OPERATION OF DISTRIBUTION NETWORKS WITH DISTRIBUTED GENERATION

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Chapter 1

Introduction

Distribution networks are presently attracting increasing interest by all electrical market stakeholders. In the recent years in fact, due to economical, environmental and political reasons, the traditional power system, characterized by centralized bulk power production and wide/long transmission networks, is increasingly supported also by energy-resources connected to the distribution grid, a tendency commonly denoted as distributed generation (DG).

It is worth adding that in the recent years DG penetration in the distribution systems has become faster and tangible in a way that in several countries the maximum limit of allowed connections that can be managed with the traditional passive networks approach has been reached. Hence, over the coming years, networks structure, design and operation will have to be radically modified in a way in which generation must be viewed as an integral part of the distribution network system. Important investments and research are then needed to renew the electrical distribution segment in order to achieve a sort of “self-healing” distribution system, which allows not only managing large clusters of energy resources, but also the increase of the service quality level.

There is a general consensus in the fact that the migration towards this new kind of grid paradigm is achievable through efforts focused on the control, automation and adjustment of the operation procedures currently used.

Within this context, the thesis focuses on the operation of the so-called active distribution networks. The followed approach is to centralize all the operation and control functions in a single platform called “Distribution Management System” (DMS). Such an approach is justified by the need of managing small and medium-size dispersed generators, also belonging to different operators and characterized by non-dispatchable generation profiles (e.g., renewable energy resources) as potential elements of the electrical/energy market.

Multiple levels of intervention are required to an advanced DMS operating within an active distribution network. As an example, it must be able to schedule the steady state configurations of the system performing any kind of optimization, deliver control commands and supervise the transient phases between different stationary operating points and recognize/process electromagnetic transients for protection devices.
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Specific energy-resources scheduling procedures, which can be included as functions in the DMS, need to be developed with the aim of operating the dispersed resources in an optimal technical-economical manner during both the normal and the emergency conditions. Furthermore, for these latter, detailed analysis needs to be carried out to define suitable control strategies to face, for instance, islanding transitions or network restoration. Finally, to consider distributed resources as active elements for network regulation means also to guarantee the network availability and operability (e.g., reducing as more as possible outage times due to faults). For this purpose fault location procedures conceived specifically for the distribution grid are expected to be of utmost interest.

The thesis is organized as follows:

Chapter 2 presents an overview of the main DG issues. Starting from the reasons why DG is harvesting increase credibility, the main benefits and the relevant technical problems concerning its connection to the distribution grid are discussed. Then, being one of the open issues related to what exactly can be considered as DG, a briefly discussion about the DG definition is provided. Finally, in order to contextualize our research, the most innovative approaches and the main research projects world-wide under development for the DG integration in distribution grids are described and discussed.

Chapter 3 presents the scheduler of the distributed energy resources that has been developed within the framework of this dissertation. Such an algorithm, realized practically in the form of a software module, has been conceived to operate within the main functionalities of a DMS. It aims to integrate the use of distributed energy-resources, in coordination with traditional devices (e.g., on load tap-changers), to achieve technical purpose (e.g., voltage regulation, congestion management) and an overall optimal operation of the grid. The chapter discuss the mathematical formulation of the optimization problems, the application of different optimization methods and the results obtained by analysing the scheduler performances on several tests networks with different voltage levels and size.

Chapter 4 refers to a real case study and deals with the control strategies appropriately conceived for the islanding transition and consequent emergency operation of a large scale distribution power plant. The chapter describes the developed dynamic simulator of such a system and analyses both the transients related to the islanding transition and the black-start up restoration.

Chapter 5 describe a new approach for fault location in distribution networks. The aim is to use the continuous wavelet transform to identify the characteristic frequencies of
the voltage transients associated to the fault itself. Such a frequencies are then associate to the travelling waves paths which, knowing the network topology, allows to locate the faulted point. The main original contribution is the introduction of a mother wavelet directly inferred from the fault transient.

Chapter 6 is devoted to the conclusions.

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Introduction
Chapter 2

Power Systems and Distributed Generation

2.1. A more decentralized asset for Electrical Power Systems

For many aspects, decentralized generation is not a completely new concept. In fact, historically, the first power plants were built up close to the customers requiring energy supply. They were small isolated systems which often have been interconnected together and extended also in order to cover vast regions [Marnay et al., 2004].

Later, as consequence of important technological evolutions, the electricity demand increased and the improvement of AC systems allowed the transport of electricity over long distances, lead to an increase in the size of the generation units. Centralization of control and transmission over long distances allowed utilities to capture low cost sources and economies of scale, while diversifying risks. All this resulted in increasing convenience and lower per unit costs in a way that massive electricity systems, consisting of huge transmission and distribution grids and large generation plants, were constructed, imposing the actual configuration of the electrical power system [Pepermans et al., 2003].

Although during the years this classical paradigm suffered by several problems of reliability and efficiency, only from the latest 1980s, when economic and social scenarios changed, the on-site generation started to receive increased interest and serious analysis of the potential benefits.

Factors driving to this change were (i) the de-regulamentation of the electricity market, (ii) the attractive possibility to achieve enhanced power reliability and quality together with capture the waste heat due to use of energy-resources in combined heat and power (CHP) systems.

Actually this tendency is encouraged by the world-policies finalized at the promotion of renewable energy resources, market competitiveness as well as at the maximization of efficiency for any energy-system. Such a condition is being emphasized with the implementation of “shallow connection costs” which are not generally enough to cover the investments that distribution networks would require to allow the integration of distributed energy resources. For these reasons the rate of energy-resources connections to distribution networks is rapidly increasing, in a way that in several countries the maximum limit of allowed connections that can be managed with the traditional passive networks approach has been reached. The prospect of a radical change in the structure of
power delivery become day by day concrete with the availability of small and reasonably low-cost power sources. The will of taking advantage from this benefits was measured with new issues related to the increasing presence of energy sources connected along the distribution networks that have not been conceived to support them. Important investments and research are therefore needed to renew the electrical distribution segment in order to allow for the electrical infrastructure – already involved in the deregulation process and called to provide more reliable and high-quality supplies – to successfully manage the challenges due to present and future scenarios.

2.2. Benefits and issues of distributed generation

The electrical power systems of developed countries are changing searching to reach three main energy-related challenges namely, environmental sustainability, security of supply, and competitiveness. These fundamental improvements must be pursued considering the continuously increasing electricity demand. In this context governments, researchers and electricity stakeholders, look at DG as to a one of the more suitable solutions.

The motivation adducted for this interest are:

a) *increase of security and reliability of supply*: use of DG and Renewable Energy Resources (RERs) can increase the autonomy of the electrical provision, diversify the energy source portfolio and assess system support in terms of local/global regulations and ancillary services supply. Considering indeed the islanding opportunity, DG can reduce/avoid power outages of customers and deliver profitable contribution for the restoration process.

b) *advantages in transmission and distribution network operation and planning*: high penetration of opportunely integrated DG reduce congestions in upstream systems leading to the deferment of transmission system development. The built up of DG plants is favorite also from an authorization point of view. In fact, it is generally easier to find sites for RER and other DG plants instead than for large central power plants. Furthermore, DG units can be brought online much more quickly.

c) *energy market competitiveness*: development of small-scale, efficient, relative cheaper generators enable DG plants to be more attractive for both the new-entry small players of the electricity market and big companies fostering the competition (because investment decisions are driven by shorter term profits).

d) *more efficient use of primary energy resources and emissions reduction*: it is generally not techno-economically feasible, for large fossil fuel-based power plants, to utilize the waste heat stemming from the energy conversion process. Small-scale efficient and environmentally friendly CHP plants can be exactly
dimensioned to match needs of several customers, allowing to use locally the waste heat produced as consequence of electricity generation. This possibility could increase the efficiency, capturing high economical benefits and, together with the use of RER, contribute to the harmful pollutant emissions (e.g. Greenhouse Gases GHG) reduction. To generate energy locally and avoid its transportation lead also to losses reduction.

e) **extensively use of RER:** the recent EU target of pursuing globally 20% of energy consumption covered by RER by 2020 and the obvious notation that they are naturally distributed along the territory, foreshadows a massive DG deployment.

Along with the potential benefits here discussed, also several issues related to technical problems are under investigation. In fact, whereas few generators cannot be a problem, the future vision of the electrical power systems foreshadows a scenario considerably based on GD, which inevitably introduce a quantity of related problems.

The major issues related to the presence of DERs in the distribution networks can be listed as in the follows:

a) **distribution planning and operation issues:** DG is preferably installed into the distribution network and starting from the present situation, both protection systems and networks architecture call for a revision. Specifically, protection systems need to be redesigned in order to manage more critical voltage and fault current values, while at the same time being able to deal with bidirectional power exchanges. The introduction of monitoring and control systems (e.g., SCADA), on the example of actual transmission network, are also desirable.

b) **power reserve and balancing:** RER are quite unpredictable, intermittent and not dispatchable. A large amount of such a sources can cause serious problems if Distribution Network Operators (DNOs) are not able to opportunely get reserve power from the upstream grid. More, also Transmission Network Operation (TNOs) have the problem to exactly forecast the reserve in the cheapest way avoiding that suddenly loss of power generate wade system instability. That is, the costs of imbalances will become increasingly important. For the same reasons, at local level the DNOs must be able to manage fast reacting local power generation. In addition, they must be able to effectively communicate with the interconnected transmission control systems, in order to make the proper power reserve available in the systems.

c) **power quality:** many DERs are interfaced with the grid by electronic devices interfaces which generate noteworthy harmonic pollution.

d) **infrastructure and provisions:** given the recorded growth trend of natural gas fuelled CHP technologies integrated in distribution networks, security of supply may be of rising concern due to gas demand/offer unbalances. These may be also
linked to possible unscheduled imported gas shortages or constraints in the gas transmission/distribution systems.

Although DG is becoming an important paradigm for electricity generation, it will ever not able to replace the centralized power production. In fact centralized generation remains necessary to maintain a stable operation of the power system in terms of voltage and frequency, actually carried out by controls recognized to be sufficiently fast and robust. It has also to be noticed that a stable operation of the bulk power grid is also necessary for the DG units connected to the network via asynchronous machines. The load following or balance is a fundamental issue to transfer to the DG controls for which, important role will be played by electronic devices interface and storage facilities.

2.3. About the definition of distributed generation and distribution network

Nowadays there is not yet a completely shared definition of DG. The reasons why are many as many are the voltage levels of the distribution systems through the different countries, and as many as the different situations faced up by practical arrangements in each country.

In an easy way the European Directive 2003/54/EC [2003] approach DG as “generation plants connected to the distribution system”. This fairly definition introduce however another important problem that is, the definition of what are commonly considered as distribution system. The same directive defines the distribution system as “the transport of electricity on high-voltage, medium voltage and low voltage distribution systems with a view to its delivery to customers, but not including supply”.

In the follows, a briefly overview of the main definitions used at international level are discussed.

The International Energy Agency (IEA) [2002] defines DG as generating plants serving a customer onsite or providing support to a distribution network, connected to the grid at distribution-level voltages.

The CIGRE WG 37-23 [2003] defines DG unit as a generation unit that is not centrally planned, not centrally dispatched, usually connected to the distribution network and smaller than 50-100 MW.

The IEEE Standard 1547 [2003] defines the DG as generation of electricity by facilities, which size is usually 10 MW or less, so as to allow interconnection at nearly any point in the power system [L’Abbate et al., 2007].
Andersson et al. [2000] conclude that “DG is an electric power source connected directly to the distribution network or on the customer site of the meter” and, after more rational discussions of numerous definition used in both literature and practice, clarify and generalize the definition [Andersson et al., 2001] including that, neither the rating of DG power sources, the area of their power delivery, the technology used, the environmental impact, the mode of operation, the ownership and the penetration affect the definition of what DG is.

Concluding, Peças Lopes et al. [2007] note that nowadays it is more common for DG to be considered in the context of the wider concept of distributed energy resources (DERs), which includes not only DG but also energy storage and responsive loads.

There is another problem strictly related to the definition of DG. It concerns the definition of what can be considered as distribution network. Better, it concerns the necessity to distinguish between distribution and transmission networks.

In fact, the more involved part of the electrical power system interested by DG, is the distribution grid, that is the infrastructure more accessible by small consumers/producers.

A first easy way could be distinguish the distribution and transmission networks on the basis of the different voltage level. But, as summarized by L’Abbate et al. [2007], although at utilization level the voltage is practically standard (220/240 V for single-phase, 380/440 V for three-phase), for all the other subsystems there is no voltage level uniformity and standard across Europe. For instance, in some countries in Europe distribution voltage levels may reach 110 kV and even 150 kV.

It has to be remarked that also the legal definition of both transmission and distribution systems varies from country to country in the EU.

The possibility to clearly introduce a separation between the transmission and distribution networks could be of great importance in order to define the administrative and operative area of TSOs and DNOs. Finally, it became very important also for what concerns the public aids and incentives as, for example, for RER.

2.4. Integration of Distributed Generation into the Distribution Networks

As illustrated before, planning and developing new architectures for the distribution grids attains a twofold target: enjoy the benefits of DG and avoid the propagation of

1 Andersson et al., [2000 and 2001] retain useful however to introduce categories of different ratings of DG, e.g.: Micro DG (≈1W÷5 kW), Small DG (5 kW ÷5 MW), Medium (5 MW ÷50 MW) and Large (50 MW ÷300 MW).
problems from distribution to the transmission network. This issue calls not only for a technical solution but for a combined effort, helped by the standardization and normalization, aimed at the definition of the borders between electricity transmission and distribution [Andersson et al., 2001].

In fact considering the actual development, structure and operation philosophy of the bulk power system, the distribution networks has been always conceived in the role of a passive appendix of the transmission system and little attention has been paid to their specific planning, operation, and management.

As a consequence, the first easy attempt to enhance the distribution systems is based on the extension of the technologies developed for the transmission system. If many of them can be used at least as example, others have to be completely readapted because of the substantial differences between the two ambits.

First of all the transmission network has been conceived to be actively managed and strictly controlled and monitored in terms of power flows, whilst distribution network was designed to transfer an unidirectional power flow with scarce opportunity to control and handle generation.

Furthermore the transmission system is based on a meshed structure that, allowing to fed each node from multiple points, expand the flexibility and the reliability of the service. The distribution networks instead is practically elsewhere operated as radial with possibility to obtain at most a second point of supply closing the predisposed loops or rings. Due to the evident operation conditions, in terms of rated voltages and currents, the distribution networks differs from the transmission ones for the highest resistance values and hence for the highest losses.

Besides from an organization standpoint, the TSOs are opportunely coordinated at continent level whilst DSOs are, for historical as well as geographical, socio-political, and economic reasons, thousands only in Europe and each managing different situations [Fulli et al., 2007].

Hence, it follows that the distribution system is subjected to opposite pressures. On the one hand, there are persistent demands of new high value added services, a continuous load growth mainly located in the tertiary and among the residential customers, and the need to allow the system access to new investors. On the other hand, there is the strong requirement of Distribution System Operators (DSOs) to obtain economic efficiency ensuring the minimum quality levels fixed by regulators, in a scenario characterized by a progressive reduction of the revenues from the distribution service and by a major influence of performance-based revenue mechanisms.

For all these reasons, important investments and research are needed to renew the electrical distribution segment in order to achieve a sort of “self-healing” distribution system, which allows not only managing large clusters of energy resources, but also the increase of the service quality level.
These requirements, together with the continuous improvements in the information and communication technologies (ICTs), foreseen for the electrical distribution networks, a development similar to the one of computer networks.

In the follows an outline of the more promising and innovative approaches for the DG integration in the distribution network is presented.

### 2.4.1. Active Distribution Networks (ADNs)

ADNs are considered, technically and economically, as the first quite easy and feasible solution to initially facilitate DG penetration into the current passive distribution systems. The basic idea of an ADNs is that new ICT technology and opportune control strategies can be used to coordinate DERs operation. The ADNs concept, following and sustaining the electricity market de-regulamentation, presuppose first of all that the primary role of the network is to provide connectivity between points of power supply and demand. In this context the DERs owners behave responsible to what happen on the grid.

A sort of definition could be as in the follows\(^2\). *ADNs are distribution networks equipped with systems able to control in an optimized manner distributed energy resources namely generators, loads and storage devices. The most innovative concept is that DERs become active subjects of the system giving to the DSOs the possibility to managing the electricity flows. Within the network, they could be responsible for system support, becoming supplier of ancillary services and operating in agreement of the DSOs requirements. Either such a role and responsibility have to be opportunely dispensed by developing suitable regulamentation and connection agreements.*

The transition from a passive networks towards an ADNs must deal with:
- the realization of more meshed configurations for the distribution networks;
- an opportune upgrade of the protection schemes able also to managing bidirectional power flows;
- the integration into existing systems of ICT and power electronics-based devices;

The ADNs model requires relatively little further investment in infrastructure (except to reinforce some areas of the network to provide increased interconnection and investment in automated switch gear) and is currently in act in many developed countries.

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\(^2\) Adapted from a discussion with Dr. M. Paolone and Prof. F. Pilo.
2.4.2. Microgrid

Hatziargyriou et al. [2007] in an exhaustive summary on microgrids research, development, and demonstration projects refers to microgrid as locally-controlled cluster of DERs operating within its local LV (≤ 1 kV) or MV (usually 1÷69 kV) distribution network. Anyway, small isolated power systems are included by authors as microgrids and, according to Marnay and Bailey [2004], a conclusion could be that “the number of definitions of “microgrid” is roughly equivalent to the number of analysis working in this area”.

L’Abbate et al. [2007] resumes the microgrids concept in three main features, namely:

a. appearing to the upstream network as a single and autonomous controlled unit;
b. possibility to automatically transfer to islanded mode in case of faults or inadequate power quality level in the upstream network;
c. possibility to provide network support and ancillary services, if needed.

Numerous pilot plants are actually under investigation as support of equally numerous research projects which, starting from a common idea, explore specific features.

The CERTS\(^3\) microgrid (CM) concept is one of the most world famous research project on microgrids. Its background is into the will to use the DERs to reduce the cost of electrical energy and improve the Power Quality Requirements (PQR) principally considering the needs of industrial power plants. In fact, trustworthy researches cited by Lasseter [1998] proved that about 35% of total U.S. industrial electric power demand was met by on-site generation and that the trend was increasing. It was due above all to the economic advantages, gained by industry with stable energy demand, using private CHP power plants instead of buy electricity from utilities. It was recognized the same potential for smaller users such as housing and office buildings. In order to take full advantage of DERs also from an electrical point of view, an increasing quantity of research efforts were focused on this context and, as an example, Lasseter [2000] presents the analysis of the internal electrical power plant of an industrial firm. The presence of two micro-turbines allows to improve the voltage profile and drastically reduce the network losses. Moreover, the possibility to provide power and voltage support allows also a demonstration of islanding transition by disconnecting the loads from the external MV network and giving to the micro-sources the control of the voltage and the frequency. However, as Lasseter [2001] recognize, the increased interest for the topic, the progresses in the development of small-scale generators and the trend to involve the lowest voltage

\(^3\) Consortium for Electric Reliability Technology Solutions (CERTS).
grids, create a new class of problems which requires innovative approaches to managing and operating the distributed resources.

The CM is one of the first innovative solutions going in this direction. Its main focus is above all on the locally and differential enhancement of PQR using microgrids suitably based on CHP devices and power electronic based micro-sources\(^4\) [Marnay and Bailey, 2004]. To achieve that a seamless islanding capability requirement is fundamental in order to continue to serve critical internal loads until acceptable utility service is restored\(^5\). As announced by Lasseter et al. [2002] the CM has been conceived to create a very robust system which operation does not require costly fast electrical controls or expensive site-specific engineering. This because each generator respond to locally monitored frequency and voltage by opportune droop control incorporating in its power electronic interface device and each device is designed to achieve dispersed plug-and-play capability making system configuration flexible, variable and not dependent from the presence of any single and specific device (peer-to-peer concept). Fig.2.1. shows a typical set-up of the CM in which all the DERs are supervised by an straightforward as possible and centralized Energy Manager which maintain economic dispatch sending active power and voltage set-point to each Microsource Controller.

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\(^4\) One of the features differs a micro-source from a large synchronous generator is the less inertia of such a micro-sources. If the traditional electric power systems satisfy the initial energy unbalance using the energy stored in generator’s inertia, sources such as micro-turbines and fuel cell have slow power output response assumed in a range from 10 to 200 seconds. This issue requires the introduction of energy storage elements and development of ad-hoc controllers for micro-sources. Furthermore, both DC sources (PV panels, fuel cells) and high frequency AC sources (micro gas turbines) require power electronics to interface with the power network. Power electronics interfaces intercept flexibility and new possibilities of control able to deliver premium quality. In the CM the presence of power electronic based micro-sources is more important with reference to any rated power capacity. Mainly for reasons of availability and controllability the initial attention of CM study focused on microturbines and assumes their size is less than 500 kW. However, fuel cells and other emerging technologies that might ultimately be used in microgrids could be larger. The role that Microgrids can play as elements of larger power parks, whose total installed capacity is measures in the 10’s of MW, is also considered [Lasseter et al., 2002].

\(^5\) The CM is built and operated so that critical loads are protected and high power quality is ensured where it is necessary, while other loads are served with PQR commensurate with their importance and/or reschedulability. Specific internal design allow then to deliver heterogeneous PQR to different kind of loads classified as sensitive, adjustable and shedable connected to three different kind of circuits. The shedable loads are exposed directly to normal grid power supply and in the event of inadequate grid power quality, e.g. voltage sag, a static switch opens and circuits served sensitive or adjustable loads pass in an intentional island until acceptable power quality is restored [Marnay and Bailey, 2004].
Although within the microgrid standards of operation and methods of control could diverge significantly from the traditional ones, in order to meet the specific needs of the user, the easy and solid control framework qualify the CM at least as a good citizen who complies with grid rules and does no harm beyond what would be acceptable from an existing customer. A further feature of CM is that the energy exportation is not foreseen and although the market participation is not a priority, could serve as model citizen as small source of power or ancillary services.

The CM concept has been anticipate and followed by bench tests and developed focusing on the microsources controllers functionalities [Lasseter and Piagi, 2006a; Lasseter et al., 2006b]. The attempt to include the microgrid in a wider context introducing dynamic distribution network is presented in [Lasseter, 2006c]. Details about the CERTS test bed and operation results have been discussed along the years [Lasseter, 2007; Lasseter and Piagi, 2007; Lasseter, 2008].

If the background of the U.S. working groups derived mainly from the needs of the industry and PQR [Lasseter, 1998; Lasseter, 2000; Iannucci et al., 2003; Gumerman et al., 2003] the experience of European, although supported by EU, was more related to operation of isolated power systems often with increasing penetration of renewable dispersed generation [Papadopoulos and Hatzigiou, 1989; Papadopoulos et al, 1991; Nogaret et al., 1994; Hatzigiou et al., 2000; Hatzigiou et al., 2001].

From a geographically point of view an ideal territory where all these issues must be naturally faced is represented by the Greek islands. For this reason the National Technical
University of Athens (NTUA) was and is still actually at the head of the EU task forces on this topic. As Hatziargyriou et al. [2007] explain, microgrids are considered a basic feature of future active distribution networks, able to take full advantage of DERs, if coordinated and operated efficiently. Within the period 1998 ÷ 2006, EU has funded two important project on microgrids. The projects involve utilities, manufacturers and research centers with the aim to face all the issues related to microgrids and developing innovative solutions for their overcoming. The European microgrid concept results quite different from the American one seen above. First of all it focus mainly on the large scale integration of micro generation to LV distribution network. In fact, Peças Lopes et al. [2003] observe as, following the increasing penetration of dispersed generation in MV networks, the connection of microgeneration to LV networks starts to be important requiring opportune investigation. The main differences with the CM are in the attention here devoted to the market participation on which is based the optimal operation of the microgrid. Fig.2.2. shows a possible configuration of a microgrid and a general control scheme.

Fig.2.2. – Illustration of a LV microgrid with several microsources, electrical loads and control and management equipment. More than one microgrids can be operate within the same distribution network [Peças Lopes et al., 2003; Hatziargyriou et al., 2005].

Hatziargyriou et al. [2005] describe a fully decentralized three levels control composed by, a Micro Source Controller (MC) which, as for the CM, uses local information to control the voltage and the frequency of the microgrid in transient conditions. The EU microgrid aims to an active participation to the activities of the external network behaving an exigent model citizen. In fact the Microgrid Central
Chapter 2

Controller (MGCC) which is always responsible for the maximization of the Microgrid value and the optimization of its operation, is here involved in more advanced operation having function of (i) economic scheduling, (ii) short term electrical load, RER power production and heat forecasting, (iii) security assessment and (iv) demand side management (DSM). The Distribution Management System (DMS) manages the external MV distribution network in which more than one microgrid can be installed and allows interaction between DNO and MGCC, e.g. for market purpose.

