted by 4 wires (neutral + 3 conductors) and the loads are both single-phase (135) and three-phase (4). The average voltage threshold is required to be equal to 0.95 p.u., in order to satisfy the power quality service imposed by DSO (ΔV_{TH} =5%). Loads are residential and from commercial and offices, characterised by different daily load curves.

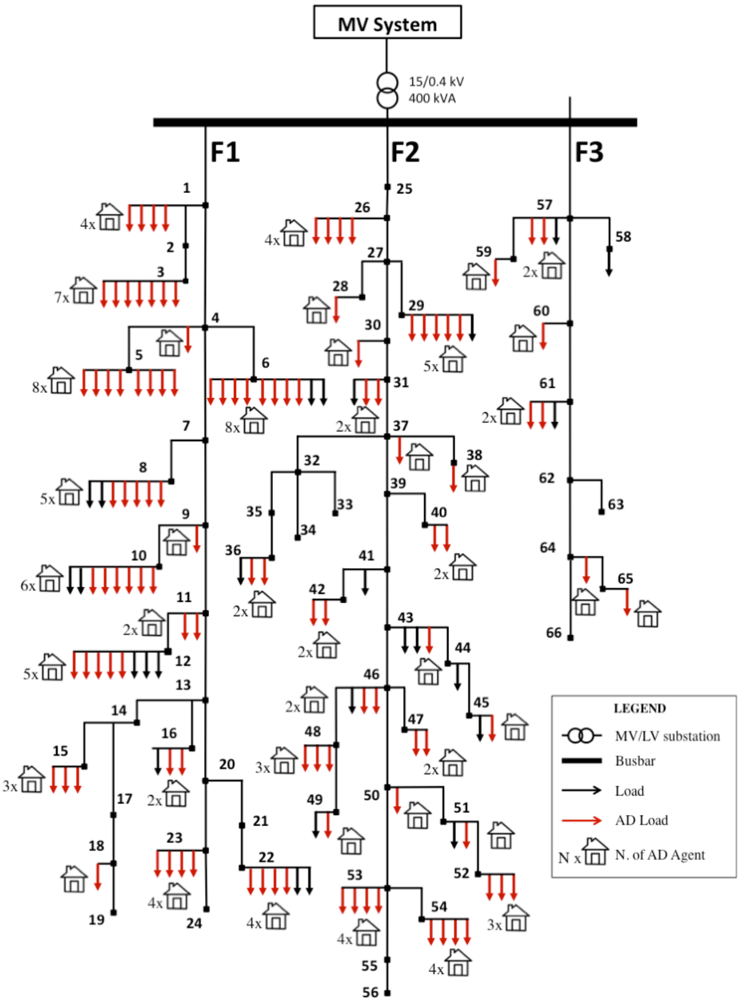


Figure 49: The LV Test network.

The number of loads involved in AD programs through the Aggregator is 113 (100% of the residential loads, in order to stress the studies), with different participation factors.

The time granularity for simulations and for the load profiles is 1 hour; the time window is 24 hours wide since all simulations are devoted to day-ahead markets. The network suffer excessive voltage drop in Feeder F1 and F2.

Having ensured that after a finite time the iterative methodology leads to a stable configuration, its performance is studied by observing the daily load curve (Figure 50) and the average voltage profiles (Figure 50) in the different cases analysed. If the Aggregator offers no AD-based service in the distribution system, the load profile is the one scheduled (light blue curve in Figure 50) and critical feeders F1 and F2 can pose the DSO in a difficult situation, being the voltage below the contractual limits. In Figure 50 b) the blue and red continuous lines show the voltage violation in the feeder F1 and F2, respectively. In the first case (Case 1), by considering the MAS AD with voltage control and disregarding the payback effect (f 0 = 1; f1 = 0; f2 = 0) the Agents obtain the goal of consuming the power with a more suitable profile, with a significant improvement during the peak hours (green broken line in Figure 52). At the same time, voltage remains within the regulation range imposed by DSO with a positive effect in the feeder F1 and in the feeder F2 (blue and red broken lines in Figure 51).

Nevertheless, the real behaviour of the AD user is different. Taking into account the customer's level of participation and the payback effect is necessary. For this reason, in Case 2 the FIR model in (6) is implemented in the MAS AD control.

The AD model parameters are assumed equal to: f 0 = 1; f1 = 0,2; f2 = -0,2 in this Case. It can be noticed a load profile variation compared with Case 1 (red curve in Figure 52) and a reduction in the

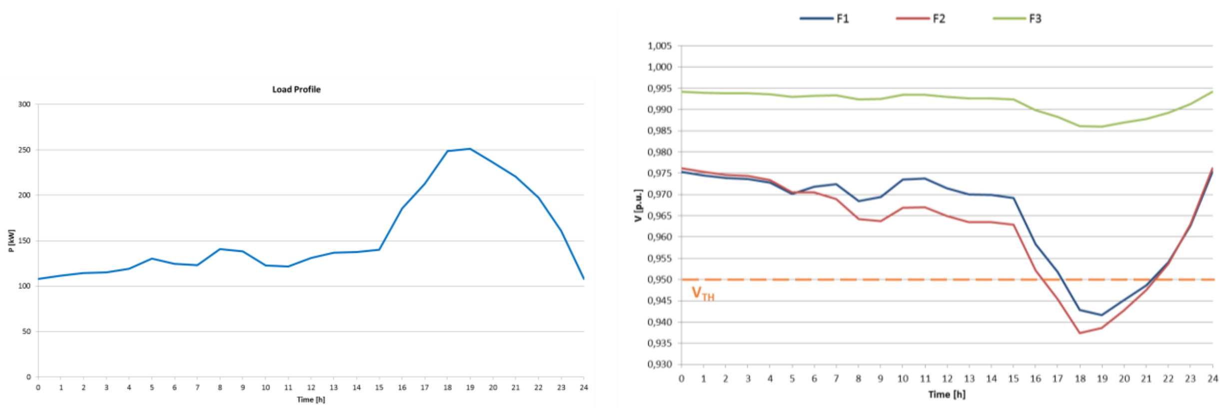


Figure 50: Total Load Demand and Voltage profile of the three feeders of the analysed network.

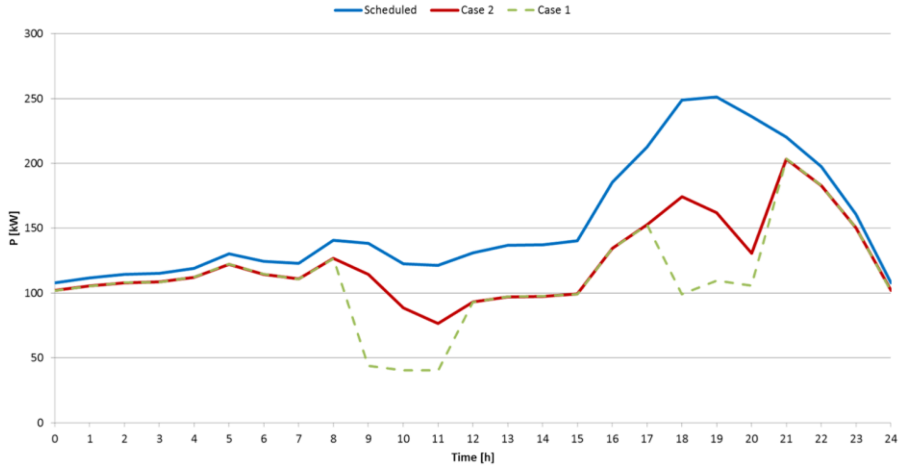


Figure 52: Load Demand in the different cases analysed.

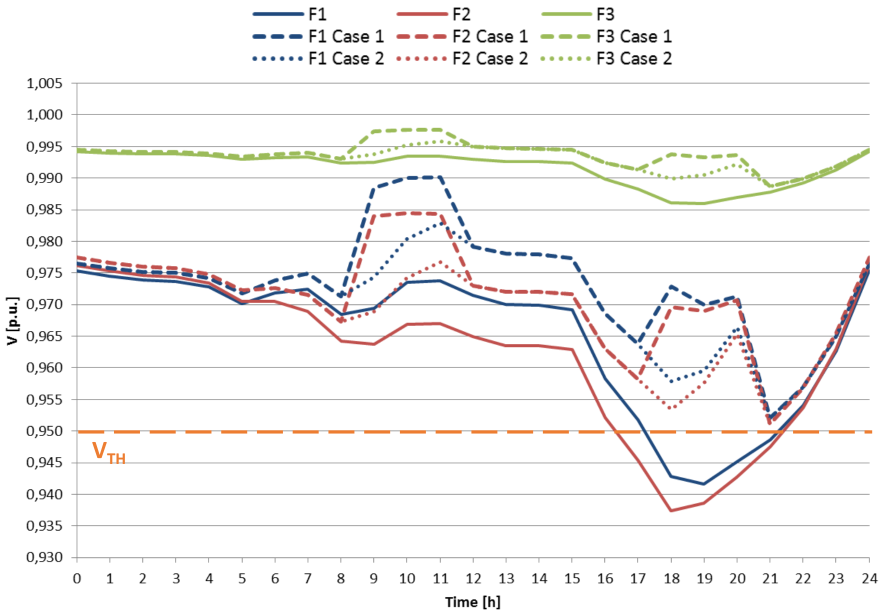


Figure 51: Voltage profile by feeder.

positive effect in the feeders F1 and F2 (dotted lines in Figure 51), but the voltage remains above the contractual limits. The AD strategy obtained through the MAS control methodology proposed is the optimal solution for the system and allows the Aggregator to offer the AD-based service to the DSO.

