POLITECNICO
MILANO 1863

SCUOLA DI INGEGNERIA INDUSTRIALE
E DELL'INFORMAZIONE

Analysis of demand response solutions for congestion management in distribution networks: a real case study

TESI DI LAUREA MAGISTRALE IN
ENERGY AND MANAGEMENT ENGINEERING
INGEGNERIA ENERGETICA E GESTIONALE

Author: Riccardo Del Frate

Student ID: 946726
Advisor: Davide Falabretti
Co-advisors: Francesco Gulotta – Enrico Cagno
Academic Year: 2021-22

Abstract

The need of tackling the problem of global warming has led to definition of ambitious goals and objectives regarding the energy systems across the world, leading to a quick spread of Distributed Energy Resources (DER), typically small-scale renewables, like rooftop solar. This shift from the traditional centralized energy production made by large size fossil fuels-based plants is transforming the power systems. Traditionally the distribution system operators (DSO) have maintained their network within operating bounds by physically expanding the grid, to avoid issues such as congestions. A new approach called demand response (DR) has emerged as an alternative: the congestions are solved through a voluntary power reduction made by the flexible loads located in the grid. The scope of this work is to verify the technical and economic feasibility of such solution. When a congestion on the grid is forecasted, the DSO can acquire on a local market the required flexibility. The flexible resources can bid to offer a standardized product, which is characterized by a price [€/MWh] and a quantity [MWh], representing the active power willing to be reduced for 1 hour. An algorithm was specifically developed to simulate the grid operations and the interaction with the flexible resources. The economic results of the DR solution are then compared to the results of the conventional grid extension (GE) solution. The robustness of the algorithm is tested on a series of simulations on fictitious grids with different parameters. After the methodology is validated, the same analysis is applied to the real distribution grid of Trieste, considering the loads connected at medium voltage and using as input data real historic series of energy profiles. A series of hourly simulations on a one year long time span are carried out. Firstly, the grid is considered in normal operating conditions, assuming different values of percentage increase of the electricity demand. In this case, the congestion can form only with an increase of demand of at least +20%, which according to the scenarios outlined by Terna should not happen before 15 years. Secondly, different faults are simulated in the grid with different possible re-configurations to counter-feed the loads. The results are shown to be strongly dependent on the initial condition of the specific case and on the assumptions of the frequency of the faults. Applying a conservative approach, the DR results to be more convenient than the GE in half of the cases. The simulations also show that the economic convenience of the DR increases when the length of the line, the magnitude of the congestions, the price of the bids and the frequency of congestions on a given time span decrease. The potential savings for the DSO are calculated and, on the basis of that, a further and eventual remuneration based on the capacity made available by the flexible resources is proposed.

Key-words: Active distribution networks, demand response, grid extensions, distributed energy resources, decentralized flexibility.

Abstract in Italiano

La necessità di affrontare il problema del riscaldamento globale ha portato alla definizione di obiettivi e traguardi ambiziosi per quanto riguarda i sistemi energetici in tutto il mondo, portando a una rapida diffusione delle risorse energetiche distribuite (DER), tipicamente le fonti rinnovabili su piccola scala, come il fotovoltaico sui tetti. Questo spostamento dalla tradizionale produzione centralizzata di energia, realizzata con impianti di grandi dimensioni basati su combustibili fossili, sta trasformando radicalmente i sistemi energetici. Tradizionalmente, i gestori della rete di distribuzione (DSO) hanno mantenuto la rete entro i limiti operativi espandendo fisicamente la rete, per evitare problemi come le congestioni. Un nuovo approccio, chiamato demand response (DR), è emerso come alternativa per risolvere questo problema: le congestioni vengono risolte attraverso una riduzione volontaria della potenza da parte dei carichi flessibili situati nella rete. Lo scopo di questa tesi è verificare la fattibilità tecnica ed economica di questa soluzione. Quando si prevede una congestione sulla rete, il DSO può acquistare su un mercato locale la flessibilità necessaria. Le risorse flessibili possono fare offerte per offrire un prodotto standardizzato, caratterizzato da un prezzo [€/MWh] e da una quantità [MWh], che rappresenta la potenza attiva che si vuole ridurre. È stato sviluppato un algoritmo per simulare le operazioni di rete e l'interazione con le risorse flessibili. I risultati economici del DR vengono poi confrontati con quelli della soluzione convenzionale di estensione della rete (GE). La robustezza dell'algoritmo viene testata su una serie di simulazioni su reti fittizie con diversi parametri. Dopo aver validato la metodologia, la stessa analisi viene applicata alla rete di distribuzione reale di Trieste, considerando i carichi connessi in media tensione e utilizzando come dati di input serie storiche reali di profili energetici. Vengono effettuate una serie di simulazioni orarie su un arco temporale di un anno. In primo luogo, la rete viene considerata in condizioni di funzionamento normale, assumendo diversi valori di incremento percentuale della domanda elettrica. In questo caso, la congestione può formarsi solo con un aumento della domanda di almeno +20%, che secondo gli scenari delineati da Terna non dovrebbe verificarsi prima di 15 anni. In secondo luogo, sono stati simulati diversi guasti nella rete con diverse possibili riconfigurazioni per controalimentare i carichi. I risultati sono fortemente dipendenti dalle condizioni iniziali del caso specifico e dalle ipotesi sulla frequenza dei guasti. Applicando un approccio conservativo, la DR risulta più conveniente della GE nella metà dei casi. Le simulazioni mostrano inoltre che la convenienza economica della DR aumenta quando la lunghezza della linea, l'entità delle congestioni, il prezzo delle offerte e la frequenza delle congestioni in un determinato arco di tempo diminuiscono. Vengono calcolati i potenziali risparmi per il DSO e, sulla base di questi, viene proposta un'ulteriore ed eventuale remunerazione basata sulla capacità resa disponibile dalle risorse flessibili.

Parole chiave: Reti di distribuzione attive, demand response, estensioni della rete, risorse energetiche distribuite, flessibilità decentralizzata.

Contents

Abstract .... **iii**
Abstract in Italiano .... **iv**
Contents .... **vi**
Introduction **1**
1 Current situation **3**
1.1. Global energy context 3
1.2. New challenges in electricity distribution systems 5
1.3. European pilot projects 6
1.3.1. Coordinet 7
1.3.2. EcoGrid 9
1.3.3. Inteflex 11
1.3.4. PlatOne 12
1.4. TSO-DSO coordination 12
1.5. Focus on Italy: ARERA resolutions 14
1.5.1. Resolution 300/17 15
1.5.2. Electric dispatching integrated text (TIDE) 16
1.5.3. Resolution 363/2021/R/rif 16
1.6. Demand response as an alternative to grid extension 17
1.7. Summary of findings 18
2 Demand response and Grid Extensions pricing and schemes **20**
2.1. Demand response 20
2.1.1. Demand response schemes 20
2.1.2. Caused discomfort 22
2.1.3. Potential benefits 23
2.1.4. Demand response costs 24
2.2. Grid extension 25
2.3. Summary of findings 27
3 Methodology **29**

3.1. Framework of application 29
3.2. Definition of Demand Response and Grid Extension solutions 32
3.3. Grid characterization 33
3.3.1. Grid parameters 34
3.3.2. Loads and generators profiles 37
3.4. Power Flow calculation and output 37
3.4.1. Power flow calculation 37
3.4.2. Power flow outputs 39
3.5. Demand response solution 40
3.5.1. Active resources characterization 41
3.5.2. Bidding mechanism 42
3.5.3. DR algorithm 43
3.5.4. DR outputs 48
3.6. Grid extension solution 49
3.6.1. Cable catalogue upload 51
3.6.2. GE algorithm 51
3.6.3. GE output 54
4 Algorithm testing and validation 55
4.1. Case 1: variable power 57
4.2. Case 2: variable power 2 60
4.3. Case 3: variable length 63
4.4. Case 4: variable prices 66
4.5. Test conclusions 68
5 Application to Trieste grid 70
5.1. Distribution grid description 71
5.2. Smart metering 75
5.3. Grid in normal conditions 76
5.4. Fault conditions 79
5.5. Part 1: different grid reconfigurations 80
5.5.1. Case 1 80
5.5.2. Case 2 83
5.5.3. Case 3 85
5.5.4. Case 4 88
5.6. Part 2: fault simulations at different locations 89
5.6.1. Case 1 89
5.6.2. Case 2 91
5.6.3. Case 3 91

5.6.4. Case 4 92
5.6.5. Results 94
6 Results of the simulations: economic comparison of the solutions 95
6.1. I: congestion distribution along the year 96
6.2. II: average yearly cost of DR solution 103
6.3. III: congestion event with variable length 107
6.4. IV: worst case scenarios 111
6.5. V: more than one congestion 115
6.6. Key findings 119
7 Results of the simulations: flexible resources utilization 123
7.1. Case 1 126
7.2. Case 2 128
7.3. Case 3 130
7.4. Case 4 133
7.5. Key findings 135
Conclusion and future developments 139
Bibliography 143
Appendix 149
List of Figures 175
List of Tables 181
List of Acronyms 183
Acknowledgments 185

Introduction

The parties participating to the Paris Climate Agreement have established the legal framework for decarbonizing our society by aiming for a considerable decrease in greenhouse gas emissions. Mechanisms were developed to achieve the anticipated global CO2 emission reduction and to validate the climate agreement on a completely global scale based on national pledges towards the "far below 2 °C" target. In particular, the European Union defined legally binding targets for 2030, such as a 40% reduction in greenhouse gas emission with respect to 1990 and a renewable energy share of 32%. The climate objectives call for the already high share of power generation from renewable energy sources (RES) to rise even further, at the price of a declining share of generation from fossil fuels. Electricity markets are becoming more volatile and require balancing from ancillary services (AS) due to the inherent non-programmability of most RES, such as solar and wind. Traditional fossil-based power capacity has dominated regarding the provision of AS up until this point but are now being phased out. Additionally, electrification is increasing the demand of electric power, but also the amount and diversity of electrical devices that can modify their power usage. The concept of distributed energy resources (DER) started to widespread, indicating a wide range of technologies that are positioned close to clients, such as energy efficiency and demand response solutions, roof-top solar photovoltaic (PV) and batteries. In particular, demand response (DR) aims at changing the load profile of electricity-consuming assets, in order to provide flexibility to the system operator to help him preserve the grid stability. The focus of this thesis work is to study the technical-economic feasibility of using a DR scheme to solve congestions in the distribution grids and comparing it to the conventional solution of physical grid extension (GE).

In Chapter 1 a thorough analysis of the current global energy context, the new trends and consequent challenges on the electricity distribution system is done. Different European pilot projects which are trying to find solutions to the proposed problems are then presented. Particular attention is posed on the coordination and communication between TSO and DSO, which is a fundamental requisite for the success of the execution of the projects. A focus is done on the resolutions made by ARERA, the Italian energy regulator, which outlines the guidelines for the new role of the DSO. The chapter closes with a comparison of the two solutions which can be applied by the DSO to solve and/or prevent congestions in the grid: the conventional GE and the innovative DR.

In Chapter 2 a literature review is done in order to identify possible schemes for the application of the DR, with the relative pricing structure. A tariff with a variable remuneration related to the energy reduction and a fixed remuneration based on the capacity is proposed. The same operation is done for the GE solution, by looking at public documents published by Italian DSOs to assess its cost.

In Chapter 3 the methodology of the thesis work is defined. The aim is to propose a way in which the DSO can purchase flexibility to solve congestions. The flexibility is provided by the loads located on the distribution grid, which can voluntarily reduce their active power demand to reduce the flow of current and power in the congested lines. To do so, the loads can bid in a local market an offer composed of the price [€/MWh] and the power that they are willing to reduce for 1 hour [MWh]. An algorithm is defined in order to simulate the DR scheme applied to any grid with different type of users. Furthermore, a procedure is identified in order to estimate the GE cost that would be needed to prevent the formation of any congestions in the given grid.

In Chapter 4 the algorithm is tested on a series of fictitious grids to test its robustness, and to identify trends in the results. The grids are characterized by a series of parameters (such as the topology and the electrical parameters) and the loads and generators energy profile. Different grids are tested by changing the different parameters one by one to identify the effect of each one of them on the final results.

In Chapter 5 the real distribution grid of Trieste is described, limited to the medium voltage. In fact, the objective is to apply the algorithm to the real grid, using as input data historical series of the load and generation profiles, to see under which circumstances the congestion can form and to compare the yearly prices of the DR and GE solutions. Different cases are described. In the first part the grid is assumed to be without any faults, and different increases in the electric demand are simulated. In the second part, faults are simulated in different locations of the grid. A total of 4 main cases and 15 sub-cases are identified.

In Chapter 6 different indicators are identified in order to compare the economic results of the GE and DR solutions. For the latter, only the variable part of the tariff related to the energy is considered. The indicators are applied to the 4 main cases, simulating 1 year of grid operations.

In Chapter 7 the focus is on the different possible utilization by the DSO of the various flexible resources present in the grid. Based on the results of the previous chapter and by the position of the loads on the grid, different capacity remuneration values are proposed.

1 Current situation

1.1. Global energy context

The effects of rising greenhouse gases emissions (GHG) are reaching a breaking point from which it will be impossible to turn back. The scientific community as a whole has come to the conclusion that human activity is the primary cause of climate change, and this conclusion is supported by data-driven studies and research. The most recent Intergovernmental Panel on Climate Change (IPCC) 2021 report [1] states that drastic and immediate reductions in greenhouse gas emissions are required if the average global temperature increase of 1.5 °C or 2 °C has to be avoided at the end of the current century. Nevertheless, with the current course of action the increase will result in a 3 °C rise in global temperatures [2] , exceeding the Paris Agreement's goal of a 1.5 °C limit [3]. To combat global warming and its effects, it is imperative to take immediate action and to raise awareness of climate-related issues. International organizations are going in this direction. Most recently, the Conference of Parties (COP) 26 meeting in Glasgow in 2021 invited 200 nations to submit their climate action plans to address the situation [4], followed by the COP 27 in Sharm El Sheikh in 2022. At the same time, the world's energy situation is going through a time of rapid change: developing countries expanding economies and the electrification of consumption (e.g. the domestic heating, electric transports) in developed countries are leading the rising of the electricity energy demand worldwide.

In this context the World Energy Council proposed the concept of Energy Trilemma [5] to outline the characteristics that world energy systems should have:

- Energy security: it indicates a country’s capability to withstand and recover quickly from system shocks and supply disruption, as well as its ability to reliably satisfy present and future energy demand. The indicator also covers the effectiveness of managing internal and external energy sources, as well as the dependability and resilience of the energy infrastructure along the whole value chain.
- Energy equity: it evaluates a country’s capability to provide easy access the supply of energy for domestic and commercial/industrial use. The dimension includes fundamental access to power, clean cooking methods, and levels of

energy consumption that support prosperity, as well as the cost of electricity, gas, and fuel.
- Environmental sustainability: indicates the level of transformation of a nation's energy sector toward mitigating and preventing potential environmental harm and repercussions from climate change. This aspect emphasizes air quality, decarbonization, transmission and distribution productivity and efficiency.

Focusing on Europe, different protocols and challenging objectives have already been set regarding different time horizons. The first one was the “2020 climate & energy package”, a set of laws and target firstly discussed in 2007 and enacted in legislation in 2009 [6]. The three main targets are:

- 20% cut in greenhouse gas emissions (from 1990 levels)
- 20% of EU energy from renewables
- 20% improvement in energy efficiency.

Secondly, as part of the European Green Deal [7] a new set of targets for the decade from 2021 to 2030 was proposed in 2019 under the name of “2030 climate & energy framework” [8]. The three main targets are conceptually the same as in 2020, but the numerical objectives were updated:

- 40% cut in greenhouse gas emissions (from 1990 levels)
- 32% of EU energy from renewables
- 32.5% improvement in energy efficiency.

It is immediate to see the great importance that is given to renewable energies in the energy transition, and in particular in the electric sector. In fact, in the decade between 2011 and 2021 the global share of renewable electricity has increased from 20.4% to 28.3%, almost 8 percentages points [9].

Among the renewable energy resources (RES) there is a subset of sources called non-programmable RES, among which there are solar and wind energy, hydroelectric energy (limited to the run-of-river typology) etc. The non-programmability of these sources does not make it impossible to predict the availability and, consequently the production of electricity. It rather involves the difficulty of controlling and modifying the amount of energy fed into the grid, on the basis of a default program previously agreed. In general, different sources of non-programmable electricity production are characterized by different possibility and accuracy of predicting the injecting power into the network.

In this context, small-scale, clean installations located behind the consumer meters, such as photovoltaic panels (PV), energy storage and electric vehicles (EVs), are spreading. Furthermore, electricity consumption is rising due to electrification, which is simultaneously increasing the number and the variety of electrical equipment that can quickly adjust their power consumption [10]. A new concept, called distributed energy resources (DER) is emerging. The term is used to cover “a wide range of technologies that are located close to customers, such as energy efficiency and demand response solutions, solar photovoltaic (PV) assemblies and batteries” [11]. Depending on the type, DERs can produce, store, or control energy use. The term can also be used in a more general term to include all the ‘behind-the-meter’ resources [12]. The growing uptake of DER can provide several advantages to customers, promoting decarbonization, and enhancing system resilience. However, this evolution is presenting new difficulties and issues for the electrical grids.

1.2. New challenges in electricity distribution systems

The sudden increase in the RES and DER production has changed the old logics of grid management. It is required to identify the key conditions that must constantly be met for the electric grid to function properly in order to comprehend the new issues brought on by the penetration of these new resources. Firstly, there needs to be an instantaneous equilibrium between the demand of supply of electricity, given the difficulties and the cost of storing it at large scale. Secondly, the technical boundaries of any given network line need to be respected (frequency, voltages, currents etc). It is clear why the first condition is becoming more difficult to be met: the non-programmable RES cannot always be matched with demand due to their aleatoric nature. Furthermore, the conventional power plants based on fossil fuels historically have played a significant role in the secure and reliable use of the electric system. However, they are being decommissioned as a result of the diffusion of RES [13]. Besides, the RES and DER are often of much smaller scale and situated on the distribution network, contrarily to the old classic power plants which are located on the transmission network. This implies a series of issues for the distribution grid which in general were designed prior to the huge development of the RES. They were in fact built for unidirectional power flows, from higher voltages to lower voltages. Thus, the presence of RES on the distribution grid can create negative impacts such reverse power flows, increases in line losses, voltage rise and a worsening of network instability [14].