Pecas Lopes et al. [2005a; 2005b] assign, describe and develop [2006] further features for MGCC enabling islanding mode of operation, like islanded operation control, synchronizing of the microgrid system with the main, black start capabilities. Madureira et al. [2006] propose further improvements for secondary frequency control during islanding operation. Moreira et al. [2006] simulate a black start restoration procedure opportunely coordinating the operation of inverter based microsources and storage devices.

Together with the progressive technological adaptation of MV grid as ADNs, microgrid concept is the more adopted paradigm for the DERs integration in the distribution system as prove, reported by Barnes et al. [2007], the significant number of test beds build up worldwide. Hatzargyriou et al. [2007] show as in Japan, microgrids are not only demonstration installations but completely integrated power systems feeding, with different qualities of supply, public offices and services such as universities, high schools, sewage plants. The study and monitoring of these plants are demonstrating the technical feasibility of microgrids with a focus on incorporating renewable energy while maintaining constant grid inflows, and on providing multiple levels of PQR that is the main issue for the Japan researchers. However now the dominant issue is the economic evaluation of the microgrids which is still challenging because, until today, clear economic and environmental benefits have not yet been demonstrated.

Considering the different situation in which a microgrid could operate, also the protection must to be opportunely re-think and re-designed as explained by Lasseter and Nikkhajoei [2007]. Finally, Kroposki et al. [2008] testify the importance assigned to the microgrids presenting instead research conducted in microgrid standards, technologies, and applications to allow successful implementation of this concept.

2.4.3. Virtual Power Plant

A Virtual Power Plant (VPP) is a concept including both DERs and distribution grid. It represents the possibility to aggregate DERs not located at the same bus with the aim to cooperate and behave as a single unit for (i) the market participation, (ii) DERs
scheduling and (iii) to provide system support services. In the VPP controllable loads are also included.

The main goal of this entity is to maximize the economical benefits taking advantage of its larger capacity to participate in the energy market more aggressively. From a network point of view it has the advantage to reduce complexity by reducing the order of the system, namely the number of independent DERs connected into the grid. From a DERs standpoint instead, being an aggregation of multi-fuel, multi-location and multi-owned small generation units, allows to optimize the energy portfolio and to cope with intermittency and forecasting errors in particular when dealing with renewable sources.

L’Abbate et al.[2007] underline that the VPP concept is not itself a new technology but rather a scheme to combine decentralised generation and storage and exploit the technical and economic synergies between system’s components. This aggregation is not pursued by physically connecting the plants but by interlinking them via soft technologies (ICT). Obviously modern communications and control technology play a key role in the VPP implementation.

Hypothesize a central controller, Caldon et al. [2004] present an optimisation problem formulated as a constrained nonlinear minimization algorithm, where the objective function is the variable cost associated with the supply of thermal and electric energy to the loads. Here the information required from the algorithm have been supposed known without presuppose any kind of connection among the resources.

Dimeas and Hatziargyriou [2007] face a different scenario by considering the market participation of a VPP which components are not simple DERs but microgrids supervised by a decentralized controller. Such a paper demonstrates that all the discussed DERs integration solutions can be composed among them and provides interesting consideration on the complexity of the operation of a VPP. Decentralized control means that each element have to be able to decide which is the more profitable action to pursue. For example a PV panel has to decide which is the more profitable action to undertake between decide to sell its production considering only the current market price or to cooperate with a battery in order to store energy and sell it later when prices are higher. Each units must have high degree of autonomy and all the VPP management system have to be very flexible.

Surdu et al. [2006] present the FENIX EU project whose objective is the development of a smart interfaces for commercial and grid integration of DERs into large scale VPP implementing new DMS and Energy Management Systems (EMS) applications as well as regulatory solutions to include such a large scale VPP in the current system operation.
2.4.4. Energy Hubs

All solutions up to now analyzed of whatever complexity are electrical-centred. It means that the electrical energy is considered not only as the unique energy vector but it is also the unique subject of several optimizations (cost of the supply and generation, losses), regulations, availability and reliability. In this kind of modelling, many parameters as other energy vectors (gas, heat, hydrogen) are considered by means of boundary condition given by electrical energy production costs. The electrical energy market participation is included in order to reach an overall minimization of the costs and system management.

These considerations can be generalized for different energy carriers such as natural gas, heat and hydrogen. Investigation of literature shows that efforts focused on the operational optimization of systems employing energy carriers different from electricity have been developed in the past and sometimes in parallel with the equivalent study on electrical power systems. Together with well known studies on electrical power systems\(^6\), dynamic programming for the optimization of the natural-gas pipelines\(^7\) and works on the optimal operation of district heating systems\(^8\) are from long term investigated. For long term such a studies followed the common approach to consider only one form of energy at a time.

But having DG into the network means also distribute energy carriers, such as natural-gas or hydrogen, also only for the electrical energy production. Furthermore, the aim to reach an increasing and global efficiency in the use of all natural resources lead to the consciousness that our energy needs go beyond electricity. In fact, more recently, the combined modelling, analysis as well as integrated planning of energy systems including multiple energy carriers received a justified and growing interest\(^9\).

Energy Hub: the concept

Following this way, a new approach to the problem of integration of DG into the distribution systems has been introduced by the researchers of the Swiss Federal Institute of Technology (ETH) of Zurich, led by Professor Andersson. They are in a partnership with other technical and scientific organizations for an ambitious project named “Vision of Future Energy Networks” [Andersson et al., 2007].

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\(^6\) [e.g., Carpentier, 1979].
\(^7\) [Wong and Larson, 1968].
\(^8\) [Benonysson et al., 1995].
\(^9\) [Groscurth et al., 1995; Bouwmans et al., 2002; An et al., 2003; Bakken et al., 2004; De Mello and Ohishi, 2005; Wiedman et al., 2005].
They address the problem starting in antithesis with the others conceptual solution analyzed above. In fact considering too restrictive the boundary conditions given by the necessity to think the future starting from what actually exist, they go beyond with a radical greenfield approach, thinking how a real optimal energy systems (no more electrical power system) should look in the future and what can be expected from them. These introductions show how this approach looks like a new way of thinking to realize which a time horizon of 30–50 years from now has been planned.

This approach is based on the key concept of the Hybrid Energy Hubs (EH) defined in the 2007 by Andersson et al. as an interface between power generations plants, consumers, and the transportation infrastructures, as a unit where multiple energy carriers can be converted, conditioned, and stored.

A reference scheme is provided by Fig.2.3 in which appear that an EH requires power at their input ports and provides certain required energy services (such as e.g. electricity, heating, cooling, and compressed air) at the output ports. Within the EH, energy is converted and conditioned using several known technologies such as CHP technology, transformers, power-electronic devices, compressors, heat exchangers and other equipment.

A first powerful advantage of the EH concept is a new way to modelling not only future systems but also actual real energy system such as conventional power plants (e.g. hydroelectric with pump storage, thermal with community heat extraction), industrial plants (e.g. steel production, paper mills), big buildings (e.g. airports, hospitals), residential areas, villages, and island power systems (e.g. ships, aircrafts).

The main advantage of this kind of modelling is in the opportunity to evaluate an all comprehensive optimization obtaining an overall benefits. Moreover as detailed by Andersson and Geidl [2007] the components within the hub may establish redundant connections between inputs and outputs increasing in this way the system reliability. In fact EH generally increase the availability of energy for the load, because it is no longer fully dependent on a single infrastructure moreover offering a certain degree of freedom in supplying the load. EH can thereby substitute for unattractive energy carriers, for example at high-tariff times. Last but not least EH modelling joint of synergy effects between different energy carriers. In fact EH process various energy carriers, each of which showing specific characteristics. Electricity, for example, can be transmitted over long distances with comparably low losses. Chemical carriers can be stored employing relatively simple and cheap technology.
Energy Hub: tools and applications

The development of the EH is conceptually important because allows to introduce some analysis and optimization instruments for such a systems. In fact as already underlined, economic and physical performances of different energy carriers are well understood, but global features of integrated systems have not yet been investigated extensively.

After the conceptual and mathematical formulation of the model, the aim of the following steps was to develop the same tools as are available for electricity systems (e.g., power flow, economic dispatch, reliability, and stability). For this purpose a first optimization approach has been proposed by Andersson and Geidl [2005] and applied to an algorithm for the optimal power flow. Within the same year a generalized approach for optimal power dispatch and conversion in systems including an arbitrary number of energy carriers has been more investigated and presented by same authors. After considering the so-called operational optimization that is, more aimed to optimizing the power flows and conversions within the hubs and the networks for a given internal...
topology, in the 2006 also the so-called *topological or structural optimization* has been addressed by Andersson and Geidl. Such a tool optimize the internal characteristics of the EH, with the purpose to find the optimal coupling matrix according to given objectives. Furthermore, in this tool the network flow model is enhanced by directly including line losses in the equations.

In 2007 Andersson and Geidl enhance the proposed models introducing storage elements models for EH and a multiperiod optimization, performed for given loads and energy prices, enabling to address optimal storage utilization. Furthermore, a mixed-integer optimization procedure has been introduced for the determination of optimal hub layouts by selecting the best-fitting elements from a set of available converter and storage devices to be placed in the hub. In other terms it aims at the definition of the best internal configuration of the EH in terms of which are the more convenient conversion elements to install, which is the best size and their optimal number.

Further investigation and details concerning the mathematical modelization of the optimization problem and relevant calculation problems have been faced by Andersson and Geidl in the 2007.

After a first part of modelling and theoretical evaluation, a potentially pilot application has been identified and built up by a municipal utility in Switzerland [Andersson et al., 2007].

As a consequence of the presentation of those works, the EH modelling concept has been successfully applied for instance by Chicco and Mancarella [2005], for the characterization of tri-generation plants, and by Hemmes et al. [2008], for the conception of fuel cell based energy systems.
Chapter 3

Optimal technical scheduling
of distributed energy resources

3.1. Development of an on-line short-term scheduler

As seen in the chapter 2, the coordinated operation of distribution networks in presence of high penetration of distributed energy resources (DERs), can be approached in several ways, varying from a fully decentralized approach to a centralized one. Both approaches have peculiar characteristics and may be more or less appropriate depending on the specific situations [Choi and Kim, 2001; Repo et al., 2003; Hatziargyriou et al., 2005; Dimeas and Hatziargyriou, 2005].

In the former approach, the main responsibility is given to the DERs controllers that compete to maximize their production in order to satisfy the demand and possibly maximize exports to the grid. In the second case, the main responsibility for optimized operation lies with an automatic energy resources scheduler (ERS) that performs optimization functions and communicates the updated set points to DERs and controllable loads.

Assuming the more general scenario in which the dispersed energy resources belong to different operators, the coordinated integration of different DERs suggests the adoption of a centralized approach. The basic idea is to centralize all the operation and control functions in a single platform called Distribution Management System (DMS). Such an approach is justified by the need of managing small and medium-size dispersed generators, characterized also by non-dispatchable generation profiles (e.g. renewable energy resources). Such a DMS, suitably integrated with local control systems to ensure system security during fast transient dynamics (e.g. due to random load or configuration changes), is aimed to optimize the system operation during its slow modifications (e.g. due to daily, weekly and seasonal load variations).

Basically, the DSO tends to optimize its resources on both economical and technical requirements. The DSO has two opportunities to supply customers: to get energy from the primary network at market prices or to produce by its own generation. The developed and
implemented algorithm aims at better exploiting the generation units on the basis of their availability, production costs and operation constraints.

To reach such a purpose, a two-stages procedure has been proposed: a day-ahead economic scheduler, that calculates the active power set points during the following day in order to minimize the overall costs, and an intra-day scheduler that, on the basis of measurements and short-term load and renewable production forecasts, updates every 15 minutes the DERs and ULTCs set points [Bertani et al., 2006].

In what follows, specific attention is devoted to the intra-day scheduler whilst details about the day-ahead one can be found in literature [Borghetti et al., 2007a and 2007b].

3.1.1. Mathematical formulation of the optimization problem

In order to generalize the optimal scheduling problem for a distribution network with distributed generation, we can refer to a network with:

- $N$ voltage observable nodes (here assumed equal to the number of total network busses);
- $N_{BR}$ branches (or lines);
- $N_{DER}$ DERs considered dispatchable and actively participating to the regulations and $N_{fDER}$ considered indeed as fixed power injection devices;
- $N_{ULTC}$ transformers equipped with ULTCs;
- $N_L$ load nodes;
- all the DERs owned by a single DNO.

The active resources here considered are the dispatchable DERs and the ULTCs. That is, the control variables are: the active ($P_{DER}$) and reactive power ($Q_{DER}$) operation setpoints of each DER and the operating tap position ($n_{ULTC}$) of each ULTCs. They are represented by means of a $(2N_{DER}+N_{ULTC})$ size vector:

$$\mathbf{x} = [P_{DER} \ Q_{DER} \ n_{ULTC}]^T$$  (3.1)

As seen in the introduction, in order to take advantage of the DERs presence within the network, an opportune management of the active resources, by modifying the control variables (3.1), must be realized. The objectives of the optimization are:

- the minimization of the voltage deviations with respect to the rated value $\bar{V}$

$$\min_{P_{DER},Q_{DER},n_{ULTC}} \sum_{i=1}^{N} |V_i - \bar{V}|$$  (3.2)

- the minimization of the power production cost $C$ at every period $t$, taking into account production cost $C_{P,j}$ of the $j$-th DER at output level $P_j$, considered constant in time interval $\Delta t$, and price $C_{net}$ of energy $P_{net} \Delta t$ imported from the feeding
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\[ \min_{P_{\text{DER}}, Q_{\text{DER}}, \Delta t, t} C = C_{\text{net}} P_{\text{net}} \Delta t + \sum_{j=1}^{N_{\text{BER}}} C_{P,j} P_j \Delta t \]  
(3.3)

c. the minimization of the losses \( P_{\text{loss}} \) in the system

\[ \min_{P_{\text{DER}}, Q_{\text{DER}}, \Delta t, t} P_{\text{loss}} = \min_{P_{\text{DER}}, Q_{\text{DER}}, \Delta t, t} \sum_{j=1}^{N_{\text{BER}}} R_{l_i} I_i^2 \]  
(3.4)

where \( N_{\text{BR}} \) is the number of branches, \( R_l \) is the \( l \)-th branch resistance and \( I_i \) is the \( l \)-th branch current.

Objective (3.3) should be extended to all the intervals of a considered horizon, taking into account inter-temporal constraints and energy storage. In the intra-day scheduler, subject of this chapter, objective (3.3) is therefore replaced with the minimization of the deviation of the DERs active power output with respect to the vector of their predefined maximum efficiency values \( \overline{P} \) (which, as mentioned before, are obtained by means of the day-ahead scheduler).

The objective is the minimization of the linear combination of three components namely, the absolute value of the deviations of each \( j \)-th DER active power output with respect the corresponding predefined maximum efficiency value \( P_j \), the network losses (with a reference value assumed equal to zero) and the absolute values of the voltage deviations at each \( i \)-th observable bus with respect rated value \( V \). The objective function can be written as:

\[ \min_{P_{\text{DER}}, Q_{\text{DER}}, \Delta t, t} \left\{ \sum_{j=1}^{N_{\text{BER}}} \alpha \left| P_j - \overline{P} \right| + \beta P_{\text{loss}} + \sum_{i=1}^{N} \gamma \left| V_i - \overline{V} \right| \right\} \]  
(3.5)

where coefficients \( \alpha, \beta \) and \( \gamma \) are the weights of the multi-objective optimization problem. The problem should be solved by a reliable and automatic fast procedure. For this reason a linear-constrained optimization approach is applied. The problem is therefore solved with an iterative procedure. At the beginning of every iteration \( k \), as a result of a three-phase power flow calculation, the deviations of DERs active power outputs \( \Delta P_j = \overline{P}_j - P_j^{k-1} \), the value of \( P_{\text{loss}} \) and the deviations of the voltages at each observable bus \( \Delta V_i = V_i - V_i^{k-1} \) are known. The value of the objective function at the iteration \( k \) is then evaluated by linearizing the voltage and power loss functions with reference to the control variables variations \( \Delta x \):
\[ |\Delta V| = K_{iP} \Delta P + K_{iQ} \Delta Q + K_{in} \Delta n \quad \forall \text{ bus } i \]
\[ \Delta P_{\text{loss}} = H_{iuP} \Delta P + H_{iuQ} \Delta Q + H_{iun} \Delta n \]

where
- \( \Delta P, \Delta Q \) and \( \Delta n \) are the vectors of the variations of \( P \) and \( Q \) operating levels as well as of ULTCs position;
- \( K_{iP}, K_{iQ}, \) and \( K_{in} \) are the vectors of sensitivity coefficients of voltage deviations at the various buses;
- \( H_{iuP}, H_{iuQ}, \) and \( H_{iun} \) are the vectors of sensitivity coefficients of active network losses.

Using (3.6), the mathematical expression of (3.5) can be written explicitly as:

\[
\min_{\Delta x} |C \cdot \Delta x - d| \tag{3.7}
\]

In which

\[
C = \begin{bmatrix}
\alpha \cdot \mathbf{I}_{N_{\text{der}}} & 0 & 0 \\
\beta \cdot H_{p} & \beta \cdot H_{Q} & \beta \cdot H_{n} \\
\gamma \cdot K_{iP} & \gamma \cdot K_{iQ} & \gamma \cdot K_{in} \\
\ldots & \ldots & \ldots \\
\gamma \cdot K_{\Delta P} & \gamma \cdot K_{\Delta Q} & \gamma \cdot K_{\Delta n}
\end{bmatrix}, \quad \Delta x = \begin{bmatrix} \Delta P \\ \Delta Q \\ \Delta n \end{bmatrix}, \quad d = \begin{bmatrix} \alpha \cdot \Delta P \\ -\beta \cdot P_{\text{loss}} \\ \gamma \cdot \Delta V \end{bmatrix} \tag{3.8}
\]

and \( \mathbf{I}_{N_{\text{der}}} \) is the unit matrix of size \( N_{\text{der}} \). The problem is then solved considering opportune constraints.

### 3.1.2. Optimization problem constraints

The constraints are (i) the upper and lower limits of the values of the controlled variables, namely the DERs power outputs and ULTCs positions, taking into account the required power reserves; (ii) voltage limits in all the nodes and power transfer limits in the network branches and from the primary network. Also the minimum power factor \( p_{f_{\text{min}}} \) constraints at the DERs and at the primary network (slack bus) nodes are included.

#### A. DERs capability constraints

The active DERs are constrained to the respect of their capability limits. In particular, the active power limits are implemented as upper and lower bounds

\[
\mathbf{lb}_{\text{DER}} \leq \Delta P \leq \mathbf{ub}_{\text{DER}}
\]
whilst the reactive power limits are imposed indirectly by respecting a minimum power factor $p_{f_{\text{min}}}$ constraint:

$$A_{\text{DER}} \cdot \Delta x \leq b_{\text{DER}}$$  

$$\begin{bmatrix} -A_{\text{QDER}} \cdot I_{N_{\text{DER}}} & 0_{N_{\text{ULTC}}} \\ -A_{\text{QDER}} & -I_{N_{\text{ULTC}}}, 0_{N_{\text{ULTC}}} \end{bmatrix} \cdot \Delta x \leq \begin{bmatrix} A_{\text{QDER}} \cdot P_{\max,\text{DER}} - b_{\text{QDER}} \\ A_{\text{QDER}} \cdot P_{\max,\text{DER}} + b_{\text{QDER}} \end{bmatrix}$$

Where $A_{\text{QDER}} = \text{diag}\left[\tan(\cos^{-1} p_{f_{\text{min},j}})\right]_{N_{\text{DER}}}$, $b_{\text{QDER}} = \left[Q_{\text{ini},j}\right]_{N_{\text{DER}}}$, $0_{N_{\text{ULTC}}}$ is a zero square matrix of size $N_{\text{ULTC}}$, $P_{\max,\text{DER}}$ is the vector of the maximum active power of DERs and $Q_{\text{ini},j}$ are $j$-th DER reactive power outputs at the previous iterations$^1$.

### B. ULTCs constraints

ULTCs are supposed to be installed on the secondary side of the transformers. Assuming the primary voltage as constant, the voltage variation due to a variation in the position of the tap-changer can be quantified with the relation:

$$\Delta V_2 = V_{2n} \cdot \frac{v_{\text{pt}}}{100} \cdot \Delta n_{\text{ULTC}}$$

Where $V_{2n}$ is the secondary winding rated voltage, $v_{\text{pt}}$ (voltage per tap) is the voltage variation assigned to each position of the tap changer, expressed in per cent of $V_{2n}$.

ULTCs positions $n$, are constrained to assume integer values limited at the real number of available taps of the tap-changer model. Such a limits are taken into account

---

$^1$ The reactive power set-point of the $j$-th DER must respect the relation $Q_{\text{max},j} \leq Q_j \leq Q_{\text{max},j}$. In the case in which the capability curve is defined starting from the active power delivered, the relation can be formulated generally introducing the controlled variables and assuming that

$$Q_{\text{min},j} = -Q_{\text{max},j} = P_j \cdot \tan(\cos^{-1} \varphi_{\text{min},j})$$

$$-(P_j + \Delta P_j) \cdot \tan(\cos^{-1} \varphi_{\text{min},j}) \leq Q_j + \Delta Q_j \leq (P_j + \Delta P_j) \cdot \tan(\cos^{-1} \varphi_{\text{min},j})$$

$$\Delta P_j \cdot \tan(\cos^{-1} \varphi_{\text{min},j}) - \Delta Q_j \leq P_j + Q_j$$

$$-\Delta P_j \cdot \tan(\cos^{-1} \varphi_{\text{min},j}) + \Delta Q_j \leq P_j - Q_j$$

It is possible to specify the equations by supposing $Q_{\text{min},j} = -Q_{\text{max},j} = P_{\text{max},j} \cdot \tan(\cos^{-1} \varphi_{\text{min},j})$, that is introducing a rectangular capability curve:

$$-P_{\text{max},j} \cdot \tan(\cos^{-1} \varphi_{\text{min},j}) \leq Q_j + \Delta Q_j \leq P_{\text{max},j} \cdot \tan(\cos^{-1} \varphi_{\text{min},j})$$

$$P_{\text{max},j} \cdot \tan(\cos^{-1} \varphi_{\text{min},j}) - Q_j \leq \Delta Q_j \leq P_{\text{max},j} \cdot \tan(\cos^{-1} \varphi_{\text{min},j}) - Q_j$$

Such a constraint, being related to the maximum active power of the DER, could be implemented more simply as lower and upper bound.
by means of upper and lower bounds.

\[ \mathbf{l} \mathbf{b}_{ULTC} \leq \Delta \mathbf{n} \leq \mathbf{u} \mathbf{b}_{ULTC} \]  \hspace{1cm} (3.10)

**C. Limits on the power exchanged with the primary network**

Limits on the power exchanged with the primary network (operating as slack bus) could depend from the capability of the interface transformer or from specific contracts stipulated with the DNO.

Inequality constraints impose to the active and reactive power exchanged with primary network, the respect of specified limit. The excess of active and reactive power exchange at the slack bus is reallocated among the other DERs.

The power exchange with the external network is constrained to respect the condition

\[ P_{S,\text{min}} \leq P_S \leq P_{S,\text{max}} \]  \hspace{1cm} (3.11)

It represents mainly the constraints introduced by interface transformer or connection. \( P_S \) indicates the active power exchanged with the external network at the generic iteration \( k \). It could be both imported or exported depending from the operational condition of the network. Into a system, the power of slack bus can be expressed by the energy balance equation such as:

\[ P_{S}^{(k)} = \sum_{i=1}^{N_j} P_i + P_{Loss}^{(k)} - \sum_{j=1}^{N_{agg}} P_j^{(k)} - \sum_{j=1}^{G-N_{agg}} P_j \]  \hspace{1cm} (3.12)

Where, \( G \) is the total number of DERs and the \( P_{loss} \) are the active power losses. It is worth notice that the sum on \( G-N_{DER} \) represent the contribution of non-dispatchable or non-controllable DERs (such as wind turbines, PVs).