4.5.3 Case 3: MAS for Demand Side Integration

In [91] the MAS control system has been tested in an urban area with a plausible penetration of EVs connected to the distribution network. The depicted test network is a radial LV network, representative of urban Italian distribution networks. It is supplied by one MV/LV secondary substation with a 15/0.4 kV 630 kVA transformer (Figure 53). Eight feeders, with 63 LV buses and 193 urban loads (residential and from commercial and offices) constitute the network. Each feeder is constituted by 4 wires (neutral + 3 conductors) and the loads are both single-phase (175) and three-phase (18). The average voltage threshold is required to be equal to 0.97 p.u., in order to satisfy the power quality service imposed by DSO (ΔV_{TH} =3%).

All the residential loads (147) are involved in DSI through the Aggregator, with different participation factors. The AD model parameters, taking into account the customer's level of participation and the payback effect, are f_0 = 0,55; f_1 = 0,4; f_2 = 0,05.

EV charging stations are connected to the LV nodes as shown in Figure 53, mostly at the end of the feeders in order to stress the studies with the worst scenarios. The number of EVs in the test network is 59 (40% of the total residential loads in the AD programs).

The MAS control system can deal with different habits for EV recharging, mostly based on different home arrival and departure times; furthermore, since different drivers can drive for different distances, the SoC of each single battery can be different. Finally, in order to simulate real DSI policies, which leave the final customer the power to decide at what extent participating to the direct control of demand, each EV owner can override Aggregator suggestion and decide the time for completing the battery recharge and the desired level of SoC. Since the behaviour of EV owners

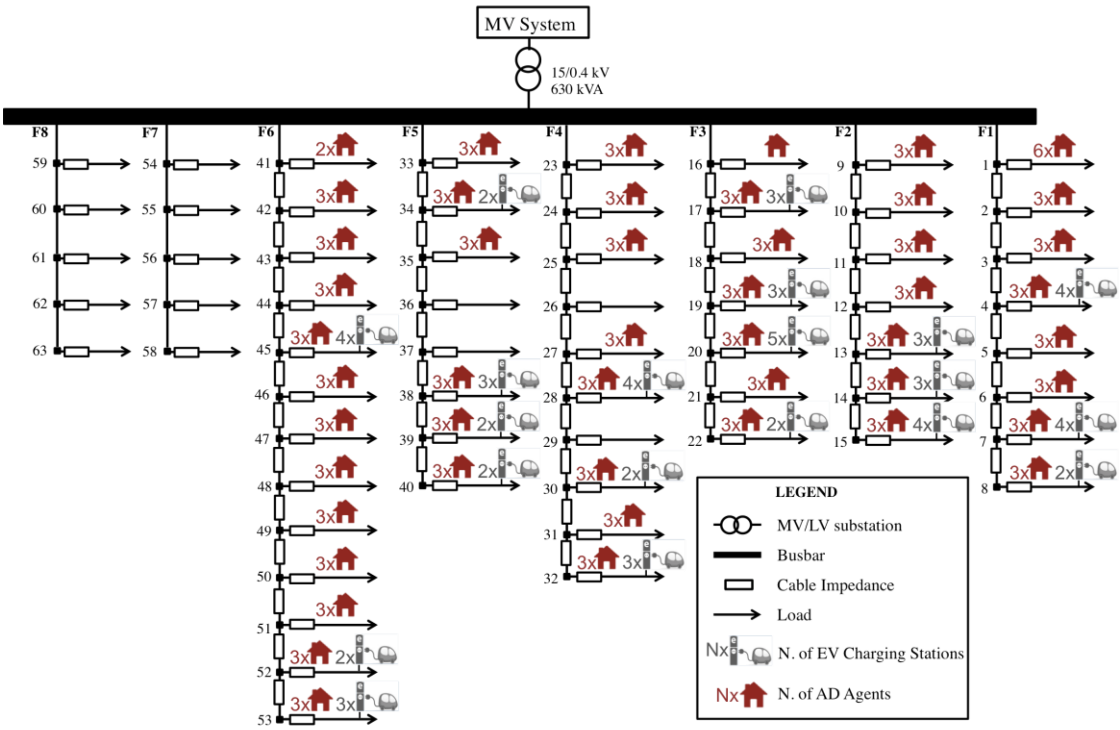


Figure 53: The LV network [91].

is stochastic, the arrival and departure time as well as the SoC at arrival and departure (assuming that when the charge is completed the EV owner can leave the house) can be generated randomly. Anyway, without loss of generality, in order to better analyse the direct control with the comparison of several cases studies, the arrival and departure times of the EVs have been considered fixed for each one of the two sets of EV (see Table IX) [110]. Finally, the EV $SoC_{arrival}$ is considered in the study equal to 30%, whereas the desired EV $SoC_{departure}$ is 100% of the total charging capacity, even if those parameters can be custom by each EV owner.

Table IX – Arrival and departure time for two different EV sets assumed in the test case.

EV Set	Number of EVs	% of total EVs	T_{in}	T_{out}
1	41	70	6:00 p.m.	7:00 a.m.
2	18	30	5:00 p.m.	11:00 p.m.

As in previous cases, the time granularity for simulations and for the load profiles is 1 hour; the time window is 24 hours wide since all simulations are devoted to day-ahead markets.

The results of simulations show that excessive voltage drop and overloading of system elements can limit the allowable amount of EV charging load.

Different Cases have been analysed to show the MAS:

- Case 0: Uncoordinated recharge of the EV batteries (*Dumb charging*),
- Case 1: Intelligent recharge with a smart use of battery load profiles (EV SET 1),
- Case 2: Intelligent recharge with a smart use of battery load profiles (EV SET 2),
- Case 3: intelligent recharge with a smart use of battery load profiles with AD Agent contribution in the MAS control.

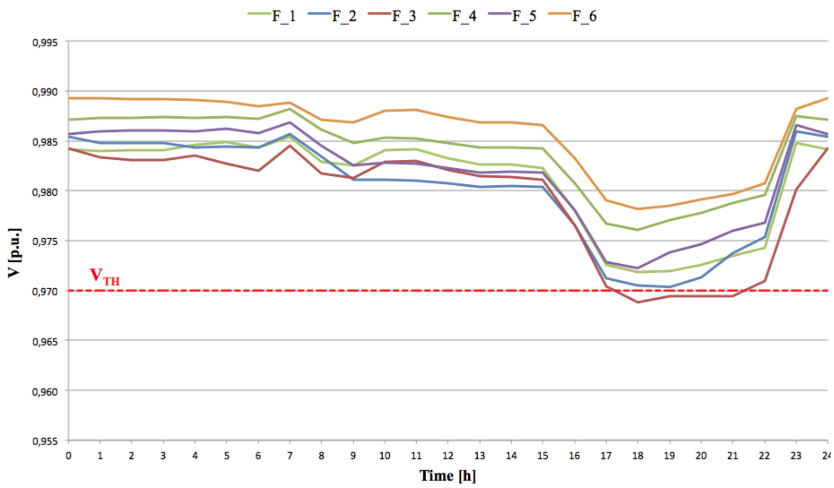
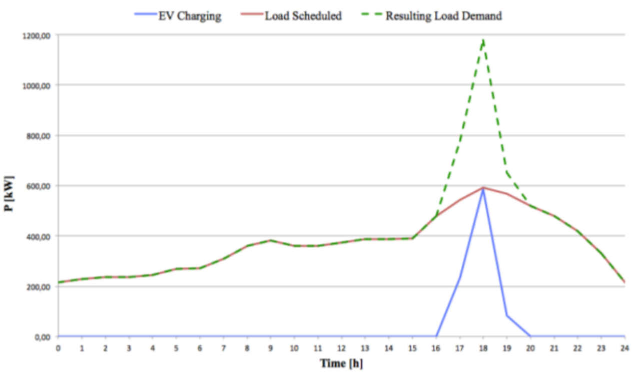


Figure 54: Case 1 - Average voltage profiles without AD support ($SOC_{departure}$=100%).