A safe supply of electricity to end consumers is one of the main responsibilities of distribution system operators (DSOs). The goal is to reduce the number of disruptions in the supply of energy as well as distribution network losses. DSOs are also in charge of measuring and metering operations. DSOs run, maintain, and expand the distribution network for medium-voltage and low-voltage. Like transmission system operators (TSOs), DSOs must take long-term views into account when making planning decisions (i.e. deciding to invest in expanding the grid). Essential for their operations is the accurate real-time knowledge of the grid's state. Historically, the distribution network has been conceived and run as a centralized, passive system, following the “fit and forget” paradigm [15]. To maintain the system within deterministic operating bounds, the grid is strengthened by expanding the capacity of the cables and creating more interconnection points. In other words, operational issues are resolved during the planning process with very high investment costs, which would increase exponentially to prevent all the issues introduced by the rapid pace penetration of RES. Thus, in recent years a new approach for the distribution grid management has emerged, called "fit and manage" or active network management (ANM) [16]. The operational problems can be solved within the active management close to real time, and not just in the planning phase. The quantity of DER that can be connected to the network without the requirement for reinforcement has been demonstrated to be significantly increased using ANM [17]. An example of ANM strategy is the demand-side management. It is defined as "a global or integrated approach aimed at influencing the amount and timing of electricity consumption in order to reduce primary energy consumption and peak loads" [18]. A subset of demand-side management is the Demand Response (DR), which aims at changing the load profile of electricity-consuming assets [19].

To improve the electricity system's capacity to handle the new challenges, flexibility development is essential. Flexibility has been defined by the International Energy Agency (IEA) as "the ability of a power system to reliably and cost-effectively manage the variability and uncertainty of demand and supply across all relevant timescales, from ensuring instantaneous stability of the power system to supporting long-term security of supply" [20]. The development of DER and DR programs provides the new ways for the flexibility solutions and services needed to support the evolution of the distribution grids.

1.3. European pilot projects

With the ongoing legislation, the continuous regulation required to respect the grid requirements before mentioned, is done through the Ancillary Services (AS) which are traded on the Market for Ancillary Services. Providing ancillary services means modifying the injections or withdrawals programs in real time (through automatisms or voluntary actions), in order to meet the needs of the TSO which must guarantee, for every moment and in every node, the balance between supply and demand. The AS can in principle be classified into global if they are necessary for the safe operation of the national electricity system, and into local AS if they necessary for the safe operation of the distribution networks only (or portions of them). The current market for global AS is not open to everyone but to only units classified as qualified, usually relevant programmable production units, like thermoelectric and hydroelectric plants of large size. The major global ancillary services are [21]:

- Frequency regulation:
    - Primary and secondary reserve: it consists in making available a capacity band activated by an automatic regulation device capable of modulating the power, both increasing and decreasing, in response to a frequency variation. It makes it possible to automatically correct in real time, for a

few seconds, the instantaneous imbalances of the total production and total needs of the electricity system. It must be continuously available and should be distributed within the electrical system as evenly as possible.
    - Tertiary reverse: it consists in making margins available with respect to the maximum or minimum power in the programs of the enabled units or in the willingness to accept changes to the programs of the enabled unit in order to create margins.
- Voltage regulation:
    - Primary and secondary reserve: consists in regulating the reactive power production of a generation group (or groups pertaining to a plant) with an automatic regulation device on the basis of the voltage deviation from a reference value.
- Congestion resolution: it consists in making margins available with respect to the maximum or minimum power in the programs of the enabled units or in the willingness to accept changes to the programs of the enabled unit so that they can be executed in compliance with network constraints.

As already mentioned, the continuous diffusion of distributed generation plants, growing also due to the European decarbonization objectives, the contextual diffusion of small-sized storage systems, the diffusion of electric mobility planned for the next few years, make it necessary to carry out an important review of the role of distribution companies. They will take on two additional roles with respect to those traditionally of their competence [22] :

- The role of neutral facilitator for procurement purposes of the global ancillary services made available for the security of the system as a whole.
- The role of acquirer of resources for local ancillary services (i.e. services necessary for the safe operation of only distribution networks or portions of them).

These new roles are already partially tested and limited to the current European pilot projects. The aim of the projects is to determine and identify which are the local ancillary serves and products that will be needed (Coordinet), how they can be requested and paid by the DSOs (Ecogrid and Interflex), which are the policies and regulations that will support this transition process (Platone).

1.3.1. Coordinet

The CoordiNet project, co-funded by the European Union (EU), aims to show how TSOs and DSOs can operate in concert to buy and activate system services, encouraging collaboration among all actors, and removing obstacles to DERs' full market participation [23]. The project's outcomes will support the development of scalable tools and procedures enabling system operators and outside parties to connect, manage, and organize flexibility providers in a secure manner.

Distribution system operators can employ grid services to ensure the growth and stable operation of transmission and distribution grids. Grid services are defined as “services provided to DSOs and TSOs to keep the operation of the grid within acceptable limits for security of supply and are delivered mainly by third parties” [24]. Standard products for grid services must be defined in order to enable a market-based allocation of these grid services and, consequently, allow market parties to effectively bid into the new markets. The major local ancillary services are summarized in Figure 1.1.

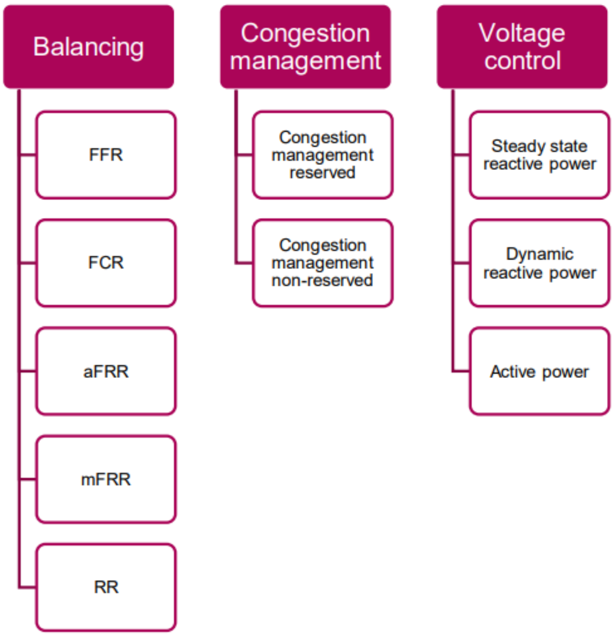


Figure 1.1: summary of local ancillary services [25]

- Balancing: it includes all activities and procedures, on all timeframes, by which TSOs continuously maintain the preservation of system frequency within a predetermined stability range and ensure compliance with the required quality. However, this category is important also for DSOs because they define standardized balancing products that are related to DSO services. The standard products defined are fast frequency reserve (FFR), frequency containment reserves (FCR), frequency restoration reserves with automatic activation (aFRR), frequency restoration reserves with manual activation (mFRR), replacement reserves (RR).
- Congestion management: since a grid's hosting capacity is constrained by the properties of its physical assets, network congestion results (i.e. lines, cables, transformers) when one or more limitations (thermal limits, voltage limits, or

stability limits) prevent the physical flow of power over the network. Congestion management is the technique of reducing and preventing grid congestions. The standard products are:

  - Congestion management reserved: it is a capacity-based product that is purchased for services at a specific availability price and is then turned on when the required system operator requests the service. It is used for structural congestions.
  - Congestion management non-reserved: it is an energy-based product purchased for congestion management services at an energy price. The purchase is done closer to the time of delivery. This product can be used for sporadic congestions.
- Voltage control: voltage is a localized characteristic of the power system that needs to stay below a specified threshold locally to preserve the safety of grid assets. However, due to changes in the network, such as active power injections and offtakes, and topological changes, voltage fluctuations are unavoidable. Operators of the system control the injection and absorption of reactive energy to maintain voltage within operational limits. The standard products are steady state reactive power, dynamic reactive power, dynamic active power.

After defining the standard products, a crucial aspect is to define the market through which the DSO can activate the flexibility. The technical characteristics of the grids, along with economic and societal issues, have an impact on how the markets for grid services designed. Information about bids is the main factor: more locational information is needed to be included in the bid submitted to the market in a future market design suited to higher degrees of DER, and to setup DR pilot projects.

1.3.2. EcoGrid

The main goal of EcoGrid EU is to create and execute on a large-scale a real-time market that can be used by smart electricity distribution networks with a high penetration of renewable energy sources and engaged users [26]. The EcoGrid EU idea employs indirect control by way of a real-time pricing signal that modifies the consumption influencing the electricity load, through a bid-less market in this case. Even if bid-less it works through a market-based platform with enabling information and communication technology (ICT) software and hardware solutions, bringing the current energy market closer to real time and incorporating smaller assets like electric heating and heat pumps (HP). An opportunity to effectively leverage currently inactive demand side resources exists when the power system is operated closer to real time. Additionally, it will enable and guarantee a more effective integration of variable and unpredictable RES. Additionally, there is the possibility to significantly reduce peak load.

The core principle of the EcoGrid EU market concept is to continuously signal a price for flexible resources to respond to in order to balance the electricity system. By raising the price when there is a power shortage in the system and vice versa, the price signal will be continuously updated to maintain the balance of the system. In Figure 1.2 it is possible to see the time dimension of the EcoGrid new real-time market, with respect to the current market-based operation and direct control mechanisms.

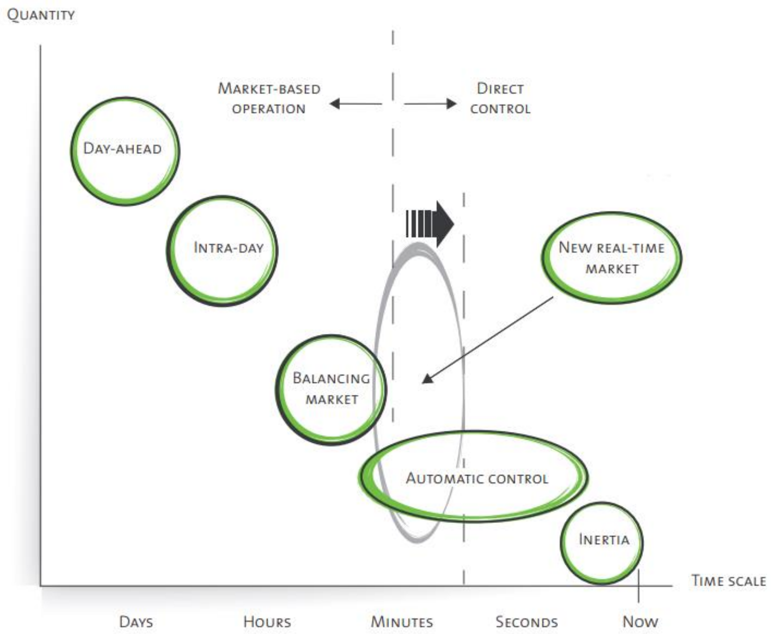


Figure 1.2: EcoGrid new real-time market [26]

The EcoGrid EU demonstration showed that after receiving a real-time pricing signal, customers responded in a way that assisted in balancing the power system. From a replication standpoint, client participation is essential for success. The ambitious goal requires significant communication efforts on the part of the market maker. Keeping the participants involved throughout the project was also a major challenge. The design of immediately available equipment that is specifically designed for automatically providing power system services to the DSO upon receiving an external control signal of any kind is another prerequisite for a real-time market. Furthermore, the project has shown that overall system efficiency can be increased as a result of the flexible demand response, which can be forecast with some degree of precision. The main beneficiary of this kind of project is the DSO, which gain additional balancing resources generated by demand-side participation.

The final conclusion of the project is to start encouraging demand-side engagement within Europe's current market structures while at the same time fostering innovation that will better equip customers and market participants for upcoming projects and schemes. The creation of standards to enable compatibility across various home automation solutions is one of the key elements in the development of such smart technologies. And finally, that "smartness from a consumer point of view is certainly not about kWh, but rather about convenience or comfort" (Jacob Østergaard, head of Center for Electric Power and Energy (CEE) at DTU Electrical Engineering) [26].

1.3.3. Inteflex

Interflex relied on the observation that there should be a need for flexibilities to generate a corresponding offer. Power producers, consumers and prosumers), or their aggregators, can receive signals from the DSO as a flexibility customer and respond by offering generation and/or consumption flexibilities. The project is based on local flexibility markets where the acquisition and activation of flexibilities is done through regional processes based on open market principles in response to the demand from DSO. The flexibility is activated through demand response and customer empowerment, using smart functions and grid automation [27].

When a prevision of a congestion on the distribution grid is done, a flexibility request is issued by the DSO to the aggregators via the information technology (IT) platform. The desired flex power (up or down) for a certain congestion point and time window are both contained in a flexibility request. The DSO can additionally communicate to the aggregators the cost it is willing to pay for such a request. The DSO then compares the bids from various aggregators and chose the best ones. If the aggregator bids and DSO demand are aligned, the aggregators forward to the DSO the activation requests of the flexibility through the designed activation channels. Thus, the flexibility service at the lowest possible cost is provided.

The project highlighted that the crucial element is the flexibility sourcing. The DSO, which must rely on reliable means to fulfill its performance goals, may be at risk depending on the degree of local availability and reliability of the flexibility's resources, in particular in the early phases of setting up the project. Most likely, complementary markets will be required: spot markets for opportunistic offers on the one hand, and reserve markets based on procurement contracts on the other, to secure the required capacity.

Market offers must be standardized, and regulations must be adjusted and put into practice in order to promote the widespread use of flexibility with an eye toward maximizing the utilization of the assets currently and in the future of the energy system. In order to promote the growth of industrialized flexibility markets in the near future, regulatory frameworks outlining straightforward processes are required. It may be needed to change the tax and tariff structure, such as implementing variable network tariffs, to furtherly open the participation for local flexibility in the future.

A possible alternative to the market approach could be the direct DSO activation, through a contractual agreement between DSO and the potential active users. This alternative could cut down the transaction costs but would rise the problem of ensuring effective flexibility allocation and determining appropriate compensation rates. Both alternatives were successfully tested by the Interflex projects. As a positive side effect, the project stimulated the development of Citizen Energy Communities, and attracted a large number of pilot customers for the DR solutions.

1.3.4. PlatOne

A cutting-edge technology solution capable of providing energy flexibility mechanisms inside a free and open European market is what PlatOne (Platform for Operation of distribution networks) seeks to create and test [28]. The methods utilized for this aim will be built on platforms able to receive data from many sources, such as distributed smart devices spread throughout urban areas or weather forecasting systems. These platforms will enable the gathering and development of information that is helpful to DSOs, customers, and aggregators through communication and data exchange. The DSO will be seen assuming a new position as a market enabler for end users and as an observer of the distribution network, removing all technical barriers by actively investing in smart meters. The DSO objectives are local balancing (to maximize local generation consumption in order to make null the power interchange between the medium-voltage and low-voltage feeder) and acquiring flexibility (through market and aggregators). An indirect dynamic network tariffs as an indirect control approach is used, in order to set a DER optimal usage and alleviate congestion and voltage limit violation problems within the distribution network.

A focus on the regulatory aspects in European countries has been done in the project. A major issue is the fact that DSOs are nearly never allowed to own energy storage systems, which have an important role in helping the penetration of RES and consequently achieve the decarbonization goals. For this reason, it is difficult to include the deployment of energy storage in network design, being it typically not covered by legislation. Aggregation services are still not allowed in all European countries, even though a European directive has already moved in this direction [29]. Energy communities could also help aggregate users into giving flexibility, but a lack of harmonization in the legislation of different countries make it difficult to define standard products and procedures, inhibiting scalability and replicability. Since the necessary European directives for cybersecurity, data management, and data protection are now being revised and will not be put into effect until after the project is complete, it is difficult to foresee how they will affect the project. In general, a clear lack of legislation and harmonization among different countries is the main problem.

1.4. TSO-DSO coordination

The DSO apart from activating DERs for the provision of local services could also operate as facilitators for the provision of services for system as a whole, in coordination with the TSO. Thus, a real time coordination effort is necessary. A paradigm shift is necessary from the historical way that TSO and DSO communicate, since the DSO can actively influence the way that the DER flexibility and services are supplied. Having a proper TSO-DSO cooperation is essential to guaranteeing both the effective running of the power system as well as the fulfillment of the DSO mission. It is important to highlight that up to today, it is likely that all services will eventually be required and utilized by the TSO. Future TSO-DSO coordination models, though, will also need to take distribution-level markets into account. Numerous difficulties and issues must also be taken into account. The most notable is the complexity of system operation and dispatch that will increase as a result of the abundance of DER and new controlled network assets. Furthermore, in order to permit and ease the transition for TSO-DSO coordination models, new policies and regulations must be developed.

The SmartNet project seeks to compare several designs for optimal interaction between TSOs and DSOs, including information sharing for monitoring and purchasing of auxiliary services [30]. Each coordination scheme is characterized by different roles and market architectures. Five schemes have been identified:

1. Centralized AS market model: the DSO is not heavily involved, the TSO runs a market for ancillary services for both resources connected at the transmission and distribution levels. Thus, there is not a distinct local market. The management of the TSO's own market for auxiliary services is its own responsibility. DSO grid constraints are not actively considered by the TSO, hence to ensure that the activation of resources from the distribution grid by the TSO does not result in extra limitations at the DSO-grid, a prequalification phase could be deployed. Thus, the active role of the DSO is limited to such phase.
2. Local AS market model: the resources connected at the DSO-grid level have a distinct local market organized by the DSO. The DSO runs a local flexible market, clearing it, and selecting the required bids for local use. After and if all local constraints have been resolved, the DSO collects and passes the remaining bids to the TSO-market in an aggregated form, while guaranteeing that only offers that respect the DSO grid limitations are permitted to participate in the market. The TSO is in charge of running its own ancillary services market. In this model, the focus and the priority are on the DSO needs.
3. Shared balancing responsibility model: the responsibilities are shared between the DSO and the TSO, according to a predefined schedule. There are two separate markets for the transmission and the distribution grid. In this case, the flexibility and services at the distribution level cannot be offered to the TSO.
4. Common TSO-DSO AS market model: the resources offering the flexibility participate to the same market regardless of if they are connected at the distribution or transmission level. The market clearing procedure incorporates the restrictions and constraints given by the DSO. There is no predefined precedence between TSO and DSO in acquiring the resources. The combined optimization of the needs for flexibility at the distribution level and the needs

for flexibility at the transmission level will determine which resources the DSO or the TSO will employ, trying to minimize to total system costs.