Between two iterations, the values contained into the objective function change and it is possible to write for them:

\[ P_{Loss}^{(kj)} = P_{Loss}^{(k-1,j)} + \Delta P_{Loss}^{(kj)} \]

\[ \sum_{j=1}^{N_{agg}} P_j^{(kj)} = \sum_{j=1}^{N_{agg}} P_j^{(k-1,j)} + \Delta P_j^{(kj)} \]  \hspace{1cm} (3.13)

In terms of variation, which are the unknown of the optimization problem, (3.11) can be expressed as
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\[ P_{S,\text{min}} - P_{S}^{(k-1)} \leq \Delta P_{S}^{(k)} \leq P_{S,\text{max}} - P_{S}^{(k-1)} \]

Considering separately the two inequalities, by substituting (3.13) into (3.12) and solving with respect to the unknown of the problem, it results

\[ P_{S,\text{min}} - P_{S}^{(k-1)} \leq \Delta P_{\text{Loss}}^{(k)} - \sum_{j=1}^{N_{\text{agg}}} \Delta P_{j}^{(k)} \leq P_{S,\text{max}} - P_{S}^{(k-1)} \]

\[ \sum_{j=1}^{N_{\text{agg}}} \Delta P_{j}^{(k)} - \Delta P_{\text{Loss}}^{(k)} \leq -P_{S,\text{min}} + P_{S}^{(k-1)} \]

\[ \Delta P_{\text{Loss}}^{(k)} - \sum_{j=1}^{N_{\text{agg}}} \Delta P_{j}^{(k)} \leq P_{S,\text{max}} - P_{S}^{(k-1)} \]

If the variation of the active power set-points of the \( N_{\text{DER}} \) active DERs are obtained as a result of the optimization process, the value of the active power losses can be estimated using the calculated sensitivity factors:

\[ \Delta P_{\text{Loss}}^{(k)} = H_{P_{\text{Loss}}} \cdot \Delta x = H_{P_{\text{Loss}}} \Delta P + H_{P_{\text{Loss}}} Q + H_{P_{\text{Loss}}} \Delta n \]

\[ \sum_{j=1}^{N_{\text{agg}}} (1 - H_{P_{\text{Loss}}} P_{j}) \Delta P_{j}^{(k)} - \sum_{j=1}^{N_{\text{agg}}} H_{P_{\text{Loss}}} Q_{j} \Delta Q_{j}^{(k)} - \sum_{h=1}^{N_{\text{agg}}} H_{P_{\text{Loss}}} n_{h} \Delta n_{h}^{(k)} \leq -P_{S,\text{min}} + P_{S}^{(k-1)} \]

\[ \sum_{j=1}^{N_{\text{agg}}} (H_{P_{\text{Loss}}} P_{j} - 1) \Delta P_{j}^{(k)} + \sum_{j=1}^{N_{\text{agg}}} H_{P_{\text{Loss}}} Q_{j} \Delta Q_{j}^{(k)} + \sum_{h=1}^{N_{\text{agg}}} H_{P_{\text{Loss}}} n_{h} \Delta n_{h}^{(k)} \leq P_{S,\text{max}} - P_{S}^{(k-1)} \]

With a matrix format

\[ A_{P_{\text{Loss}}} \cdot x \leq -P_{S,\text{min}} + P_{S}^{(k-1)} \]

\[ -A_{P_{\text{Loss}}} \cdot x \leq P_{S,\text{max}} - P_{S}^{(k-1)} \]

where

\[ A_{P_{\text{Loss}}} = \begin{bmatrix} (1 - H_{P_{\text{Loss}} P}) & -H_{P_{\text{Loss}}} Q & -H_{P_{\text{Loss}}} \end{bmatrix} \]

Similar equations can be written for the reactive power of the slack bus, obtaining as a result

\[ A_{Q_{\text{Loss}}} \cdot x \leq -Q_{S,\text{min}} + Q_{S}^{(k-1)} \]

\[ -A_{Q_{\text{Loss}}} \cdot x \leq Q_{S,\text{max}} - Q_{S}^{(k-1)} \]

where

\[ A_{Q_{\text{Loss}}} = \begin{bmatrix} -H_{Q_{\text{Loss}} P}, (1 - H_{Q_{\text{Loss}} Q}), -H_{Q_{\text{Loss}}} \end{bmatrix} \]
Besides, there is another constraint on the slack bus. It concerns the possibility to impose a limit for the power factor depending from the active power delivered. The implementation has been carried out as in the follows:

\[ Q_{S,\text{min}} \leq Q_S \leq Q_{S,\text{max}} \quad \Rightarrow \quad Q_S^{(k)} - Q_{S,\text{min}} \leq \Delta Q_S^{(k)} \leq Q_{S,\text{max}} - Q_S^{(k-1)} \]

In order to constrain the value of the active and reactive power we can write:

\[ Q_S^{(k)} = P_S^{(k)} \cdot \tan \varphi_S = (P_S^{(k-1)} + \Delta P_S^{(k)}) \cdot \tan \varphi_S = (P_S^{(k-1)} + \sum_{j=1}^{N_{sec}} \Delta P_j^{(k)} - \Delta P_{\text{Loss}}^{(k)}) \cdot \tan \varphi_S \]

\[ Q_S^{(k)} = -Q_S^{(k)} \]

\[ \Delta Q_S^{(k)} = \Delta Q_S^{(k)} \quad \text{for} \quad k \neq 1 \]

\[ - (P_S^{(k-1)} + \Delta P_{\text{Loss}}^{(k)} - \sum_{j=1}^{N_{sec}} \Delta P_j^{(k)}) \cdot \tan \varphi_S - Q_S^{(k)} \leq Q_{S,\text{ini}} + \Delta P_S^{(k-1)} \cdot \tan \varphi_S \]

\[ - (P_S^{(k-1)} + \Delta P_{\text{Loss}}^{(k)} - \sum_{j=1}^{N_{sec}} \Delta P_j^{(k)}) \cdot \tan \varphi_S + \Delta Q_S^{(k)} \leq P_S^{(k-1)} \cdot \tan \varphi_S - Q_S^{(k-1)} \]

Considering separately the two inequalities and solving with respect to the unknown of the problem, it results

\[ (A_{\text{Ploss}} \cdot \tan \varphi_S + A_{\text{Qloss}}) \cdot x \leq + Q_{S,\text{ini}} + P_S^{(k-1)} \cdot \tan \varphi_S \]

\[ (A_{\text{Ploss}} \cdot \tan \varphi_S - A_{\text{Qloss}}) \cdot x \leq - Q_{S,\text{ini}} + P_S^{(k-1)} \cdot \tan \varphi_S \]

Taking into account

\[ A_{\text{slack}} \cdot x \leq b_{\text{slack}} \quad (3.14) \]

Where, \( P_{S,\text{min}}, P_{S,\text{max}}, Q_{S,\text{min}} \) and \( Q_{S,\text{max}} \) are respectively the minimum and maximum
transit of active and reactive power allowed for slack bus. $P_{ini,S}$ and $Q_{ini,S}$ are instead the active and reactive power exchanged with the slack bus at the previously iteration.

**D. Lines ampacity limits**

In order to constrain the current flow to the respect of the ampacity of each line, the sensitivity of the currents with reference to the control variable variation must be evaluated. As done in (3.6), for the currents result:

$$|\Delta I| = J_P \Delta P + J_Q \Delta Q + J_n \Delta n \quad \forall \text{ branch } i$$

$$|\Delta I| = J \cdot x$$

The problem impose that the current into each line, at the iteration $k$, must be lower than the current ampacity of such a line. That is, using an expression similar to the (3.7):

$$|J \cdot \Delta x + I_{ini}| \leq I_{MAX} \quad (3.15)$$

**3.1.3. Sensitivity matrix calculation**

A first way to determine the sensitivity matrix is given by implementing practically the sensitivity coefficients definition, expressed, for what concern the voltage, by:

$$K_{ij}^p = \frac{\Delta V_i}{\Delta P_j} \left|_{\Delta^P j, \Delta^Q j, \Delta n = 0} \right.$$  

$$K_{ij}^Q = \frac{\Delta V_i}{\Delta Q_j} \left|_{\Delta^P j, \Delta^Q j, \Delta n = 0} \right.$$  

$$K_{ij}^{ULTC} = \frac{\Delta V_j}{\Delta V_i} \left|_{\Delta^P j, \Delta^Q j, \Delta n = 0} \right.$$  

(3.16)

It means that the sensitivity coefficients are estimated by a series of load flow calculations each performed for a small variation of a different control variable.

However, whether such a load flow calculation is carried out by using Newton-Raphson based methods, the voltage sensitivity coefficients can be derived directly from the Jacobian matrix.

$$J = \begin{bmatrix} \frac{\partial P}{\partial V_R} & \frac{\partial P}{\partial V_X} \\ \frac{\partial Q}{\partial V_R} & \frac{\partial Q}{\partial V_X} \end{bmatrix} \quad (3.17)$$
Trustworthy calculations needs, anyway, a Jacobian matrix up-dated for each change occurring into the network model. Being the optimization problem based on an iterative procedure, a load flow have to be calculated at the beginning of each iteration. Unfortunately, the Jacobian matrix used by EMTP to solve load flow calculation is not directly accessible. However, using the network model as test field, the data of all the system branches, namely lines and transformers, are known together with the up-dated network topology. Using these data, once determined the connectivity matrix of the whole system, the admittance matrix $Y$ can be calculated. Each term of (3.17) is calculated as a function of the $Y$ elements and the real and imaginary part of node voltages, using well known equation [e.g., Marconato, 2002].

In this way, the inverse of the Jacobian matrix gives the values of the sensitivity coefficients as calculated with respect to the real and imaginary part of the node voltages.

$$K^p_{j,Re} = \frac{V'_{i,Re} - V_{i,Re}}{\Delta P_j}; K^Q_{j,Im} = \frac{V'_{i,Im} - V_{i,Im}}{\Delta P_j}$$

It means that, to obtain the sensitivity coefficients calculated with respect to the voltage amplitude of each $i$-th node:

$$|\Delta V_i| = \left| V_{i,Re} - V'_{i,Re} + j \left| V_{i,Im} - V'_{i,Im} \right| \right|$$

Where $V_{i,Re}$ and $V_{i,Im}$ are the components of the initial node voltages vector $V$ expressed as real and imaginary parts, and $V'_{i,Re}$ and $V'_{i,Im}$ are the same components for the complex vector calculated as: $V' = J^{-1} + V$.

The current flows can be modified by acting on the control variables as for the voltages. The hypothesis here is that, for the calculation of the sensitivity coefficients of the currents, no further load flow have to be carried out. In fact such a current sensitivity coefficients can be calculated starting from the already calculated voltage sensitivity coefficients.

Considering a line connecting $i$-th node and $j$-th node, and adopting a standard PI line model, it is easy to derive the expression of the current flowing through.

$$I_{ij} = V_i \cdot j \omega C_{ij} + \frac{V_i - V_j}{R_{ij} + j \omega L_{ij}}$$

Considering a variation of one of the controlled variables such as e.g., active power of one single DERs, we can write the variation of the considered current as
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\[ I_{ij} + \Delta I_{ij}^p = (V + \Delta V_{ij}^p) \cdot j\omega C_{ij} + \frac{(V_{ij} + \Delta V_{ij}^p) - (V_j + \Delta V_j^p)}{R_j + j\omega L_j} \]

\[ \Delta I_{ij}^p = \Delta V_{ij}^p \cdot \left( j\omega C_{ij} + \frac{1}{R_j + j\omega L_j} \right) - \Delta V_j^p \cdot \frac{1}{R_j + j\omega L_j} \]

Considering that \( \Delta V_{ij}^p = \Delta V_{ij,Re}^p + j\Delta V_{ij,Im}^p = K_{ij,Re}^p \cdot \Delta P_{h} + jK_{ij,Im}^p \cdot \Delta P_{h} \) these lasts coefficients can be calculated without any further load flow calculation using the relations:

\[ \Delta I_{ij}^p = (K_{ij,Re}^p + jK_{ij,Im}^p) \cdot \left( j\omega C_{ij} \cdot \frac{R_j}{R_j + j\omega L_j} \right) \cdot \Delta P_{h} = \frac{(K_{ij,Re}^p + jK_{ij,Im}^p)}{R_j + j\omega L_j} \cdot \Delta P_{h} \]

\[ \frac{\Delta I_{ij}^p}{\Delta P_{h}} = (K_{ij,Re}^p + jK_{ij,Im}^p) \cdot \frac{R_j}{R_j + j\omega L_j} \cdot \frac{(K_{ij,Re}^p + jK_{ij,Im}^p)}{R_j + j\omega L_j} \]

Where \( h \) indicates the \( h \)-th controlled DERs. In order to easily obtain the amplitude of the current variation, two approximations can be reasonably assumed, namely (i) considering the phase deviation of the current phasor, before and after the small perturbation introduced by the \( h \)-th DERs, as sufficiently small (Fig.3.1) and (ii) considering negligible the current flowing through the PI transversal capacitance with respect to the component flowing through the longitudinal impedance. The influence of these approximations has been evaluated by simulating different situations and the results confirm their reasonability.

As a consequence we have that: \( |I_{ij}'| - |I_{ij}| = \Delta I_{ij} \cdot \cos \theta \).

![Fig.3.1. – Graphical representation of the current phasors.](image)

Hence,
In the follows the optimization problem until here outlined, is implemented by using different optimization methods. The presentation is structured in a way to follows the enhancement introduced in the algorithm during the three years.

### 3.2. Least square based optimization procedure

Although the terms included in the objective function (3.5) does not change, the least square solver requires to minimize a different objective function, based on the square norm of the linear combination of the three components:

\[
\begin{align*}
\sum_{j=1}^{N_{\text{REF}}} \alpha_j^2 (P_j - \overline{P}_j)^2 + \beta^2 P_{\text{loss}}^2 + \sum_{i=1}^{N} \gamma^2 (V_i - \overline{V})^2
\end{align*}
\]  

(3.18)

Equations (3.6) are included in the objective of the least square optimization problem as

\[
\min_{\Delta x} \| C \cdot \Delta x - d \|^2
\]  

(3.19)

All the constraints are included exactly as reported in the previously paragraph. There is only one remarks. The discussed least square solver accepts as inputs variables continuously defined. That is, the tap-position as well as the transformation ratio of the ULTCs will be continuously defined variable within the range defined by (3.10).

Because the problem being solved is always convex, a global solution of the linear-constrained least square is found, although not necessarily a unique one, by using, standard quadratic programming solvers, such as an active set projection method [Gill et al., 1981]. At each iteration, after obtaining solution \( \Delta x \) of the linearized optimization
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problem, the initial values of the control variables are modified by $\xi \Delta x$, where coefficient $\xi \in [0,1]$ is calculated so to minimize the value of objective function (3.18), taking into account the limits on the slack-bus maximum power. We have applied the golden section method for the solution of this nonlinear one-dimensional problem (see Fig.3.2).

The iterative procedure stops when the difference between the values of objective function (3.18) at two subsequent iterations is lower than a predefined value (objective function not changing) or when the variations of the control variables are smaller than a predefined value (control variables not changing). A maximum number of iterations is also enforced.

3.3. Goal attainment based optimization procedure

Similarly to the least square approach, the linear constrained multi-objective problem can be addressed by using the goal attainment method [Gembicki, 1974], which has been proposed in the literature as an effective strategy for the problem of interest [e.g., Villacci et al., 2006]. The goal attainment method solves the multi-object optimization problem by defining a set of control goals together with a set of under- or over-achievement weighting coefficients, which allow the relative degree $\gamma$ of under- or over-achievement of the goals to be minimized. The problem formulation is

$$\min_{n_{\text{DER}}, q_{\text{DER}}, n_{\text{UTC}}} \gamma$$

Such that

$$|C \cdot \Delta x - d| - \text{weight} \cdot \gamma \leq \text{goal}$$

(3.21a)

and

$$C = \begin{bmatrix}
N_{\text{DER}} & 0 & 0 \\
L_p & L_Q & L_n \\
K_{1p} & K_{1Q} & K_{1n} \\
\vdots & \vdots & \vdots \\
K_{np} & K_{nQ} & K_{nn}
\end{bmatrix} \quad d = \begin{bmatrix}
\Delta P \\
- \Delta V
\end{bmatrix}$$

(3.21b)

where

- $\text{weight} = [\text{weight}_V, \text{weight}_P, \text{weight}_{\text{loss}}]$, being $\text{weight}_V$ the bus voltages weighting vector, $\text{weight}_P$ the weighting vector of the DERs active power outputs and $\text{weight}_{\text{loss}}$ the losses weight;

- $\text{goal} = [\text{goal}_V, \text{goal}_P, \text{goal}_{\text{loss}}]$, being $\text{goal}_V$ the vector of maximum voltage deviations that the objectives attempt to attain and assumed equal to 1% of the rated voltage value, whilst $\text{goal}_P$ and $\text{goal}_{\text{loss}}$ are chosen equal to 0.
The remaining constraints are the same as those already described for the least square approach. The discussed goal attainment solver accepts as inputs variables continuously defined. That is, the tap-position as well as the transformation ratio of the ULTCs will be continuously defined variables within the range defined by (3.10).

At each iteration, the initial values of the control variables are modified by \( \xi \Delta x \), where coefficient \( \xi \in [0,1] \) is calculated so to minimize the maximum relative degree of under- or over-achievement of the goals by means the application of the golden section method (see Fig.3.2). As for the application of the least square approach, the iterative procedure may stop both when objective function is not changing or when the control variables are not changing between two subsequent iterations.

**3.4. Mixed Integer Linear Programming (MILP) optimization solution**

This approach differs from the two above presented for the possibility to include in the optimization procedure both continuous and discrete variables. This features allows a more realistic modelization of the quantities which are naturally discrete (e.g., tap position of ULTCs). The MILP solver requires a problem mathematically formulated as:

\[
\min_x \{ f^T \cdot x' \} \tag{3.22}
\]

Such a minimization is subjected to the following constraints

\[
A \cdot x' \leq b \tag{3.23}
\]

\[
lb \leq x' \leq ub
\]

\[
x'_\text{int} = \text{int}
\]

In order to outline the problem (3.5) as required by (3.22) we need to linearize the abs function by introducing \( (N_{\text{DER}}+1+N) \) so-called slack variables, \( s_j \), which impose the following constraints:

\[
C \cdot \Delta x_j - d \leq s_j
\]

\[
-(C \cdot \Delta x_j - d) \leq s_j
\]

That, written referring to the form of (3.23a), results:
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\[
C \cdot \Delta x_j - s_j \leq d
\]
\[
- C \cdot \Delta x_j - s_j \leq -d
\]

(3.24)

Where C is in this case as in (3.21b). The same operation must be done for the (3.15) obtaining:

\[
J \cdot \Delta x - c_j \leq -I_{\text{ini}}
\]
\[
- J \cdot \Delta x - c_j \leq I_{\text{ini}}
\]

(3.25)

Where \( c_j \) are the current slack variables used to linearize the absolute value function.

In this way the problem (3.5) is solved indirectly by searching an optimal solution for the slack variables vectors, \( s \) and \( c \). Then the values of the controlled variables \( x \) are linked with them by means of (3.24) and (3.25). Adapted at the specific case (3.22) becomes:

\[
f = \begin{bmatrix} 0_{N_{\text{area}}} \\ \gamma \\ \beta \\ \alpha \\ 0_{N_{\text{area}}} \end{bmatrix} \begin{bmatrix} \Delta x \\ s \\ c \end{bmatrix}
\]

(3.26)

Where \( 0_{N_{\text{area}}} \) is a zero vector of the same size of control variable vector \( x \), that is \( (2N_{\text{DER}}+N_{\text{ULTC}}) \). \( 0_{N_{\text{area}}} \) is a zero vector of size \( N_{\text{BR}} \). The presence of \( 0_{N_{\text{area}}} \) means that (3.22) optimize (3.7) by minimizing the slack variables \( s \) and not the controlled variables \( x \). At the same time the presence of \( 0_{N_{\text{area}}} \) means that the current flows are not optimized within (3.22) but constrained using the slack variables \( c \). The vectors \( \alpha, \beta, \gamma \) instead are vectors of weights with size \( N_{\text{DER}}, 1 \) and \( N \) respectively, \( s \) is the vector of the \( (N_{\text{DER}}+N+1) \) slack variables for the problem (3.24) and \( c \) the vector of the slack variables for the problem (3.25).

The relations concerning DERs capability, slack bus power transit and minimum power factor as well as the line ampacity limits are implemented by using (3.23a), that can be implemented as in (3.27), and (3.23b). Also for the MILP based optimization procedure the reference scheme is the one of Fig.3.2.
\[
\begin{bmatrix}
A_{\text{DER}} & 0_s & 0_c \\
A_{\text{Slack}} & 0_s & 0_c \\
C & -I_s & 0_c \\
-C & -I_s & 0_c \\
J & 0_s & -I_c \\
-J & 0_s & -I_c \\
\end{bmatrix} \cdot \begin{bmatrix}
x' \end{bmatrix} \leq \begin{bmatrix}
b_{\text{DER}} \\
b_{\text{Slack}} \\
d \\
-d \\
-I_{\text{ini}} \\
I_{\text{ini}} \\
\end{bmatrix}
\]

(3.27)

Where 0_s and 0_c are zero matrix of dimension (N+N_{\text{DER}}+1) and N_{\text{BR}} respectively. I_s and I_c are unit matrix of size (N+N_{\text{DER}}+1) and N_{\text{BR}} respectively.

The optimization problems are solved by computer programs implemented in the Matlab environment. The power flow calculations are instead carried out by the EMTP-RV environment [Mahseredjian et al., 2002; Mahseredjian et al., 2005; Mahseredjian et al., 2006]. The algorithm of the intra-day scheduler has been implemented by means of an interface between Matlab and EMTP-RV. Such an interface, is realized by means of the JavaScript modelling programming environment that is part of the EMTP-RV. For that purpose the Matlab code, aimed at solving the constrained minimization problem above described, has been compiled as a COM (Component Object Model) object and included as ActiveX (Active eXtension) control inside the developed JavaScript code. Moreover, specific JavaScript procedures have been also developed in order (i) to simplify the development of the EMTP-RV models relevant to new network configurations and (ii) to provide an easy and direct access to all the EMTP-RV network-models for their automatic set point updates and power flow output calculations.

Fig. 3.2. – Scheme of the scheduling procedure.
3.5. Application of the developed short-term scheduling algorithm

3.5.1. Low voltage microgrid case study

The preliminary version of the ERS has been developed in the framework of the Italian Electrical Power System Research Program in collaboration with CESI RICERCA and others Italian universities [Bertani et al., 2006]. Within this context numerous cases have been investigated in order to test the performances of the ERS considering several microgrid configuration (radial, loop), loads and generation levels as well as different level of DERs penetration.

This paragraph illustrates some results of the operation of such a ERS opportune integrated in the Microgrid Management System (MMS) of a test facility settled at the CESI RICERCA laboratories. The test facility consists of renewable generators, cogeneration plants, energy storage systems and controllable loads that can be connected at different points of an automated low voltage grid working in radial, ring and meshed configurations [Bertani et al., 2006; Barnes et al., 2007].

The ERS is conceived to exploit the microgrid network taking into account random load or system configuration changes, and to optimize its operation during daily, weekly and seasonal load variations.

A preliminary version of the developed ERS is actually working within the MMS of the CESI microgrid and results of experimental operation and tests have been reported recently by Marciandi et al., [2008].

Fig.3.3 reports one of the considered configurations of the microgrid test facility with the DERs listed in Tab.3.1. The LV lines are considered balanced and two different values for the reactances of lines LS1, LS2 and LS3 have been considered, namely 0.084 Ω/km (configuration A) and 0.6 Ω/km (configuration B). The initial set-points of DERs are obtained by applying the day-ahead scheduler whose, in this case consider also the integral constrains due to the presence of storage devices. Load and RES forecasting function are included in the algorithm of the day-ahead scheduler. The loads consumption for the considered configuration are $P_{ACCL1} = 85.5$ kW, $Q_{ACCL1} = 41.41$ kvar, $P_{PRL} = 93$ kW, $Q_{PRL} = 45$ kvar, as well as for the power injected by the RES, $P_{PVH} = 3.13$ kW, $P_{PVG} = 1.57$ kW. The DERs set points calculated by the day-ahead scheduler are reported in the first columns of Tab.3.2.
Fig. 3.3. – Example configuration of the microgrid test facility, where Pb indicates the lead acid battery; RDX is the Redox battery; Zbr is the Zebra battery; mT is the microturbine; PVH and PVG are two PV units; PRL and ACCL1 are the controlled loads and CAP is a capacitor bank.