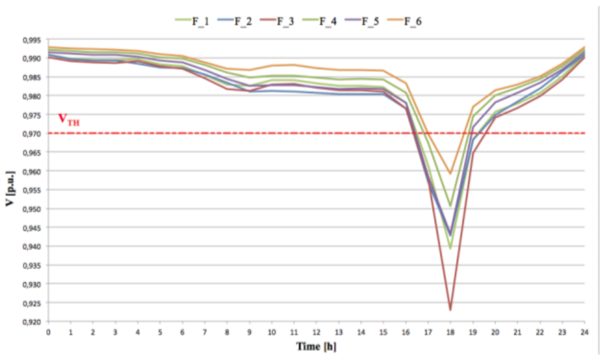
In Case 0, with the *Dumb charging,* the EVs start charging at the home arrival: the peak load demand rises (Figure 55 a)) and the voltage may be adversely affected (Figure 55 b)). Figure 55 a) shows the excessive peak of power demand, that requires the refurbishment of a new transformer in the secondary substation and new conductors with a bigger cross section to improve voltage regulation and to avoid overloads. Furthermore, by projecting the local situation on a large scale, it is worth to notice that the growth rate of the demand in the evening, when few support can come from renewables, stresses the traditional generation park that cannot follow too fast load rates.

In *Case 1*, when the EVs recharge, the average voltage profiles in the feeders (Figure 54) are marked by an excessive voltage drop, mostly in feeder F3 between 17:00 and 21:30. The MAS direct control cannot succeed since the percentage of EV with late arrival time is significant and there is not enough time to spread the demand on a sufficient number of hours. This means that the coincidence factor cannot be reduced with optimal operation and network investments might be still necessary (i.e. resizing of feeder F3) in order to comply with the EVs request to be fully charged at departure time.

In *Case 2*, the relaxation of the $SoC_{departure}$ for the EV belonging to the Set 2 in Table IX allows complying with all technical constraints. In this case, the MAS direct control is capable to give a solution only by accepting 80% of $SoC_{departure}$ for the vehicles included in Set 2. Figure 56 a) shows that the Agents shift EV demand to load profile valleys and limit the growth of demand in evening. The voltage remains within the regulation range (red curve in Figure 56 b)) and no power congestions appear.

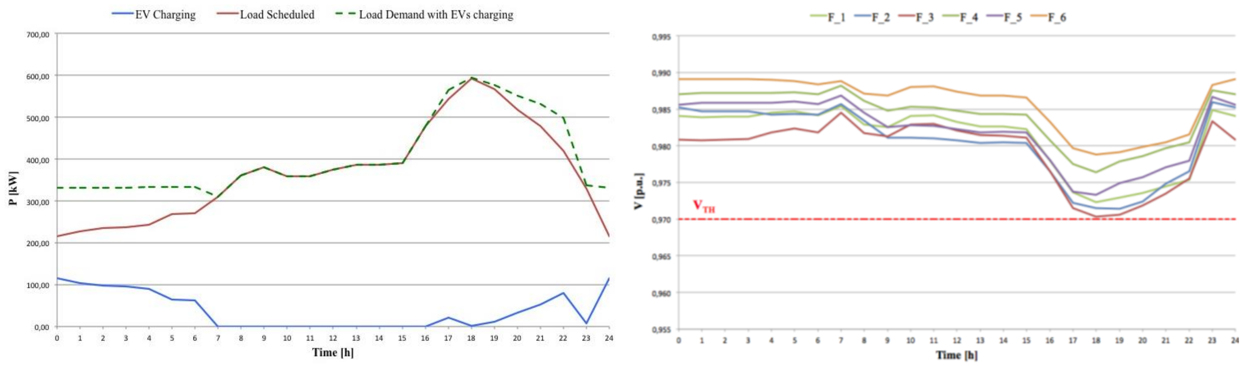


a)



b)

Figure 55: a) Load Profiles with Dumb Charging; b) Average voltage profiles with Dumb charging.



a) b)

Figure 56: a) Case 3 - Load profiles b) Average voltage profiles without AD support ($SOC_{departure}$=80%).

a) b)

Figure 57: a) Case 3 - Load profile with 85% AD ($SOC_{departure}$=100%). b) Average voltage profiles by feeder with 85% AD ($SOC_{departure}$=100%).

In Case 3, by introducing the AD Agent contribution in the MAS control, the EVs can be fully charged. The curves in Figure 57 a) and Figure 57 b) and show the positive effect on the power and voltage profile, respectively. In fact, the reduced demand at the peak hours further improves the voltage profile compared with Case 2, for the benefit of power quality. It is worth to notice that this result is obtained with the participation of 85% of total responsive demand that means a sufficient margin to take into account possible overrides form customers. Finally, the maximum allowable EV penetration in the test network by considering 100% AD available has been evaluated. By implementing the MAS control, the maximum allowable number of EVs without investment for network reinforcing is 55% of the total residential loads.

Conclusions

The distribution network is facing new challenges because of several factors. The increase of the load demand due to new loads as electric vehicles and heat pumps, environmental issues (reduce carbon emissions), but also the increasing presence of generators at medium and low voltage level (often from renewable energy sources) are undermining the reliability of the distribution network. Moreover, the system and its infrastructures (lines, transformers) are ageing and are not able to support all these changes.

For all these reasons, since 2005, firstly in academic ambit and then in industries the interest on Smart Grid increased. A Smart Grid is an electricity network that can intelligently integrate the actions of all users connected to it – generators, consumers – in order to efficiently deliver sustainable, economic and secure electricity supplies. The Smart Grid concept combines a number of technologies, end-user solutions and addresses a number of policy and regulatory drivers. In this framework different techniques to control, operate and thereby integrate distributed energy resources into the network have been developed. In this Thesis different approaches have been analysed and original algorithms are proposed for centralised control and a hierarchical/ distributed control of distribution systems.

The first one has been developed within the ATLANTIDE project. It is characterised by a central controller, the DMS. The DMS uses ad hoc DSE algorithms that provide the real-time status of the network, by gathering data from the distributed measurement system (insufficient at distribution level) and other available information retrieved from historical data (pseudo-measurements). Moreover the centralised control profits by the fluctuations of energy primary reserve, cost of fuels, and reduces risks due to presence of stochastic sources. Real-time intra-day optimization is performed to avoid contingencies and to find the economically optimal operation points of the network. The DMS allows the DSO to manage DG active and reactive power dispatch, storage devices and active demand, reducing technical barriers to renewable integration and increase the hosting capacity of the network. The research focused also on the impact of DSE on DMS management, proving the need of a design that comprehensively considers the energy management algorithm and the state estimation.

The development of hierarchical/distributed control systems based on Multi-Agent System (MAS) technology is the most significant contribution of the research activity described in the Thesis. The MAS allows the remote management of loads, without the need of a complex flow of data and information, and is better suited than centralised control systems for LV applications. The MAS integrates the intelligent recharging of EV with the participation of AD through an intermediate player called Aggregator. The methodology consists in an iterative exchange of information between a Master Agent and Agents that control responsive loads and EV recharging stations. The hierarchical/decentralised control is based on a single-objective, non-cooperative, dynamic game, which converges to Nash equilibrium under the condition of weakly coupled Agents.

The case studies provided in the Thesis underline the importance of the Active Management of the distribution network in the smart grid paradigm, in order to face the problems caused by an increasing presence of DG, but also new loads as EVs ensuring, at the same time, the reduction of the operational cost related to the active management, taking into account technical and economical constraints.

Appendix

Appendix A: Overview of the main projects on Smart Grids

Introduction

The Joint Research Centre's 2013-14 Smart Grid database contains 459 smart grid R&D and Demo &Deployment projects from all 28 European Union countries [101].

In the last years the European Union and the State Members incentive research, development, and demonstration projects focused on development of the Smart Grids through funding programmes created by the European Union/European Commission to support and foster research in the European Research Area. These programmes are called *Framework Programmes for Research and Technological Development*, also named *Framework Programmes* (FP).

The framework programmes up until Framework Programme 6 (FP6) covered five-year periods, but from Framework Programme 7 (FP7) on, programmes will run for seven years.

It is important to highlight that the budget for the project is still increasing. In fact, for the first FP (1984–1988) the budget in billions was 3.75 €, for the FP7 (2007-2013) the budget (in billion) was €50.521 over 7 years + €2.7 for Euratom over 5 years [102] and for Horizon 2020 (FP8) nearly €80 billion of funding will be available over 7 years (2014 to 2020).