5. Integrated flexibility market model: no party has precedence over the others, the one with the highest willingness to pay receives the resources. There is not a distinct local market, and the DSO constraints can be introduced only in the clearing market phase. A new independent market operator would be needed to guarantee neutrality. TSOs and DSOs can also sell the DER that has already been contracted to other market players. The distribution of flexibility is determined solely by market factors, also private and non-institutional players could participate in the market.

[31] and [32] analyzed the different coordination schemes experimented in the SmartNet project. The centralized scheme (1) was found to be less efficient than the TSO-DSO common market scheme (4) in cases where congestions on the distribution networks are not negligible. Models that implement a local distribution market (2) and (3) are usually more expensive than centralized schemes such (1) and (4). This is due to the inherent complexity in the algorithms, as well as the fact that local markets may be affected by problems of scarcity of offers that generate a liquidity problem. Such models can be difficult to implement if there is a huge number of different DSOs that are very different from each other, like in Italy. The model with shared balancing responsibilities (3) was found to be economically inefficient as it presupposes that the balance is guaranteed primarily with the local resources and only then with the global ones. The model with local market (2) is very complex to manage since it presupposes the presence of two markets and requires a strong interrelation between DSO and TSO. It is in fact always needed to ensure that local congestion resolution by the DSO does not affect the market of the overall balancing managed by the TSO, and it is necessary to prevent double erroneous activations of the same resource if it is offered simultaneously on more than one markets. The integrated model of flexibility (5) was not simulated in actual pilot projects as it was considered too complex.

On the basis of the SmartNet project, it appears that the preferable schemes are the centralized scheme (1) in cases where congestions on the distribution networks are negligible and the TSO-DSO common market scheme (4) in other cases.

1.5. Focus on Italy: ARERA resolutions

In order to allow the integration and further dissemination of non-programmable RES and DER, while ensuring the safety of the electrical system, the innovation of the regulation of the dispatching and selective promotion of network investments play a primary role. These new actors should actively participate in the operation of the electricity system through the supply of ancillary services, appropriately revised to take into account the needs of the changed electricity system. Pilot projects are currently under development, but it is already starting to take shape the possible future regulation of dispatching. In particular, three resolutions by ARERA (the regulatory authority for energy in Italy) are analyzed in order to see how this theme is being approached by the regulator in Italy. In the first one the organic reform of dispatching activities in Italy is introduced. In the second one the new tasks of the DSOs are explained. In the third one the characteristics of pilot projects on the distribution level are described.

1.5.1. Resolution 300/17

Title: *First opening of the market for the dispatching service to the electricity demand and to production units also from renewable sources not already enabled as well as the storage systems. Establishment of pilot projects in view of the constitution of the "Electric dispatching integrated text" coherent with the European balancing code* [33], published the 5th may 2017.

In order to acquire useful information for the definition of the reform of the dispatching service, pilot projects are set up. The main topics are:

- Participation to the dispatching services market (MSD) of demand and production units not enabled up to date. MSD is the market through which Terna S.p.A. (the Italian TSO) procures the resources necessary for the management and control of the system as a whole.
- The methods of aggregation for the purpose of participating in the energy markets and the MSD for the production and consumption units.
- The modalities for the remuneration of ancillary services currently not remunerated explicitly.
- The non-relevant production and consumption units could be enabled to participate in the MSD on an aggregate basis, in compliance with appropriate localization and geographical, helping to form dispatching points. These units are called "unità virtuali abilitate miste "(UVAM).

Even though in this phase the pilot projects regard the TSO and the transmission systems, they have consequences also for the DSO. In fact, distribution companies need to be adequately informed regarding points of entry or withdrawal for which an application for authorization is presented. They need to report to Terna the presence of any critical issues on their networks to be taken into account for the purpose of defining the UVAM. They also have the possibility to declare, with adequate justification, the inability to include one or more users in the UVAM connected to their grid or indicate ex-ante limitations. Thus, a more active role for the DSO is already included in this phase, since they are concessionaires of the networks on which many units of production and consumption could be enabled to supply the dispatching services.

1.5.2. Electric dispatching integrated text (TIDE)

The objective of the text published in 2019 is to define the main lines of action aimed to make the regulation of dispatching activities suitable for efficiently guaranteeing the safety of the electrical system in a context in rapid and continuous evolution. This new context and its expected evolution create the urgency to reform the dispatching service and the ways in which it is possible to provide necessary resources, as well as the ways in which they are remunerated, so that all barriers are removed to not prevent the use of all available resources when economically convenient [34]. In this document the new role and activities of the DSO are furtherly investigated and defined.

The first one is the DSO as a neutral facilitator for global ancillary services. The role must be applied increasingly closer to the real time, based on the state of real operation of the network, not only on the hypothetical exercise, as in the previous deliberation. In addition, in order to broaden the observability, by both Terna and the distribution companies, of energy flows and the status of resources on the distribution networks, the implementation of data exchange between TSO, DSO and "Significant Grid Users" is expected.

The second role is the DSO as buyer of local ancillary services, defined as services having the purpose of managing specific problems of the distribution network. The rules adopted by the DSO in purchasing must be objective, transparent and non-discriminatory, and must be developed in coordination with TSOs and other interested parties and stakeholders. The tool identified by the Authority for providing the necessary resources is the market, but exceptions may be provided in the event that the procurement of resources in this way would not be efficient. The DSO must allow everyone to participate, including aggregators of production units from RES, consumption units and storage systems. In a first phase, the acquisition of resources for local services is based on pilot projects which are aimed at collecting useful elements and data and to test the most appropriate ways for the procurement and remunerations of such services, as well as to experiment the ways in which TSO and DSO can interact with each other.

Regulatory guarantees are needed to ensure the neutrality of DSOs in carrying out their new functions. In this regard, it deems necessary to carry out investigations aimed at assessing whether the current unbundling is sufficient to ensure the full neutrality of distribution companies with particular reference to the future role of buyer of local services.

1.5.3. Resolution 363/2021/R/rif

Title: *Pilot projects for the procurement of local ancillary services* [35], published the 3rd august 2021.

As anticipated in the TIDE, the pilot projects referred have the aim of testing the most appropriate regulatory solutions for the procurement of local ancillary services and the relative remuneration, favoring the convergence of solutions proposed during the experimentation within a more general framework of uniform rules at national level.

In order to start a pilot project, the DSO must identify the local ancillary services object of the experimentation, evaluate in detail the solutions to experiment for their procurement, the relative costs, as well as the possible alternatives including upgrading and developing the electricity grid and infrastructure. DSOs define non-discriminatory clauses that allow the widest possible participation, guaranteeing neutrality technological and defining the perimeters of aggregation so that within them the given service can be provided indiscriminately by production and / or by consumption units (in single or aggregated form). The latter can request the authorization even for only one of the local ancillary services that the DSO needs.

The costs incurred by the DSOs for the adaptation of infrastructures and communication channels as well as the costs for the dissemination activities of the results are covered, when possible, by European fundings. When this is not possible, the related costs are covered using the current tariff tools.

1.6. Demand response as an alternative to grid extension

The change in the production mix in progress, increasingly evident for the purposes of achievement of the European objectives by 2030 and 2050, requires significant interventions both from infrastructural point of view and from the point of view of dispatching (integrated management of production and consumption of electricity). The infrastructural interventions on the electricity grids must be analyzed together with the interventions related to dispatching in order to find the least expensive solution.

Distribution system reliability is defined by the Institute of Electrical and Electronics Engineers (IEEE) "as the ability of the distribution system to perform its function under stated conditions for a stated period of time without failure" [36], and has a direct correlation to the served consumers satisfaction levels. There is a variety of things that may have an impact on how well the distribution network performs. These networks are frequently exposed to natural events and could be affected by extreme weather conditions. Furthermore, any single outage or failure might potentially have a significant impact on a large number of consumers due to the radial structure of the grid, which has rarely a more intricate and redundant meshed structure [37]. The distribution lines, distribution cables, power transformers, service transformers, capacitors, and voltage regulators are among the parts that are typically prone to failure. It is obvious that an increased system reliability may be obtained by increasing the distribution grid's redundancy through capacity expansion projects. However, this is constrained in part because new infrastructure investments are expensive and in part because adding more cables and generating units raises environmental concerns.

The distribution system's inadequate capacity jeopardizes its performance, particularly during peak usage times when all or almost all of the system's capacity is used and the grid operates with little to no safety margins. Such conditions can make it possible for a simple transformer or line overheating or component fault to have a strong impact on the possibility of delivering electrical energy to the final consumers. Even in normal conditions, the grid may get overloaded as a result of EV and HP increasing electric demand [38]. When many of these loads request power from the grid at the same time, the distribution system operator is faced with congestion problems. Alleviating such issues is considered as one of the main duties of DSOs.

The other option is demand response, to help change the system's demand profile by partially curtailing the load or transferring it from peak to off-peak hours, which will lower the peak demand and free up system capacity during those hours. Although not a long-term solution, it can help delay the building of new lines in the short term. Demand response has become a feasible option for utilities all around the world due to the cost savings and environmental benefits of delaying plans for system development. It generates financial advantages for the utility and the consumers by lowering the volatility of the electricity market, postponing investments, and lowering electricity rates. Besides, DR is one of the paradigms of smart grids.

1.7. Summary of findings

The need of tackling the problem of global warming has led to definition of ambitious goals and objectives regarding the energy systems across the world. This commitment is particularly strong in Europe and in the European Union, which has set programs and plans with different temporal horizons. In this environment, there has been a huge spread of DER, typically of small scale and owned by the user of electricity, like rooftop solar panels and battery storage. This shift from the traditional centralized production made by large size fossil fuels is also transforming the ways that electric energy is traded, delivered and consumed. The future scenario of the power system presents opportunities while also posing new risks and problems that may arise from improper grid planning and management, and to the fact that most of the distribution grids were built in the last century. To avoid or defer grid investments but at the same time preserve the security of supply and resiliency, a demand response scheme could be helpful. It involves shifting or shedding electricity demand to provide flexibility in wholesale and ancillary power markets, helping to solve congestions and to balance the grid. Pilot projects at the transmission level, with the TSO as the main counterpart, have been already activated in the last decade. More recently, the same need has emerged also at the distribution level, to give to the DSO new tools to solve grid issues, like the presence of congestions. Different European projects have started to test demand response at the distribution level, to examine potential challenges and issues and define new markets, business models and policies. The presence of a local market managed by the DSO brings out the theme of TSO-DSO collaboration, which need to work closely to guarantee the functioning of the electric system as a whole. In Italy the European directives are being applied by the local Authority ARERA, to allow the diffusion of demand response pilot projects at the distribution level.

2 Demand response and Grid Extensions pricing and schemes

In order to compare the different solutions of demand response (DR) and grid extension (GE), and to simulate different scenarios, it is important to understand their price structure. In this chapter the different cost items and their numerical values will be analyzed, through an extensive literature review. The objective is to come up with price ranges for both solutions that can be used as price inputs for the application of the congestion resolution algorithms to the real distribution grid of Trieste.

2.1. Demand response

2.1.1. Demand response schemes

In [39] framework is proposed to catalog different DR programs, starting from a division in incentive-based programs and price-based programs. In the former participants are remunerated with a bill credit or discount called classical incentive-based program (IBP) or according to their performance, thus proportionally to the amount of load reduction in the congested hours, in a scheme known as market-based IBP. On the other hand, the Price-based program (PBP) is based on the fact that electricity prices and tariffs are not flat but follows the real time cost of electricity. By offering higher prices during peak hours the demand curve is flattened in the mentioned hours. The two categories can in turn be divided as it is shown in Figure 2.1.

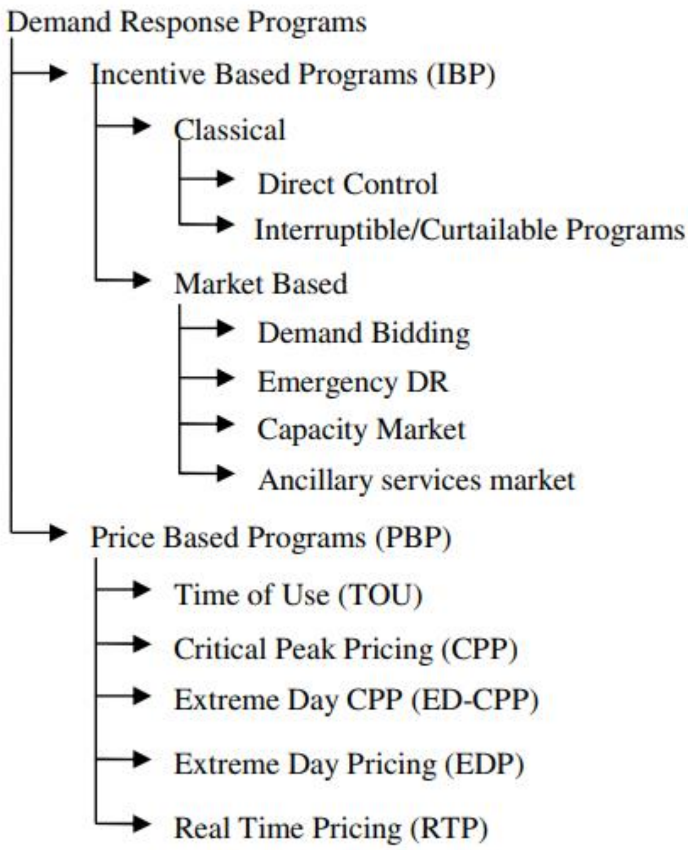


Figure 2.1: A classification of DR programs

Incentive based programs:

- Direct control: the distribution system operator (DSO) can remotely reduce participants power demand with a short notice, assuming that there is the technical possibility.
- Interruptible/Curtailable Programs: the participants are asked to reduce their power demand when it is forecasted that it will be needed and are paid upfront. They incur in penalties if they do not activate the flexibility.
- Demand bidding/Emergency DR: users bid a specific load reduction in an electricity wholesale market. If the bid is accepted the user has to reduce its demand by the proposed amount.
- Capacity market: participants who commit to the program receive a day-ahead notice by the system operator when a contingency arises and need to provide a pre-defined amount of load reduction.
- Ancillary services market: participants can bid their load curtail straight in the spot markets, and if the bid is accepted it is paid at the sport energy market price.

Price based programs:

- Time of use: it is the simplest one, the prices are divided in peak and off-peaks time frames.
- Critical peak pricing: a pre-defined tariff is added to the electricity prices when a congestion arises, for a limited number of hours.
- Extreme day critical peak pricing: it is similar to the previous, but the tariff is applied for the whole 24 hours of the day with the peak in the demand.
- Real time pricing: customers are charged hourly with a tariff that reflects the real cost of electricity in the wholesale market.

The aforementioned DR schemes are mostly proportional to the amount of energy modulated by the active resources, but there can also be a fixed compensation proportional to the capacity band. Enel X's commercial offer, for example, follows the scheme envisaged by the UVAM pilot project set up by Terna includes two items: a fixed remuneration, directly proportional to the capacity made available for modulation, awarded by auction, and a variable remuneration, proportional to the energy demand during modulation events [40]. Contrarily to the UVAM which are applied at the transmission level, the DR scheme tested in this thesis work is applied at the distribution level.

2.1.2. Caused discomfort

A potential way of predicting the price and cost of a DR program is by forecasting the discomfort, and quantifying it with a reimbursement, or the economic loss that the active resources would incur into. According to [41] there are three general actions that a potential customer can undertake in order to participate in a DR program:

- Reduce electricity consumption during peak periods when prices are high: in this case there might be a potential and temporary reduction of comfort for the user if the reduction is achieved through a change of the operating point of heating, ventilation, and air conditioning (HVAC) systems.
- Shift peak demand consumption to off-peak hours. In this case there might be no discomfort at all when this action is undertaken by a domestic user (e.g. shifting activities which involve the use of appliances like the washing machine and dishwasher). If the action is undertaken by an industrial user there might be a potential cost for rescheduling its activities and to make up for the missed production.
- Using on-site generation: user would not experience any kind of discomfort, but may potential incur in additional cost to run its owned distributed generation.

2.1.3. Potential benefits

A complimentary approach proposed by [30] does not consider the potential discomfort for the user to put a price on the service, but rather the user and the system potential benefits.