<table>
<thead>
<tr>
<th>Resource</th>
<th>Rated output</th>
<th>Energy</th>
</tr>
</thead>
<tbody>
<tr>
<td>CHP micro-turbine</td>
<td>100 kWe</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>167 kWth</td>
<td></td>
</tr>
<tr>
<td>Boiler</td>
<td>500 kWth</td>
<td>-</td>
</tr>
<tr>
<td>Redox battery</td>
<td>42 kW</td>
<td>84 kWh</td>
</tr>
<tr>
<td>Zebra battery</td>
<td>64 kW</td>
<td>32 kWh</td>
</tr>
<tr>
<td>Lead-acid battery</td>
<td>100 kW</td>
<td>100 kWh</td>
</tr>
<tr>
<td>MV grid</td>
<td>630 kW</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>(MV/LV transformer)</td>
<td></td>
</tr>
</tbody>
</table>

Tab. 3.1 – Model parameters of the considered DERs.
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<table>
<thead>
<tr>
<th>Microgrid configuration A</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Initial outputs</td>
<td>Final outputs $\alpha=0$</td>
<td>Final outputs $\alpha=0.2$</td>
<td>Final outputs $\alpha=0.4$</td>
<td>Final outputs $\alpha=1$</td>
<td>Final outputs $\alpha=2$</td>
</tr>
<tr>
<td>$P_{Pb}(\text{kW})$</td>
<td>4.16</td>
<td>62.41</td>
<td>50.83</td>
<td>29.41</td>
<td>13.19</td>
<td>7.58</td>
</tr>
<tr>
<td>$P_{RX}(\text{kW})$</td>
<td>3.91</td>
<td>1.00</td>
<td>1.00</td>
<td>1.00</td>
<td>1.41</td>
<td>3.91</td>
</tr>
<tr>
<td>$P_{Zc}(\text{kW})$</td>
<td>1.51</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>1.43</td>
</tr>
<tr>
<td>$P_{m}(\text{kW})$</td>
<td>100.00</td>
<td>50.00</td>
<td>61.59</td>
<td>83.00</td>
<td>98.81</td>
<td>100.49</td>
</tr>
<tr>
<td>$Q_{Pb}(\text{kvar})$</td>
<td>50.00</td>
<td>50.00</td>
<td>50.00</td>
<td>50.00</td>
<td>50.00</td>
<td>50.00</td>
</tr>
<tr>
<td>$Q_{RX}(\text{kvar})$</td>
<td>-2.41</td>
<td>0.62</td>
<td>0.62</td>
<td>-0.62</td>
<td>-0.87</td>
<td>-2.42</td>
</tr>
<tr>
<td>$Q_{Zc}(\text{kvar})$</td>
<td>-32.00</td>
<td>29.12</td>
<td>-1.13</td>
<td>-32.00</td>
<td>-32.00</td>
<td>-32.00</td>
</tr>
<tr>
<td>$Q_m(\text{kvar})$</td>
<td>65.82</td>
<td>-14.74</td>
<td>15.75</td>
<td>48.72</td>
<td>49.48</td>
<td>51.22</td>
</tr>
</tbody>
</table>

Tab.3.2. – DER active and reactive power outputs of before and after the optimisation procedure for a 3 kW and 1 kvar forecasted load variation of both ACCL1 and PRL loads.

The mean absolute voltage deviations of the observable node voltages of Fig.3.4.a are within 1.59V and 4.9V, for $\alpha=0$ and $\alpha=10$ respectively. Quality of voltage profile increase in Fig.3.4b where mean absolute voltage deviations of the observable node voltages are within 1.33V and 1.99V, for $\alpha=0$ and $\alpha=10$ respectively. Results are justified by the fact that LV lines are dominated by the resistive components and in these conditions active power flows are still fundamental for voltage regulation. The configuration B, called also weak configuration, presents an increased value of reactance arriving to be quite similar to a MV grid.
3.5.2. IEEE 34-nodes distribution test feeder

The IEEE 34-node test feeder is composed by branches characterized by different conductor configurations. In order to simplify the simulation results, the following assumptions have been made: (i) all the branches of the network are composed by overhead lines which conductor configuration is the “ID #500” reported by IEEE Working Group on Distribution Planning [1991], where the phase sequence a, b and c refers to the line conductors from left to right; (ii) the network loads are assumed located in correspondence of the line terminations and (iii) the DERs are assumed connected to the network via distribution power transformers (see Fig.3.5). All the transformers are
represented by means of a 50 Hz standard model and the relevant parameters are reported in Tab.3.3.

![Test network implemented in EMTP-RV, based on the IEEE 34-node test distribution feeder.](image)

Fig.3.5. – Test network implemented in EMTP-RV, based on the IEEE 34-node test distribution feeder.

Three different dispatchable electric power production units are considered to be connected to the network in correspondence of nodes 802, 818 and 856 (see Tab.3.4). The system also includes a boiler. The relevant power limits and costs are reported in Tab.3.4. Two not-dispatchable electric power production units are also connected to the network, namely a photovoltaic (PV) array for a total peak power equal to 50 kW connected to the node 844 and a 750 kW wind generator connected to the node 826.
Chapter 3

<table>
<thead>
<tr>
<th>Transformer name</th>
<th>Rated power (MVA)</th>
<th>Rated dividing ratio (kV/kV)</th>
<th>Short circuit voltage (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tr_1</td>
<td>25</td>
<td>150/24.9</td>
<td>9</td>
</tr>
<tr>
<td>V_reg_1; V_reg_2</td>
<td>15</td>
<td>24.9/24.9</td>
<td>8</td>
</tr>
<tr>
<td>Tr_2; Tr_3;Tr_5</td>
<td>10</td>
<td>24.9/6</td>
<td>6</td>
</tr>
<tr>
<td>Tr_4</td>
<td>2</td>
<td>24.9/0.69</td>
<td>6</td>
</tr>
<tr>
<td>Tr_6</td>
<td>5</td>
<td>24.9/0.69</td>
<td>6</td>
</tr>
</tbody>
</table>

Tab. 3.3. – Data of the DERs power transformers.

Transformers Tr1, V_reg_1 and V_reg_2 are equipped with ULTCs installed on the secondary winding (the one at lowest voltage). They are characterized by 17 possible tap positions allowing regulation between ±8 x 1.5% of the rated voltage. Using such a network as reference, an extensive analysis has been carried out to investigate the proposed optimization strategies.

<table>
<thead>
<tr>
<th>Dispatchable DER</th>
<th>Symbol</th>
<th>Rated output (kW)</th>
<th>$P^\text{min}$ (kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CHP gas-turbine</td>
<td>Gen_818</td>
<td>1800 (electric) 2819 (thermal)</td>
<td>720 (el.) 1342 (th.)</td>
</tr>
<tr>
<td>Boiler</td>
<td></td>
<td>2000</td>
<td></td>
</tr>
<tr>
<td>Diesel</td>
<td>Gen_856</td>
<td>2000</td>
<td>800</td>
</tr>
<tr>
<td>Gas turbine</td>
<td>Gen_802</td>
<td>4000</td>
<td>1600</td>
</tr>
</tbody>
</table>

Tab. 3.4. – Model parameters of the considered dispatchable DERs.

A. Combined action of day ahead and intra day schedulers during a 24 hours simulated scenario

The action of the scheduler starts from the day-ahead scheduling solution over a one-day horizon with 15-minute time intervals. The considered thermal and electrical load profiles have been derived from historical data, whereas the market prices have been taken from the Italian spot market. Typical PV and wind production profiles are also considered.

The action of the intra-day scheduler is based on the least square solution method considering always $\beta=0$ (the losses are not considered in the optimization process). Any ULTCs is activated in the network during these simulations.

In order to provide an example of the effectiveness of the intra-day scheduler action, we have first considered an high load period of the one-day horizon already considered in the previous section, namely the 39-th time period. Fig. 3.6. shows the voltage amplitudes at the various network buses for different operating conditions of dispatchable DERs of the considered period, namely, (i) without available dispatchable DERs, (ii) with only
Gen-856, and (iii) with all the DERs available. The voltage profiles in the presence of dispatchable DERs, namely the operating conditions (ii) and (iii), are obtained for two different $\alpha$-coefficient values of objective function (3.18), namely, 0 and 50.

![Voltage profiles for different operating conditions](image)

Fig. 3.6. – Intraday scheduling solution: phase-a voltage profiles at various network buses for different operating conditions of dispatchable DERs at period 39 (namely, without available dispatchable DERs, with only Gen-856 and with all the DERs available) for two different $\alpha$-coefficient values of scheduler objective function (0 and 50).

Tab. 3.5. reports the load requests and the actual renewable production levels in the considered period, with the corresponding power factor $pf$ values.

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Power level (kW)</th>
<th>$pf$</th>
<th>Symbol</th>
<th>Power level (kW)</th>
<th>$pf$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Load 800</td>
<td>3002.8</td>
<td>0.9</td>
<td>Load 848</td>
<td>200</td>
<td>0.95</td>
</tr>
<tr>
<td>Load 810</td>
<td>1290.7</td>
<td>0.9</td>
<td>Load 856</td>
<td>2000</td>
<td>0.95</td>
</tr>
<tr>
<td>Load 822</td>
<td>610</td>
<td>0.9</td>
<td>Load 864</td>
<td>141</td>
<td>0.9</td>
</tr>
<tr>
<td>Load 826</td>
<td>580</td>
<td>0.95</td>
<td>RERs</td>
<td>15.98</td>
<td>1</td>
</tr>
<tr>
<td>Load 838</td>
<td>120</td>
<td>0.9</td>
<td>PV</td>
<td>15.98</td>
<td>1</td>
</tr>
<tr>
<td>Load 840</td>
<td>160</td>
<td>0.95</td>
<td>Wind</td>
<td>300</td>
<td>0.9</td>
</tr>
</tbody>
</table>

Tab. 3.5. – Loads and RES production levels, with the relevant power factor $pf$, in the 39-th period.

For the case of $\alpha=0$, only the voltage deviations are minimized; for the case of $\alpha$ equal to a large number (namely 50), the output of each DER $j$ is equal to the corresponding value $P_{j,\text{set}}$ defined by the day-ahead scheduler. The $P_{\text{set}}$ values in the considered period are 1800 kW (Gen-818), 1647 kW (Gen-856), and 4000 kW (Gen-802).

The results of Fig. 3.6. refer to phase-a of the system and, in view of the unbalanced line configuration of the considered 34-nodes IEEE radial distribution test feeder, Tab. 3.6 and Tab. 3.7 show the values of the mean absolute deviation voltages for all the three phases and the DERs output deviations with respect to the $P_{\text{set}}$ values in correspondence of the considered DERs operating conditions.
Chapter 3

<table>
<thead>
<tr>
<th>DERs operating condition</th>
<th>voltage mean absolute deviation (V)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>phase a</td>
</tr>
<tr>
<td>without DERs</td>
<td>874</td>
</tr>
<tr>
<td>Gen-856, $\alpha=50$</td>
<td>339</td>
</tr>
<tr>
<td>Gen-856, $\alpha=0$</td>
<td>185</td>
</tr>
<tr>
<td>all DERs, $\alpha=50$</td>
<td>42</td>
</tr>
<tr>
<td>all DERs, $\alpha=0$</td>
<td>40</td>
</tr>
</tbody>
</table>

Tab.3.6. – Mean absolute deviation value of the voltages for all the three phases and for the considered DERs operating conditions.

<table>
<thead>
<tr>
<th>DERs operating condition</th>
<th>DERs output deviations (kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gen-818</td>
</tr>
<tr>
<td>Gen-856, $\alpha=50$</td>
<td>0</td>
</tr>
<tr>
<td>Gen-856, $\alpha=0$</td>
<td>-</td>
</tr>
<tr>
<td>all DERs, $\alpha=50$</td>
<td>0</td>
</tr>
<tr>
<td>all DERs, $\alpha=0$</td>
<td>0</td>
</tr>
</tbody>
</table>

Tab.3.7. – DERs output deviations with respect to the $P_{set}$ values, for the considered DERs operating conditions.

In order to provide the overall behavior of the intra-day scheduler, it has been applied for the first 15-minutes interval of each of the 24 hours, considered in the day-ahead optimization. In particular, Fig.3.7. shows the mean absolute phase voltage deviations and Fig.3.8. the DERs output absolute deviations. The results presented in these figures refer to two different values of the $\alpha$-coefficient, namely 0 and 1. Fig.3.7. shows that even for the case of $\alpha=1$, the mean absolute voltage deviation values are slightly worse than those obtained for the case of $\alpha=0$ (in particular limited to few tens of volts), whilst, as shown by Fig.3.8.a, the DERs active power output absolute deviations can be very different from those provided by the day-ahead scheduler.

Fig.3.7. – Intraday scheduling solution: mean absolute phase voltage deviations for two different $\alpha$-coefficient values: $\alpha = 0$ and $\alpha = 1$. The voltage deviations values refer to the phase-to-ground voltage maximum value.
Fig. 3.8. – Intraday scheduling solution: DERs active power output deviations with respect Pset for two different $\alpha$-coefficient values: a) $\alpha = 0$, b) $\alpha = 1$.

B. Least square optimization method with only ULTCs

This section shows the results obtained by applying the proposed scheduler, equipped with the least square optimization solver, to the case of the distribution network connected to the 150 kV feeding network. As mentioned, bus LF1, the high voltage terminal of transformer Tr_1, is the slack bus, whose voltage is assumed equal to 1 p.u..

Fig. 3.9 shows the comparison between the initial voltage profile and the ones obtained after the action of the scheduler on the controllable DERs outputs with reference to the following cases:

(i) 1 ULTC (Tr_1);
(ii) 2 ULTCs (Tr_1 and V_reg_1)
(iii) all the 3 available ULTCs
The single optimization objective of the scheduler is the minimization of voltage profile deviations. The results are obtained by means the least square optimization solution with $\alpha=0$, $\beta=0$, and $\gamma=1$. 

![Graph showing voltage profile deviations with ULTC actions](image)

The comparison between the original configuration and the results obtained for the three considered cases after the scheduler action is shown in Tab.3.8.

<table>
<thead>
<tr>
<th></th>
<th>initial condition</th>
<th>1 ULTC</th>
<th>2 ULTCs</th>
<th>3 ULTCs</th>
</tr>
</thead>
<tbody>
<tr>
<td>voltage mean absolute deviation (V)</td>
<td>152.3</td>
<td>29.78</td>
<td>29.34</td>
<td>12.23</td>
</tr>
<tr>
<td>DERs output deviations (kW)</td>
<td>$\Delta P_{802} = 0$</td>
<td>$\Delta P_{802} = -883.5$</td>
<td>$\Delta P_{802} = -943.1$</td>
<td>$\Delta P_{802} = -940.1$</td>
</tr>
<tr>
<td></td>
<td>$\Delta P_{818} = 0$</td>
<td>$\Delta P_{818} = 0$</td>
<td>$\Delta P_{818} = 0$</td>
<td>$\Delta P_{818} = 0$</td>
</tr>
<tr>
<td></td>
<td>$\Delta P_{856} = 0$</td>
<td>$\Delta P_{856} = 353.2$</td>
<td>$\Delta P_{856} = 353.2$</td>
<td>$\Delta P_{856} = 353.2$</td>
</tr>
<tr>
<td>losses (kW)</td>
<td>32.40</td>
<td>28.90</td>
<td>28.48</td>
<td>26.80</td>
</tr>
<tr>
<td>ULTC optimal positions</td>
<td>$n_{Tr_1} = 6.024$</td>
<td>$n_{Tr_1} = 6.028$</td>
<td>$n_{Tr_1} = 6.03$</td>
<td>$n_{Tr_1} = 6.03$</td>
</tr>
<tr>
<td></td>
<td>$n_{V_reg_1} = 1$</td>
<td>$n_{V_reg_1} = 1$</td>
<td>$n_{V_reg_1} = 1.002$</td>
<td>$n_{V_reg_1} = 1.002$</td>
</tr>
<tr>
<td></td>
<td>$n_{V_reg_2} = 1$</td>
<td>$n_{V_reg_2} = 1$</td>
<td>$n_{V_reg_2} = 1$</td>
<td>$n_{V_reg_2} = 0.996$</td>
</tr>
</tbody>
</table>

Tab.3.8. – Influence of the ULTC action.
C. Least square optimization method with both DERs and ULTCs

We consider now the case in which all the three ULTCs are available and we compare the results obtained by applying both the least square method and the goal attainment method. Such comparison makes reference to different sets of weights and goals values, being the initial condition of the network the same as considered in the previous calculations of Fig.3.9 and Tab.3.8.

In particular, for the case that refers to the application of the least square optimization solver, Fig.3.10 and Tab.3.9 shows the comparison between the results obtained for the following different sets of the $\alpha$-$\beta$-$\gamma$ values:

- (lsq0) $\alpha=0, \beta=0, \gamma=1$, i.e. corresponding to the already considered case (iii);
- (lsq1) $\alpha=50, \beta=0, \gamma=1$;
- (lsq2) $\alpha=0, \beta=1, \gamma=1$;
- (lsq3) $\alpha=50, \beta=1, \gamma=1$.

Case (lsq1) selects as single optimization objective the minimization of voltage profile deviations. Case (lsq2) takes into account also the minimization of network losses. Case (lsq3) tends to keep DERs active power outputs close to their $P$ values by means the high value of the $\alpha$-coefficient. Case (lsq4) minimizes both the voltage deviations and the losses by keeping, as for the case (lsq3), DERs active power outputs at their $\tilde{P}$ values.

Fig.3.10. – Comparison between the voltage profiles obtained by applying the least-square solution method for different sets of the $\alpha$-$\beta$-$\gamma$ values.
### Tab.3.9. – Comparison between the results obtained by applying the least-square method for different sets of \( \alpha-\beta-\gamma \) values.

<table>
<thead>
<tr>
<th>Voltage mean absolute deviation (V)</th>
<th>lsq0</th>
<th>lsq1</th>
<th>lsq2</th>
<th>lsq3</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>12.23</td>
<td>12.6</td>
<td>12.32</td>
<td>12.6</td>
</tr>
<tr>
<td>DERs output deviations (kW)</td>
<td>( \Delta P_{802} = -940.1 )</td>
<td>( \Delta P_{802} = 0 )</td>
<td>( \Delta P_{802} = 1702.5 )</td>
<td>( \Delta P_{802} = 0 )</td>
</tr>
<tr>
<td></td>
<td>( \Delta P_{818} = 0 )</td>
<td>( \Delta P_{818} = 0 )</td>
<td>( \Delta P_{818} = 0 )</td>
<td>( \Delta P_{818} = 0 )</td>
</tr>
<tr>
<td></td>
<td>( \Delta P_{856} = 353.2 )</td>
<td>( \Delta P_{856} = 0 )</td>
<td>( \Delta P_{856} = 353.2 )</td>
<td>( \Delta P_{856} = 0 )</td>
</tr>
<tr>
<td>Losses (kW)</td>
<td>26.8</td>
<td>30.69</td>
<td>20.85</td>
<td>30.64</td>
</tr>
<tr>
<td>ULTC optimal positions</td>
<td>( n_{Tr_1} = 6.03 )</td>
<td>( n_{Tr_1} = 6.023 )</td>
<td>( n_{Tr_1} = 6.017 )</td>
<td>( n_{Tr_1} = 6.022 )</td>
</tr>
<tr>
<td></td>
<td>( n_{V_reg_1} = 1.002 )</td>
<td>( n_{V_reg_1} = 1.002 )</td>
<td>( n_{V_reg_1} = 1.002 )</td>
<td>( n_{V_reg_1} = 1.002 )</td>
</tr>
<tr>
<td></td>
<td>( n_{V_reg_2} = 0.996 )</td>
<td>( n_{V_reg_2} = 0.996 )</td>
<td>( n_{V_reg_2} = 0.996 )</td>
<td>( n_{V_reg_2} = 0.996 )</td>
</tr>
<tr>
<td>Objective function</td>
<td>25819</td>
<td>26254</td>
<td>26460</td>
<td>27197</td>
</tr>
<tr>
<td>Stopping criterion</td>
<td>both</td>
<td>control variable not changing</td>
<td>both</td>
<td>control variable not changing</td>
</tr>
<tr>
<td>Iterations</td>
<td>3</td>
<td>2</td>
<td>3</td>
<td>2</td>
</tr>
<tr>
<td>( \xi ) values</td>
<td>1,1,1</td>
<td>1,1</td>
<td>1,1,1</td>
<td>1,1</td>
</tr>
</tbody>
</table>

### D. Goal attainment optimization method with both DERs and ULTC

For the case that refers to the use of the goal attainment method, Fig.3.11 and Tab.3.10 compare the results obtained for the following sets of weighting coefficients:

- (goal1) \( \text{weight}_P = 0.1 \bar{P} \) and \( \text{weight}_{loss} = \infty \);
- (goal2) \( \text{weight}_P = \infty \) and \( \text{weight}_{loss} = 10 \);
- (goal3) \( \text{weight}_P = 0.1 \bar{P} \) and \( \text{weight}_{loss} = 10 \);

whilst \( \text{weight}_V \) is always assumed equal to \( \text{goal}_V \), i.e. equal to 1% of the rated voltage value \( \bar{P} \).
Fig. 3.11. – Comparison between the voltage profiles obtained by applying the goal attainment method for different sets of weighting coefficients.

<table>
<thead>
<tr>
<th></th>
<th>goal1</th>
<th>goal2</th>
<th>goal3</th>
</tr>
</thead>
<tbody>
<tr>
<td>voltage mean absolute deviation (V)</td>
<td>163.04</td>
<td>133.88</td>
<td>468.31</td>
</tr>
<tr>
<td>DERs output deviations (kW)</td>
<td>$\Delta P_{802} = 0$</td>
<td>$\Delta P_{802} = -1104.4$</td>
<td>$\Delta P_{802} = -373.7$</td>
</tr>
<tr>
<td></td>
<td>$\Delta P_{818} = 0$</td>
<td>$\Delta P_{818} = -618.6$</td>
<td>$\Delta P_{818} = -292.4$</td>
</tr>
<tr>
<td></td>
<td>$\Delta P_{856} = 0$</td>
<td>$\Delta P_{856} = 99.8$</td>
<td>$\Delta P_{856} = -267.5$</td>
</tr>
<tr>
<td>losses (kW)</td>
<td>30.83</td>
<td>23.40</td>
<td>26.63</td>
</tr>
<tr>
<td>ULTC optimal positions</td>
<td>$n_{Vr_1} = 6.067$</td>
<td>$n_{Vr_1} = 5.967$</td>
<td>$n_{Vr_1} = 5.873$</td>
</tr>
<tr>
<td></td>
<td>$n_{V_r _reg _1} = 0.988$</td>
<td>$n_{V_r _reg _1} = 0.984$</td>
<td>$n_{V_r _reg _1} = 0.990$</td>
</tr>
<tr>
<td></td>
<td>$n_{V_r _reg _2} = 1.012$</td>
<td>$n_{V_r _reg _2} = 0.996$</td>
<td>$n_{V_r _reg _2} = 0.996$</td>
</tr>
<tr>
<td>objective function</td>
<td>0</td>
<td>2.34</td>
<td>2.66</td>
</tr>
<tr>
<td>stopping criterion</td>
<td>objective fun. not changing</td>
<td>objective fun. not changing</td>
<td>objective fun. not changing</td>
</tr>
<tr>
<td>iterations</td>
<td>2</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>$\xi$ values</td>
<td>1.0</td>
<td>0.6, 0</td>
<td>0.9, 0</td>
</tr>
</tbody>
</table>

Tab. 3.10. – Comparison between the results obtained by applying the goal attainment method for different sets of weighting coefficients.
As expected, the voltage profiles obtained by applying the least square optimization method are similar to each other, since, for the considered DERs reactive capability limits, the action on the reactive power set points is sufficient to provide an adequate voltage control on the considered test distribution system.

The voltage profiles obtained with the goal attainment method respect the maximum 1% variation goal for the weighting coefficient sets (goal1) and (goal2). For the case of set (goal3), the higher variations are obtained because both the goals of null active power deviations and losses are searched. The results obtained by using both the least square and the goal attainment method show that the minimum losses are in general associated with operating conditions characterized by lower voltage deviations. On the contrary, higher voltage deviations are obtained when DERs active output deviations are forced to be zero.

**3.5.3. Typical Italian urban and rural distribution networks**

The performances of the proposed scheduler has been evaluated also by considering a typical Italian MV distribution grid which EMTP-RV model is illustrated in Fig.3.12. Such a grid, selected as real test network in the framework of an Italian “Smart Grid” Project [Scalari et al., 2008], includes both urban and rural feeders. The two urban feeders are characterized by the presence of cable lines and high load density. The two rural ones present longer overhead lines and a lower load density. All the feeders are connected to a 132/20 kV sub-station by means of two transformers equipped with ULTCs. ULTCs are installed on the secondary winding (the one at lowest voltage) of the transformers. They are characterized by 17 possible tap positions allowing regulation between $\pm 8 \times 1.5\%$ of the rated voltage. The allowed secondary voltage limits are within 17.6 kV e 22.4 kV.

The analyzed configuration considers the presence of 16 DERs, 7 connected to the urban feeders and 9 to the rural ones. Among them, 10 are dispatchable and can be included in the scheduler optimization. In the system are installed also 6 renewable energy resources (RER) namely 5 wind turbine (WTs) and 1 PV. Tab.3.11 provides details about the point where the DERs are connected, their rated (maximum) active power output as well as if they are dispatchable or not. For all the dispatchable DERs, a characteristic minimum power factor of 0.8 (lead or lag) has been considered.