In Italy, the Regulator (Autorità per l'Energia Elettrica ed il Gas, AEEG) fund through the decision ARG/elt 39/10 [103] Smart Grid demonstration projects for a total amount of 25 M€.

Main European Projects

The research projects related to Smart grid and the integration of Renewable Energy Sources and Distributed Energy Resources in the distribution network can be divided into two main categories: research projects on RES and research projects on impact of EV.

In the following, the main projects on RES, funded by the EU through FP5 FP6 and FP7 are described.

Projects on Renewable Energy Resources integration on Distribution Network

- **INVESTIRE**

INVESTIRE (*Investigation of Storage Technologies for Intermittent Renewable Energies*) project is a project funded by European Community. The project joined more than 30 partners including Photovoltaic Industry, research institutions and universities from France, Germany, Sweden and Netherlands.

The main objectives of the INVESTIRE network were to review and assess existing storage technologies in the context of renewable energy applications, to facilitate exchange of information between the main players, and to propose appropriate R&D actions for the future. The project reviewed available storage technologies and storage requirements of renewable energy systems. The technical, environmental, and economic suitability of each storage technology were assessed, and the gap between conventional lead-acid batteries and emerging technologies evaluated [104].

- **SUSTELNET**

SUSTELNET (*Policy and regulatory roadmaps for the integration of distributed generation and development of sustainable electricity networks*) is a European project supported within the Fifth Framework programme (EU 5th Framework Program) for Research and Technological Development (1998-2002).

The project started in 2002 and finished in 2004, with budget of 1.7 million €.

Within the SUSTELNET research project, a consortium of 10 research organisations from different State (Netherlands, United Kingdom, Germany, Italy, Denmark, Czech Republic, Poland and Hungary) analysed the technical, socio-economic and institutional dynamics of the European electricity supply system and markets.

The objectives of this research project were to:

- Analyse the long-term technical, socio-economical and institutional dynamics that underlie the changes in the architecture of the European electricity infrastructure and markets
- Develop medium-to-long term transition strategies for network regulation and market transformation to facilitate the integration of RES and decentralised electricity systems
- Lay the foundations for a multi-stakeholder regulatory process on the regulation of distribution networks in the EU.

- **DISPOWER**

DISPOWER (*Distributed generation with high penetration of renewable energy resources)* is a European project supported within the Fifth Framework programme (EU 5th Framework Programme) for Research and Technological Development (1998-2002) [105].

The consortium has 38 partners like industries, DSO e TSO, research centre and universities from Germany, Austria, Belgium, Denmark, France, Greece, Italy, Netherlands, Poland, Spain and the UK.

The highlighting are:

- Strategies and concepts for grid stability and system control in DG networks.
- Investigations on power quality improvements and requirements.
- Development of management systems for local grids with high penetration of DG units.
- Assessment of impacts to consumers by ICTs, energy trading and load management.
- Planning tools to insure reliable and cost effective integration of DG components in regional and local grids.
- Investigations on contract and tariff issues regarding energy trading and wheeling and ancillary services.
- Improvement and adaptation of test facilities, experiments for further development of DG components, control systems and design tools.

- **CRISP**

CRISP (*Critical Infrastructures for Sustainable Power*) project, finished in 2006, supported with 1.6 million Euro within the Fifth Framework programme (EU 5th Framework Program) for Research and Technological Development (1998-2002). The group of participants includes research centres, Universities and industries from Sweden, France and Netherlands [106].

Main emphases:

- Design and testing of new operating strategies for distributed power generation.
- As enabled by recent advances in ICT technologies for distributed intelligence.
- Focusing on practical scenarios for supply-demand matching, intelligent load shedding, fault detection and diagnostics and network security

- **MicroGrids**

Microgrids: Large Scale Integration of Micro-Generation to Low Voltage Grids, within the 5th Framework Program (1998–2002) [107]. The Consortium, led by the National Technical University of Athens (NTUA), included 14 partners from seven EU countries, including utilities such as EdF (France), PPC (Greece), and EdP (Portugal); manufacturers, such as EmForce, SMA, GERMANOS, and URENCO; plus research institutions and universities such as Labein, INESC Porto, the University of Manchester, ISET Kassel, and Ecole de Mines. The project allowed to improve control algorithms, both hierarchical and distributed (agent based), study islanded and interconnected operating philosophies, and create laboratory microgrids of various complexities and functionalities.

- **More MicroGrids**

More Microgrids: Advanced Architectures and Control Concepts for More Microgrids (6th Framework Programme, 2002–2006) [107]. The Consortium, led by NTUA, comprises manufacturers (e.g., Siemens, ABB, SMA, ZIV, I-Power, Anco, Germanos, and EmForce); power utilities from Denmark, Germany, Portugal, the Netherlands, and Poland; and research teams from Greece, the United Kingdom, France, Spain, Portugal, and Germany.

- **DGFACTS**

DGFACTS (*Improvement of the Quality of Supply in Distributed Generation Networks through the Integrated Application of Power Electronic Techniques*) supported within the Fifth Framework programme (EU 5th Framework Programme) for Research and Technological Development (1998-2002).

The aim of the DGFACTS project is to solve the set of quality of supply (QS) problems arising from the integration of Distributed Generation (DG) into the electric Distribution networks. Current power quality, efficiency and reliability, ensured by the utilities and supported by the use of powerful conventional generators, could dramatically decrease because of a more spread responsibility on the Grid Quality Management and the technical shortcomings because of the characteristics of the DG-units and the Distributed Generation Networks themselves. The project will introduce the use of the FACTS concept in distribution systems by designing a set of modular systems (DGFACTS) to optimally improve the stability and QS of each distribution network with high DG+RES penetration. In addition, the project will face the management of QS responsibilities in this new scenario [108].

- **EU-DEEP**

EU-DEEP (European Distributed EnErgy Partnership) is a project Funded by the Sixth Framework programme (EU 6th Framework Programme) for Research and Technological Development. The project lasted five years of research and involved involving 42 partners from 16 countries (Greece, Germany, Sweden, Italy, and France).

The overarching goal of EU-DEEP was to design, develop and validate an innovative methodology, based on future energy market requirements, and able to produce innovative business solutions for enhanced DER deployment in Europe by 2010.

The project objectives were therefore to address the removal of the above barriers by providing solutions based on a demand-pull approach:

- Innovative business options to favour DER integration
- Equipment and electric system specifications to connect safely more DER units to existing grids
- An in-depth understanding of the effect of large penetration of DER on the performances of the electrical system and on the electricity market
- Market rules recommendations to regulators and policy makers that will support the three studied aggregation routes
- A comprehensive set of dissemination actions targeting all stakeholders of DER in Europe [109].

- **ADDRESS**

The ADDRESS (*Active Distribution network with full integration of Demand and distributed energy RESourceS*) [52] is a five-years project (2008-2013) formed by 25 partners from 11 EU countries, co-founded by the European Commission under the 7th Framework Programme. The project coordinator is ENEL Distribuzione and the consortium spanning the entire electricity supply chain, qualified R&D bodies, SMEs and manufacturers.

The ADDRESS Consortium has selected the test sites in three European countries with different network topologies and acceptance conditions which, taken together, provide a validation of the entire concept. Additionally, in Spain and France different climate conditions (warm in Spain, cold in France) will ensure different equipment and usage patterns.

Its target is to enable the Active Demand in the context of the smart grids of the future, or in other words, the active participation of small and commercial consumers in power system markets and provision of services to the different power system participants.

In the proposed architecture (Figure 58), Aggregators are the mediators between the consumers and the markets. They play a central role for both sides:

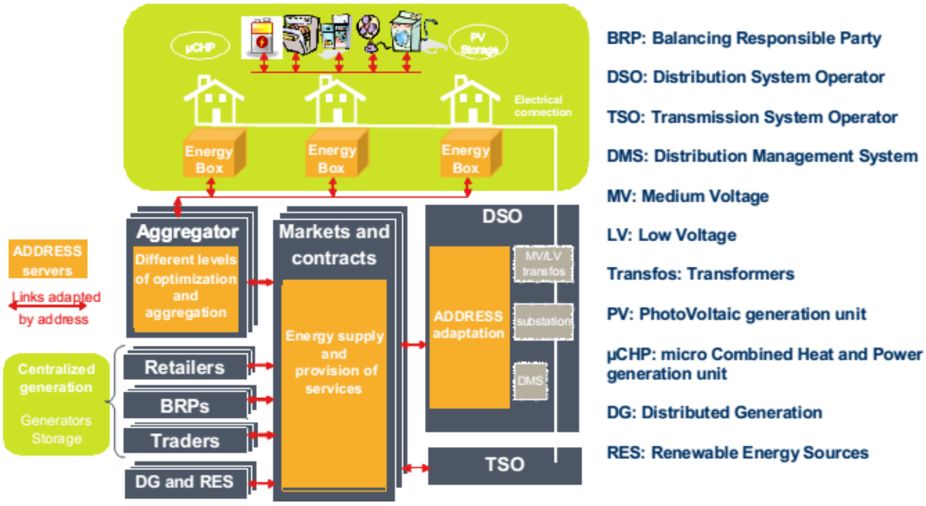


Figure 58: ADDRESS conceptual architecture [52].