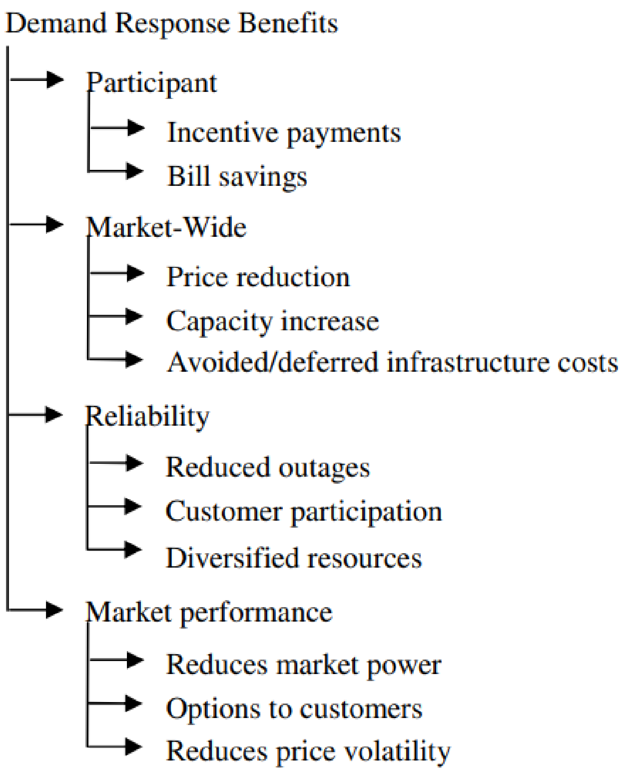


Figure 2.2: A classification of DR benefits

As highlighted in the previous section, the participants in DR schemes can be remunerated through different schemes leading to an individual gain. But the benefits of the DR solution are not limited to the individuals, but also to the market and, more in general, to the overall system. When it leads to a flattening of the demand curve, there is a more efficient use of the energy production and distribution infrastructures. An important consequence is the possibility to defer or avoid grid extension through infrastructure enforcement and upgrades (which will be the focus of the thesis work). Increase reliability is another important benefit: DR can increase the resilience of the grid operations, increasing the security of supply. This is due to the fact that the active resources can actively help to reduce the possibility of congestions and prevent outages, reducing their own risk of being exposed to an interruption of the electricity delivery. Lastly, active consumer can exert a power on the market (in market-based schemes), since the generation cost of electricity increases exponentially close to maximum generation capacity.

2.1.4. Demand response costs

A third approach, after the caused discomfort and the potential benefits, is simply based on the cost to setup the DR initiatives, as described in [42], divided between participants and system costs.

Type of cost	Cost	Quantification
Participant costs		
Initial costs	Enabling technology investment	Yes
	Establishing response plan or strategy	No
Event specific costs	Comfort/inconvienience costs	No
	Reduced amenity/lost business	No
	Rescheduling costs (e.g. overtime pay)	No
	Onsite generator fuel and maintenance costs	No
System costs		
Initial costs	Metering/communication system upgrades	Yes
	Utility equipment or software costs, billing system upgrades	Partial
	Consumer education	Partial
Ongoing programme costs	Programme administration/managment	Partial
	Marketing/recruitment	Partial
	Payments to participating customers	Partial
	Programme evaluation	No
	Metering/communication	Yes

Figure 2.3: A classification of DR setups costs

The first thing to be noticed, which is true for all the section in this chapter, is the fact that is relatively easy to identify the various cost items, but what is quite difficult is the actual quantification of each of them. In particular, for the participants costs the analysis is more qualitative, and there is an overlap from the items already seen in section 0. Regarding the system costs, the easiest to quantify are the one regarding the enabling infrastructure for the DR, such as the metering upgrades. These investments costs when seen along the 30 years plan horizon of the thesis work, are quite small considered yearly. Furthermore, in Italy the substitution with the new metering has already started in 2014 regardless of the DR programs [43], to provide information on the times of use of electricity: to promote energy efficiency, increasing awareness of customers' consumption behaviors, encouraging competition in post-meter services and making data available to the end customer or to designated third parties by the customer. Thus, the installation cost can be considered zero with respect to the business-as-usual case. The other costs, with the exception of “payment to participating customers” which is analyzed in section 2.1.1, refer to a more managerial part of the DR program, and are difficult to quantify, but at the same time are unlikely to dominate DR related costs [44].

2.2. Grid extension

The planning activity of the electricity distribution network must take into account the expected evolution for the electricity system as a whole, assuming future scenarios of the operating arrangements of the network. In this regard, a fundamental point of reference for the distribution network manager it consists of the forecasts elaborated by the transmission network operator, relating to the entire system national electricity [45]. Based on these forecasts, the transmission system operator elaborates and updates its Development Plan, containing interventions on the transmission grid that will inevitably involve, to varying degrees, the distribution networks. The forecasts of the loads on your network, by the distribution network manager, constitute another fundamental prerequisite for the elaboration of the Development Plan of the distribution network itself. In this regard, it should be noted that the reference context presents increasing complexities, given by the evolution of the distribution network from "passive network" to "active network", which imposed a new paradigm in network management and planning.

The forecasts of the evolution of the electricity system are the basis for the planning of the interventions development of the distribution network. By estimating the increase in energy demand and power, carried out on the basis of the historical series and through the growth forecasts of the share of energy produced from renewable sources, the main intervention in electricity distribution systems, such as new primary substations and lines, are evaluated. In particular, the main investments on the network concern interventions for the connection of power plants generation to the distribution network, interventions functional to the evolution of the load and improvement quality of service, interventions aimed at adapting to environmental regulations and technical standards of reference and interventions to increase the resilience of the distribution network. Finally, an important component in investments on the network is made up of digitization projects and technological innovation.

In Italy the various DSO need to present periodically “The annual and multi-year development plan for infrastructures”, in coordination with Terna, indicating the main interventions and the forecast of the relative realization times which they plan to do in the following years [46]. This is done in order to favor the coordinated development of the network and production plants. Thus, it is not difficult to find the main grid development and extension interventions of the grid planned by the DSO on the basis of the analysis of the critical issues and needs that emerge from the study of the possible evolutionary scenarios of the network itself. Furthermore, in a technical document called “Technical rules for connections”, published by each DSO, it is often present a cost sheet with the cost for the construction work of various cables and lines, expressed per each kilometer.

Some examples are shown in Table 2.1 and Table 2.2.

- eDistribuzione (first Italian DSO in term of served customers) [47]:

Type of cable	Cost [k€/km]
Overhead cable line Al 35 mm2	45
Overhead cable line Al 70 mm2	48
Overhead cable line Al 150 mm2	50
Overhead cable line Al 240 mm2	60
Underground cable line Al 185 mm2 on natural land	55
Underground cable line Al 185 mm2 on asphalted road with inert fillings natural and restorations	90

Table 2.1: eDistribuzione construction work for MV connections

The costs related to the authorization process, to the acquisition of the necessary easements and concessions and the execution of any mitigation works are valued separately, therefore not considered for the purpose of defining these average costs. Actual costs can increase significantly from average costs because of the following variables: cost of third-party services and supplies, cost of labor and supply materials (concrete, aggregates, vehicles work, etc.).

- Unareti (second Italian DSO in term of served customers) [48]:

Type of cable	Cost [k€/km]
MV line in overhead cable stranded Al 3x150 + 1x50 mm2	102.3
MV line in overhead cable stranded Al 3x150 + 1x50 mm2 on rough terrain	132.5
MV underground cable Al 3x185 mm2, in standard execution	192.9

Table 2.2: Unareti construction work for MV connections

The costs for the easement of power lines and the resolution of interference with other plants for special works are excluded. Also, the easement price for the cabin and obtaining building permit costs are excluded from the values.

Similar tables can be found for other Italian DSOs with similar costs: Areti [49], Edison [50], Distribuzione Elettrica Adriatica [51].

2.3. Summary of findings

In conclusion, there are several ways through which a DR scheme can be priced. It can start from the users' point of view, starting from the caused discomfort, or it could be estimated starting from different remuneration schemes. The opposite point of view is from the system operator: the pricing can start from the potential system benefit/avoided costs, or from the actual costs needed to setup the DR scheme. Unfortunately, identifying the different costs items is much easier than quantifying them since a lot of variables are involved: typology of participants, technology involved, type of remuneration scheme etc.

Regarding the GE, it is easier than the DR to obtain a quantitative estimate, even though it is just a lower limit, since a part of the cost items are very site specific and cannot be estimated without an on-site inspection. Hence, the costs in the proposed tables must be interpreted as indicative and rough costs

Therefore, in this thesis work it is possible to calculate with real data the cost of the traditional GE solution. Since it is not possible to obtain an estimate of the DR cost, several simulations with various price ranges will be conducted. Considering that the strike price for the UVAM project is 400 €/MWh, this will be the maximum order of magnitude of the various offers. A market-based demand bidding remuneration scheme will be used, to be able to select a random offer in each price range for each active resource available, in order to have a heterogenous bid offer profile for every given simulation. Thus, it will be possible to compare the final cost for the DR solution with various price ranges, and by comparing it to the annual cost of the GE solution, analyze in which conditions and with which price offers one solution is more convenient than the other.

3 Methodology

3.1. Framework of application

The thesis work main topic is the distribution of electric energy, the last stage of the electric energy value chain. It regards all the aspects through which electricity is carried from the transmission systems, through a transformer to the individual consumer. The focus of the thesis is on medium voltage (MV) distribution grids.

The grid can potentially incur in a congestion when in a given branch the current (or the apparent power) which flows to satisfy the demand, is higher than the branch maximum carrying capacity. This situation needs to be prevented because it would ruin the conductors due to overheating and would mine the stability and security of the grid. A congestion may happen during normal operations of the grid, if the demand increases significantly with respect to when the grid was designed. It can also happen when there is a failure in a substation or in a branch: to reach the users that are downstream the failure a counter-feeding is necessary. This means that one or mode nodes can be connected to a different primary substation (with respect to the normal operations) if the grid topology is re-configured. The reconfiguration is the process of "changing system topology via altering its power supply" [52], to shift the electrical load from the part of the network presenting the fault to another part of the grid. This operation significantly increases the current flowing on the branches involved, since they now need to serve more nodes than originally planned, increasing the probability of incurring in a congestion.

The classic solution adopted by distribution system operators (DSOs) to prevent the formation of congestions is by expanding the grid itself, substituting the old branches and/or adding new conductors to increase the current carrying capacity. Thus, the grid extension (GE) solution depends solely on the grid's branches capacity and the forecasted demand.

On the other hand, the pure loads and the prosumer (when the load is higher than the generation at a given time) can offer a service of flexibility to the grid, called demand response (DR). The willingness of the loads to offer the service to the DSO is expressed by making a bid in a local market, where the DSO is the counterpart. The active resources can bid in the local market an offer for each hour, consisting of a price [€/MWh] and an active power capacity band for 1 hour [MWh] that they are willing to reduce. In this thesis work, it has been assumed that each load is able to produce three offers, each one characterized by its own price and capacity band.

The service consists in a reduction of the hourly active power demand and can be used by the DSOs in order to prevent congestions in the grid. When a congestion is forecasted, the DSO can select the most economic offers in the local market and activate the service from the loads. The loads which are available and technically capable of offering this service are called active or flexible resources.

In this work, a variable percentage of loads in the grid is always assumed to be active, in order to have the possibility to test a DR scheme. For a domestic or residential user, the supply of the flexibility service may cause a minor discomfort. Since the active power demand reduction asked to them is quick and for a short period of time without a rescheduling, this demand side management strategy is called load cutting (or load shedding). For business or industrial users, the supply of the flexibility may cause a rescheduling of the production to a time when the grid is not congested. In this case the demand side management could be done through load shifting. The different effect of the two strategies on the load profile curve can be seen in Figure 3.1 [53].

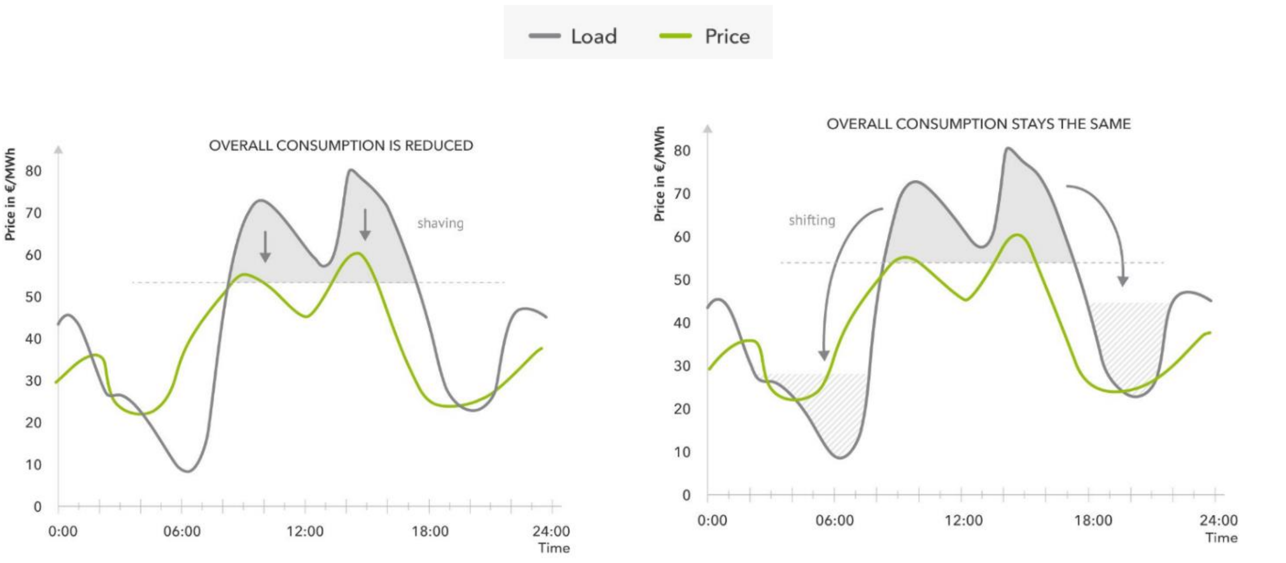


Figure 3.1: Load cutting (left) and load shifting (right) profiles [54]

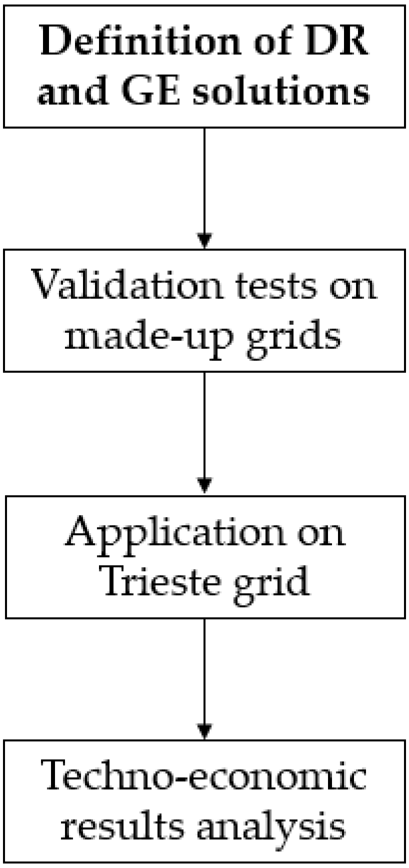
There is no difference if the focus is only on the peaks since both strategies have the same aim of flattening them. The difference can be seen before and after the peak itself, since in the peak shaving case the load curve does not change and in the peak shifting it is raised, to recover for the missed production. Another beneficial effect of the latter solution is that the curve is globally flatter, with reduced ramps and fluctuations.

In this work only the first strategy is analyzed, without deepening how the industrial customers could recover the lost production. In both cases, it is avoided the formation of spikes in the consumption-time curve. The actual power reduction can be done by the active resources in different ways (scaling down the actual demand, using on-site generation, relying on a battery) but these will not be investigated. What matters to the DSO, whose point of view is taken, is the way through which the active resources' flexibility is chosen and activated. When a congestion is forecasted, the DSO will select hourly the offers among the ones that have the capability to reduce the congestion, starting from the cheapest one.

The two approaches have two fundamental differences. The first difference is that the GE is always technically possible, whereas the DR may not. In fact, in the case of the GE it is just a matter of choosing a cable with a maximum carrying capacity (MCC) big enough to prevent the congestion. On the other hand, the DR is based on a market where the players owning the load can bid the percentage(s) of their active power demand that they are willing to reduce. This value can vary depending on the type of customer (residential, industrial, small business etc.) but it will likely be quiet far from 100%, which would mean a complete disconnection from the grid. Thus, if the value of the congestion is relatively high the DR may not be enough to solve it even if all the players offers would be accepted. The algorithms proposed in this thesis work has the objective of evaluating different situations to check in which conditions the DR is actually feasible and when it is, to compare its cost for the DSO compared to the traditional GE.

The second difference is that the two solutions have a very different time frame of applicability. The GE has to be done preventively with long forecast horizons (months/years), before the congestion actually happens, since it involves important construction work and a not irrelevant initial investment with a high capital expenditure (CAPEX). On the other hand, the DR can be done almost in real time with the congestions, with low CAPEX and very changeable operating expenses (OPEX). Therefore, the choice between one method or the other needs to be done in advance with a time lapse at least equal to the duration of the construction work. The aim of the algorithm is to give to a DSO a tool to plan in advance its grid management strategies, based on different demand prediction and grid network structures.

The thesis work can be summarized in these four main operations, in Flowchart 3.1. The first phase regards the definition and formalization of the two proposed solutions, describing in detail their procedures and outputs. In the second phase both solutions are tested to validate their robustness and accuracy. The tests are conducted on fictitious grids, which have the characteristic topology of distribution grids: radial, with one sub-station serving each node and with the possibility of counterfeeding through grid re-configuration. In the third phase the two solutions are applied to a real case study relevant to an urban scenario: the distribution grid of Trieste (Italy), using as inputs a historical series of one year, with a time step of 1 hour. The fourth and last phase of the thesis work is the techno-economic analysis of the results given by the application of the two solutions. The objective is to verify which is the most convenient solution for each case, and to outline suggestions and best-practices to determine it for any distribution grid.