Simulations on this networks has been carried out considering the MILP optimization procedure in order to consider a more realistic discrete value for the tap-position of the ULTCs.
Fig. 3.12. – 120-nodes 20 kV distribution network used as reference. The urban feeders 1 and 2 as well as the rural feeders 1 and 2 are distinguishable.

<table>
<thead>
<tr>
<th>Connection feeder</th>
<th>N</th>
<th>Node</th>
<th>Dispatchable (Y/N)</th>
<th>$P_{MAX}$ (kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Urban 1</td>
<td>1</td>
<td>GD_04</td>
<td>Y</td>
<td>3500</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>GD_18</td>
<td>Y</td>
<td>150</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>GD_19</td>
<td>Y</td>
<td>3000</td>
</tr>
<tr>
<td></td>
<td>4</td>
<td>GD_20</td>
<td>Y</td>
<td>5500</td>
</tr>
<tr>
<td>Urban 2</td>
<td>5</td>
<td>GD_21</td>
<td>Y</td>
<td>5000</td>
</tr>
<tr>
<td></td>
<td>6</td>
<td>GD_23</td>
<td>Y</td>
<td>1000</td>
</tr>
<tr>
<td></td>
<td>7</td>
<td>GD_31</td>
<td>Y</td>
<td>5000</td>
</tr>
<tr>
<td>Rural 1</td>
<td>8</td>
<td>GD_40</td>
<td>Y</td>
<td>1500</td>
</tr>
<tr>
<td></td>
<td>9</td>
<td>GD_49</td>
<td>Y</td>
<td>3000</td>
</tr>
<tr>
<td></td>
<td>10</td>
<td>GD_54</td>
<td>Y</td>
<td>3000</td>
</tr>
<tr>
<td></td>
<td>11</td>
<td>DG_58</td>
<td>N</td>
<td>1700</td>
</tr>
<tr>
<td></td>
<td>12</td>
<td>DG_63</td>
<td>N</td>
<td>1700</td>
</tr>
<tr>
<td>Rural 2</td>
<td>13</td>
<td>DG_95</td>
<td>N</td>
<td>1000</td>
</tr>
<tr>
<td></td>
<td>14</td>
<td>DG_109</td>
<td>N</td>
<td>2550</td>
</tr>
<tr>
<td></td>
<td>15</td>
<td>DG_116</td>
<td>N</td>
<td>2550</td>
</tr>
<tr>
<td></td>
<td>16</td>
<td>DG_119</td>
<td>N</td>
<td>2550</td>
</tr>
</tbody>
</table>

Tab. 3.11. – Main characteristics of the DERs connected to the test network represented in Fig. 3.12.
The total electrical load requests, the power generated by RER and the set-points of the dispatchable DERs, have been obtained by applying the economical day-ahead scheduler. Typical 24-hours loads, wind and solar irradiation profiles have been assumed in order to deals with a realistic network configuration.

However, in the follows, only the two time intervals characterized respectively by the maximum and minimum load request have been considered. These two situations have been used as starting points for the intra-day scheduler optimization. Tab.3.12 reports the total loads request and the total power production of both renewable based and dispatchable DERs.

<table>
<thead>
<tr>
<th>Configuration</th>
<th>Load request (MVA)</th>
<th>Generation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Dispatchable DERs (MW)</td>
</tr>
<tr>
<td>Maximum load</td>
<td>19.25 +j 6.39</td>
<td>27.90</td>
</tr>
<tr>
<td>Minimum load</td>
<td>7.61 +j 3.15</td>
<td>10.95</td>
</tr>
</tbody>
</table>

Tab.3.12. – Load and generation for the considered network configurations.

The aim of the simulations is, for both the configurations of maximum and minimum load request, the optimization of the network voltage profile. For each configuration two simulations have been carried out selecting different values for $\alpha$, namely $\alpha=50$ and $\alpha=0$.

Whether the term related to the minimization of the network losses is not included ($\beta=0$), the procedure consider instead the lines ampacity limits (Tab.3.13).

<table>
<thead>
<tr>
<th>Optimization procedure</th>
<th>Objectives</th>
<th>Ampacity limits</th>
<th>Dispatchable DERs</th>
<th>ULTCs</th>
</tr>
</thead>
<tbody>
<tr>
<td>MILP</td>
<td>0-50</td>
<td>0</td>
<td>Yes</td>
<td>10</td>
</tr>
</tbody>
</table>

Tab.3.13. – Objectives and parameter settled for the optimizations.

A. MILP optimization of the network configuration characterized by the maximum load request.

Tab.3.14 summarizes the initial operation set-points of the DERs for the configuration of maximum load request. Tab.3.14 report also the results of the intra-day scheduler optimization for both the cases with $\alpha=0$ and $\alpha=50$. It has been assumed that, for each DERs, the initial values of the reactive power is equal to zero. This assumption allows to achieve directly an optimal solution also in terms of reactive power.
Optimal technical scheduling of distributed energy resources

<table>
<thead>
<tr>
<th>Connection feeder</th>
<th>N</th>
<th>Node</th>
<th>Initial condition</th>
<th>Optimized condition ($\alpha=0$)</th>
<th>Optimized condition ($\alpha=50$)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>$P$ (kW)</td>
<td>$P$ (kW)</td>
<td>$Q$ (kVAR)</td>
</tr>
<tr>
<td>Urban 1</td>
<td>1</td>
<td>GD_04</td>
<td>3500</td>
<td>3500</td>
<td>2625</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>GD_18</td>
<td>500</td>
<td>500</td>
<td>375</td>
</tr>
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<td>3</td>
<td>GD_19</td>
<td>3000</td>
<td>3000</td>
<td>2250</td>
</tr>
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<td>4</td>
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<td>5500</td>
<td>457</td>
<td>508</td>
</tr>
<tr>
<td>Urban 2</td>
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<td>GD_21</td>
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<td>1439</td>
<td>-1817</td>
</tr>
<tr>
<td></td>
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<td>1000</td>
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</tr>
<tr>
<td></td>
<td>7</td>
<td>GD_31</td>
<td>5000</td>
<td>5000</td>
<td>3750</td>
</tr>
<tr>
<td>Rural 1</td>
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<td>GD_40</td>
<td>1172</td>
<td>0</td>
<td>428</td>
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<tr>
<td></td>
<td>9</td>
<td>GD_49</td>
<td>2141</td>
<td>1836</td>
<td>-2014</td>
</tr>
<tr>
<td></td>
<td>10</td>
<td>GD_54</td>
<td>2141</td>
<td>603</td>
<td>-642</td>
</tr>
<tr>
<td></td>
<td>11</td>
<td>DG_58</td>
<td>261</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>12</td>
<td>DG_63</td>
<td>200</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Rural 2</td>
<td>13</td>
<td>DG_95</td>
<td>0</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>14</td>
<td>DG_109</td>
<td>469</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>15</td>
<td>DG_116</td>
<td>528</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>16</td>
<td>DG_119</td>
<td>677</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Tab.3.14. – Maximum load request scenario. DERs active and reactive power set-point before and after two simulated case characterized respectively by $\alpha=0$ and $\alpha=50$. The set-point of the RES are assumed to be constant during the simulation.

Tab.3.15 shows instead the optimization results regarding the ULTCs tap positions. Fig.3.13 ÷ Fig.3.16 show the voltage profiles before and after the optimization (case with $\alpha=0$) for all the feeders included in the test network.

<table>
<thead>
<tr>
<th>Component</th>
<th>Initial condition</th>
<th>Optimized condition ($\alpha=0$)</th>
<th>Optimized condition ($\alpha=50$)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Tap position</td>
<td>Tap position</td>
<td>Tap position</td>
</tr>
<tr>
<td>Tr_1_132kV_20kV</td>
<td>0</td>
<td>-2</td>
<td>0</td>
</tr>
<tr>
<td>Tr_2_132kV_20kV</td>
<td>0</td>
<td>3</td>
<td>3</td>
</tr>
</tbody>
</table>

Tab.3.15. – Maximum load request scenario. Main characteristics and initial operation set-points of the ULTCs.
Fig. 3.13. – Scenario with maximum load request and $\alpha=0$: voltage profiles before and after the optimization for urban feeder 1.

Fig. 3.14. – Scenario with maximum load request and $\alpha=0$: voltage profiles before and after the optimization for urban feeder 2.
Fig. 3.15. – Scenario with maximum load request and $\alpha = 0$: voltage profiles before and after the optimization for rural feeder 1.

As could be seen, all the node voltages are within the allowed range ($\pm 5\%$ of the network rated voltage). Simulation results shown that the algorithm attains the respect of the line ampacity in both the simulated cases.
Tab.3.16 resumes the simulation results reporting the values of the active power exchanged with the primary network (operating as slack bus), the network losses and the voltage mean absolute deviation.

<table>
<thead>
<tr>
<th>Power exchanged with the external grid (MW)</th>
<th>Losses (MW)</th>
<th>Voltage Mean Absolute Deviation (V)</th>
</tr>
</thead>
<tbody>
<tr>
<td>α=0</td>
<td>-129·10⁻⁶</td>
<td>0.253</td>
</tr>
<tr>
<td>α=50</td>
<td>-10.36</td>
<td>0.553</td>
</tr>
</tbody>
</table>

Tab.3.16. – Maximum load request scenario: simulation results for the cases α=0 and α=50.

B. MILP optimization of the network configuration characterized by the minimum load request.

For the minimum load request configuration, the simulation parameters are those reported in Tab.3.13. Tab.3.19 resume the DERs set-points before and after the two simulations carried out as well as Tab.3.17 reports the discrete tap-positions of the ULTCs before and after the optimization.

<table>
<thead>
<tr>
<th>Component</th>
<th>Initial condition</th>
<th>Optimized condition (α=0)</th>
<th>Optimized condition (α=50)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Tap position</td>
<td>Tap position</td>
<td>Tap position</td>
</tr>
<tr>
<td>Tr_1_132kV_20kV</td>
<td>0</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Tr_2_132kV_20kV</td>
<td>0</td>
<td>-1</td>
<td>0</td>
</tr>
</tbody>
</table>

Tab.3.17. – Minimum load request scenario. Main characteristics and initial operation set-points of the OLTCs.

Tab.3.18 resumes the simulation results reporting the values of the active power exchanged with the external network (operating as slack bus), the network losses and the voltage mean absolute deviation.

<table>
<thead>
<tr>
<th>Power exchanged with the external grid (MW)</th>
<th>Losses (MW)</th>
<th>Voltage Mean Absolute Deviation (V)</th>
</tr>
</thead>
<tbody>
<tr>
<td>α=0</td>
<td>-129·10⁻⁶</td>
<td>0.194</td>
</tr>
<tr>
<td>α=50</td>
<td>-7.52</td>
<td>0.404</td>
</tr>
</tbody>
</table>

Tab.3.18. – Minimum load request scenario: simulation results for the cases α=0 and α=50.
Optimal technical scheduling of distributed energy resources

<table>
<thead>
<tr>
<th>Connection feeder</th>
<th>N</th>
<th>Node</th>
<th>Initial condition</th>
<th>Optimized condition ($\alpha=0$)</th>
<th>Optimized condition ($\alpha=50$)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>$P$ (kW)</td>
<td>$P$ (kW)</td>
<td>$Q$ (kVAR)</td>
</tr>
<tr>
<td>Urban 1</td>
<td>1</td>
<td>GD_04</td>
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<td>1041</td>
<td>-691</td>
</tr>
<tr>
<td></td>
<td>2</td>
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<td>500</td>
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<td>3</td>
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<td>900</td>
<td>1081</td>
<td>-1738</td>
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<tr>
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<td>1650</td>
<td>1</td>
<td>-126</td>
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<tr>
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<td>0.4</td>
<td>16</td>
</tr>
<tr>
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<td>GD_23</td>
<td>300</td>
<td>0.1</td>
<td>473</td>
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<td></td>
<td>7</td>
<td>GD_31</td>
<td>1500</td>
<td>2908</td>
<td>1031</td>
</tr>
<tr>
<td>Rural 1</td>
<td>8</td>
<td>GD_40</td>
<td>900</td>
<td>1416</td>
<td>865</td>
</tr>
<tr>
<td></td>
<td>9</td>
<td>GD_49</td>
<td>1500</td>
<td>492</td>
<td>404</td>
</tr>
<tr>
<td></td>
<td>10</td>
<td>GD_54</td>
<td>1500</td>
<td>120</td>
<td>-36</td>
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<tr>
<td></td>
<td>11</td>
<td>DG_58</td>
<td>739</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td></td>
<td>12</td>
<td>DG_63</td>
<td>538</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Rural 2</td>
<td>13</td>
<td>DG_95</td>
<td>0</td>
<td>-</td>
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<tr>
<td></td>
<td>16</td>
<td>DG_119</td>
<td>950</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

Tab.3.19. – Minimum load request scenario. DERs active and reactive power set-point before and after two simulated case characterized respectively by $\alpha=0$ and $\alpha=50$. The set-point of the RES are assumed to be constant during the simulation.
Chapter 4

Control of distributed energy resources during islanding and emergency operation

As pointed out in the conclusions of the chapter 2, a feasible win win approach to face DG integration in the traditional power system is to start either from the bottom to the upper and vice versa. This means that, if on the one hand micro and small scale DERs have to be controlled and trained to work together forming a small autonomous system, on the other hand the well known features of the bulk power plants will be extended, with opportune adequacy, to decreasing size power production plants.

In this chapter the real case of a large scale DG plant is considered. The main objective is to enhance the control systems of the traditional power plants in order to perform non-conventional manoeuvres, such as the disconnection from the external grid and the consequent operation, in an autonomous island, on the loads of the surrounding electrical network. This eventuality could be helpful to guarantee the continuity of supply when an emergency condition happen on the external distribution grid.

Another related issue concerns the black-start-up capability of the generation plant that might deliver an important ancillary service not only supplying the local users but, also helping the national power system during eventual restoration procedure.

4.1. Issues and perspectives

The term “islanding”, in the follows, denotes an independent operation of an electrical network portion, in isolation from the main grid and energized by one or more DERs. As seen in the chapter 2, “islanding” means also that DERs can actively deliver an UPS service for the grid at which they are connected. The islanding operation of a distribution network with DERs is a very largely discussed issue.

Since from the early 1980s, when DERs meant mainly CHP plants at the service of industries, Redfern et al.[1993] remarked that “providing protection against islanding probably is the single most challenging aspect of designing the electrical system involved in cogeneration”. Together with the safety aspect of having a section of the network energized also after the loss of main supply, there is the dangerous scenario given by
potentially out-of-synchronism re-connection of the DERs with the external network. As prefigured by Redfern et al.[1995] the islanding protections become completely integrated in the protection packages specifically developed for DERs as well as object of extensive laboratory and field tests.

Under the present regulatory framework leading distribution system operation, an islanding scenario is only permitted for loads with dedicated generation units, as the typical case of industrial generation [Katiraei et al., 2005]. Anyway, considering the actual growing penetration of DERs, also the distribution networks could be interested by such an eventuality. Starting from the fact that, among DNOs there are no shared and standardized guidelines and that, customers and developers of DERs are calling for substantially changes in what concern the role of islanding operation, the detailed Econnect Report [2001] analyses the current practice and discuss a set of proposal of change. In fact as authors conclude, problems related to the islanding of distribution networks are consequence of the fact that the system is not specifically designed to support it. Furthermore, following the actual statements for the DNO, is mandatory to protect the network and its customers from the risky operation. This means also that DNO must prevent or avoid these situation in order also to respect the contracted supply obligations including limits on voltage, frequency, flicker and harmonics.

Waiting for further developments in the regulatory framework, many researches and test beds show the technical feasibility of the distribution network islanding. Islanding capability of a HV network is used by Vittal et al.[2003] to implement a self-healing approach in which the system is adaptively divided into smaller islands in order to minimize the impact of critical system conditions and foreseen a potentially fast restoration.

Fulton and Abbey [2004] present the real case of a British Columbia Hydro plant for which the planned islanding of a distribution feeder has been considered as a reliable alternative to the enhancement of the transmission network. On such a system islanding operation has been performed successfully numerous times during years. Authors discuss also the additional control equipment installed on the medium scale DER in order to enhance its regulation capability during islanding and relevant costs.

Katiraei et al. [2005] investigate the capability of a real MV distribution network with medium scale DERs to sustain a stable operation during and after a pre-planned islanding manoeuvres. The study highlights the fundamental support delivered by an opportunely controlled power electronically interfaced DER for what concern the stability of frequency and voltage, even during islanding transients.

Katiraei et al. [2008] conceiving the planned islanding as an “early utility adaptation of the Microgrid concept”, show as, due to specific needs, several utilities worldwide has re-evaluated their system planning in critical areas including opportunity to carry out planned islanding.
One of the aspects immediately related to the islanding operation is the system restoration. In fact, if a seamless islanding transfer is not achievable, DERs require adequate black-start-up capability in order to start energy delivery from zero to rated capacity with full voltage and frequency control. This further addition involve the evolution of the most standard DERs with important cost implications and the changes in the design and control of existing MV networks.

As a conclusion, both *Econnect Reports* [2001; 2005] outlined as only in few case the islanding operation would be commercially viable but this scenario should be strongly different if and when a greater amount of DERs, connected to an actively managed network, could participate in an ancillary services market opportune regulated.

### 4.2. A real case analysis: the HERA Imola project

The occasion to operate on a real power system was due to a collaboration with HERA S.p.A., multi-utility operating in north Italy, in the framework of a pilot project to design and build a combined heat and power (CHP) station connected to a town local network. The main purpose of the project was to realize a new power plant with the aim also to improve service reliability for the industrial and residential local customers. Furthermore, the perspective to employ such a new generation plant located near a town of almost 100,000 people to improve power reliability, has been one of the key driver for both plant realization and its acceptation by local people.

Several analysis on such a real case study has been carried out in order to investigate and outline strategies for the disconnection of the generation plant from the external distribution grid and the restoration of the local grid itself. Previous experiences [e.g., Borghetti et al., 2001 and Salvati et al., 2004] showed that, the definition of power restoration procedures requires the accurate analysis of the dynamic behaviour of power plants during load rejection, islanding and restarting stages, which could be carried out also by means of specific computer aided simulations.

For this reason the first part of the research has been devoted to the development of a computer simulator aimed at reproducing the islanding and black-start-up energization transients of both generation plant and the local distribution network with the relevant loads. The simulator has been implemented in EMTP-RV\(^1\) simulation environment.

The considered large scale distributed generation unit is an 80 MW combined cycle power plant. It is composed by two aeroderivative gas turbines (GT) and a steam turbine unit (ST). Fig.4.1 shows the scheme of the power plant implemented in the simulator to represents the dynamic behaviour of the GTs, the heat recovery steam generator (HRSG),

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\(^{1}\) [Mahseredjian et al., 2002; Mahseredjian et al., 2005; Mahseredjian et al., 2006].
Chapter 4

the ST and their control systems. The simulator also includes the synchronous generator models along with their exciters and automatic voltage regulators (AVRs). The synchronous generators of the three units are connected to a 132 kV power plant substation through 15/132 kV step-up transformers. The power plant substation is assumed to be linked, by means of a cable line, to a distribution substation that feeds the local loads and provides the connection with the external transmission network. In the next paragraph some details about the adopted models and settings are discussed.

Fig.4.1. – Scheme of the HERA Imola Project large scale distributed power plant.
4.3. The model of the power plant

The models of the system elements are those of the EMTP-RV libraries and allow to conduct, starting from the same steady state condition both high details electromagnetic transient simulation and more longer simulation of electromechanical transients and controls. All the system elements are referred to the model configuration of Fig.4.1.

A. Electrical Power System

The considered generation plant and its surrounding distribution network are connected to an external HV (132 kV) transmission network modeled as a prevalent power, ideal, three-phase positive-sequence voltage generator. A reactance corresponding to a three-phase fault current of 20kA has been adopted for the connection of the external network with the primary distribution sub-station. For the calculations of the initial steady-state conditions, for the configuration in which the system is connected to the grid, such a grid is considered as slack bus.

There are two types of transformers. The step-up transformers of the three generation units, namely TR-GT1, TR-ST and TR-GT2, are three identical 40MVA, 15/132 kV, YnD11 machines. The step-down distribution transformers TR-D1, TR-D2 and TR-D3 instead, are 30MVA, 132/15kV, YnYn11 identical units. The step-up unit transformers model includes also a non-linear magnetization branch whose parameters are inferred from experimental data delivered by manufacturer.

For the purpose of the study, only the 800 m cable line, connecting the generation plant with the 132kV distribution sub-station, appears of interest. Others connection such as segregate and armored bus-bars are characterized by limited length and impedance value that is, they have less influence in the propagation effects and have been therefore, neglected.

For the cable line instead, two models have been implemented: the frequency dependent model [Martí, 1982] and the exact Π-model, both obtained by making reference to the manufacturer data of the 132 kV three-phase cable. The two different models are adopted for the simulation of electromagnetic transients and electromechanical ones respectively.

The auxiliary equipment of the whole plant are considered as connected to the GTs. For such a loads a consumption of 800kW and 500 kVAr has been estimated.

Distribution network loads are represented by constant RLC devices that is, neglecting the power consumption dependency from both frequency and voltage.
B. Synchronous Generators

The electrical generators are 4-poules synchronous machines whose main electrical data are reported in Tab. 4.1.

<table>
<thead>
<tr>
<th></th>
<th>$x_d$</th>
<th>$x'_d$</th>
<th>$x''_d$</th>
<th>$x_q$</th>
<th>$x'_q$</th>
<th>$T''_d$</th>
<th>$T''_d$</th>
<th>$T''_q$</th>
<th>$x_0$</th>
<th>$x_1$</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>GT</strong></td>
<td>2.13</td>
<td>0.29</td>
<td>0.18</td>
<td>1.09</td>
<td>0.43</td>
<td>1.09</td>
<td>0.04</td>
<td>0.04</td>
<td>0.13</td>
<td>0.13</td>
</tr>
<tr>
<td><strong>ST</strong></td>
<td>2.22</td>
<td>0.29</td>
<td>0.2</td>
<td>1.11</td>
<td>0.4</td>
<td>1.3</td>
<td>0.08</td>
<td>0.075</td>
<td>0.07</td>
<td>0.15</td>
</tr>
</tbody>
</table>

Tab. 4.1. – Values of the synchronous machines electrical parameters (all the reactance values are in p.u. whilst time constant are in seconds).

The generators of the GTs units are identical and their rated power is 32.875 MVA. The rated power of the ST generator is instead slightly greater as 33.1 MVA. For each of them saturation curves, provided by manufacturer, have been taken into account. All the three synchronous generators have two inputs: excitation voltage $E_f$ and mechanical power $P_m$. The excitation voltages are provided by the AVR and brushless exciter models of the GT units and ST unit. The mechanical power values are provided by the models of the GTs ($P_{mGT}$) and the one of the ST ($P_{mST}$). The synchronous machine model allows also a detailed modeling of the mechanical drive train, as shown in Fig. 4.4 and as explained in the paragraph concerning GTs. The implemented generator models have been verified by comparing a set of simulation results and characteristic transients delivered by manufacturer.

C. Exciters and Automatic Voltage Regulators (AVRs)

The exciters of the GT units are of brushless type. This kind of exciters supply the field circuit of the synchronous generator by a DC voltage produced using the combined action of an AC generator and a non-controlled diode rectifier. The main data of the exciter are reported in Tab. 4.2.

<table>
<thead>
<tr>
<th></th>
<th>Stator</th>
<th>Rotor</th>
</tr>
</thead>
<tbody>
<tr>
<td>No load voltage (V)</td>
<td>17</td>
<td>27</td>
</tr>
<tr>
<td>No load current (A)</td>
<td>2.8</td>
<td>283</td>
</tr>
<tr>
<td>Exciter rated current (A)</td>
<td>50</td>
<td>80</td>
</tr>
<tr>
<td>Rated current (A)</td>
<td>8.2</td>
<td>841</td>
</tr>
<tr>
<td>Ceiling voltage (V)</td>
<td>98</td>
<td>153</td>
</tr>
<tr>
<td>Ceiling current (A)</td>
<td>16.1</td>
<td>1618</td>
</tr>
<tr>
<td>Exciter response (1/s)</td>
<td>2.24</td>
<td></td>
</tr>
</tbody>
</table>

Tab. 4.2. – Data of the GT exciter.