- They will collect the requests and signals coming from the markets and the different power system participants,
- They will gather the “flexibilities” and contributions provided by the consumers to meet those requests and signals and to offer the services to the different power system participants through the markets.

At the consumer level, the Energy Box (located on the consumer side) is the interface between the consumer and an aggregator. It carries out the optimization and the control of the loads, DER and possibly energy storage at the consumer’s premises. It consists of hardware and software (with a certain level of intelligence) and may carry out the optimization and the control of appliances, local DER and energy storage at consumer’s premises.

Projects on Electric Vehicles integration on Distribution Network

- **EDISON**

The EDISON project has utilized Danish and international competences to develop optimal system solutions for EV system integration, including network issues, market solutions, and optimal interaction between different energy technologies. Furthermore, the Bornholm electric power system has provided an optimal platform for demonstration of the developed solutions. The project has been organized in seven work packages and an additional work package for administration and dissemination activities.

- **G4V Grid for Vehicles**

G4V project (*Grid for Vehicles)* has received funding from the European Union Seventh Framework Programme (FP7/2007-2013).

G4V endeavours to provide a set of recommendations to support the evolution of the European electricity grids into an intelligent power system of the future, which can efficiently integrate and serve a mass market of EVs and PHEVs in Europe by offering a variety of services and products to meet the requirements of a wide range of involved stakeholders.

- **MERGE**

One of the most important project on the impact of the EVS is the MERGE project [110]. MERGE (Mobile Energy Resources for Grids of Electricity) is a European project supported within the Seventh Framework Programme for Research and Technological Development.

Its mission is to evaluate the impacts that EVs will have on EU electric power system regarding planning operation and market functioning. The focus will be placed on EV and Smart MicroGrid simultaneous deployment together with renewable energy increase, leading to CO2 emission reduction through the identification of enabling technologies and advanced control approaches.

- **Green eMotion**

Green eMotion is a European project supported within the Seventh Framework Programme for Research and Technological Development. The consortium consists of forty-three partners from industry (e.g., ALSTOM, BOSCH, IBM), the energy sector (e.g., ENEL, EDF, EURELECTRIC, RWE), electric vehicle manufacturers, and municipalities (Rome, Barcelona, Copenhagen, Malaga) as well as universities and research institutions (RSE, Trinity College of Dublin).

The primary goal of the project is to define Europe-wide standards. To this end, practical research is being conducted in different demo regions all over Europe with the aim of developing and demonstrating a commonly accepted and user-friendly framework that combines interoperable and scalable technical solutions with a sustainable business platform. For the implementation of this framework, Green eMotion will take into account smart grid developments, innovative ICT solutions, different types of EVs, as well as urban mobility concepts.

- **PowerUp**

PowerUp project was funded the Seventh Framework Programme for Research and Technological Development (2007-2013).

PowerUp aims to develop the V2G interface, involving a full development cycle of physical/link-layer specification, charging control protocol design, prototyping, conformance testing, field trials, and standardisation. Its results will ensure that EVs smoothly integrate into emerging smart-grid networks. Thereby the efficiencies resulting from robust grid operation may be achieved; V2G capabilities will smoothen the daily fluctuation of electricity demand and will enable EVs to act as emergency energy supplies. To achieve these desired results, it is essential that any electric vehicle type would be compatible with any European smart-grid network.

- **PROVIDER**

The project PROVIDER (Planning gRids fOr electric Vehicles and Distributed Energy Resources) is developed by a consortium of DSOs, research centres and European university. Its main objectives are:

1. Make an overview of the current solutions being adopted to deal with EV and DER integration.
2. Survey the procedures currently adopted by DSO to make expansion/reinforcement planning of LV and MV grids from interconnected and island systems.
3. Specific a framework for enabling the coordination between EV and DER.
4. Define the ICT requirements for enabling the direct control of EV/DER.
5. Define reliable short, medium and long-term scenarios of EV, DER (including distributed renewable generation) and ICT deployment and demand evolution.
6. Study operational tools to maximize the coordination between DER and EV.
7. Develop new and/or upgrade existing network planning strategies, taking into account the new operational tools designed to maximize the coordination between DER and EV.
8. Create a suite of tools to test the new and/or upgraded network planning strategies.
9. Provide recommendations of the most suitable network planning methods for systems with different characteristics within Europe, considering the Key Performance Indicators (KPI) associated with minimization of investment levels, costs of operation, reliability, usage of renewable sources, etc.
10. Provide regulatory recommendations about network planning activities and guidelines for standardisation bodies, aiming at promoting the large-scale roll out of EV and DER.

Main Italian projects

The main Italian projects that study the evolution of the distribution network into Smart Grid were funded by EU, the Italian Regulator and by Italian Research Fund for the Power System development. In the following, a brief description of the main Italian projects divided in LV network and MV network will be proposed.

- **Main Italian projects on LV network**

  The main initiatives on **LV network** (with ENEL leader of the project) are:

  - **ADDRESS**
  - **Smart Info**

    Smart Info is an innovative device, certified by Enel in July 2011 that establishes a direct connection between the grid and the customer and enables an easy access to the information recorded by their meter. The purpose of the project is providing clients with a tool to increase their awareness on energy consumptions, providing information ugh a wide range of standard media (such as personal computers, dedicated displays, white goods) that will be available in the market.

    The Enel Smart Info will participate in a domestic framework to support new advances services, such as: automatic control of loads, integration of smart white goods, enabling of real time tariffs active demand services.

  - **Energy@home**

    This project in collaboration with Telecom Italia, Indesit and Electrolux: integration of the smart info in a domotic network. Its goal is to develop a communication infrastructure to provide Value Added Services based upon information exchange related to energy usage in the Home Area Network (HAN). Zigbee is the chosen technology to enable communication inside the HAN.

- **Main Italian projects on MV network**

  The project on **MV network**, with Enel project leader are:

  - **Enel Telegestore**

    Enel Telegestore Project provides the installation of more than 32 million smart meters [111]. The Telegestore (remote management system) is the innovative solution that Enel has deployed since 2001 in Italy for the remote management of the new electronic meters. It still represents the only actually worldwide operating large scale smart metering solution. These smart meters allow Enel to periodically collect data on voltage quality and interruptions, daily consumptions, active and reactive energy measurements, and remotely manage contractual activities. Meters are able to transmit data regarding consumptions, receive updates of the contractual parameters and remotely manage the supply connectivity.

In its present configuration, the remote control system is composed of two part (Figure 59). First, each MV/LV transformer station is equipped with a concentrator that collects all data coming from meters, via a power-line carrier, and is capable of sending instructions to individual meters. Second, from the concentrator upwards, communication is mainly based on the public network (GSM/GPRS). ENEL Distribuzione primarily conceived its smart metering system with the objectives of significantly reducing OPEX, including energy thefts. The present configuration does not allow real-time control of the end-point meters or the management of the customer loads. Indeed, this was not among the objectives that guided ENEL's decision to develop a smart metering system.

- **Interregional Operational Program (POI)**

The Interregional Operational Program (POI), approved in 2007 by the European Commission and completed in 2013, aims to increase energy consumption produced by renewable sources and to promote local development opportunities by enhancing energy efficiency. In order to improve the development and implementation of distributed generation, the POI will develop a broadband communication network between the medium voltage network and substation, generators and loads. The Programme also helps to improve remote control systems, the Remote Terminal Unit used across the grid-controlled area and control

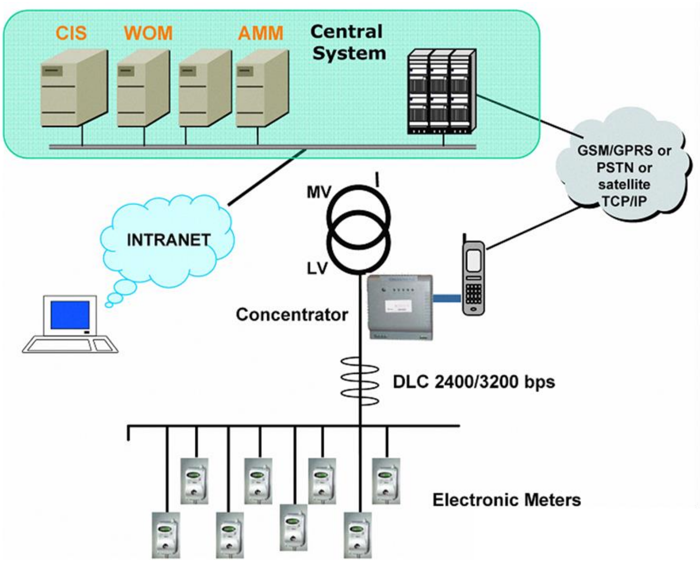


Figure 59 System Architecture [111].

systems for the consumers who own renewable plants and communicate with the network as central distributed generation players (prosumers).