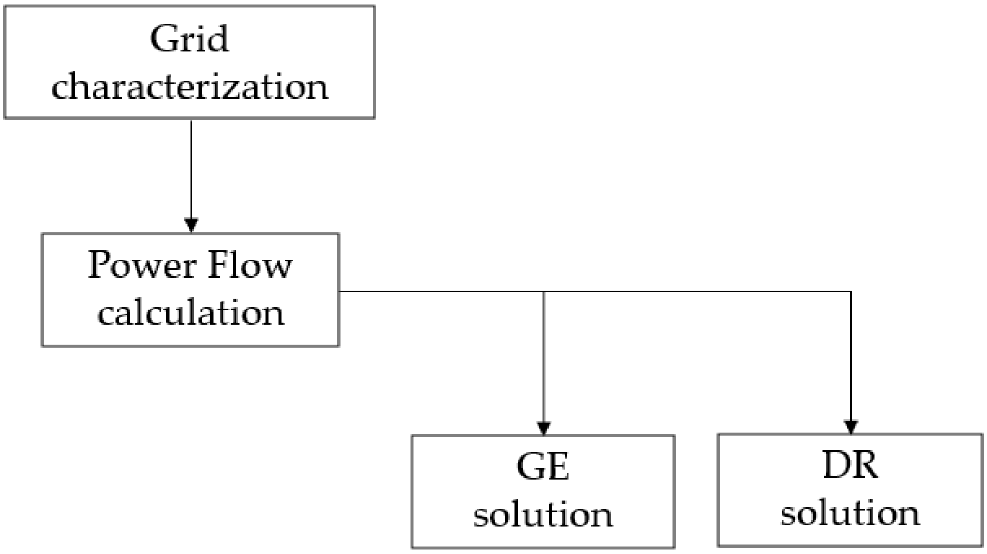


Flowchart 3.1 thesis structure

This chapter will focus on the first phase of the flowchart: the *definition of DR and GE solutions*, whereas the following phases will be analyzed and described in the next chapters.

3.2. Definition of Demand Response and Grid Extension solutions

This section is dedicated to explaining the structure of the chapter. The aim is to give a complete and accurate description of the methodology adopted in this thesis work to obtain the final outputs, which are analyzed in the following chapters, starting from the given inputs. The phases indicated in Flowchart 3.2 are all the steps which lead to formation of outputs for the GE and DR solutions, given a grid and its users as input.



Flowchart 3.2: DR and GE solutions structure

The phases are:

- Grid characterization: it includes all the operations regarding the upload of the input data. The input data can be divided in 2 parts: the data about the grid structure (topology, electrical characteristics of the branches and the conductor etc) and the user's energy profiles (demand and/or generation profile).
- Power Flow calculation and output: it includes all the operations that are done to calculate the main electrical variables (voltages, currents etc) in a defined time span starting with the input data.
- GE and DR solution and outputs: it includes all the operations and the algorithms that use as input data the output of the Power Flow, and as outputs the new electrical variables and total costs of application of each solution.

3.3. Grid characterization

The grid characterization is in turn divided in two phases:

- Grid parameters upload: it includes all the operations which lead to the creation of the grid itself, defining all its electrical parameters and topology.
- Loads and generators profiles upload: it includes all the operations which lead to the creation of all the users which populate the grid.

3.3.1. Grid parameters

In the grid model there is a fictious node (the slack node) representing the high voltage (HV) national grid, and one or more nodes representing the primary substations HV/MV. Each one of the other nodes is connected through a path to a single primary substation. In each node is present one or more users which can be a pure load, a pure generator, or a prosumer (when the user has both a demand and a production curve of electricity).

The grid itself is built using the following parameters in a matrix form, which are the main inputs to solve the Power Flow.

- Branches: it contains all the information of the branch connecting two nodes such as the starting point, the final point, the resistance [Ω], reactance [Ω/km], susceptance [μS/km], length [km], nominal voltage [kV], maximum carrying capacity [A].
- Nodes: it contains all the information about the nodes present on their grid such as the nominal voltage [kV] and geographical coordinates.

The distribution grid has usually a radial structure, meaning that each node is served by only one primary substation. Often, the path that starts from the substation runs into bifurcations, leading to the origination of different sub-paths.

The first condition for an active resource to be able to help solving a congestion is that the load needs to be on a node downstream the congestion itself. Otherwise, if the load was located on a node upstream the congestion there would be no effect on the congestion itself.

The division in "paths" creates a second condition: the load needs to be on the same path as the congestion, otherwise there is no influence on it since the power and currents are independent between each path.

For example, in the grid represented in Figure 3.2 there are three different paths starting from the slack point (node 1), which represents a primary substation:

- path 1 (node 2, 5 and 8)
- path 2 (node 3, 6 and 9)
- path 3 (node 4, 7 and 10).

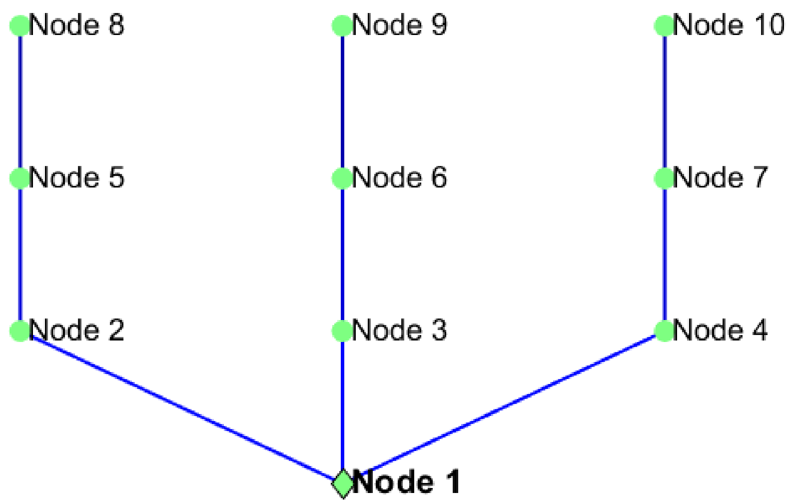


Figure 3.2: Grid network with different paths

A congestion happening on the branch between 2 and 5 will be solved only by reducing the loads which are located on nodes that share the same path to the slack node (i.e., node 5 and 8), excluding the other two paths, which obviously do not have influence on the congestion at all.

There can be also a grid topology in which there is a crossroads within the same path, as it can be seen in Figure 3.3, downstream to node 8 and 9.

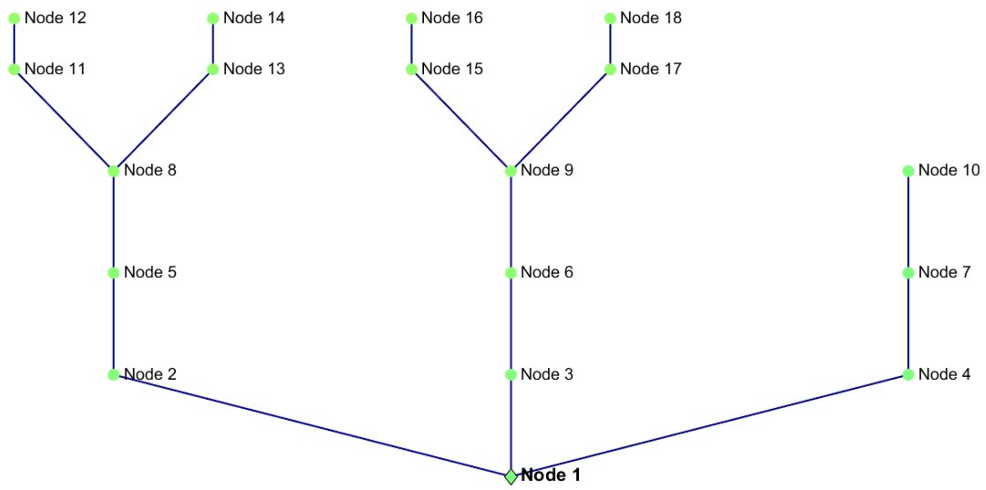


Figure 3.3: Grid network with different paths and crossroads

At an algorithm level, it has been decided to keep the nodes after the crossroads on the same path, and consequently on the same table of the active resources' characterization:

- path 1 (node 2, 5, 8, 11, 12, 13, 14)
- path 2 (node 3, 6 ,9, 15, 16, 17, 18)
- path 3 (node 4, 7 and 10).

If the congestion is present before the crossroads (upstream node 8), it does not matter which load is reduced as long as it is downstream the congestion. Conversely, a congestion between node 8 and 11 can be solved only by reducing the load on nodes 11 and 12, and it would be useless to do so on nodes 13 and 14, and analogously for the other crossroads. Therefore, a sub-path division is necessary in order for the algorithm to be applied correctly, for example:

- path 1 (node 2, 5, 8)
  - path 1.1 (node 11, 12)
  - path 1.2 (node 13, 14)
- path 2 (node 3, 6 ,9)
  - path 2.1 (node 15, 16)
  - path 2.2 (node 17, 18)
- path 3 (node 4, 7 and 10).

This operation is actually necessary whenever there is a branch ramification created by the presence of a crossroad. Theoretically, depending on the grid topology, a "sub-subpath" could be present. If this is the case, the same conceptual operation is conducted each time. Thus, essentially for a load to be eligible for the DR, the congestion has to be on one of the branches that are located in the path between the given load and the slack node.

The solution can be in case of failure of a branch on the network besides normal operations. For example, if there is a failure between node 1 and 2 of the grid configuration in Figure 3.1 the nodes 2, 5 and 8 need to be fed by shifting the electrical node from one feeder to another, as in Figure 3.4.

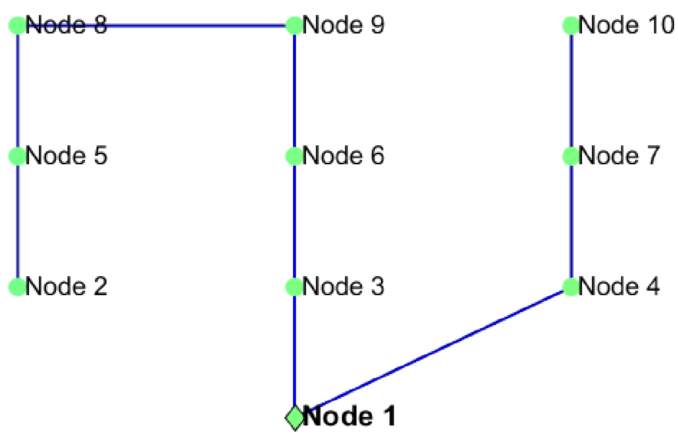


Figure 3.4: Grid with failure and counterfeeding

Of course, the branch connecting node 8 and 9 must be already present, in order to be able to counterfeed a line. Real distribution grids have a meshed topology, rather than a radial, and thus in many cases a line can be fed also from a different point, to cope with faults of branches and components.

It can be seen how the paths to the slack node depend on the topology of the grid in any given moment, since they may change when a fault is present.

3.3.2. Loads and generators profiles

There are three main typologies of user in the grid:

- Pure loads: it contains all the information about the loads present on the grid such as the nominal power [MW], the typology (inductive or capacitive), the node on which they are located, the power factor (cos φ), the load curve during the year (in P.U. with respect to the nominal power).
- Pure generators: it contains all the information about the generator present on their grid such as the typology of plant (PV, wind turbines, hydroelectric plant, controllable plant), the nominal power [MW], the node where they are located, the typology of generation (PQ, PE, slack), the power factor, if they are under or over excited, the voltage setpoint, the generation curve during the year in P.U. with respect to the nominal power, and considered negative). The most upstream node is always the slack generator, which represents the linkage of the distribution grid to the national grid (HV/MV or MV/LV). Thus, it is possible to assume that the voltage is known and constant along the whole year,
- Prosumer: it is modeled in the same way as the pure loads, but the profile curve in P.U. can also contain negative values, to represent an instant in time in which the generation overcomes the consumption and thus the user behave as a

3.4. Power Flow calculation and output

3.4.1. Power flow calculation

The GE and DR solutions use as inputs the electrical variables relevant to a grid and its users. Therefore, a method to obtain these variables given the grid and its parameters as input is necessary. The method that allow to do this is the Power Flow.

The model to do the Power Flow calculation has been developed in Matlab environment. The software is based on the library called "Matpower", a free and open-source electric power system simulation and optimization tools for Matlab [55]. The core part of the software is used to operate the Power Flow calculations, to obtain the relative electrical variables, given the grid and its users as input. The calculations are done on the grid in equilibrium conditions, it is a static regime analysis to verify the compliance with the constraints on the nodes (such as the voltage limits) and on the branches (such as the currents circulating). The temporal dimension is executed by applying the Power Flow methodology on a series of snapshots of the network with a fixed time frame. The time frame needs to coincide with the time frame of the input data, e.g. the power profiles of the distributed generation and loads, which is typically hourly (for Italian grid users with a nominal power at least of 55 kW connected to the low voltage (LV), or connected to the MV or to the HV [56].

There are two main Matlab functions:

- Powerflow: it is used to calculate the matrix of the tensions (in p.u.). An additional code is used to initialize the matrixes of the nodes, the generators and the branches, the matrix of nodal admittances (in sparse format), the matrixes of the nodal admittances.
- Current: it is used to calculate the secondary unknowns of the problem. It is used to calculate the incoming and outgoing current in and from each branch in complex value. Similarly, it is used to calculate the active and reactive power in and from each branch.

The Power Flow is a non-linear problem which can be solved iteratively or by linearization. The Power Flow software can use both the Gauss method and the Newton-Rapson method to calculate all the electrical parameters. In the Gauss method the solution is found starting from a first attempt, from which to start an iterative process. The unknowns are the nodal, module and phase voltages. It is reasonable to assume that under conditions of normal operations and in equilibrium, the modules of the voltages are close to the nominal values and the tension's phases are relatively small. The Newton-Rapson method is based on Taylor series development limited to first order of the problem. This method too involves defining a starting profile of the variables as a first attempt solution. The Gauss method updates the voltage one node at a time, leading to a linear convergence. On the other hand, the Newton-Rapson method has a quadratic convergence (which means less iterations) but it is prone to the phenomenon of divergence, meaning that the difference between consecutive solutions increase instead of decreasing. Therefore, the software written to solve the Power Flow problem applies at first the Gauss method, and then uses its output as input for the Newton-Rapson, to have a fast and convergent solution.

The main results of the Power Flow are two matrixes for each time step:

- Bus: it contains the voltage magnitude [kV] and the voltage angle [degrees].
- Branch: it contains the "from" bus, the "to" bus, the current rating [A], the active power injection "from bus" and "to bus" [MW], the reactive power injection "from bus" and "to bus" [MVAR].

3.4.2. Power flow outputs

Using the results given by the Power Flow software it is possible to outline two matrixes which give a first idea on the state of any given grid, and that will be used by the DR and GE solutions as inputs.

- Branch currents: it is a matrix $i \times t$, where i is equal to the number of branches in the grid, and t is equal to the number of time frames (typically 8760, considering a time step of 1 hour and a simulation of 1 year). It represents the magnitude of the current of each branch in any timestep simulated. It gives a first idea about which lines are the more loaded and which value of current pass through them.
- Branch loading: it is a matrix with the same dimensions of the previous one, where each item is calculated with equation (3.1).

$$Loading\ [\%]_{i,t} = \frac{Branch\ Current_{i,t}}{Maximum\ carrying\ capacity_i} \qquad (3.1)$$

  Obviously, this value should not be higher than 100% to preserve the security of the grid and to avoid the conductors in the cables to be overheated. This matrix is useful to see and analyze when and where a potential congestion may be present. The objective of the DR and GE solutions will be to bring all these values under the acceptable threshold.

The Power Flow calculates for every branch two values of current, with the first one ("from node") slightly higher other than the second ("to node") due to the presence of transversal branches. To have a more conservative approach, the higher value is taken as the reference value (i.e. the "from node" value). When this value is higher than the maximum carrying capacity of the given branch it means that a congestion is present.

With equations (3.2)and (3.3) it is possible to calculate the values of apparent power:

$$S_{max}\ [VA] = \sqrt{3} \times V_{nominal} \times MCC \qquad (3.2)$$

$$S_{i,t}[VA] = \sqrt{P_{i,t}^2 + Q_{i,t}^2} \qquad (3.3)$$

Where S_{max} represent the maximum apparent power that can flow into the branch, since it is calculated using the MCC as the value of the current, and $S_{i,t}$ represent the value of apparent power flowing in the branch i at the timestep t. A congestion can in fact be detected also by comparing the value of the apparent power (3.2) on a given branch and at a given timestep with the value of the maximum apparent power admissible in that branch (3.3). Similarly, to the previous case, the highest values of active and reactive power are considered as the reference in order to be more conservative.

Detecting a congestion by checking whether the current or the apparent power flowing in each branch are higher than the threshold value is substantially the same operation. However, both the catalogues of electric cable producer [57] for power transmission and the official documents of various Italian distributors regarding projects of grid extensions [47] [48] [50] [49] [51], report the current and not the apparent power as the limiting electrical variable. By choosing to express the outputs in term of current, it is easier to detect the congestion in the grid by simply subtracting the MCC to the value of the current calculated by the Power Flow. If the resulting value is higher than 0, it means that a congestion is present, and consequently the loading will be over 100%.

The two approaches are linked by equation (3.4).

$$Current_{i,j}\,[A] = \frac{S_{i,j}}{\sqrt{3} \times V_{i,j}} \tag{3.4}$$

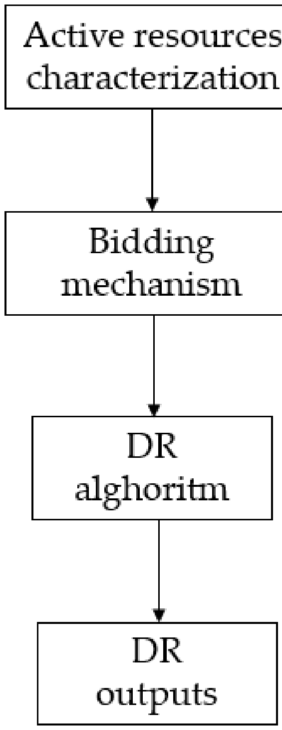
which relates the current with the apparent power.

Using (3.4), the Branch current and Branch loading matrixes can be obtained also with respect to the apparent power instead of the current.

3.5. Demand response solution

The DR solution consists of 4 phases, as shown in Flowchart 3.3:

- Active resources characterization: the active loads which offer the flexibility services are characterized based on different parameters and their position in the grid.
- Bidding mechanism: it is the phase in which the flexibility market is formed, by the bidding of the various resources.
- DR algorithm: is the phase in which the technical feasibility of the DR solution to solve the congestion is tested, and the new electrical variables are calculated.
- DR outputs: based on the results of the DR algorithm, outputs are produced to be able to analyze the overall DR solution.