2 [Kundur and Dandeno, 1983; Dommel, 1996].
The model adopted for the exciter corresponds to Type AC8B of IEEE Std.421 [2005], illustrated in Fig.4.2. The AVR is a PID control with independent values of the proportional ($K_P$), integral ($K_I$), and derivative ($K_{DIFF}$) gains and derivative time constant $T_d$. The behavior of brushless exciters depends on the generator loading condition and requires also the field current as input. This kind of exciters does not allow negative values for the field voltage and current. As illustrated by Fig.4.2 the exciter voltage $V_E$ is corrected by a feedback ring that takes into account the sum of three contributions: (i) the product between $V_E$ and the saturation function $S_E(V_E)$, (ii) the product between $V_E$ and exciter constant $K_E$ and (iii) the product between demagnetizing factor $K_D$ and field current $I_f$.

![Fig.4.2. – Model of GT AVR and excitation system.](image)

The output field voltage $E_f$ is calculated taking into account also the reduction due to the commutation reactance of the rectifier, by means the rectifier regulation block. As explained by IEEE Std.421 [2005], the impedance of the AC source supplying the AC side of rectifiers is characterized by predominantly inductive impedance. The impedance causes a strongly non linear decrease of the rectifier voltage output. This effect depends on the value of the current supplied by the rectifier and is represented by means a rectifier loading factor $K_c$ proportional to commutating reactance and the rectifier regulation characteristic. The values of the main parameters adopted for the exciter model are reported in Tab.4.3.

<table>
<thead>
<tr>
<th>$V_{RMAX}$ = 11.9</th>
<th>$K_C = 0.29$</th>
<th>$K_D = 1.03$</th>
</tr>
</thead>
<tbody>
<tr>
<td>$K_E = 1.0$</td>
<td>$T_E = 0.31$</td>
<td>$E_1 = 5.2$ p.u.</td>
</tr>
<tr>
<td>$E_2 = 7$ p.u.</td>
<td>$S_E(E_1) = 0.58$</td>
<td>$S_E(E_2) = 0.61$</td>
</tr>
</tbody>
</table>

Tab.4.3. – Values of the main parameters of the GT exciter model.

D. GTs

The model adopted for the two GTs is based on a transfer function that represents the dynamic link between fuel flow rate and output mechanical power and includes the fuel
metering valve (FMV) dynamic and a speed governor. The considered GT is an aeroderivative industrial RB211 package, characterized by a rated output to the electrical generator equal to 33 MW at 4850 rpm speed and by 94 kg/s exhaust mass flow at 503°C. The adopted model is illustrated in Fig.4.3. The GT dynamics is represented by a 4 poles-4 zeros transfer function that represent the dynamic link between fuel flow rate and output mechanical power as in

$$GT(s) = K \frac{\left(\tau_{z1}s + 1\right) \left(\tau_{z2}s + 1\right) \left(\tau_{z3}s^2 + \tau_{z4}s + 1\right)}{\left(\tau_{p1}s + 1\right) \left(\tau_{p2}s + 1\right) \left(\tau_{p3}s^2 + \tau_{p4}s + 1\right)} \quad (4.1)$$

A feedback algebraic look-up table block determines the required correction at partial loads. The FMV dynamic is represented by a first order transfer function with time constant $T_{FMV}$ equal to 0.1 s. The droop of the speed governor is assumed equal to 5%. The model includes also an acceleration limiter.

![Fig.4.3. – Model of the GT and its speed governor.](image)

The GT is connected to the rotor of the synchronous machine by means of a mechanical gearbox with transmission ratio equal to 1500/4850. Fig.4.4 illustrates the adopted two-mass model of the GT drive trains. Mass 1 represents the inertia of the low-speed GT shaft and the gearbox, whilst mass 2 represents the generator rotor.

![Fig.4.4. – Scheme of the GT drive train two-mass model](image)

---

3 The figure shows the model parameters, namely $J_1,J_2$ inertia constant of mass 1 and 2, respectively; HSP spring constant pertaining to the elastic connection between the two masses; $DSR_1,DSR_2$ speed deviation
E. Heat Recovery Steam Generator (HRSG)

The HRSG model is adapted from the one proposed by Kunitomi et al. [2003], relevant to the HP section with a bypass control valve at the HRSG output. The model is based on the following main assumptions: fast feed water adjustments, negligible effects of temperature control and water flows to the attemperators, constant enthalpy value of the steam at the ST inlet. As shown in Fig.4.1 and Fig.4.5, the inputs of the HRSG model are $Q_{GT}$ and $p_{HP}$. In agreement with the CIGRE Task Force C4.02.25 [2003], $Q_{GT}$ is assumed to be a non-linear function of the gas turbine output power $P_{mGT}$. Concerning $p_{HP}$, it is calculated from the difference between the steam mass flow rate at the HRSGs outputs ($w_{HRSG}$) and the steam turbine inlet mass flow rate ($w_{ST}$) through a transfer function that takes into account the time constant associated with the steam storage capacity into the collector volume.

$$\begin{align*}
Q_{GT} (\text{steam equivalent}) + & \\
\frac{1}{sT_e} & \frac{p_e}{p_{sh}} \\
1/ST_{sh} & \frac{w_{HRSG}}{w_{sh}} \\
\frac{K_{sh} \sqrt{x}}{K_e} & \\
\frac{1}{sT_{sh}} & p_{sh} \\
p_{HP} &
\end{align*}$$

Fig.4.5. – Model of the HRSG.

Fig.4.5 illustrates the structure of the implemented HP section HRSG model, which takes into account the evaporator time constant $T_e$ for the calculation of the pressure $p_e$ in the drum according to the energy balance equation, a time constant $T_{sh}$ relevant to the superheaters (SH) storage capacity. The steam flow rates between drum and SH and between SH and the collector are determined from the pressure drop relationship with flow rate being proportional to square root of pressure drop.

F. Steam Turbine

The model of the steam turbine, shown in Fig.4.6, represents the time delay associated with the steam store in the inlet chest, the main valve dynamic implements self-damping coefficient for each mass; DSD$_i$, absolute speed self-damping coefficient of mass 1, subject to the GT mechanical torque $T_m$. The $J_2$ value is assumed equal to 1.285 s. The DSD$_1$ value is assumed equal to 48 Nms/rad, in order to take into account the power losses associated with the gearbox (1.2 MW at synchronous speed of 1500 rpm).

$^4$ [Kunitomi et al., 2003; CIGRE Task Force C4.02.25, 2003; Kiat Yee et al., 2008].
three control operation modes: i) no-load speed control, ii) control to keep a constant value of upstream pressure $p_{\text{HP}}$, iii) power and speed regulation. The no-load speed control mode is used at the startup and synchronizing phases, whilst in normal conditions the two modes are the pressure control or power-speed regulation.

![Diagram](image)

**Fig.4.6. – Model of the ST and its controls.**

### 4.4. Parameters identification procedure

This paragraph is devoted to the parameter identification of the GT model and of its speed governor, together with the parameter identification of the two-mass model of the GT train drive.

The complexity of power plants operation, of their interaction with the electrical network, as well as the need of implementing coordinated control systems to cope with specific operational requirements, call for the development/use of advanced and accurate simulation tools. This may represent the adequate complement or substitute the practice of repetitive prototyping and expensive tests on real systems. Within this context, the parameter identification of power plant dynamic models represents one of the main issues for proper simulation of the transients occurring during critical operation conditions [Sancha et al., 1997; CIGRE Task Force 38.02.14, 1999; Borghetti et al., 2001]. The modern conception of simulation tools, such as EMTP-RV, allows to interface the simulation environment with external software, as, for instance, those used for signal processing calculations and parameter identification. EMTP-RV is used indeed for such a purpose in order to carry out multiple simulations and to retrieve the data of the quantities of interest of the resulting transients. These data are compared with the available experimental ones. An optimization problem is then solved to obtain the most adequate values of the model parameters, as described in what follows.
Being $\mathbf{p}=[p_1, p_2, \ldots, p_i, \ldots, p_n]$ the set of $n$ model parameters to be identified, $\mathbf{p}_0$ a vector of the initial guess values, $\mathbf{s}(\mathbf{p})$ the vector of $N$ samples of the calculated transient by using parameters vector $\mathbf{p}$, the optimization problem tries to find parameter vector $\mathbf{p}^\ast$ that minimizes the norm of the difference between the calculated transient and the available experimental data $\mathbf{s}_e$:

$$\mathbf{p}^\ast = \arg \min_{\mathbf{p}} \frac{1}{2} \| \mathbf{F}(\mathbf{p}) \|_2^2 \quad (4.2)$$

Where

$$\mathbf{F}(\mathbf{p}) = \begin{bmatrix} s_{e,1} - s_{e,i}(\mathbf{p}) \\ \vdots \\ s_{e,j} - s_{e,i}(\mathbf{p}) \\ \vdots \\ s_{e,N} - s_{e,N}(\mathbf{p}) \end{bmatrix} \quad (4.3)$$

The optimization problem is implemented in a Matlab script and solved by using the lsqnonlin\textsuperscript{5} function of the Optimization Toolbox. The interface between Matlab and EMTP-RV environment is provided by specific Matlab scripts that allow the communication between the two programs, as illustrated in Fig.4.7.

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\textsuperscript{5} [Matlab Optimization Toolbox, 2007].
waveform from the results database and make it available within the Matlab workspace and also subsequently execute the EMTP-RV simulations.

A. Identification of GT automatic voltage regulator parameters

The AVR parameter identification is based on the recorded transient of the terminal voltage $V_t$ of a GT unit after a load rejection at rated output. The set of parameters selected for the optimal identification is $p=[K_P, K_I, K_{DIFF}, T_d]$. Fig.4.8 shows the comparison between the experimental voltage transient and the simulation results using the implemented model. Tab.4.4 shows the initial guess values and the identified values of the AVR parameters, together with the allowed range of variations, and the example values exploited by IEEE Std.421 [2005].

![Figure 4.8](image)

Fig.4.8. – Comparison between a full load rejection voltage transient at the GT unit terminals and the corresponding transients obtained by using the implemented model.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Initial guess values</th>
<th>Std. IEEE example values</th>
<th>Range</th>
<th>Identified values</th>
</tr>
</thead>
<tbody>
<tr>
<td>$K_P$</td>
<td>35</td>
<td>80</td>
<td>7-280</td>
<td>132.8</td>
</tr>
<tr>
<td>$K_I$</td>
<td>5</td>
<td>5</td>
<td>1-100</td>
<td>35.05</td>
</tr>
<tr>
<td>$K_{DIFF}$</td>
<td>6</td>
<td>10</td>
<td>1-80</td>
<td>25.58</td>
</tr>
<tr>
<td>$T_d$</td>
<td>0.1</td>
<td>0.1</td>
<td>-</td>
<td>0.012</td>
</tr>
</tbody>
</table>

Tab.4.4. – Initial and identified AVR parameters, together with the allowed range of variations and the example values reported in IEEE Std.421 [2005].
B. Identification of the parameters of the GT dynamic model and its governor

The identification procedure is applied in two steps. In the first step, the identification is based on the GT speed transient recorded during a load rejection from 18 MW to no-load full-speed condition. In this step, the parameters of the GT transfer function and the parameters of the GT drive train are identified assuming a closing step input to the FMV block. Fig. 4.9 shows the comparison between the experimental GT angular speed transient and the corresponding simulation results using the implemented model. Tab. 4.5 shows the initial guess values and the identified parameter values of the GT transfer function and the drive train model.

![Comparison between the GT angular speed transient recorded during a 18 MW load rejection and the corresponding transients obtained by using the implemented model.](image)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Initial guess value</th>
<th>Optimized values</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\tau_{z2}$ (s)</td>
<td>3.13</td>
<td>0.06</td>
</tr>
<tr>
<td>$\tau_{p2}$ (s)</td>
<td>30.03</td>
<td>5.15</td>
</tr>
<tr>
<td>$\tau_{z31}$ (s)</td>
<td>0.032</td>
<td>0.24</td>
</tr>
<tr>
<td>$\tau_{z32}$ (s)</td>
<td>0.31</td>
<td>0.16</td>
</tr>
<tr>
<td>$\tau_{p31}$ (s)</td>
<td>0.38</td>
<td>0.3</td>
</tr>
<tr>
<td>$\tau_{p32}$ (s)</td>
<td>1.08</td>
<td>1.08</td>
</tr>
<tr>
<td>$J_1$ (s)</td>
<td>0.73</td>
<td>0.89</td>
</tr>
<tr>
<td>$DSR_1$ (Nms/rad)</td>
<td>$5\cdot10^3$</td>
<td>$3.67\cdot10^3$</td>
</tr>
<tr>
<td>$HSP$ (Nm/rad)</td>
<td>$4\cdot10^6$</td>
<td>$7.858\cdot10^6$</td>
</tr>
<tr>
<td>$DSR_2$ (Nms/rad)</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

Tab. 4.5. – Initial and identified parameters of the GT model.
In the second identification step relevant to the proportional \((K_{govP})\) and integral \((K_{govI})\) speed governor parameters, we use, as reference, the \(P_m\) transients provided by the Rolls-Royce Aeroengine Performance Program (RRAP) for small perturbations of the \(\Delta \omega\) speed governor input at 20 MW initial power output. In particular the \(\Delta \omega\) varies as a sinusoid function, with amplitude equal to 5 rpm and frequency equal to 0.2 Hz, followed, after 25 s, by a 1.73 rpm positive step of and, after 85 s, a 3.46 rpm negative step. Fig.4.10 shows the comparison between the \(P_m\) transients obtained by the detailed RRAP and the implemented model. Tab.4.6 shows the initial guess values and the identified parameter values of the GT speed governor model.

![Comparison between the GT \(P_m\) transient simulated with a detailed model (reference) and those obtained by the implemented model, for small speed perturbations.](image)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Initial guess value</th>
<th>Identified values</th>
</tr>
</thead>
<tbody>
<tr>
<td>(K_{govP})</td>
<td>7.5</td>
<td>2.1</td>
</tr>
<tr>
<td>(K_{govI})</td>
<td>0.25</td>
<td>0.23</td>
</tr>
</tbody>
</table>

Tab.4.6. – Initial and identified parameters of the GT speed governor model.

### 4.5. Analysis of the islanding transition

The following simulations show the analysis of different islanding strategies for rather large levels of power exported to the external transmission network. The success of the islanding manoeuvre is related to the balance between the power production and local network load. Due to the structure and characteristics of the considered system, initial scenarios of both import and export power flows to the transmission network should be
taken into consideration. The islanding manoeuvre for the case of an initial import scenario requires the fast reduction of the local network load. On the other hand, an initial export scenario, which is the case here analyzed, requires a proper control strategy of the three production units in order to preserve stable and secure operating conditions of the system. For the case in which the system is exporting power to the transmission grid, the most critical constraints are:

- over-speed limits of the GT and ST units (e.g. 110%);
- GT combustion constraint;
- HRSG overpressure limits.

The frequency regulation is mainly performed by the GTs. At rated power output, the Dry Low Emission (DLE) combustion system of the GTs is controlled in order to minimize NOx emission. When the GT load is lower than around 55-60% (15°C reference temperature), the combustor control changes to the conventional combustion mode [James, 2002]. In order to preserve the combustion stability, such a transition may be performed only at low GT output change rate and therefore it represents a critical constraint for the system frequency control when the islanding manoeuvre causes a significant power surplus. If also the ST unit contributes to load balancing and frequency regulation, the HRSG overpressures and HP collector pressure \( p_{\text{HP}} \) must be limited by means the bypass valve opening. In order to successfully perform the islanding manoeuvre in the case of a rather large power export, two basic techniques are here compared: shutdown of one of the two GTs or the fast reduction of the ST control valve opening. In particular, for the case of a power export equal to half power plant generating capacity, namely 40 MW, we compare the results obtained for three different operation modes of GTs and ST units:

- Operation Mode 1 (om1): ST pressure controlled, GT1 frequency controlled with LFI and GT2 frequency controlled without LFI;
- Operation Mode 2 (om2): ST pressure controlled, GT1 frequency controlled with LFI and GT2 shutdown;
- Operation Mode 3 (om3): GT1 frequency controlled with LFI, GT2 frequency controlled without LFI and fast reduction of ST output power to the lower limit.

The GT2 shutdown is achieved by the load reference fast removal and by the subsequent action of the reverse active power relay with a 10 s delay. The ST output fast reduction is obtained by setting the reference of the power controlled ST to the minimum value (3.4 MW). The closing rate limit of the ST control valve servomotor is assumed equal to -1 pu/s. An even faster ST action could be achieved by the intervention of a load drop anticipator (LDA) relay.
Chapter 4

A. Operating mode om1)

The islanding manoeuvre transient when the system is exporting 40 MW is calculated by assuming the initial GT outputs equal to 30.5 MW and ST output equal to 22.7 MW. The transient simulation is started by the opening of BR1 at 1 s from the reference time. (The automatic power management system may command the islanding manoeuvre within 0.2 s after a violation of the transmission network frequency decay limit). ST is controlled in order to maintain $p_{HP}$ at the rated value. GT1 and GT2 participate, instead, to the frequency regulation with a 5% droop. The islanding manoeuvre is assumed to activate the GT1 LFI device that integrates the frequency error in order to bring it back to the 50 Hz rated value. Fig.4.11 shows the transients of the GTs and ST mechanical powers $P_m$ and of the corresponding active power outputs $P_e$. Fig.4.12 shows the rotors angular speed and Fig.4.13 shows the pressures at the steam collector and at the two HRSG evaporators.

Fig.4.11. – GTs and ST mechanical powers and active power outputs (in pu of the corresponding synchronous generator rated power) during islanding manoeuvre for the case of 40 MW power flow export and operation mode om1).
As shown in Fig.4.11 the GTs combustion constraint is violated. This is due to the fact that the islanding manoeuvre is performed with all the three units in operation with the mechanical output of the pressure controlled ST that does not significantly change, as it follows the slow pressure dynamics shown in Fig.4.13. As the HP collector pressure is lower than the rated value, the bypass control valves at the HRSG outputs stay closed.
Therefore, the frequency is controlled only by the fast reduction of the GTs output, so as to compensate the significant initial positive power imbalance. The different behaviour of the two GTs is due to the fact that only the LFI of GT1 is active, whilst GT2 is controlled only by its droop speed governor. The transient does not reach a new steady state in the considered 40 s time interval after the islanding manoeuvre due to the action of the GT1 LFI and the time constants related to HRSGs and steam collector dynamics which cause the pressure slow droop of the steam collector pressure (see Fig.4.13) and of the corresponding ST output (see 4.11).

B. Operating mode om2) and om3)

The islanding manoeuvre transient is calculated assuming the initial steady state of the simulation of om1). Both the commands of GT2 shutdown and ST output fast reduction are simultaneous to the BR1 opening. Fig.4.14 and Fig.4.15 show the transients of GTs and ST mechanical powers \( P_m \) and active power outputs \( P_e \) obtained by applying operation modes om2) and om3), respectively. Fig.4.14 shows that with the GT2 shutdown – operating mode om2) – the GT1 mechanical power transient violates the combustion constraint. The GT2 shutdown is realized by the fast closing of the fuel valve in correspondence to the BR1 opening, then the relevant mechanical power decreases and, at 17 s, the unit starts to absorb active power from the network. The reverse power relay, used to protect the turbine against motoring, operates by opening generator breaker BR-GT2 at 27 s. Within the first 7-8 seconds after the BR1 opening, the GT2 active output reduction is similar to the one that would be forced by the speed governor (shown in Fig.4.11) with, therefore, limited additional benefits for the combustion constraints of GT1. Fig.4.15 shows that by a ST output fast reduction to the minimum limit – operation mode om3) – both the GT1 and GT2 mechanical power transients do not violate the combustion constraint. GT1 mechanical power crosses the combustion constraint only at low change rate by the action of the LFI device. This behaviour may result in a successful islanding manoeuvre.
Control of distributed energy resources during islanding and emergency operation

Fig. 4.14. – GTs and ST mechanical powers and active power outputs during islanding manoeuvre for the case of 40 MW power flow export and operation mode om2).

Fig. 4.15. – GTs and ST mechanical powers and active power outputs during islanding manoeuvre for the case of 40 MW power flow export and operation mode om3).

Fig. 4.16 shows that by applying operation mode om3) also the frequency regulation improves. However, the fast reduction of the ST power requires that the pressure of the steam collector is regulated by the action of the bypass control valves located at the HRSG outputs, as shown in Fig. 4.17. The bypass valve opening rate limit is assumed equal to 0.5 pu/s. By adopting operation modes om1) and om2), the bypass valves stay closed.
Fig. 4.16. – GT1 shaft angular speed transients, obtained by adopting operation modes om2 and om3).

Fig. 4.17. – Steam collector pressure transients, obtained by adopting operation modes om2 and om3), and bypass valve opening for the case of om3).
4.6. **Analysis of the energization manoeuvres and black start-up capability**

The following simulations aim at verifying the feasibility of the energization of the path from a TG unit, with autonomous black-start capabilities, to the local distribution network loads. The simulation results of Fig.4.18, Fig.4.19 and Fig.4.20 show the transients during the subsequent energization of the components along the path from unit GT1, assumed with autonomous black-start capabilities, to the distribution network loads after a blackout. In particular, Fig.4.18 shows the generator armature currents during the energization of step-up transformer TR-GT1. Fig.4.19 shows the line to ground transient voltages at the 132 kV distribution substation during the energization of the 800 m cable line. Fig.4.20 shows the GT generator armature currents during the energization of distribution transformer TR-D1 feeding the aggregate load of one of the distribution feeders.

![Fig.4.18. – GT synchronous generator armature current transient during TR-GT1 energization.](image-url)
Fig. 4.19. – Line to ground transient voltages at the 132 kV distribution substation during the energization of the 800 m cable line.

Fig. 4.20. – GT synchronous generator armature currents during the energization of the distribution transformer TR-D1 feeding the aggregate load of one of the distribution feeders (0.58 MW, 0.28 MVAr load).

Fig. 4.21 compares the GT1 generator active and reactive (PQ) power trajectory during the TR-GT1 energization with the capability limits provided by the manufacturer. As power transformer residual fluxes decay very slowly and transformers can retain high levels of residual flux for long periods [Nunes et al., 2003], the comparison is carried out for two values of residual flux, namely 0 and 0.8 pu. In order to verify the minimum intervention current of BR-GT1 breaker relay during TR-GT1 energization, a statistical...
study has been performed by making reference to the random nature of the closing time of the generator breaker poles. Closing time $T_c$ of each pole is assumed a random variable characterized by a Gaussian distribution with typical mean value $\mu_{T_c} = 36$ ms and standard deviation $\sigma_{T_c} = 0.75$ ms [e.g., CIGRE Working Group 13.05, 1971; CIGRE Working Group 13-02, 1973; CIGRE Working Group 33.02, 1990].

![CAPABILITY CURVE (D-rise)](image)

An additional time delay $T_d$, uniformly distributed along a 20 ms time window (50 Hz), is added to $T_c$ to take into account the random instant within the period of the steady-state voltage waveform in which the breaker closes. Fig.4.22 shows the cumulative distribution function of the maximum RMS values of the GT1 generator currents obtained by 200 simulations of the TR-GT1 energization with reference to both null and 0.8 pu residual flux.

Fig.4.21. – Comparison between GT1 P-Q trajectories during the TR-GT1 energization and the synchronous machine capability limits.
As conclusive remarks it could be noted as the developed simulator represents a useful tool for the design of the automatic system needed to improve both reliability and speed of the energization and islanding manoeuvres of the considered power system.

The simulation results show that, for the case of system energization after its blackout, the GT unit has the capabilities to perform a successful energization manoeuvre. Concerning the islanding manoeuvre, the results show that the contribution to the frequency regulation and load balance provided by the ST, in addition to the frequency regulation provided by the GTs, is effective for a successful islanding manoeuvre performed at large export power levels. The presence of the bypass control valves is therefore required in order to compensate resulting overpressures in the steam collector.
Chapter 5

Fault location procedure
for active distribution networks

5.1. Introduction

Power quality of distribution networks, with particular reference to the number and duration of short and long interruptions, depends on the annual number of faults and on the relevant restoration times. Whether a periodical and focused maintenance could greatly reduce fault events, a rapid and accurate fault location contribute significantly to the reduction of outage times [CIRED WG03 Fault Management, 1998]. This is still important considering the typical radial structure of distribution networks.

Fault location techniques are usually off-line procedures mainly focused on the accuracy of the results. Therefore, they are not so strictly related with protection systems, which are indeed typical on-line applications characterized by the rapidity of operation.

As happen for many technologies in power systems, also the fault location methods were developed first for transmission systems. However, extend what actually used in the transmission networks to the distribution networks is not an easy task due to the significant differences in the networks configuration, dimensions and grounding connections.

For many other reasons the fault location in the distribution networks is difficult. For instance, the presence of feeders with multiple lateral branches and/or intermediate connection of loads and distributed generators, the simultaneous presence of both overhead lines and cables as well as the lack in the knowledge of the lines parameters. Furthermore, faults usually are characterized by high impedance and hence, by modest values of currents and voltages. This imply that errors due to measurement transformers can become important. Many of these issues have not yet been deeply investigated in the literature and renewed interest to this important field derive to the challenges introduced by distributed generation.