One of the most important projects is *Reti intelligenti in Media Tensione* (Smart Grid in MT) realized in Campania. The aims of the project are increase the hosting capacity, improve the energy efficiency and the power quality.

In 2007, the Italian regulator AEEG declared to be oriented to recognize some kind of incentives for distribution companies for Smart Grid demonstration projects, pilots and trials, focused on active MV distribution networks. Following this initiative in 2010, AEEG launched a call for Smart Grid demonstration projects with the decision ARG/elt 39/10 [103] that contains also the main criteria for cost/benefit assessment of the projects proposed by DNOs. In terms of technologies to be trialled, pilots can include active operation of generators, advanced protection schemes, advanced distribution SCADA, storage, etc. The expected benefits from these pilots include the increase in net energy injected by DER, hosting capacity of and voltage regulation support by DER, improved quality of service, etc.

Several Italian DSOs decide to participate to the Smart Grid demonstration projects using advanced protection schemes, control system for active MV networks. Their main characteristics are briefly summarized in Table X, while in Table XI the timing of the demonstration projects is reported.

Table X – Innovation level of the demonstration project funded with ARG/elt 39/10.

DSO	**A2A**	**A2A**	**ENEL**	**ACEA**	**ASM**	**ASSEM**	**ASSM**	**Deval**
Project name	**CP Gavardo**	**CP Lambrate**	**CP Carpinone**	**ACEA Distr.**	**Terni**	**S. Severino Marche**	**Tolentino**	**CP Villeneuve**
Bi-Directional Communication	YES	YES	YES	YES	YES	YES	YES	YES
SCADA in Primary Station	YES	YES	YES	YES	YES	YES	YES	YES
Active Demand	YES	YES	YES	YES	YES	YES	YES	YES
DSO participation to the ancillary service market	YES	YES	YES	YES	YES	YES	YES	YES
DES	NO	NO	NO	YES	YES	YES	NO	NO
Charging Station	NO	NO	NO	YES	YES	YES	NO	YES
Demand Side Response	NO	NO	NO	YES	NO	NO	NO	NO

Table XI – Timing of the demonstration projects funded with ARG/elt 39/10

DSO	A2A	A2A	ENEL	ACEA	ASM	ASSEM	ASSM	Deval
PROJECT	**CP Gavardo**	**CP Lambrate**	**CP Carpinone**	**ACEA Distr.**	**Terni**	**S. Severino Marche**	**Tolentino**	**CP Villeneuve**
END (installation e monitoring)	2013	2013	2013	2012	2013	2013	2013	2013
Time for Execution	24 months	21 months	22 months	12 months	24 months	21 months	21 months	24 months
Time for Evaluation	12 months	15 months	14 months	12 months	12 months	12 months	12 months	12 months

The Italian Research Fund for the Power System funded projects on:

- Demand Side Management (SDMxDMS, Smart Domo Grid and ICTperDR),
- Distributed Generation and Smart Grid (ECO-REDI, SmartGen, S_GRID, SCHEMA).

One of the most important is ATLANTIDE (Archivio TeLemAtico per il riferimento Nazionale di reTI di Distribuzione Elettrica) [112].

Its ambition is to realize a repository of reference models for passive and active Low Voltage (LV) and Medium Voltage (MV) distribution networks, specifically tailored to the Italian distribution system, but general enough to be applied in different contexts. During the project, reference models of networks and components have been developed and have been used for the simulation of medium and long term predictable scenarios, by taking into account the development of the distribution system according to the load profile evolution, and the challenges caused by the widespread integration of DG, RES and ES One of the first activities of the ATLANTIDE project was identifying the reference network models representative of the Italian Distribution. With the aim at selecting real network portions that fall into three main categories of sub-systems (e.g. rural, industrial and urban), specific indexes based on statistic data were identified to characterise the different contexts. Some of these indexes refer to information about socio-economic features (e.g. population density, inhabitants concentrations, number of industries and service companies), other to the electrical characteristics of distribution networks in the three contexts (total consumption of electricity, connection of RES, power flow reversal). For each network, different typologies of loads, with their own daily curves, have been considered (e.g., residential, industrial, commercial, agricultural, transport). In Figure 60: Daily curves of different typologies of load models., the daily curves of different typologies of loads are reported.

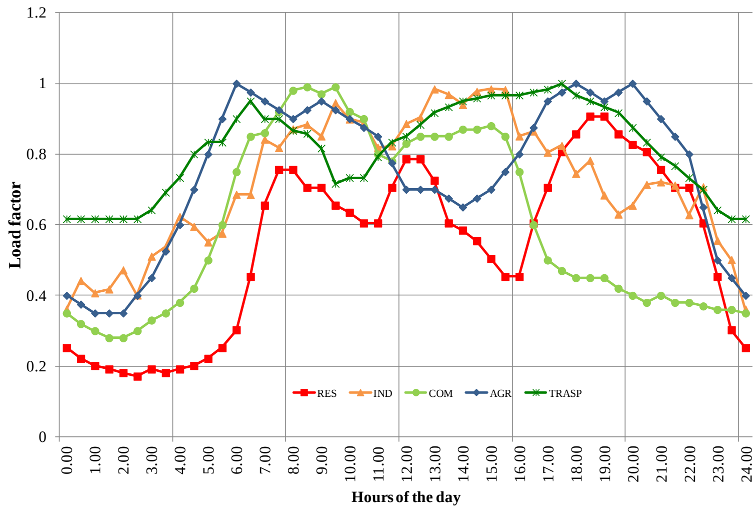


Figure 60: Daily curves of different typologies of load models.

Each network is also characterised by different type of generators (e.g., Hydro, Photovoltaic, CHP generators, Wind Turbine). Figure 61 shows the daily production curves of different typologies of generators [70],[71].

The quite large size of the selected reference networks (almost 400 nodes each) has been reduced by suitably clustering procedures. Thus, clustered reference networks, smaller in size (almost 100 nodes each), equivalent and with the same electrical behaviour as the original ones were provided in addition to the original ones, in order to reduce the computational burden of studies that do not need the highest level of detail [70],[71].

In December 2013 ATLANTIDE project reached the final stage and the repository [69], [112]. The on-line power system models and the social forum are on-line and free for use. The website is structured with two sections. The first section represents the digital archive of the components and

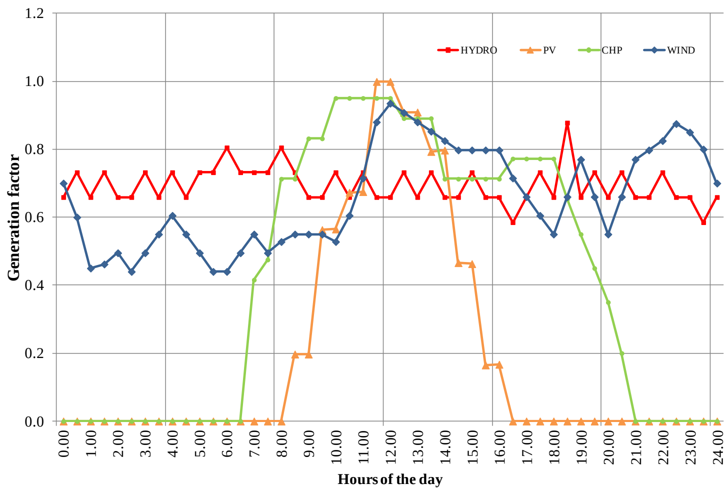


Figure 61: Daily curves of different typologies of generator models.