Flowchart 3.3: DR structure

3.5.1. Active resources characterization

As seen in Chapter 3.3.1, not all the flexible resources are suitable to solve each congestion, since the grid is divided in path and sub-paths starting from the slack node (i.e. the primary substation). Thus, before proceeding with the algorithm itself, it is necessary to characterize the active resources (i.e. the loads willing to offer a flexibility service) that will be used by the DSO for the congestion resolution. In this context, with the term *characterization* it is intended the process of uploading each load of the grid, sorting it according to which path the node is located, generating and assigning to it all the variables that will be needed for the DR algorithm execution.

The characterization is done through a matrix tables, and there is one table for every possible path that expands in the network from the slack node. Thus, even though the local market is just one, the bids offered by the active resources are divided according to which path the resource is located on. In this way, the DSO can see and select only the loads which are located on the same path where the congestion has manifested, since the other would be helpless in solving the congestion.

Once the grid topology and the active resources offers have been defined it possible to classify each load into the characterization relative to its respective path. Each active resources can offer three different bids, and each one of them behaves independently, in order to be able to rank them all by increasing price and accept the cheapest ones first. Thus, the number of active resources is equal to three times the number of active loads, since three offers for each user are considered.

The characterization table contains in each column one of the following information:

- Load number: loads are numbered in order to track the offers even when they are re-ordered.
- Percentage of power: it is the percentage of active power that the resource is willing to reduce.
- Price: it is the price measured in [€/MWh] that the active resource has offered.
- Distance: it is the number of branches that separates the node where the active resources is located and its primary substation. This number is used to select only the loads downstream the congestion, meaning that their distance from the primary substation is higher than the distance from the congestion itself and the primary substation.
- Number of activations: it is a number between 0 and the number of hours of the simulations to keep track of how many times the resources has been selected by the DSO in the selected time frame.
- Number of hourly activations: it is either 0 or 1 and it shows whether the resource has been activated in a given hour of the simulation, to avoid selecting the same resource twice. This number is set at 0 when the simulation passes from an hour to the following.
- Number of bids: it is either 1,2 and 3 and represents the bid that each resource has offered, since each offer is treated as a separate resource.
- Path: it represents on which path (and eventual sub-path if present) the resource is located and paired with the distance it gives the indication whether the resource for solving a given congestion or not.
- Node: it is the node where the load is located.

For each path the characterization of resources is a table that has on the first column the n-th bids, and on the others the information aforementioned. Therefore, each row refers to a single bid.

3.5.2. Bidding mechanism

Every load is characterized by different offers that are made to the DSO in order to decrease its own load and remunerate the service given to solve the congestion. Every offer is distinguished by a different price and power. The price is expressed in €/MWh, the power is expressed as a percentage of the power that the given load demands for any given hour. The price increases with the capacity offered since the discomfort caused by reducing the active power is increasing. Every load is modelled with three different levels of offers which are randomized with different parameters in each simulation to obtain a heterogenous and representative population. For sake of simplicity, the offer profile is assumed to be constant throughout the year for each load in each simulation. Figure 3.5 represents two random different possible profiles of offer for a customer involved in the DR.

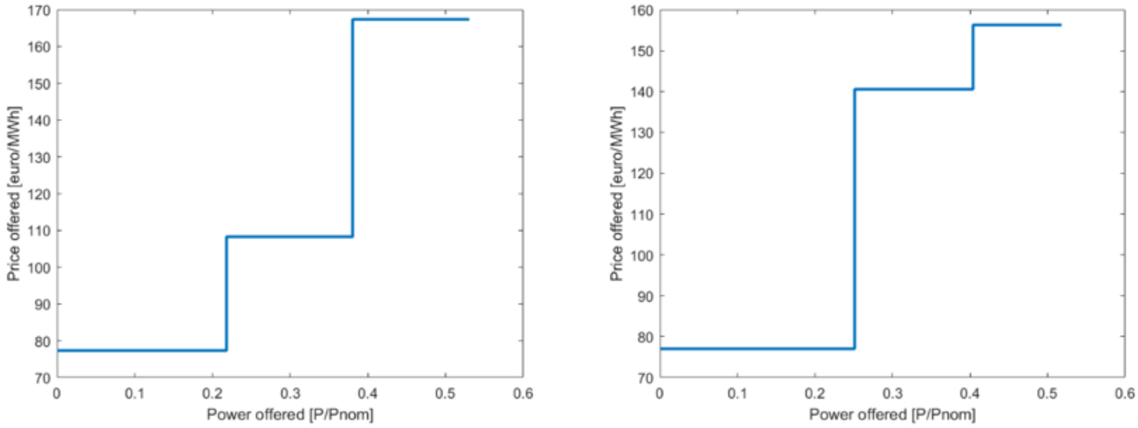


Figure 3.5: Example of bids by active resource

3.5.3. DR algorithm

It is possible to visualize the DR solution in an apparent power diagram, shown in Figure 3.6.

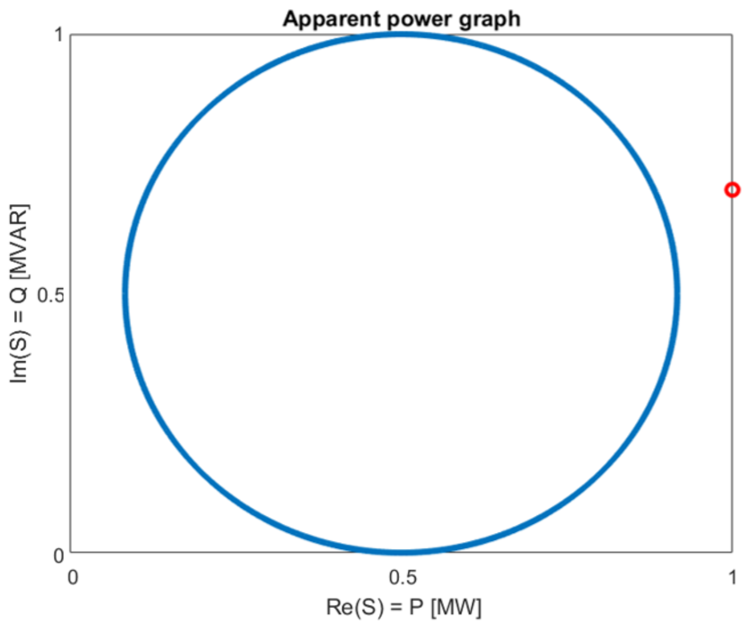


Figure 3.6: Admissible apparent power diagram with a congestion

The red point represents the value of apparent power transmitted by a branch, calculated as in equation (3.3) whereas the blue circle represents the locus of points such that equation (3.2) is verified. When the red point is located outside the admissible region, it means that a congestion is present. In this thesis work, the DR can be done by loads by reducing their hourly active power demand. For sake of simplicity, the reactive power demand is assumed to be constant. Therefore, when the DR is activated on a load the active power transmitted by the branch will decrease and consequently the apparent power will because of equation (3.3). The red point will then be translated horizontally until it is located inside the blue circle. Because of equation (3.4) when this happens also the current circulating will be lower than the MCC and thus the congestion is solved. After the DR the admissible power diagram will be the following, as shown in Figure 3.7.

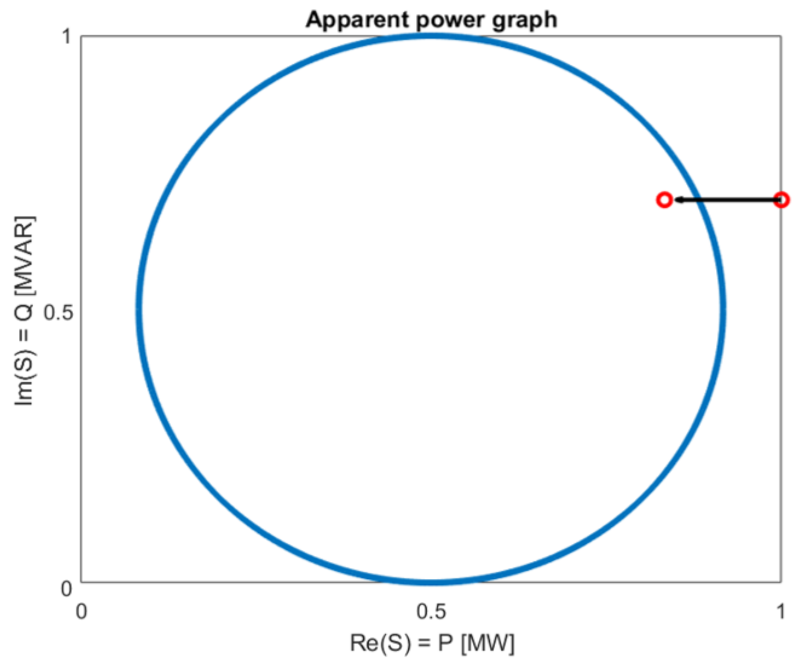
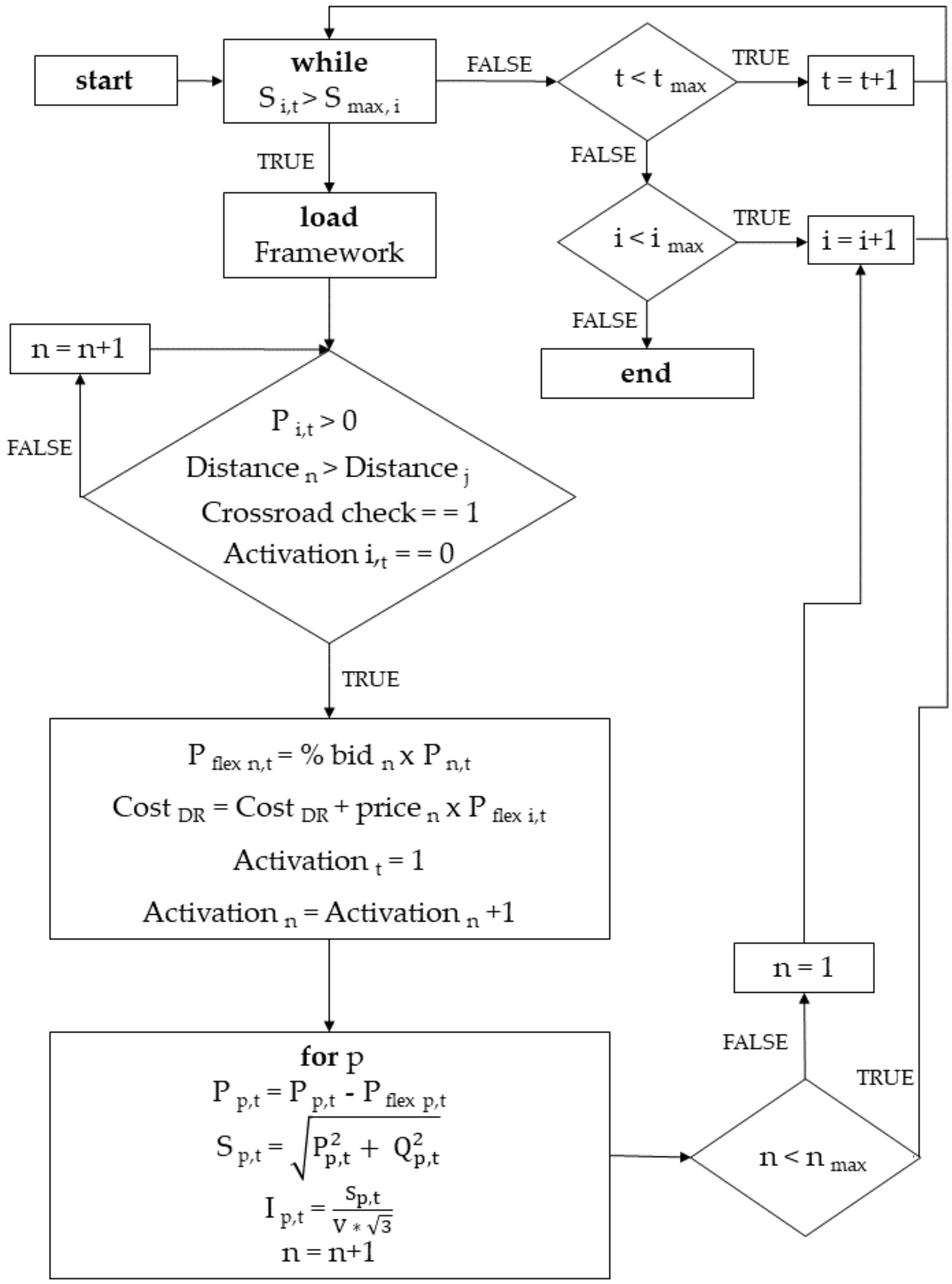


Figure 3.7: Admissible apparent power diagram without congestions (DR)

In the Flowchart 3.5, the actual algorithm is represented. The variables are defined as:

- i: number characterizing the i-th branch. It is initialized equal to 1 and its maximum value is equal to the number of branches in the grid.
- t: representing the t-th hour of the simulation. It is initialized equal to 1 and its maximum value is equal to the number of hours in the simulation (typically 8760 hours if the simulation covers one year).
- n: representing the number of the resource for each path (the order is made by increasing price). It is initialized when the characterization for each path is created.
- j: number representing the “to” node of the branch suffering the congestion. It is initialized only when a congestion is found.
- p: it is a vector containing all the i-th indexes of the branches that connects the node j-th to the slack node following the shortest route. There are the same

numbers of p vectors as there are nodes, and for the same node the p vector can be different if the grid topology changes, or when there are failures. The path nnnicalculated by using a piece of software developed internally by the research group of the Energy Department of Politecnico di Milano.



Flowchart 3.4: DR algorithm structure

The algorithm starts by initializing the variables. Then a *for* cycle iterating on each time step (from 1 to 8760, to simulate all the hours in ore year) is nested in a *for* cycle iterating on each branch of the grid. For each iteration it is checked if there is a congestion in that branch at that time, starting from the electrical parameters calculated with the Power Flow in the as-is condition. Thus, the total number of iterations can be calculated with equation (3.5).

$$Number\ of\ iterations\ =\ max_t \times max_i \tag{3.5}$$

since the control on the loading needs to be done in each branch and in each time step.

If there is not any congestion, the iteration continues. When a congestion is detected, the first step is to load the characterization of resources relative to the same path of the branch where it is happening. For the given congestion, all the active resources are scanned starting from the cheapest one. The iteration finishes when either the congestion is solved or when there are no more active resources that can be activated. In the latter case the congestion may not be fully solved, even though its intensity has been decreased.

Once the branch, timestep and active resource have been defined there is a series of condition that must be verified in order to activate the DR on the selected resource. The first condition is expressed by (3.6):

$$P_{i,t} > 0 \tag{3.6}$$

in order to select only the bids offered by resources which are behaving as pure loads in the given time. In fact, the grid where the algorithm will be used is a distribution grid, which typically is radial with the current and power flowing from the slack node or the primary cabin towards the loads. In some nodes there might be at the same time a production of power and a demand of power from the grid. The power production might be higher than the power demand, typically when the production is done with non-programmable renewables. In this case the numerical quantities of the $P_{i,t}$ would be lower than zero. If there is a congestion a prosumer could give a service to the DSO by increasing its power production, and thus reducing its power demand for the grid, but this is out of the scope of the thesis work. What this condition expresses is the fact that since the congestion is caused by the power load, it is needed to check if the given load is one of those actively contributing to the formation of the congestion.

The second condition is expressed by (3.7):

$$Distance_n > Distance_j \tag{3.7}$$

meaning that the distance between the n-th node (where the active resource is located) and the slack node has to be higher than the the distance between the j-th node (where the congestion is present), to ensure that the DR is done downstream of the congestion. The distance between the nodes is measured as the number of branches that are present in between the two nodes. In fact, when the DR is activated and the nominal power reduced, the current and the apparent power are reduced in all the branches connecting the node to the slack (including the congested branch). The distance is calculated as the sum of the branches connecting each node, in other words it is the length of the vector p for each node.

The third condition is the check on the crossroads, which can be expressed by defining the variable "before_check".

Crossroads check	
1:	**If** floor (path) == path
2:	before_check = true
3:	**else**
5:	before_check = false
6:	**end if**

The actual check is done with equation (3.8):

$$(before\_check == true)\ OR\ (before\_check == false\ AND\ path_n == path_i) \qquad (3.8)$$

Considering the grid topology already represented in Figure 3.1:

- If the congestion is present on path 1 (before node 8 and therefore before the crossroads), Before = true and it is irrelevant where the active resources is activated, as long as it is downstream the congestion.
- If the congestion is either on path 1.1 or 1.2 the active resource needs to be on the same sub-path ($path_n == path_i$), besides being downstream the congestion. In this case then a double condition needs to be verified.

The last condition is expressed by equation (3.9):

$$Activation_{n,t} = 0 \qquad (3.9)$$

Meaning that each active resource can be activated only once per each time step (the hour), and then before the activation of the flexibility is done, it is needed to be checked that the counter of activations is still set at zero, for the given time step.

If all the four conditions are true, the active resource is selected by the algorithm to be suitable for the activation of the flexibility.

Equation (3.10) shows the activation of the flexibility as the percentage offered by the player times the actual active power demand in the considered time step. It is important to remember that each player can offer three different bids: the actual percentage of the second and third offer (when and if activated) are calculated as the offer itself minus the previous offer (which has been already activated).

$$P_{flex\ n,t}\ [MW] = \%\ bid_n \times P_{n,t} \tag{3.10}$$

Equation (3.11) shows the calculation of the total variable cost for the DSO. This equation takes into account only the cost due to the actual activation of the flexibility and does not include the fixed part relative to the availability of the service, which is proportional to the nominal power of the load and does not depend on the number of activations. The next step is updating the number of activations for the selected load, which is the counter of how many times each active resource has been activated over one year. This indicator is useful to see at the end of the simulation which resources and how many times have been activated.

$$Cost_{DR,n}\ [€] = \sum_{t=1}^{8760} price_n \times P_{flex\ n,t} \tag{3.11}$$

Once the economic indicator is calculated, it is time to update all the electric variables. This operation is iterative and is done for each one of the branches upstream to the node where the load activated is located. In equation (3.12) it is shown the actual reduction of the active power which is the actual service given by the flexible resources.

$$P_{p,t}\ [MW] = P_{p,t} - P_{flex\ p,t} \tag{3.12}$$

The apparent power and current are then updated accordingly to equations (3.3) and (3.4). In equation (3.4) the voltage is assumed to be constant even after the reduction of active power, since the power reduction is very small with respect to the overall power flowing in the branch. Therefore, the values calculated with the Power Flow are used. If the congestion is still present, the algorithm starts again trying to activate the following active resource in the same path, proceeding in order of increasing price of the bid.