For what concern the power quality, the distribution networks are the most sensible part of the electrical power systems. On the one hand the huge quantity of users connected can affect negatively the service quality introducing any sort of disturbs,
whereas on the other hand, the increasing presence of sensible loads obliged DNOs to deliver supply with high standard, responding to the severe regulatory policy requirements. This means also that switching transients associated to both traditionally fault location searching techniques and subsequent service restoration reconfiguration maneuvers may also stress the equipments and affect power quality of the distribution networks.

5.2. Approaches for fault location in distribution networks

The fault location problem has been extensively investigated and several approaches have been proposed in the literature. These approaches can be grouped into the following main categories:

1. methods based on impedance measurement [e.g., Sachdev and Agarwal, 1988; Srinivasan and St.-Jacques, 1989; Girgis et al., 1992];
2. methods based on the analysis of fault-originated traveling waves [e.g., Ancell and Pahalawatha, 1994; Chaari et al., 1996; Magnago and Abur, 1998 and 1999; Thomas et al., 1998].

It is worth mentioning that expert systems, often based on the use of neural networks, have been also proposed [e.g., Ebron et al., 1990; Chen and Maun, 2000; Kandil et al., 2002].

Impedance measurement methods rely essentially on the analysis at power frequency of voltage and current fault signals. Fault location in transmission lines is the typical application field of these techniques in view of the significant line length and simple network topology. Their application to distribution networks, characterized by multi branched radial topologies, may result in a decrease of the location accuracy. Traveling wave methods involve the measurements of high frequency components as well as the implementation of complex signal analysis techniques. They rely on the analysis of the high-frequency components of fault-originated transients which are rather uninfluenced by the fault type and impedance [Magnago and Abur, 1998]. Their use in distribution network has been already proposed typically coupled with the use of the discrete wavelet analysis [e.g., Chaari et al., 1996; Magnago and Abur, 1999]. Signal analysis approaches, based on measurements of current and voltage, receive increasing interest due to development of microprocessor technology. An aspect of great interest for distribution networks is related to the number of measurement terminals required by the applied method. A really attractive approach actually pursued by researchers is based on so-called single ended methods. They needs measurements from only one terminal, typically installed in the primary station. Economical benefits derived from the less number of
units installed and the absence of any communication tool to correlate measurements of different terminals (typically based on GPS units) are recognized.

Actual research guidelines lead to conveniently combine signal-analysis based method with knowledge-based methods, in order to develop hybrid systems able to overcome limitations of the single solutions.

5.3. Development of fault location procedure based on the wavelet analysis of electromagnetic fault transients

The method presented in the thesis belongs to category 2, above discussed, and is based on the extension of the algorithm presented by Borghetti et al., [2006]. Voltage transients generated by the fault are analyzed by using the continuous wavelet transformation (CWT); the proposed CWT analysis, performed in frequency domain, is aimed at determining peculiar frequencies that can be used to infer the fault location assuming the network topology and line conductor geometry known.

In order to overcome some limitation and to improve the performances of the method proposed Borghetti et al., [2006], here is proposed an algorithm to build specific mother wavelets directly inferred from the recorded fault-originated voltage transients. The influence of such a fault-inferred mother wavelet on the fault location accuracy is analyzed, and the results compared with those obtained by using the traditional Morlet mother wavelet, which is one of the several mother wavelets proposed in the literature [e.g., Goupillaud et al., 1985; Daubechies, 1988 and 1990; Mallat, 1989a and 1989b; Rioul, 1991].

The proposed approach is based on the identification of some characteristic frequencies associated with specific paths in which the fault-originated traveling waves are propagating. These characteristic frequencies can be identified by means of adequate signal analysis techniques applied to the voltage or current waveforms recorded at an observation point (typically located at the lower voltage terminals of the transformer feeding the distribution network).

5.3.1. Fault location information inferred from travelling waves

Fault-originated traveling waves propagate along the network and reflect at line terminations, junctions between feeders, and the fault location. The relevant reflection coefficients depend to the line surge impedances, the impedances of power components connected to the network terminations and to the fault impedance value. A certain number
of paths \( p \), covered by the traveling waves, can be associated to the observation point \( m \) where the voltage or current waveforms are measured. Assuming a network topology characterized by a main feeder and some laterals (radial configuration), the number of paths is equal to the number of network laterals plus the number of feeder-lateral junctions. As an example, Fig. 5.1 shows a fault location placed between buses 812 and 814 of the first section of the main feeder of the IEEE 34-bus distribution system (see paragraph 3.5.2) Four different paths can be identified and paths #1, #3 and #4 can be associated to the relevant traveling waves and are contained in the voltage or current waveforms recorded at the observation point placed in correspondence of the bus 800 (medium voltage side of the feeding substation).

Each path \( p \) can be associated to a number of characteristic frequencies, one for each of the traveling-wave propagation modes [Clarke, 1943; Dommel, 1969]. Indeed, it is worth noting that the propagation of traveling waves in multi-conductor lines involves the presence of different propagation speeds. Therefore, the identification of characteristic frequencies related to each path \( p \) is separately carried out for the various propagation modes. In order to apply the modal transformation matrixes in time-domain, the modal transformation matrix should be real and their calculation in what follows is performed using the line constant routine of the EMTP [Dommel, 1969]. Assuming the network topology and the traveling wave speeds of the various propagation modes are known, frequency \( f_{p,i} \) of mode \( i \) through path can be evaluated \textit{a priori} as

\[
f_{p,i} = \frac{v_i}{n_p L_p}
\]

where \( v_i \) is the travelling speed of the \( i \)-th propagation mode, \( L_p \) is the length of the \( p \)-th path and \( n_p (\in \mathbb{N}) \) is the number of times needed for a given travelling wave to travel along path \( p \) before attain again the same polarity. \( p-1 \) values are used to identify the faulted section and the remaining one to identify the fault distance between observation point \( m \) and the fault location.
In order to associate a characteristic frequency to each path, we can see the fault as a step-function source triggered by the fault occurrence. The fault-generated step wave travels along the network and is reflected in correspondence to the abovementioned path extremities. Each extremity is characterized by specific voltage reflection coefficient, namely:

- extremities where a power transformer is connected can be considered as open circuits and the relevant reflection coefficient is close to +1;
- extremities that correspond to a junction between more than two lines are characterized by a negative reflection coefficient;
- the reflection coefficient of the extremity where the fault is occurring is close to -1, as the fault impedance value is lower than the line surge impedance.

The coefficient $n_p$ depends on the sign of the reflection coefficients of the two path extremities, namely $n_p$ is equal to 2 or to 4 if the reflection coefficients have the same or opposite sign, respectively.

### 5.3.2. Application of continuous wavelet analysis to fault transients

Current or voltage fault transient signals are composed by superimposing the industrial frequency waveform (constant low frequency component of large duration) and the transient disturbance caused by the fault (time-varying high frequency component of short duration). The resulting signal is therefore characterized by a continuous spectrum due to its time-variant properties. The identification of characteristic frequencies $f_{p,i}$ by means of traditional operators, such as the fast Fourier transform (FFT), is certainly not
appropriate. Indeed, such an operator analyzes the signal with a constant frequency resolution that depends to the width of the chosen observation time window\(^1\).

In view of the above, the identification of characteristic frequencies \(f_{p,i}\) should be accomplished by using appropriate signal analysis techniques that allow the adjustment of the signal spectrum versus time. Such a requirement is fulfilled by implementing the so-called time-frequency representations (TFRs) [Oppenheim and Schafer, 1989]. In particular, a signal TFR links a one-dimensional time signal \(x(t)\) to a bi-dimensional function of time and frequency, \(T_x(t,f)\). Typical examples of linear TFRs are the short time Fourier transform (STFT) and the wavelet transform. As known, STFT is a windowed Fourier transform in which the observation interval is divided into a given number of subintervals. For each subinterval, STFT is computed according to the following equation:

\[
T_{STFT}(t,f) = \int_{-\infty}^{\infty} x(\tau) w(t-\tau) e^{-j2\pi f \tau} d\tau
\]

where \(w(\tau)\) is the windowing function that defines the length of the subinterval. Similarly to the Fourier Transform, the main characteristic of the STFT is that the time-frequency resolution is constant and equal to the duration of each subinterval. Therefore, it is not the more appropriate tool for the analysis of fault signals. The wavelet transform, on the other hand, is a TFR that allows a good frequency resolution at low frequencies and a good time resolution at high frequencies [Graps, 1995]. In particular, it allows for the analysis of high frequency components very close to each other in time and low frequency components very close each other in frequency. These properties are indeed suitable for the study of transient waveforms produced by faults.

The proposed fault location approach is based on the use of a CWT. The CWT of signal \(x(t)\) is, as known, the integral of the product between \(x(t)\) and the so-called daughter-wavelets, which are time translated and scale expanded/compressed versions of a finite energy function \(\psi(t)\), called mother wavelet. This transformation, equivalent to a scalar product, produces wavelet coefficients \(C(a,b)\) that represent the TFR bi-dimensional function of time and frequency \(T_x(t,f)\). Coefficients \(C(a,b)\) can be seen as similarity indexes between the signal and the daughter wavelet located at position \(b\) (time shifting factor) with scale.

\(^1\) In order to provide an example, let consider that frequencies \(f_{p,i}\) usually ranges from few kHz to few tens of kHz and are contained in a time window of the fault signals of a typical duration of 1 ms. Therefore, the application of the traditional FFT to the fault signal results in a frequency resolution of 1 kHz that is certainly inadequate to correctly identify frequencies \(f_{p,i}\).
The analyzed part of the recorded signal $s(t)$, that corresponds to a voltage or current fault-transient, is usually characterized by a short duration of few milliseconds. Such a duration corresponds to the product between sampling time $T_s$ and number of recorded samples $N$. Therefore, in the numerical implementation of the CWT applied to signal $s(t)$, the elements of matrix $C(a,b)$ of are given by

$$C(a,b) = C(a,iT_s) = T_s \frac{1}{\sqrt{|a|}} \sum_{n=0}^{N-1} \psi^*(\frac{(n-i)T_s}{a}) s(nT_s)$$  \hspace{1cm} (5.3)

where parameter $a$ corresponds to the scale factor and product $i\cdot T_s$ corresponds to the so-called time shifting factor $b$. It is worth noting that if the center frequency of the mother wavelet $\psi(t)$ is $F_0$, the one of the daughter-wavelet $\psi(t)$ is $F_0/a$. The sum of the squared values of all coefficients belonging to the same scale, which are denoted as CWT signal energy $E_{cwt}(a)$, identifies a “scalogram” which provides the weight of each frequency component [Lobos et al., 2005]

$$E_{cwt}(a) = \sum_{n=0}^{N-1} \left| C(a,nT_s) \right|^2$$  \hspace{1cm} (5.4)

The identification of the characteristic frequencies $f_{p,i}$ associated to the fault location is realized by inspecting the relative maximum peaks of the obtained scalogram $E_{cwt}(a)$.

### 5.3.3. A first illustrative example of application

As a first example, the proposed fault location procedure is applied to the case of a three-phase balanced solid fault at bus 812 of the IEEE 34-bus distribution system simulated by means of a model implemented in the EMTP-RV environment [Mahseredjian et al., 2002; Mahseredjian et al., 2005]. Additional details on such a system, relevant transmission line propagation modes and implementation are given in 5.3.5.

Locating the observation point $m$ at bus 800 and the fault at bus 812, three traveling-waves are contained in the fault transient. They are characterized by a common path-terminal, bus 800, and other three path-terminals corresponding to buses 812 (path #1), 808 (path #2) and 810 (path #3). As reported above, if we consider, in a first

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2 The examples provided in the follows make reference to a sampling frequency equal to 10 MHz. For the transients of the experimental setup (Fig.5.11) the sampling frequency is instead equal to 1 GHz.
approximation, the fault as a step-function source triggered by the fault occurrence, the resulting voltage transient observed at bus 800 is the sum of three square waves each one characterized by a main frequency given by (5.1). Tab.5.1 shows the theoretical frequency values obtained by applying (5.1) to the considered example.

<table>
<thead>
<tr>
<th>Path</th>
<th>Path length $n_p L_p$ (km)</th>
<th>Theoretical frequencies $f_{p,i}$ (traveling wave refer to propagation mode 1 of Tab.5.3) (kHz)</th>
<th>CWT identified frequency (kHz)</th>
</tr>
</thead>
<tbody>
<tr>
<td>800-812</td>
<td>4x22.57</td>
<td>3.29</td>
<td>3.70</td>
</tr>
<tr>
<td>800-808</td>
<td>4x11.14</td>
<td>6.68</td>
<td>-</td>
</tr>
<tr>
<td>800-810</td>
<td>2x12.92</td>
<td>11.52</td>
<td>9.60</td>
</tr>
</tbody>
</table>

Tab.5.1. – Theoretical and CWT-identified characteristic frequencies relevant to the propagation paths for a three phase solid fault located at node 812 of Fig.5.1. The results make reference to the Morlet mother wavelet. The analysis refers to propagation mode 1 of Tab.5.3.

Tab.5.1. also shows the characteristic frequency values obtained by applying the CWT-analysis using with the Morlet mother wavelet to the voltage transient recorded at the medium voltage side of the feeding substation (bus 800). The CWT-analysis is performed in a time window of 2 ms and refers to propagation mode 1. The specific characteristics of line propagation modes are given in Tab.5.3.

Fig.5.2 shows the obtained scalogram relevant to the signal energy values $E_{cwt}(a)$. As it can be seen, the CWT analysis is able to identify the frequencies related to path #1 and path #3, whilst it is unable to identify path #2. The frequency associated with the second path is hidden by the other frequencies due to the large filter amplitude related to the adopted mother wavelet.
The location error is defined as
\[
    e_\% = \frac{100}{L_{p^*}} \left| \frac{L_{p^*}}{n_{p^*}} \cdot \frac{v_i}{f_{p^*,i}^{CWT}} \right| \quad (5.5)
\]

Where \(L_{p^*}\) is the length of path \(p^*\) between the observation bus and the fault location, \(v_i\) is the propagation speed of mode \(i\), \(n_{p^*}\) is equal to 4 and \(f_{p^*,i}^{CWT}\) is the CWT-identified frequency relevant path \(p^*\). The location error for the considered fault achieved by the CWT analysis is equal to 10.9%.

5.3.4. Definition of mother wavelets inferred from fault originated transients

A. Requirements for the Definition of a Mother Wavelet

As known, the CWT allows for the adoption of arbitrary mother wavelets that have to comply with the so-called admissibility condition
\[
    C_\psi = \int_{-\infty}^{+\infty} \left| \frac{\Psi(\omega)}{\omega} \right|^2 d\omega < \infty \quad (5.6)
\]

Sufficient conditions (SC) to satisfy (5.6) are SC-a) mean value of \(\psi(t)\) equal to zero, namely \(\int_{-\infty}^{+\infty} \psi(t)dt = 0\) SC-b) fast decrease to zero of \(\psi(t)\) for \(t \rightarrow \pm \infty\). If the CWT backward transformation, i.e. the signal reconstruction, must be guaranteed, the choice of the number and spacing of scales \(a\) as well as the choice of the mother wavelet, should comply with the so-called orthogonality condition [e.g., Strang and Nguyen, 1996].

\[
    f(t) = \frac{1}{C_\psi} \int_{-\infty}^{+\infty} \int_{-\infty}^{+\infty} C(a,b) \psi_{a,b}(t) \frac{da}{a^2} db \quad (5.7)
\]

The CWT adopted in the proposed fault location procedure does not require to satisfy the orthogonality condition which is needed if time-domain fault location approaches [e.g., Magnago and Abur, 1998 and 1999], based on reconstruction of the fault transient signal related to each characteristic frequency, are used.
B. Algorithm for the Construction of a Mother Wavelet Inferred From Fault-Originated Transients

We start from the concept that the CWT can be considered as a filtering process based on the scalar product between daughter wavelets and the analyzed signal. The maximization of such a scalar product is related to the similarity between the mother wavelet and the signal itself. Therefore, the proposed approach builds the mother wavelet by applying the above sufficient conditions to the initial part of the fault transient waveform. The algorithm developed for building the mother wavelet is composed by the following steps, which will be described next. In order to illustrate the implementation of each step, the description refers to the case of a three-phase solid fault located in correspondence of bus 814 of the IEEE 34-bus distribution system.

1. Being \( s(t) \) the fault transient waveform relevant to a specific propagation mode, \( \tilde{s}(t) \) is extracted as the initial part of \( s(t) \). Function \( \tilde{s}(t) \) is used to build the mother wavelet \( \psi(t) \) and starts from the fault-occurrence time with a duration \( \Delta t \) that corresponds to the minimum expected frequency content of the analyzed signal. Fig. 5.3 shows the voltage waveform of the propagation mode 1 observed at bus 800 and the selection of the part of the fault transient waveform \( \tilde{s}(t) \) used to build the mother wavelet.

![Fig. 5.3. Fault voltage transient waveform of the propagation mode 1 observed at bus 800 of the IEEE 34-bus distribution system for a three-phase solid fault in 814; the selection of \( \tilde{s}(t) \) used to build the mother wavelet.](image-url)
2. \( \tilde{s}(t) \) is then normalized with respect to its maximum value. To satisfy the above mentioned SC-a, \( \tilde{s}(t) \) is then shifted in order to obtain a mean value equal to zero. Fig.5.4 shows the modified signal \( \tilde{s}(t) \) according with this step of the algorithm.

3. Finally, in order to satisfy SC-b, the mother wavelet \( \psi(t) \) is built as a series of several \( k\Delta t \)-shifted \( \tilde{s}(t) \) multiplied by an exponential decay characterized by a time constant \( \tau \):

\[
\psi(t) = \left( \sum_{k \in \mathbb{N}} \tilde{s}(t + k\Delta t) + \tilde{s}(t - k\Delta t) \right) e^{-t/\tau}
\]

(5.8)

With

\[
\tilde{s}(t) = \begin{cases} 
\tilde{s}(t) & 0 \leq t \leq \Delta t \\
0 & t \leq 0; t \geq \Delta t 
\end{cases}
\]

(5.9)

Fig.5.5 shows the obtained mother wavelet.
The obtained mother wavelet $\psi(t)$ given by (5.8) is indeed a mother wavelet because its construction is in accordance with the two sufficient condition (SC-a and SC-b) that satisfy the admissibility condition.

As known, the wavelet analysis consists in a filtering process of the analyzed signal by means of subsequent constant-energy shifting-filter given by the daughter wavelets

$$F(C(a,b)) = \sqrt{a} \Psi^*(a \cdot \omega) X(\omega)$$ (5.10)

where $F(C(a,b))$, $X(\omega)$ and $\Psi(\omega)$ are the Fourier transforms of $C(a,b)$, the fault signal $x(t)$ and the daughter wavelet $\psi(t)$ respectively. According to this wavelet analysis basic concept, Fig.5.6 shows the frequency-domain spectrum amplitudes of three daughter wavelets (referring to three different scales) of the transient-based mother wavelet of Fig.5.5. As it can be seen, the three curves of Fig.5.6 clearly refer to a constant-energy shifting-filter.
Fig. 5.6. – Frequency domain spectrums of three daughter-wavelet (referring to three different scales) of the transient-based mother wavelet of Fig. 5.5.

Fig. 5.7 shows the comparison of the results obtained with the CWT analysis by using the fault-inferred and Morlet mother wavelets. The identified frequencies, as well as the relevant paths, are reported in Tab. 5.2. As for the case illustrated in the previous section, the CWT analysis referring to the Morlet mother wavelet is able to detect only the frequencies associated with the first and second paths while the frequency peak associated with the third path appears hidden by the second peak. On the contrary, the CWT referring to the transient-inferred mother wavelet allows the identification of all the three frequencies.

Fig. 5.7. – Comparison between the results of the CWT analysis performed with Morlet and fault-inferred mother wavelets of mode 1 of the voltage transient recorded at bus 800 for a three-phase solid fault at bus 814. The values are in per-unit with respect to the maximum.
Chapter 5

<table>
<thead>
<tr>
<th>Path</th>
<th>Path length (km)</th>
<th>Theoretical frequencies $f_{p,i}$ (traveling wave refer to propagation mode 1 of Tab.5.3) (kHz)</th>
<th>CWT identified frequency (kHz)</th>
</tr>
</thead>
<tbody>
<tr>
<td>800-814</td>
<td>4x31.63</td>
<td>2.35</td>
<td>2.90</td>
</tr>
<tr>
<td>800-808</td>
<td>4x11.14</td>
<td>6.68</td>
<td>7.35</td>
</tr>
<tr>
<td>800-810</td>
<td>2x12.92</td>
<td>11.52</td>
<td>11.35</td>
</tr>
</tbody>
</table>

Tab.5.2. – Characteristic and CWT identified-frequencies relevant to the propagation paths for a three phase solid fault located at node 814 of Fig.5.1. The analysis refers to the propagation mode 1 of Tab.5.3.

<table>
<thead>
<tr>
<th>mode</th>
<th>$r$ (Ω/km)</th>
<th>$l$ (mH/km)</th>
<th>$c$ (μF/km)</th>
<th>$z_c$ (Ω)</th>
<th>Propagation speed (km/s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>0.984</td>
<td>2.367</td>
<td>5.823·10^{-4}</td>
<td>637.99</td>
<td>2.693·10^{05}</td>
</tr>
<tr>
<td>1</td>
<td>0.136</td>
<td>0.908</td>
<td>1.243·10^{-4}</td>
<td>270.27</td>
<td>2.976·10^{05}</td>
</tr>
<tr>
<td>2</td>
<td>0.065</td>
<td>0.875</td>
<td>1.273·10^{-4}</td>
<td>262.17</td>
<td>2.997·10^{05}</td>
</tr>
</tbody>
</table>

Tab.5.3. – Value of the modal parameters calculated at 1 kHz of the considered overhead line configuration, ground resistivity equal to 100 Ωm.

As for the case illustrated in the previous section, the CWT analysis referring to the Morlet mother wavelet is able to detect only the frequencies associated with the first and second paths while the frequency peak associated with the third path appears hidden by the second peak. On the contrary, the CWT referring to the transient-inferred mother wavelet allows the identification of all the three frequencies.

5.3.5. Analysis of fault events simulated on a typical distribution network modeled in EMTP

The previous examples refer to the case of balanced solid faults. In what follows, the performances of the proposed algorithm are tested against for the cases of: 1) unbalanced faults, 2) variable values of fault impedance; 3) different exponential decay time of the mother wavelet; and 4) different fault locations along the IEEE 34-bus distribution system, as described in what follows.

A. Adapted IEEE 34-Bus Distribution Systems Adapted for This Study

The IEEE 34-bus test feeder is composed by branches characterized by different conductor configurations. In order to simplify the network configuration, the following assumptions have been made: 1) all the branches of the network are composed by
overhead lines which conductor configuration is the “ID #500” reported by IEEE Working Group on Distribution Planning, [1991] (three-phase plus neutral); 2) the network loads are assumed located in correspondence of the line terminations and connected by means of distribution power transformers. Paragraph 3.5.2 shows the IEEE 34-bus distribution system topology implemented in the EMTP-RV simulation environment. Concerning the power distribution transformers, they are represented by means of the parallel of a 50 Hz standard model and a $\Pi$ of capacitances in order to represent, in a first approximation, its response to transients at a frequency range around 100 kHz [see Fig.5.8].

The parameters adopted for the 50 Hz part of the transformer model are the following: 5MVA 150/24.9 kV $V_{sc}=9\%$ for the substation; 1 MVA 24.9/0.4 kV $V_{sc}=8\%$ for the loads and 2.5 MVA 24.9/24.9 kV $V_{sc}=4\%$ for the loads. A constant parameter line model (CP-line model) is adopted for the representation of the overhead lines [Dommel, 1969]. The adoption of a frequency dependent line model (e.g., the FD-line model [Dommel, 1969]) results in voltage transients close to those obtained with the CP-line model. This is due on the one hand to the typically limited length of distribution lines and, on the other hand, to the typical frequency content of the fault transients, which does not exceed a few tens of kHz. Tab.5.3 shows the modal parameters of the CP-line model that refers to the considered overhead line configuration. The modal parameters are calculated for a frequency equal to 1 kHz and assuming the ground resistivity equal to 100 $\Omega \cdot m$.