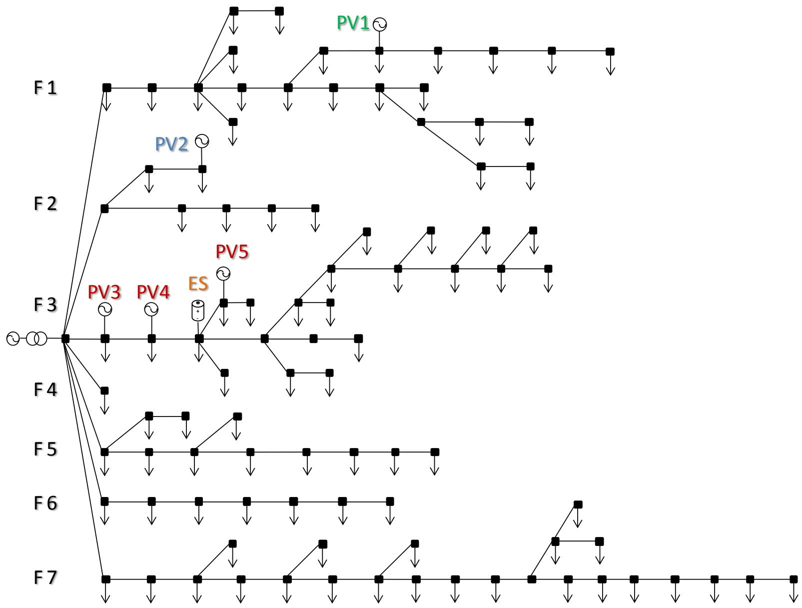


Figure 62: Schematic representation of the rural reference network.

network models. The second section, the most innovative one, allows the user to perform on-line simulations by using the representative networks available in the repository o user-defined case studies. User-defined case studies can be designed with a Graphical User Interface or directly uploaded as excel files. The ATLANTIDE website has also a blog-like home where users can share their simulation results and discuss with other registered users.

Early Smart Grid initiatives

- **Microgrid**

Microgrids are a halfway point to the ADNs. In fact, Microgrids are LV distribution networks comprising DG, storage devices and controllable loads that can operate either interconnected or isolated from the main distribution grid as a controlled entity (see Figure 63). From the grid's point of view, a Microgrid can be regarded as a controlled entity within the power system that can be operated as a single aggregated load and, given attractive remuneration, even as a small source of power or ancillary services supporting the network. From a customer point of view, Microgrids similar to traditional LV distribution networks, provide their thermal and electricity needs, but in addition, enhance local reliability, reduce emissions, improve power quality by supporting voltage and reducing voltage dips, and potentially lower costs of energy supply [113].

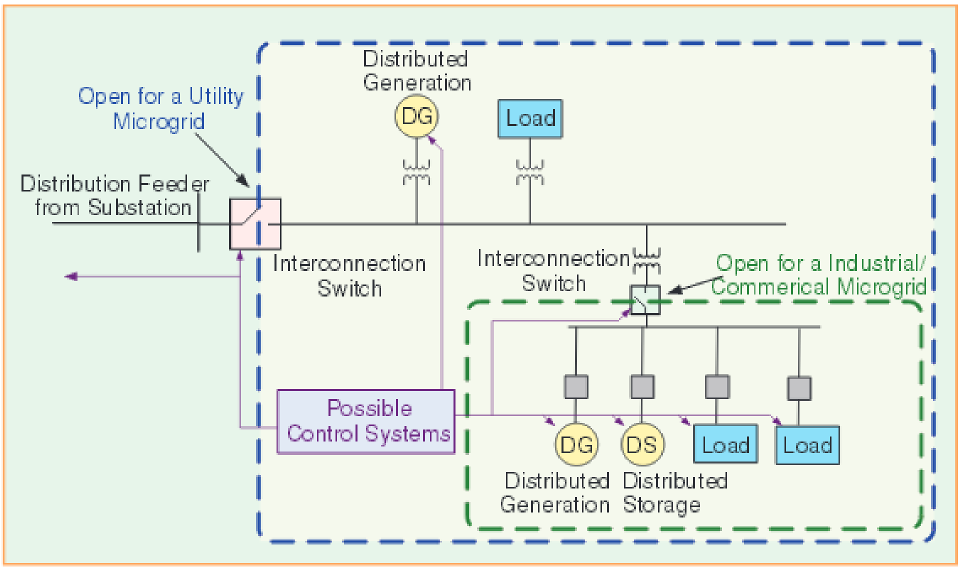


Figure 63: Typical Microgrid Structure [113].

Around the world, there are several active experiments in the microgrid area covering an array of technologies. In Europe the most important is the Microgrid Project, while in the USA has been developed the CERTS Microgrids.

- **European Microgrid**

In the Microgrid project, the control system of a microgrid is designed to safely operate the system in grid-connected and stand-alone modes. This system may be based on a central controller or imbedded as autonomous parts of each distributed generator. When the utility is disconnected the control system must control the local voltage and frequency, provide (or absorb) the instantaneous real power difference between generation and loads, provide the difference between generated reactive power and the actual reactive power consumed by the load; and protect the internal microgrid [113].

The Microgrid allows to:

- Minimize the overall energy consumption
- Improve environmental impact
- Improve energy system reliability and quality of service
- Achieve Network benefits
- Find Cost efficient electricity infrastructure replacement strategies.

In the project, a hierarchical control system (see Figure 63) is proposed [114]-[116]:

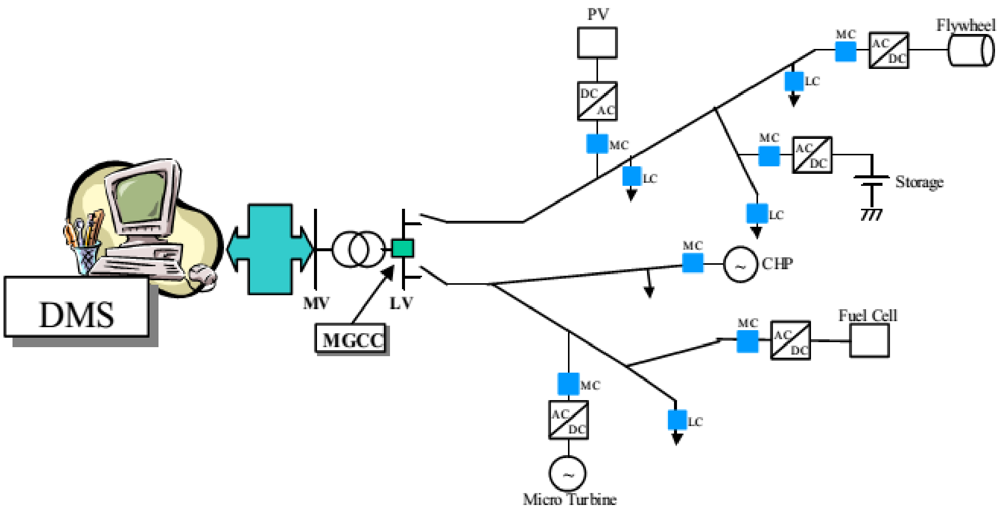


Figure 64: Structure of a Microgrid.

- *Local Micro Source Controllers* (MC), which uses local information to control the voltage and the frequency of the Microgrid in transient conditions and Load Controllers (LC), It uses local information to control the voltage and the frequency of the Microgrid in transient conditions.
- *Microgrid System Central Controller* (MGCC), responsible for the maximization of the Microgrid's value and the optimization of its operation. It uses the market prices of electricity and gas, costs and probably grid security concerns to determine the amount of power that the Microgrid should draw from the distribution system, optimizing the local production capabilities and sends control signals to the MCs and LCs.
- Distribution Management System (DMS).

The project realized some pilot installations in Greece (Kythnos Island, a microgrid), in Netherlands (Continuon's MV/LV facility), in Germany (MVV Residential Demonstration at Mannheim-Wallstadt) but also in Denmark, Italy, Portugal, and Spain.

The MAS control system was firstly in the Power System Laboratory of the National Technical University of Athens; then in the Pilot Kythnos Plant (in Greece) during the Project Microgrids. The Kythnos Microgrid is a 1-phase network, composed of overhead power lines and a communication cable running in parallel, 12kWp of Photovoltaics, a battery bank of nominal capacity 53kWh and a diesel Genset with a nominal output of 5kVA. It is electrifying 12 houses (Figure 65).

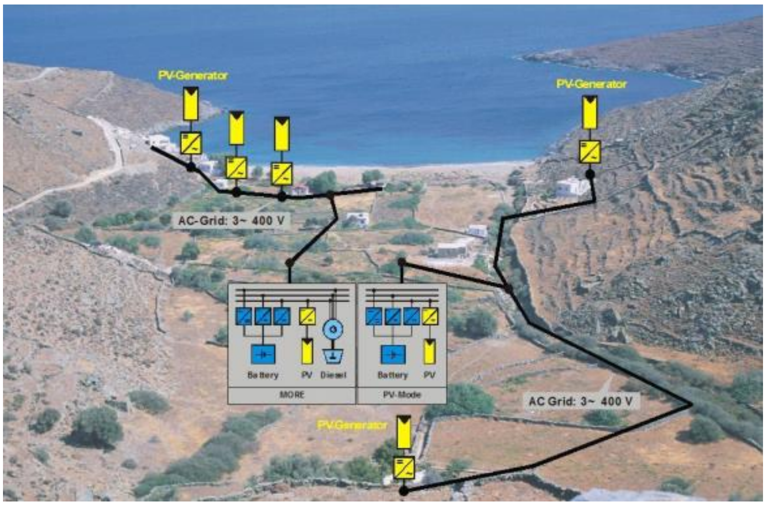


Figure 65: Control levels of the microgrid environment [107].