At this point the iteration can pass to the next one (increasing either the timestep or the branch number) if either one of two conditions are satisfied:

- The congestion has been solved and therefore the *while* cycle stops.
- The number of active resources available in the given path finished (in this case the congestion is not solved).

3.5.4. DR outputs

From the calculation of the algorithm, it is possible to define new output variables. The main output of the DR simulation is the new Current matrix, with the same structure as the Current matrix in 3.4.2, but with all the new currents after the power reduction by the active resources. It is then possible to define two new indicators, with the form of matrixes with the same dimensions: the difference between the current in each branch and at each time step and the maximum current allowable by the branch, calculated before and after the DR algorithm is applied.

These matrixes contain in each item just the share of current that causes the congestion and not the whole current flowing through each branch. If the Current matrix calculated before the algorithm does not contain any value higher than 0, it means that in the considered time span there are not any congestions, since $I_{i,t} < MCC_i$. Contrarily, the values over 0 represent the intensity of the congestion, if present.

If the DR is successful in solving every congestion, the Current matrix calculated after the algorithm will contain only values equal or less than 0. If there is any item with a value higher than 0, not all congestions have been solved. This is due to the fact that the flexibility offered by the active resources is not high enough in term of percentage with respect to their active power.

Other outputs that can be derived from the variables obtained with the DR algorithm are:

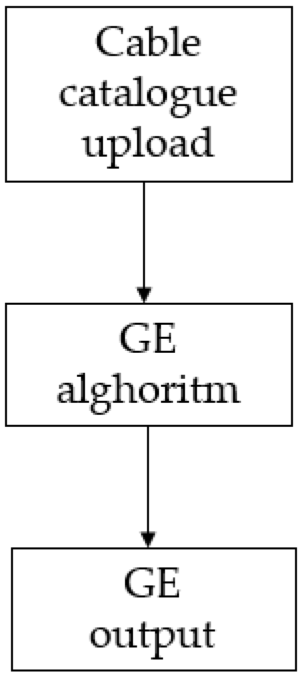
- Power reduction: it has dimensions $n \times t$, where n is the number of active resources and t the is equal to the number of time frames. Each item represents the total quantity of active power (MW) that any given active resource has reduced in each time step. If it is equal to 0 it means that in that time frame there has not been any congestion, or that the offer of the active user has not been accepted.
- DR cost: it has dimensions $n \times t$, where n is the number of active resources and t the is equal to the number of time frames. Each item represents the total costs that the DSO has to pay to the active user n related to each timestep t, calculated as the sum of the accepted bids (thus not including the possible fixed remuneration related to the power band availability).
- Congestion matrix: it has dimension $i \times t$, where i is equal to the number of branches in the grid, and t is equal to the number of time frames. It contains a 0 if in the branch is not present a congestion, and 1 if it is present. It is useful to see how many branches are congested and in which hours.

3.6. Grid extension solution

The aim of this chapter is to describe and reproduce with an algorithm the classical solution of the grid extension. After the objective is to verify the economic convenience of the investment against the innovative DR solution. The GE solutions consists simply in extending the network by inserting cables in parallel to those already installed. In this way the carrying capacity of the interested branch increases, preventing the formation of a congestion. In fact, by increasing the MCC, also the admissible apparent power will increase because of equation (3.2). The classical solution is conceptually simple but with many practical issues. First, it requires a great initial investment. The construction work can take a long time, depending on the orography of where the distribution is located, and can encounter delays. Secondly, the dimensioning of the cables is done by simulating and predicting the highest possible demand in term of power and/or current along each cable. However, a mistake in this phase is not correctable after the construction work is finished.

The GE solution is divided in three phases, as shown in Flowchart 3.5.

- Cable catalogue upload: in this phase all the data about the new possible cables is uploaded in the model, such as the typology of the cable, all the electrical specific parameters of the cable (resistance, reactance, susceptance), the specific costs.
- different cables, the electrical parameters and the costs are uploaded.
- GE algorithm: it is the algorithm itself, where the congested cables are substituted with the appropriate new ones.
- GE output: the new variables starting from the algorithm's results are calculated.



Flowchart 3.5: GE structure

3.6.1. Cable catalogue upload

The Power Flow model returns output values measured in A (for the current) or MVA (for the apparent power). Thus, the cable needs to have technical characteristics which are comparable with the output of the Power Flow, in order to be able to select the right one for the grid expansion. Regarding the reference cables of Table 2.1 and Table 2.2, the only data is the nominal section expressed in mm^2. This data as-is is not comparable. In fact, the calculation of the conductor capacity according to the section and the laying characteristics cannot be done in an immediate way, because it would be needed to build the thermal model of the conductor and the surrounding environment, which is distant from the scope of the thesis. A method to obtain in a simple way the carrying capacity of the cable in term of power or current starting from its section is needed. The values of the section and the typology of the conductors of Table 2.1and Table 2.2 is used as an input to seek and compare them with the data sheet of commercial catalogues of MV cables, such as [58] [57]. When a cable from the table is matched with a real cable on the catalogue, all the electrical parameters needed to compare it with the results of the Power Flow are simply found on the data sheet. The parameters of interest are: the maximum carrying capacity [A], specific resistance [Ω/km], specific reactance [Ω/km], and specific susceptance [μS/km].

This operation is done iteratively for each cable. When the process is finished it is possible to outline the Table 3.1, which contains the same information as Table 2.1and Table 2.2 but with the data expressed in term of the parameters of interest.

Cable number	**MCC [A]**	**Resistance [Ω/km]**	**Reactance [Ω/km]**	**Susceptance [μS/km]**
1	100	0.8	0.09	50
2	224	0.56	0.08	50
3	243	0.29	0.08	50
4	309	0.18	0.08	50
5	340	0.06	0.08	50
6	350	0.15	0.08	50

Table 3.1: Cable catalogue merged

3.6.2. GE algorithm

As for the DR solution, it is possible to visualize the GE solution in an apparent power diagram. In Figure 3.8 it is possible to see how also in this another approach the red point (representing the apparent power) is now located in the admissible operation area of the branch conductor, starting from a condition as in Figure 3.6.

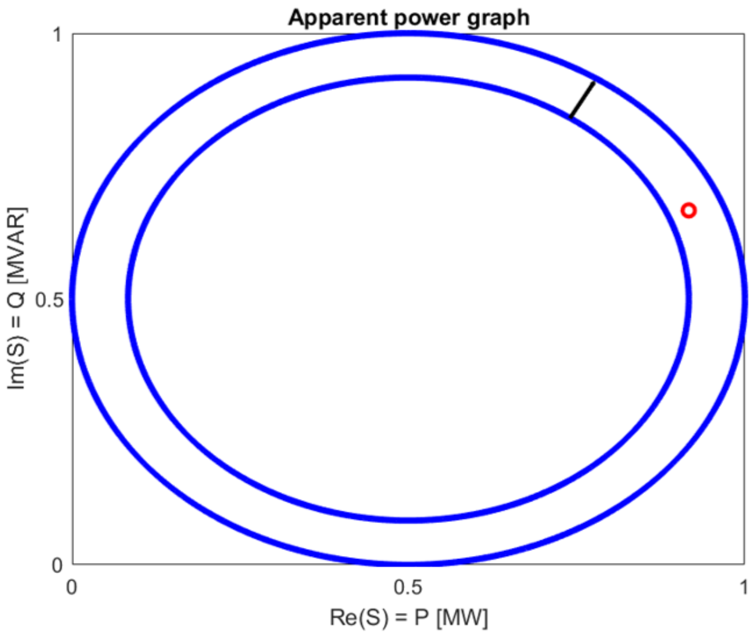


Figure 3.8: Admissible apparent power diagram without congestions (GE)

Conversely to the DR solution, it is not the red point to move inside the circle with a power reduction, but is the circle which gets bigger, meaning that the maximum apparent power carriable by the conductor has increased.

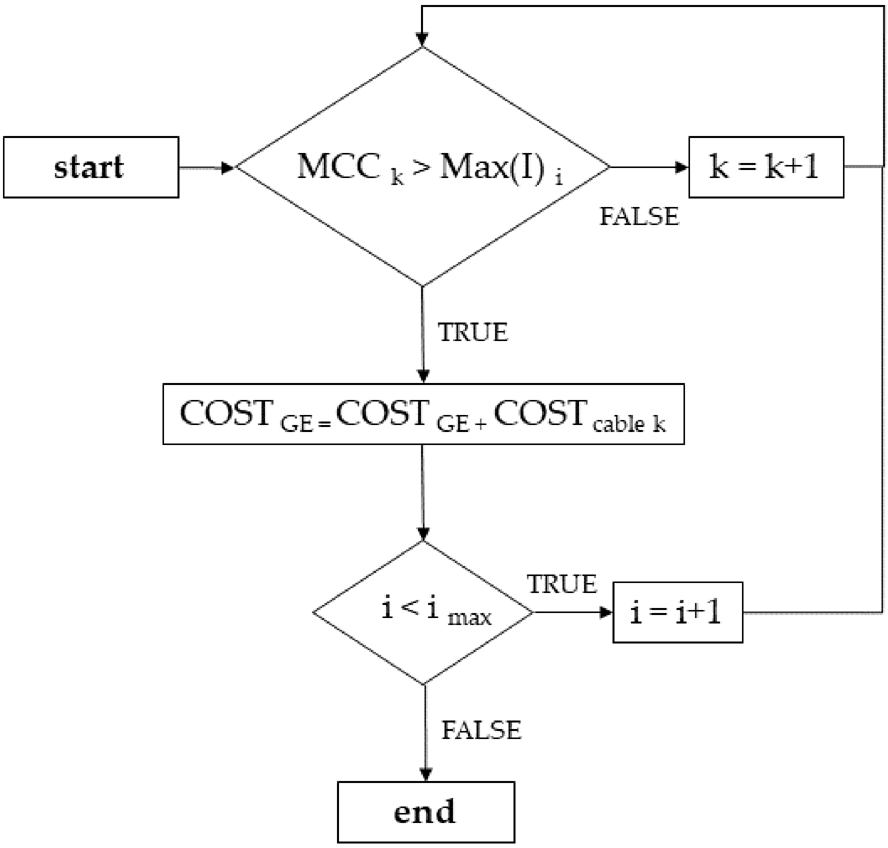
The algorithm for the grid extension is much simpler and less expensive than the demand response one in term of computational power since it does not require the calculation of the resource characterization (i.e. the division in paths, the division in three offers, the randomization of the power percentages and the bids offered), there are less conditions to start an iteration, it does not require to update all the electrical parameters. Furthermore, there is not the need to iterate on each time step, as for the DR solution, because the calculation is done directly on the most congested branch which is known straight from the Power Flow. In fact, once the worst case during the year is solved with the GE, automatically all the other timestep on the same branch are solved, since the dimensioning is done in the worst possible condition. Actually, it is done on the 90-th percentile of the current congestions, so as not to excessively oversize the branch on just sporadic events, (i.e. which occur less than 10% of the time). Conversely, the DR algorithm has to be done for every branch and for every timestep independently on how many times the flexible resources have already been activated.

New variables with respect to the DR algorithm need to be initialized for the GE algorithm:

- k: it is the k-th element of the cable manufacture table, with respect to Table 3.1. It is initialized equal to 1.

- Max(I): it is a vector with length i, therefore with as many values as there are branches in the grid. Each number represents the 90-th percentile of the current congestions on that branch along the whole year, minus the MCC of the branch. The subtraction is done to consider only the extra quota of current that causes the congestion, in order to select the minimum section (and cost) cable to be put in parallel to the existing one.

The other variables used are the same as for the DR algorithm. All the phases of the GE algorithm are shown in Flowchart 3.6.



Flowchart 3.6: GE algorithm

The algorithm starts by comparing the quota of current needed with the MCC of the cables on the selected catalogue. The cables on the catalogue have been ranked in order of increasing MCC (and thus increasing price) to select the least expensive cable to solve the congestion. If the cable tested has a MCC high enough, the total cost is updated and the algorithm jumps iterating on the following branch. If the cable is not big enough, the algorithm tests the following one on the table. Conversely to the DR algorithm, it is not possible to still have congestions when the algorithm ends (excluding the 10th percentile). Firstly, because the MCC of the cables can arrive to very high values and secondly, because in principle more than one cable could be installed on the same branch. Actually, since the choice for new cables is quite limited and the first one is already very big, it is expected that often the new MCC covers also the potential congestions caused by the 10th percentile of the highest currents. This expectation will be confirmed in Chapter 6.

The cost of the GE solution is calculated with equation (3.13):

$$Cost_{cable,k}\ [€/year] = \frac{Cost\ cable_k\ per\ km \times length\ of\ branch_i}{Useful\ life\ cable_k} \tag{3.13}$$

The cost is divided by the cable useful life in order to obtain a yearly cost, which would be then comparable to the total cost of the DR solution, which by definition covers the same time span as the simulation itself. The algorithm ends when all the branches have been scanned and the new cables added when needed.

3.6.3. GE output

The main output that can be calculated starting from the results of the GE algorithms is:

- GE cost: it is a vector with length i, where i is the number of branches in the considered grid. It contains 0 if the branch was not congested, or the yearly cost of adding a new cable calculated with equation (3.13) if the branch was congested.

There is only one main output since there is not the need of calculating new electrical variables, conversely to the DR solution. Theoretically, substituting or adding one or more cables changes the impedances of the line and therefore the solution of the power flow would change. Since this has a small effect on the final output, the effects of cable replacement on the electrical grid variables is neglected.

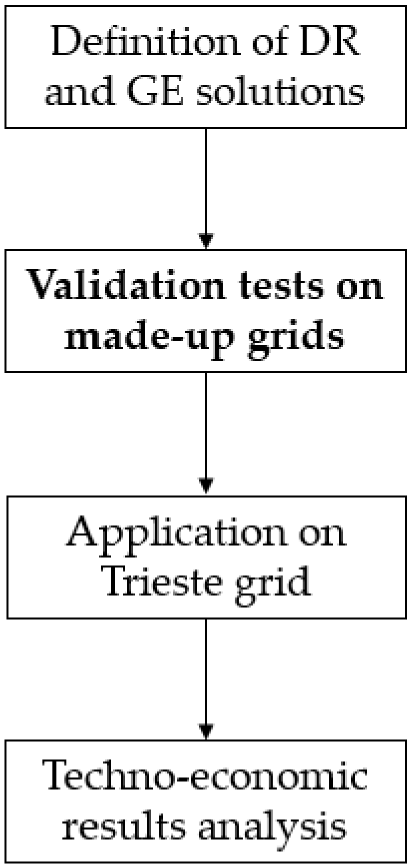
The Current matrix can be then updated wit equation (3.14).

$$I_{diff,GE\ i,t}\ [A] = I_{i,t} - MCC_{i,GE} \tag{3.14}$$

A conceptual difference between the GE and DR solution is that the DR changes the first term (the new currents), whereas the GE solution changes the second term (the branches new maximum carrying capacity). Another difference is that the amount of values higher than 0 in the GE Current matrix is known a priori, being included between none and the 10th percentile of the number of congested branches, since the algorithm is constructed in this way. This situation would not happen only if the biggest congestion in term of amplitude would be bigger than the maximum capacity of the biggest cable in the catalogue, and this is very unlikely for a well-dimensioned distribution grid, even in failure conditions. On the other hand, for the case of the DR solution the number of residual congestions is dependent on the offers in term of power capacity made by the bids and the number of loads which participate in the project, which is not known a priori.

4 Algorithm testing and validation

After having defined the demand response (DR) and (GE) solutions it is possible to proceed further to the second step of the work, as indicated in Flowchart 4.1.



Flowchart 4.1: thesis structure

In this second section different simulations are done on a grid with the topology as in Figure 3.2 (one substation, three different paths, four different sub-paths), changing various electrical and physical parameter. The same Figure is shown in Figure 4.1.