![Fig.5.8. – Analyzed IEEE 34-bus distribution system case study. Transformer model.](image)

**B. Unbalanced grounded faults**

The type of fault (balanced or unbalanced) influences the CWT signal energy $E_{cwt}(a)$ relevant to each propagation mode. In particular, for the case of unbalanced faults, the propagation mode 0 always results, as expected, in the larger energy content. Therefore, the propagation mode 0 (ground mode) is the CWT-analyzed one for the case of unbalanced grounded faults. Let consider a phase-to-ground solid fault located in correspondence of bus 812 of Fig.5.1. For this fault location, three characteristic frequencies can be identified. Tab.5.4 shows the comparison between the results obtained with the CWT analysis using the fault-inferred and Morlet mother wavelets. Also for the case of unbalanced faults, the proposed approach, suitably combined with the use of
transient-based mother wavelet, allows for the identification of all the characteristic frequencies.

<table>
<thead>
<tr>
<th>Path</th>
<th>Path length (km)</th>
<th>Theoretical frequencies $f_{p,i}$ (traveling wave refer to propagation mode 0 of Tab.5.3) (kHz)</th>
<th>CWT identified frequency (kHz)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Transient-based mother wavelet</td>
</tr>
<tr>
<td>800-812</td>
<td>4x22.57</td>
<td>2.98</td>
<td>3.90</td>
</tr>
<tr>
<td>800-808</td>
<td>4x11.14</td>
<td>6.04</td>
<td>6.00</td>
</tr>
<tr>
<td>800-810</td>
<td>2x12.92</td>
<td>10.42</td>
<td>13.00</td>
</tr>
</tbody>
</table>

Tab.5.4. – Characteristic and CWT identified frequencies relevant to the propagation paths for a phase-to-ground solid fault located at node 812 of Fig.5.1. The analysis refers to the propagation mode 0 of Tab.5.3.

C. Effect of the fault impedance

In this section the effect of the fault impedance on the accuracy of the fault location algorithm is assessed. A phase-to-ground fault has been assumed at node 806 of the IEEE 34-bus distribution system. Such a bus has been selected in order to analyze a fault location characterized by a single path. Three different fault impedances have been considered, namely 0, 10 and 100 $\Omega$ and the results are shown in Tab.5.5. Such a table also reports the location accuracy, $\Delta d$, calculated as the difference between the length of the path $p^*$, between the observation bus and the fault location, and the CWT-identified length of the same path.

<table>
<thead>
<tr>
<th>Fault Impedance ($\Omega$)</th>
<th>Theoretical frequencies $f_{p,i}$ (traveling wave refer to propagation mode 0 of Tab.5.3) (kHz)</th>
<th>CWT identified frequency (kHz)</th>
<th>$\Delta d$ (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>51.00</td>
<td>50.20</td>
<td>21.0</td>
</tr>
<tr>
<td>10</td>
<td>51.00</td>
<td>50.20</td>
<td>21.0</td>
</tr>
<tr>
<td>100</td>
<td>51.00</td>
<td>51.60</td>
<td>15.3</td>
</tr>
</tbody>
</table>

Tab.5.5. – Characteristic and CWT identified frequencies relevant to the propagation paths for a phase-to-ground fault located at node 806 of Fig.5.1. The results make reference to the transient based mother wavelet. The analysis refers to the propagation mode 0 of Tab.5.3.

As it can be seen, the accuracy of the proposed algorithm is not influenced by the different fault impedance values. This result can be justified by considering that the variation of the fault impedance result in a variation of the value of the reflection coefficient corresponding to the fault location but not in its sign. Indeed, this last is the only responsible for a change in the characteristic frequency of the fault path.

D. Influence of mother wavelet exponential decay time
In this section the influence of the exponential decay time $\tau$ of the mother wavelet expressed by (5.8) is analyzed. In particular, four different values of $\tau$ have been considered, namely: $10^{-7}$, $10^{-8}$, $10^{-9}$ and $10^{-10}$. The relevant CWT analysis of the voltage transient recorded at node 800 for a three-phase solid fault at node 814 is reported in Fig.5.9.

The results show that the increase of the exponential decay time of the mother wavelet results in a decrease of the algorithm performances in the identification of characteristic frequencies of larger amplitudes. This result can be justified by considering that the lowest is the exponential time decay, the larger is the extension of the frequency spectrum of the daughter wavelet that result in an increase of the matching between the frequencies contained in the analyzed signal with the ones of the daughter wavelets.

![Fig.5.9. – Comparison between the results of the CWT analysis performed with different mother wavelet exponential decay time. Analysis performed in the mode 1 of the voltage transient recorded at node 800 for a three-phase zero-impedance fault at node 814. The values are in per-unit with respect to the maximum.](image)

**E. Effect of variation of fault position along the IEEE34-Bus distribution system**

In what follows we extend our analysis by applying the proposed algorithm to the location of single/three phase faults at all the buses of the IEEE 34-bus distribution system. The results relevant to the three-phase fault are reported in Tab.5.6 while the results of single phase faults in Tab.5.7. Both tables also report the location accuracy, $\Delta d$, calculated following the same procedure described in previous paragraph. It can be observed that the proposed algorithm performs satisfactorily for any of the fault positions.
Tab. 5.6. – Characteristic and CWT identified frequencies of three-phase solid faults in some buses of the IEEE 34-bus distribution system. The results make reference to the transient-inferred mother wavelet.

<table>
<thead>
<tr>
<th>Fault location bus</th>
<th>Theoretical freq (kHz)</th>
<th>CWT identified frequency (kHz)</th>
<th>$\Delta d$ (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>806</td>
<td>56.76</td>
<td>54.40</td>
<td>57.30</td>
</tr>
<tr>
<td>808</td>
<td>6.73</td>
<td>7.45</td>
<td>-1083</td>
</tr>
<tr>
<td>810</td>
<td>5.8</td>
<td>6.55</td>
<td>-1481</td>
</tr>
<tr>
<td>812</td>
<td>3.32</td>
<td>3.80</td>
<td>-2853</td>
</tr>
<tr>
<td>834</td>
<td>22.75</td>
<td>21.20</td>
<td>239.7</td>
</tr>
<tr>
<td>836</td>
<td>15.80</td>
<td>13.70</td>
<td>721</td>
</tr>
<tr>
<td>838</td>
<td>11.85</td>
<td>10.40</td>
<td>874.3</td>
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<td>15.08</td>
<td>13.20</td>
<td>706.1</td>
</tr>
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<td>560.9</td>
</tr>
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<td>15.35</td>
<td>12.3</td>
<td>1211.5</td>
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<td>40.96</td>
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<td>17.60</td>
<td>367.1</td>
</tr>
<tr>
<td>862</td>
<td>15.61</td>
<td>13.40</td>
<td>791.4</td>
</tr>
<tr>
<td>864</td>
<td>37.84</td>
<td>37.90</td>
<td>-3.09</td>
</tr>
</tbody>
</table>

Tab. 5.7. – Characteristic and CWT identified frequencies of phase-to-ground faults in some buses of the IEEE 34-bus distribution system. The results make reference to the transient-inferred mother wavelet.

<table>
<thead>
<tr>
<th>Fault location bus</th>
<th>Theoretical freq (kHz)</th>
<th>CWT identified frequency (kHz)</th>
<th>$\Delta d$ (m)</th>
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<tr>
<td>806</td>
<td>51.00</td>
<td>50.20</td>
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<td>6.68</td>
<td>7.50</td>
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<tr>
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<td>6.60</td>
<td>-1646.5</td>
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<td>3.80</td>
<td>-2853</td>
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<tr>
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<td>19.30</td>
<td>218.2</td>
</tr>
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<td>836</td>
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<td>468.7</td>
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<td>11.00</td>
<td>1080.2</td>
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<tr>
<td>858</td>
<td>45.18</td>
<td>44.90</td>
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<tr>
<td>864</td>
<td>34.00</td>
<td>35.60</td>
<td>-88.9</td>
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</table>

### 5.4. Integrated use of time-frequency wavelet decompositions

In the approach above described, the identification of the characteristic frequencies $f_{p,i}$ associated to the fault location was realized by inspecting the relative maximum peaks of
the obtained scalogram $E_{cwt}(a)$. Such an approach disregard the information contained into the CWT time decomposition that, as proposed by Magnago and Abur [1998 and 1999] can be also used to successfully locate the fault.

The improvement of the method is here described. It is based on the integrated time-frequency analysis consisting in a two-step identification of the characteristic frequencies. The first step consists in a first estimation of such frequencies $f_{p,i}^*$ as done above. The second step improve such an estimation by identifying the time differences between local maximum of the signal coefficients $C(a,b)$ defined by (5.3) into a frequency range centered in the previously identified frequency $f_{p,i}^*$. Let us now to introduce, as a reference, the experimental setup built up for the experimental validation of the proposed approach.

### 5.4.1. Reduced scale experimental setup

The simulation of fault transients is typically performed by means of electromagnetic transient programs that allows to represent the propagation phenomena that takes place in the line feeders [e.g., Kezunovic et al., 1994; Li et al., 2001]. Such a kind of simulation is able to accurately reproduce electromagnetic fault transients and has been successfully used by Magnago and Abur, [1998 and 1999] and Borghetti et al., [2006].

In order to extend the application of the proposed fault location algorithm also to real electromagnetic fault transients, in this part of the thesis they are experimentally obtained by means of a reduced-scale experimental setup aimed at reproducing the response of single-phase cable feeders.

The two topologies shown in Fig.5.10 have been considered (a single feeder and a feeder including a lateral branch).

The assumed scale factor is of 1:50. All cable lengths are divided by this factor whilst the frequency of the reduced scale power supply is multiplied by such a factor in order to keep constant the ratio between the feeding voltage wavelength and the cable lengths. The reduced scale cable lengths are reported in Fig.5.10 and the equivalent power supply frequency, for a real scale frequency of 50 Hz, is equal to 2.5 kHz.
A standard RG58 signal cable characterized by a 50 \( \Omega \) surge impedance and a measured propagation speed of \( 1.786 \times 10^8 \) m/s is adopted for the network lines.

The feeding voltage is provided by an Agilent 33120A function generator placed in series with a 10 k\( \Omega \) impedance, in order to represent, as a first approximation, the primary substation transformer response to the fault-generated travelling waves.

The fault between the cable shield and its inner conductor is generated by means of a fast TTL micro-switch triggered by a National Instruments 9401 high-speed digital I/O board. The fault-originated waveforms are recorded in correspondence of the junction point between the cable feeder and the 2 k\( \Omega \) lumped impedance. The recording system is composed by a LeCroy LT264 8-bit 1-GSa/s digital oscilloscope.

### 5.4.2. Integrated use of time-frequency wavelet decomposition applied to fault transients

As in the previous paragraphs, the fault location procedure is based on the identification of the characteristic frequencies associated with the specific paths followed by the fault-originated traveling waves. Fig.5.11 shows the fault-originated transients corresponding to the two topologies of the Fig.5.10. The fault, triggered by the TTL micro-switch, can be assumed as a step-function source. The voltage transients of
Fault location for active distribution network

Fig. 5.11 can be seen as the result of the superimposition of different square waves each one characterized by a main frequency, as described by (5.1). This behavior is particularly clear for the case of Fig. 5.11a which corresponds to the single cable feeder.

Fig. 5.11. – Reduced scale voltage transients in correspondence of the measurement point of Fig. 5.10: a) configuration of Fig. 5.10a, b) configuration of Fig. 5.10b.

Tab. 5.8 shows the theoretical frequencies observed in correspondence of the Node 01 of Fig. 5.10 obtained by applying (5.1) to the two considered network configurations.
In order to provide a first example of the use of the improved procedure, we make reference to the configuration shown in Fig.5.10a (single cable feeder). As reported by Tab.5.8, this configuration is characterized by a single characteristic frequency $f_{p,i}$ equal to 2.233 MHz. Fig.5.12 shows the obtained scalogram relevant to the signal energy values $E_{cw}(a)$ provided by (5.4) by using the procedure described above and, a frequency $f_{p,i}^*$ of 2.162 MHz is identified. The error between the identified and theoretical frequency of Tab.5.8 is of 3.2 % with a relevant fault location error of 3.3 %.

As illustrated above, the $f_{p,i}^*$ of 2.162 MHz is then used to explore time differences between local maximum into the signal coefficients $C(a,b)$. In particular, Fig.5.13 shows the local maximum of $C(a,b)$ that allows to identify a time difference of 0.4425 μs that corresponds to an identified characteristic frequency of 2.26 MHz that provide a
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frequency error of 1.2 % and a fault location error of 1.2 %. It is important to note that such a time difference remain constant between local subsequent maximum values.

As it can be seen from this result an important reduction of the fault location error has been obtained. In the following section the application of the improved fault location procedure is presented for the reduced scale configuration of Fig.5.10b and for a real distribution network configuration.

![Graph](image)

**Fig.5.13.** – Coefficients C(a,b) obtained by means of the CWT analysis applied to transient of Fig.5.11a: improved estimation of the characteristic frequency associated to the faulted path between nodes 01-02.
In the follows further experimental validation of the proposed fault location procedure are discussed by making reference to more complex network topologies.

5.4.3. Analysis of fault events experimentally reproduced in a reduced scale cable distribution feeder

We here make reference to the reduced scale network topology shown in Fig.5.10b and to the fault transient illustrated by Fig.5.11b. Tab.5.8 has already reported the three characteristic frequencies associated to the fault located at the end of the main feeder.

Fig.5.14 shows the obtained scalogram relevant to the signal energy values $E_{cw}(a)$ provided by (5.4) by using the procedure described above and, the frequencies reported in Tab.5.9 are identified. As it can be seen, the error relevant to the identification of the characteristic frequency associated to the fault location is equal to 11.3 % and the relevant fault location error is equal to 12.7 %.

![Fig.5.14. – Energy scalogram relevant to the CWT analysis of the fault transient of Fig.5.11b relevant to the single cable configuration of Fig.5.10b.](image)
Fault location for active distribution network

<table>
<thead>
<tr>
<th>Path</th>
<th>Path length $n_p L_p$ (m)</th>
<th>Theoretical frequencies $f_{p,i}$ (traveling speed equal to 1.786 $10^8$ m/s) (MHz)</th>
<th>CWT identified frequencies $f_{p,i}$ by using the $E_{cw}(a)$ (MHz)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Node 01-02</td>
<td>4x20 ($n_p=4$)</td>
<td>2.233</td>
<td>1.980</td>
</tr>
<tr>
<td>Node 01-03</td>
<td>4x10 ($n_p=4$)</td>
<td>4.465</td>
<td>3.922</td>
</tr>
<tr>
<td>Node 01-04</td>
<td>2x15 ($n_p=2$)</td>
<td>5.953</td>
<td>5.844</td>
</tr>
</tbody>
</table>

Tab.5.9. – Characteristic and CWT identified frequencies using the approach of paragraph 5.3.4 relevant to the propagation paths of topologies reported in Fig.5.10b (reduced scale cable length).

Similar to the case of the single cable feeder, Fig.5.15 shows the analysis relevant to the identification of time differences between local maximum of the coefficients $C(a,b)$ in the frequency range centered in the CWT identified frequency $f_{p,i}$ by using the $E_{cw}(a)$.

The results of Fig.5.15, that refers to the characteristic frequency of the fault location path between node 01 and node 02, allows to identify a time difference of 0.490 $\mu$s that corresponds to an identified characteristic frequency of 2.04 MHz that provide a frequency error of 8.6 % and a fault location error of 9.3 %. Hence, even in this more complex case, an improvement of the fault location error has been obtained with the enhanced time-frequency approach.

![Fig.5.15. – Coefficients C(a,b) obtained by means of the CWT analysis applied to the fault transient of Fig.5.11b: improved estimation of the characteristic frequency associated to the faulted path between Nodes 01-02.](image-url)
5.4.4. Analysis of fault event experimentally recorded in a real distribution network

The proposed fault location procedure has been also applied for the evaluation of the location of a fault which electromagnetic transient has been recorded by means of the monitoring system illustrated by Yamabuki et al., [2007] and by Borghetti et al., [2008]. This monitoring system has been suitably designed to measure lightning-originated transients and it has been installed at some secondary sub-stations of a distribution network located in the northern region of Italy. Its peculiar characteristics, in terms of sensors bandwidth and sampling frequency, appears also adequate for the measurements of electromagnetic transients originated by fault events [Yamabuki et al., 2007].

The monitored distribution network is one of the 13 feeders that start from the common primary 132/20 kV substation. The distribution network operates with isolated neutral grounding. The considered feeder is composed of three-phase overhead lines of overall length equal to 21.9 km, without the presence of cable lines. The overhead lines consist of three conductors (without a shield wire), located at 10 m, 10.8 m and 10 m above ground, respectively. The feeder is composed of three branches, each 7-km long, arranged in a Y shape configuration (see also Fig.5.16). Fig.5.16 shows the network topology in plane coordinates using the Gauss-Boaga reference system.

![Fig.5.16. Topology of the considered distribution network and point of interest.](image-url)
The feeder is protected with one circuit breaker equipped with a three-level overcurrent relay (for multi-phase faults) and a three-level zero-sequence relay (for line-to-ground faults). In the considered feeder, an additional monitoring system for protection manoeuvres is also installed at the primary substation [Bernardi et al., 1998]. It consists of PC-based recording system and receives signals from the different protection devices of the feeders connected to the substation, namely: overcurrent, 0-sequence and circuit-breaker operation relays. The system records any change of status relevant to each protection device in an ASCII file that can be post-processed. In addition to the protection change of status, the system provides the relevant UTC (Universal Time Code) value by means of a GPS unit characterized by a time uncertainty of 10 ms. Considering that the monitoring system that measures the electromagnetic transient is also equipped with a UTC-GPS unit, it is possible to associate each protection manoeuvre intervention to a specific recorded transient.

The system is in operation since 2007 and several fault events have been recorded. One of them, recorded on July 24, 2007 at 18h 25m 14s, has here used to validate the proposed procedure. The fault voltage transient, shown in Fig.5.17, has been measured in correspondence of Node 01 of Fig.5.16.

The location of this fault has been identified by the distribution network maintenance crew in correspondence of the dotted ‘faulted line’ reported in Fig.5.16.

The fault has produced the intervention of a maximum current relay. Therefore, as the distribution network operates with isolated neutral grounding, the fault can be associated to a three-phase or to a phase-to-phase flashover. To distinguish between these two fault
types, we have made reference to the characteristics of the transient shown in Fig.5.16. Indeed, it can be observed that this event has produced large transients on two phases only so that it can be reasonably associated to a phase-to-phase fault. For this specific fault type only the differential propagation mode is of interest [Clarke, 1943; Dommel, 1969]. Therefore, the CWT analysis has been applied to a transient obtained as the difference between the voltage signals of the two faulted phases (A and B).

Considering that the overhead lines that compose the distribution network are characterized by the same geometry shown by Borghetti et al.,[2006], for the identification of the characteristic frequencies provided by (5.1), we have made reference to the differential propagation speed equal to 2.94·10^8 m/s.

The characteristic frequency associated to the fault location is calculated as the interval of frequencies corresponding to the paths between the observation point, Node 01, and Nodes 07 and 08 that delimit the faulted line (as shown by Fig.5.16). Tab.5.10 shows the characteristic frequencies calculated by (5.1).

<table>
<thead>
<tr>
<th>Path</th>
<th>Path length $n_pL_p$ (km)</th>
<th>Theoretical frequencies $f_{p,i}$ (traveling speed equal to 2.94·10^8 m/s) (kHz)</th>
<th>CWT identified frequencies $f_{p,i}$ by using the $E_{cwt}(a)$ (kHz)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Node 01-02</td>
<td>2x2.79 ($n_p=2$)</td>
<td>52.65</td>
<td>50.25</td>
</tr>
<tr>
<td>Node 01-03</td>
<td>4x1.76 ($n_p=4$)</td>
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<td>Node 01-04</td>
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<td>62.81</td>
<td>62.10</td>
</tr>
<tr>
<td>Node 01-05</td>
<td>4x2.90 ($n_p=4$)</td>
<td>25.35</td>
<td>25.95</td>
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<td>Node 01-06</td>
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<td>Node 01-07</td>
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<tr>
<td>Node 01-08</td>
<td>4x6.43 ($n_p=4$)</td>
<td>11.44</td>
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</tbody>
</table>

Tab.5.10.– Characteristic and CWT identified frequencies using the approach of paragraph 5.3.4 relevant to the propagation paths of topologies reported in Fig.5.16.

Fig.5.18 shows the obtained scalogram of the signal energy values $E_{cwt}(a)$ provided by (5.4) by applying the CWT to the fault transient of Fig.5.17. The scalogram of Fig.5.18 has been used to identify the characteristic frequencies also reported in Tab.5.10.
As shown by Tab.5.10, the identified fault location frequency is equal to 13.4 kHz, a value included in the interval between the characteristic frequencies associated to Nodes 07 and 08, namely 11.44 and 15.35 kHz. By applying (5.1), such an identified frequency corresponds to a distance of 5.485 km from the measurement point Node 01.

Similar to the other cases, Fig.5.19 shows the analysis relevant to the identification of time differences between local maximum of the coefficients $C(a,b)$ in the frequency range centered in the CWT identified frequencies $f_{p,i}$ by using the $E_{cwt}(a)$. The results of Fig.5.19, allows to identify a time difference of 75.7 μs that corresponds to an identified characteristic frequency of 13.21 kHz. Such a frequency is also in the interval between the characteristic frequencies associated to Nodes 07 and 08, namely 11.44 and 15.35 kHz.
Chapter 5

Fig. 5.19. – Coefficients C(a,b) obtained by means of the CWT analysis applied to the fault transient of Fig. 5.16: improved estimation of the characteristic frequency associated to the faulted path between Nodes 01-07 and 01-08.
Chapter 6

Conclusions

The thesis has dealt with the problems related to the integration of distributed energy resources (DERs) into the distribution grid. Indeed, as we have earlier illustrated, the large penetration of DERs in the distribution network, which has not been conceived to support it, are causing numerous technical as well as, considering the development of the energy market, also regulatory problems.

The thesis has focused specifically on the operation of distribution network, facing the following three main issues:

1. optimal technical-economical scheduling of DERs;
2. control of DERs in islanding and emergency condition;
3. fault location in distribution networks.

The new contributions and the main results obtained are in the follows summarized.

Optimal technical-economical scheduling of DERs. Operating within a DMS controller, the proposed scheduler appears to be a useful tool for the correct management of distribution network with high penetration of distributed energy resources. The developed scheduler, able to integrate the operation of DERs and traditional equipment (e.g., on load tap changer), appears to be adequate for the optimal management of active networks during the slow modifications (e.g., 15 minutes) due to daily load variations.

The algorithm performances has been extensive analysed considering distribution networks featured by different configurations, number of generators, voltage levels and size. The simulation tests have shown indeed that it is able to tackle both economical and technical objectives with computational time compatible for online applications.

Finally, as mentioned by Marciandi et al., [2008], an interesting experimental confirmation comes from CESI Ricerca laboratories, where a preliminary version of the proposed algorithm is working as part of the centralized DMS controlling the CESI microgrid test facility.

Control of DERs in islanding and emergency condition. This part of the thesis has been carried out by developing a realistic dynamic simulator of a real large scale distributed power plant, working in strictly collaboration with both utility and
manufacturers. The aim of the project, first time experienced in Italy, is to realize the disconnection of the generation plant from the external transmission network and operates consequently in islanding on the surrounding distribution network.

The analysis presented focus on the design of the automatic control system needed to improve the probability of success of such a disconnection, taking into account various generation plant initial operating conditions. Detailed analysis have been carried out also with the purpose to define an opportune path able to improve the speed of the black start-up energization of the considered power system.

The simulation results have shown that the contribution to the frequency regulation and load balance provided by the ST unit, in addition to the frequency regulation provided by the GTs, is effective for a successful islanding manoeuvre performed at large export power levels.

*Fault location in distribution networks.* The thesis presents a fault location algorithm based on the analysis of fault-generated travelling waves by means of the continuous wavelet transform (CWT). The original contribution here presented, discussed and tested, is based on the appropriate definition and use of mother wavelets inferred from fault transient waveforms. The definition of these mother wavelets allows to overcome some limitation related to the use of traditional mother wavelets (e.g., the Morlet one). In particular, the use of traditional mother wavelets does not allow, in general, to identify all the characteristic frequencies of the fault-originated traveling waves, along with the relevant paths, associated with a specific fault location.

A comprehensive evaluation of the performance of the proposed fault location algorithm has been confirmed by means of extensive analysis carried out with reference to different distribution network topologies, different types of fault, of their impedance and positions by making use of an advanced simulation tool. The overall effectiveness of the proposed algorithm has been successfully tested.

The procedure has been then applied to fault transient waveforms which are obtained experimentally during various fault scenarios, specially staged in reduced scale setup of a cable distribution network feeder, with satisfactory results.

Finally, the availability of a fault transient recorded in a real distribution network with known characteristics, allowed validation of the proposed procedure when applied to a real operating distribution system.
References


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Chicco G., Mancarella P., “A comprehensive approach to the characterization of trigeneration systems,” in Proc. of 6th World Energy System Conference, Turin, Italy, 2006


References


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References