- **American Microgrid**

The most important U.S. microgrid project has been developed by the Consortium for Electric Reliability Technology Solutions (CERTS): the *CERTS Microgrid* (CM) [117]. Its main focus is to seamlessly separate or island from the grid the microgrid (suitably based on CHP devices and power electronic based micro-sources) if problem arises and, reconnecting to the grid once they are resolved (instead of shut down automatically interconnected generators). The CM provides this function for relatively small sites (~<2 MW peak) without need for costly fast electrical controls or expensive site-specific engineering. No single device is essential for operation, creating a robust system [113], [116], [117].

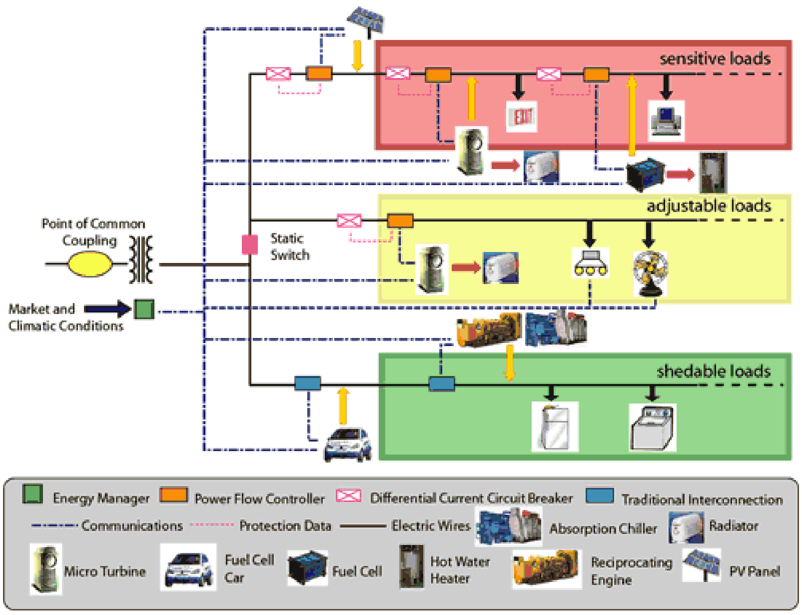


Figure 66: Example of CERTS microgrid concept [117].

Figure 66 shows a typical set-up of the CM. The CM is characterised by a lack of fast electrical controls; a single point of common coupling (PCC), and does not export (to the utility the CM appears as a single controlled load). It has no “master” controller or source. Each source is connected in a peer-to-peer fashion with a localized control scheme implemented with each component. This arrangement increases the reliability of the system in comparison to a master–slave or centralised control scheme. In the case of a master–slave architecture, the failure of the master controller could compromise the operation of the whole system [113].

Energy Hub

All the solution analysed are focused only on the electric vector, without considering natural gas, and district heating/cooling and their benefits if working together. An energy hub (see Figure 67) is considered a unit where multiple energy carriers can be converted, conditioned, and stored. It represents an interface between different energy infrastructures and/or loads [118]. Energy hubs consume power at their input ports connected to, e.g., electricity and natural gas infrastructures, and provide certain enquired energy services such as electricity, heating, cooling, and compressed air at the output ports.

Real facilities that can be considered as energy hubs are, for example, industrial plants (steel works, paper mills), big building complexes (airports, hospitals, shopping malls), rural and urban districts, and small isolated systems (trains, ships, aircrafts). Figure 2 shows an example of an energy hub, which contains a transformer, a micro-turbine, a heat exchanger, a furnace, an absorption chiller, a battery, and a hot water storage system.

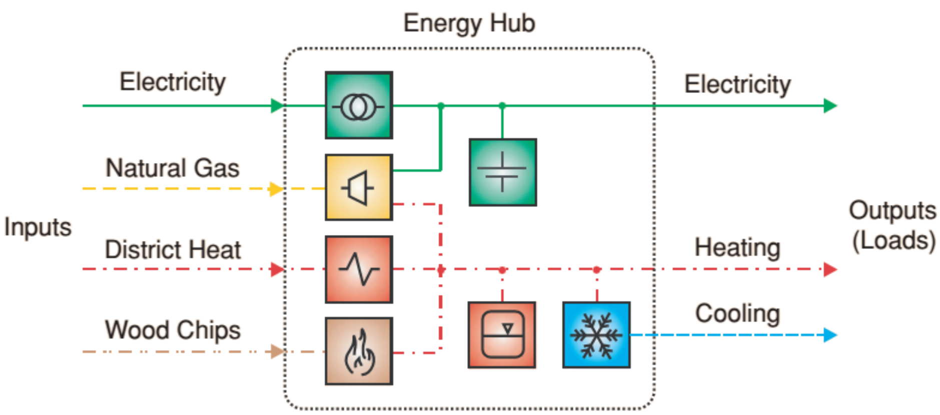


Figure 67: Example of an energy hub [118].

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List of Publications

The following papers have been accepted for publication or published based on work done within the framework of the doctorate degree, or collaboration with other researchers.

1. Celli, F. Pilo, S. Ruggeri, G.G. Soma Optimal protection devices allocation and coordination in MV distribution networks G., 11th IET DPSP 2012, Birmingham, 23-26 April 2012.
2. Celli G, Ghiani E, Pilo F, Pisano G, Ruggeri S, Soma G G., Electric Vehicles Aggregator Management in Active Distribution Networks. In: 104 Convegno Nazionale AEIT "Mobilità e Trasporto Elettrico per l'Italia di domani".Roma. 13-14 giugno 2012.
3. A. Bracale, R. Caldon, M. Coppo, D. Dal Canto, R. Langella, G. Petretto, F. Pilo, G. Pisano, D. Proto, S. Ruggeri, S. Scalari, R. Turri, Active Management of Distribution Networks with the ATLANTIDE models, MEDPOWER 2012, Cagliari, 1 – 3 Ottobre 2012.
4. R. Caldon, M. Coppo, D. Dal Canto, L. Feola, R. Langella, G. Petretto, F. Pilo, G. Pisano, D. Proto, S. Ruggeri, S. Scalari, R. Turri, Applications of DMS in the ATLANTIDE Project: models and tools, 22nd CIRED 2013, Stockholm, 10-13 June 2013.
5. R. Caldon, M. Coppo, D. Dal Canto, G. Gigliucci, L. Feola, R. Langella, F. Pilo, G. Petretto, G. Pisano, S. Ruggeri, A. Testa, R. Turri, Application of ATLANTIDE models to harmonic penetration studies, Innovative Smart Grid Technologies Europe (ISGT EUROPE), 2013 4th IEEE/PES.
6. P.A. Pegoraro, F. Pilo, G. Pisano, S. Ruggeri, S. Sulis, Co-simulation of distribution active management and distribution state estimation to reduce harmful effects of inaccuracies, PowerTech (POWERTECH), 2013 IEEE Grenoble; 01/2013.
7. S. Mocci, N. Natale, F. Pilo, S. Ruggeri, *Multi-agent control system to coordinate optimal demand response actions in active distribution networks,* MEDPOWER 2014, Athens, 2-5 November 2014.
8. S. Mocci, N. Natale, F. Pilo, S. Ruggeri, *Multi-agent control system to coordinate optimal EV charging and demand response actions in active distribution networks,* RPG, Naples, 24-25 September 2014.
9. S. Mocci, N. Natale, F. Pilo, S. Ruggeri, *Multi-Agent Control System for increasing hosting capacity in Active Distribution Networks with EV,* in proc. EnergyCon 2014, Dubrovnik, 13-16 May 2014.

10. S. Mocci, N. Natale, F. Pilo, S. Ruggeri, Decentralized And Centralized Approach In The Active Management Of Distribution Networks: A Comparison Through Business Cases, under review in 23rd International Conference on Electricity DistributionLyon, 15-18 June 2015.
11. S. Mocci, N. Natale, F. Pilo, S. Ruggeri, Demand Side Integration in LV Smart Grids with Multi-Agent Control System, in Electric Power Systems Research - ELSEVIER.

PROJECT PARTICIPATION

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1. ATLANTIDE, funded by the Italian Ministry of Economic Development under the framework of the Italian Research Fund for the Power System development.
2. e-visiØn (electric-vehicle integration for smart innovative 0-CO_2 networks), financially supported by the Sardinian Regional Government (L.R. 7/2007).