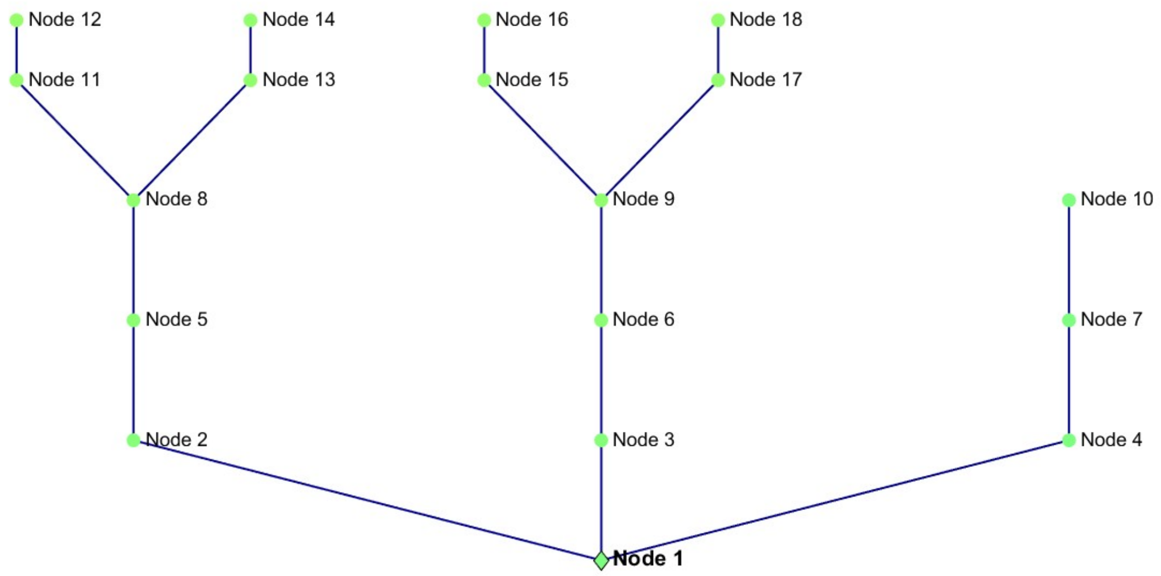


Figure 4.1: topology of the test grid

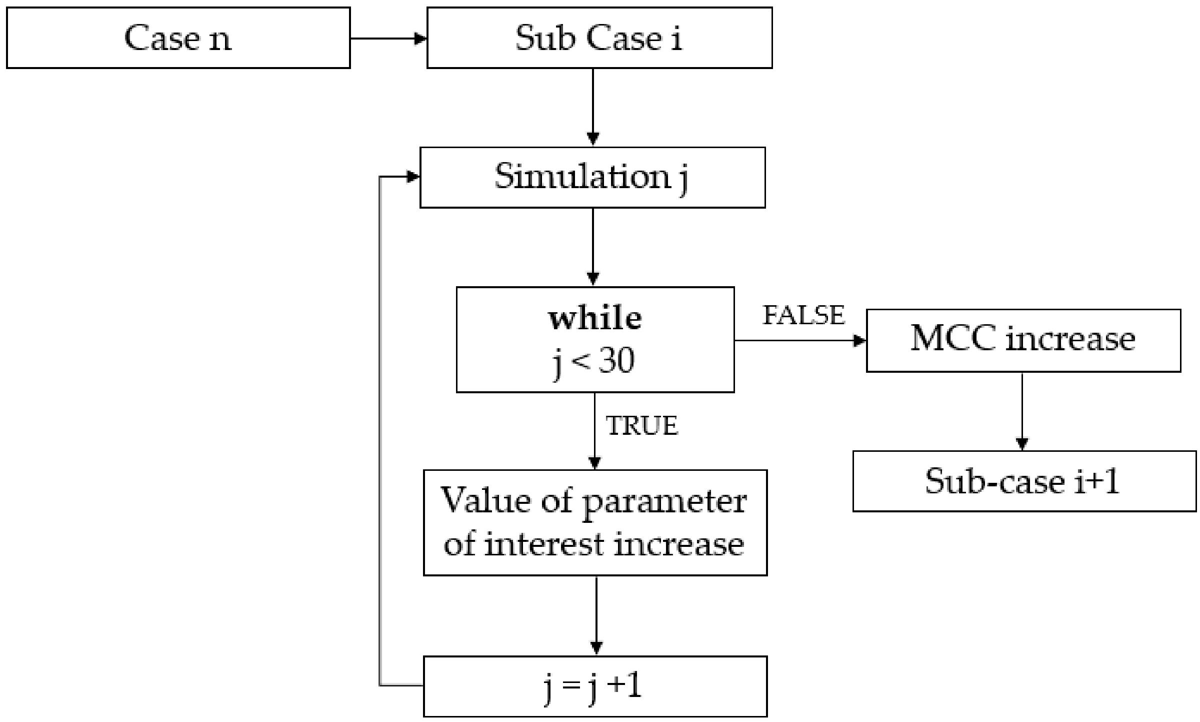
This is done in order to obtain a different number of congestions per year in different scenarios, and to compare the trend of the total yearly cost of the innovative DR solution against the traditional GE solution. Even if the final numeric result itself it is not very relevant, being the initial data randomly generated, this is useful to start to detect trends and the differential in the final prices with respect to the evolution of the initial data change. This operation is done also in order to firstly check the validity and robustness of the algorithms and methodology proposed. In fact, with a small change in the initial data, it is expected a small change in the final results.

In the validation grid there are two different loads located in each node, each one with a randomly selected yearly profile from a database of real profiles (expressed in per unit with respect to the nominal power).

The parameters that will be changed with different combinations through a random generation of initial conditions are the following:

- Branches' maximum carrying capacity (MCC)
- Nominal power of the loads
- Length of the branches
- Price of the DR bids.

In this section three different *cases* (Case 1, Case 2, Case 3) are analyzed. In each case the focus is on one of the parameters previously listed. Each single case is formed by the application of the two algorithms proposed to three *sub-cases*. Each single sub-case is in turn formed by 30 different *simulations*. Between one simulation and the other, within the subcase, only the parameter of interest (nominal power, branches length or bids price) can change, in order to isolate its effect on the economic final result (the yearly cost of the two solutions). The MCCs of the branches change between one sub-case and the other, to test different conditions, but are constant among the 30 simulations for each sub-case. Thus, for each parameter of interest there are 30 simulations for each sub-case, and 3 sub-cases for each case, meaning that for each parameter 90 different simulations with different input data are done, to test different combinations. How this procedure is done is explained in detail in the introduction of each case. The general procedure is shown in Flowchart 4.2. It is important to remember that the maximum carrying capacity (MCC) is the maximum current bearable by a conductor in the as-is case, thus before the application of the eventual GE solution.



Flowchart 4.2: Algorithm testing and validation scheme

4.1. Case 1: variable power

As shown in Table 4.1 each of the thirty *simulations* for each *case* the nominal power of the loads increases, whereas the other parameters (MCC, length of the branches, price of the bids) remain constant. Thus, for increasing simulation number the active power, and hence the apparent power, increase. The difference between *case* 1.1, 1.2 and 1.3 is the MCC of the branches, which increases in each sub-case, but stays constant within. In this case the nominal power keeps increasing between each sub-case. Otherwise, there would not be any congestions, since also the MCC has increased between different sub-cases. This is done in order to simulate different grids and to obtain a different number of congestions in different cases. It is possible to visualize the input data for each sub-case and simulations in Figure 4.2: Testing variable power data

	In-between simulations	**In-between sub-cases**
Nominal Power	Increasing	Increasing
MCC	Constant	Increasing
Branches length	Constant	Constant
Bids price	Constant	Constant

Table 4.1: Data of Case 1

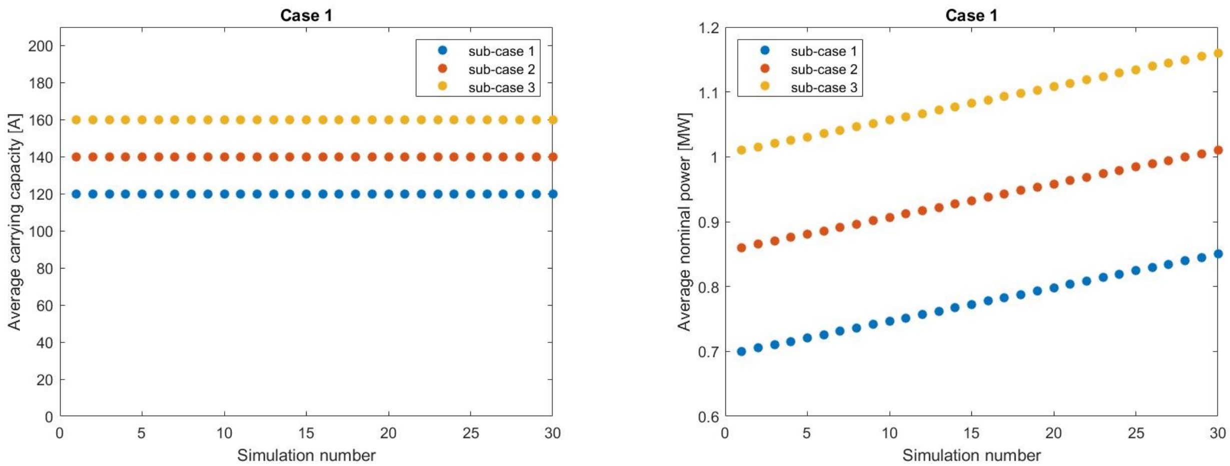


Figure 4.2: Testing variable power data

Figure 4.3, Figure 4.4 and Figure 4.5's pictures on the left represents for each simulation the total yearly cost for both the DR and GE solutions, whereas the picture on the right represents the number of congestions. Since the nominal power increases on x-axis from one simulation to the following one, also the annual number of congestions increases. That is the link between the picture on the left and on the right.

All the three sub-cases show similar patterns, even with very different number of annual congestions. In fact, each sub-case have a different value of MCC of the cables, to simulate different cable sections. The first thing that catches the eye is that, as already mentioned, the DR costs are strictly proportional to the number of congestions, whereas the GR cost has a "step" increase, and the frequency of the steps depends on the density of the catalogue considered for the cables. The real catalogue considered, represented in Table 3.1, has 6 different cables with a MCC between 100 and 340 A, thus for the majority of the congestion the GE solution is quiet over dimensioned.

In fact, when the absolute amplitude of the congestion is just under the MCC of a given potential new cable to substitute to the current, it is the ideal case for the GE solution (even though there is no safety in case of increased congestion with the respect to the forecast). The opposite case is the least ideal for the GE: if the absolute amplitude of the congestion is just above the MCC of a given potential new cable: a huge investment needs to be made but theoretically a much smaller cables would have been enough.

This is clearly visible in the graphs: in Figure 4.3 and in Figure 4.4 the GE solutions has 3 steps, whereas in Figure 4.5 it has only 2 steps, since the MCC of the initial grid has increased and therefore the number and amplitude of congestions decreased.

After doing these considerations, it is possible to see that in each case there is a given number of congestions which equalizes the prices of the two solutions.

In all the simulations in this section the DR manages to solve all the congestions that are present, so it is not repeated for every case.

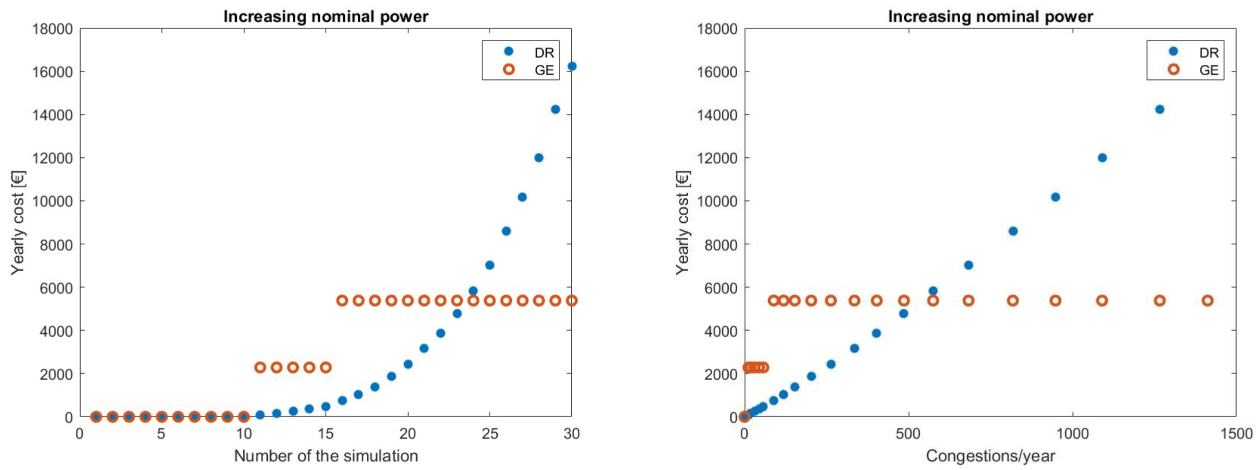


Figure 4.3: Case 1.1: increasing nominal power

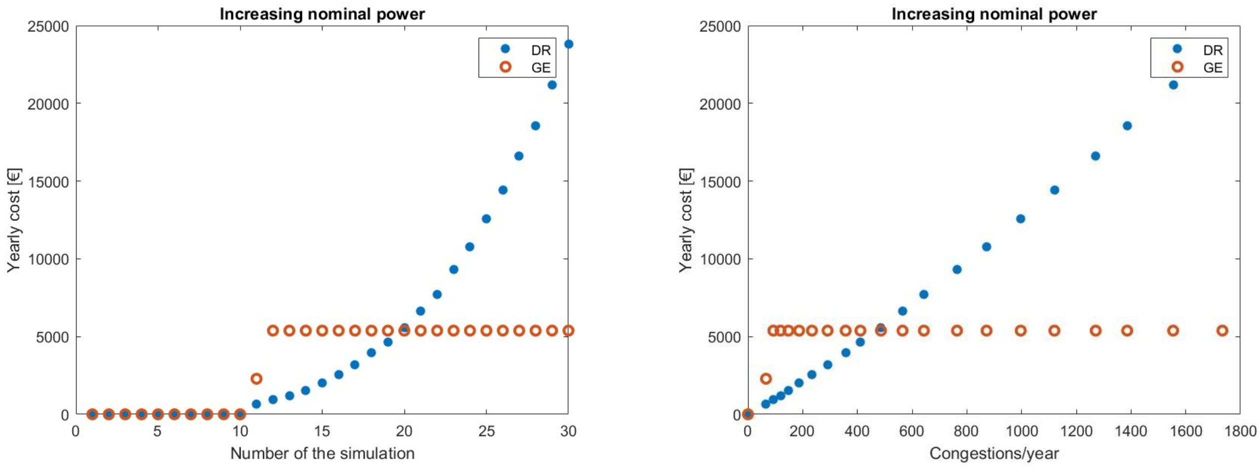


Figure 4.4: Case 1.2: increasing nominal power

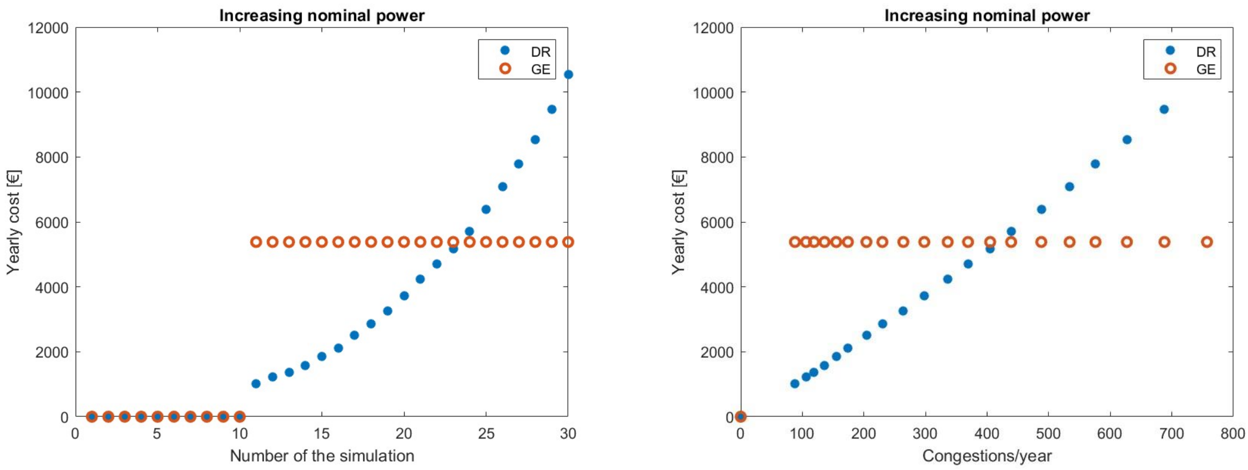


Figure 4.5: Case 1.3: increasing nominal power

4.2. Case 2: variable power 2

This Case is a variant of the previous one. The input data are the same as the Case previously discussed with the sole difference that the values of nominal power are the same in different sub-cases, to make them more comparable, as shown in Table 4.2. This variant is done in order to be able to plot the results of all the three sub-cases in just one 3D plots, showing how the final cost of the DR solution changes with respect to both the MCC and the active power of the loads. This cannot be done if both parameters change, as in the previous case. The data can be visualized in Figure 4.6.

	In-between simulations	In-between sub-cases
Nominal Power	Increasing	Constant
MCC	Constant	Increasing
Branches length	Constant	Constant
Bids price	Constant	Constant

Table 4.2: Data of Case 1.2

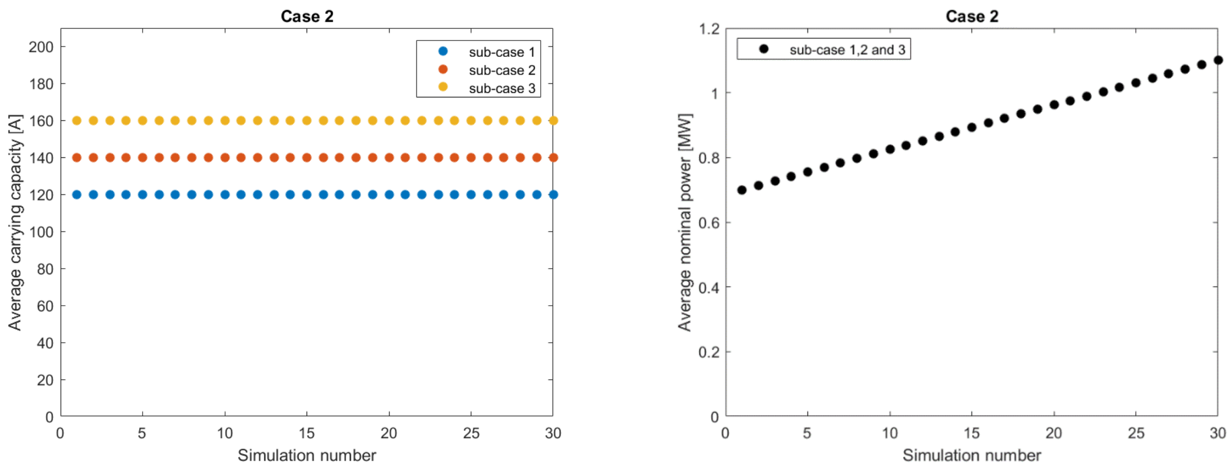


Figure 4.6: Testing variable power 2 data

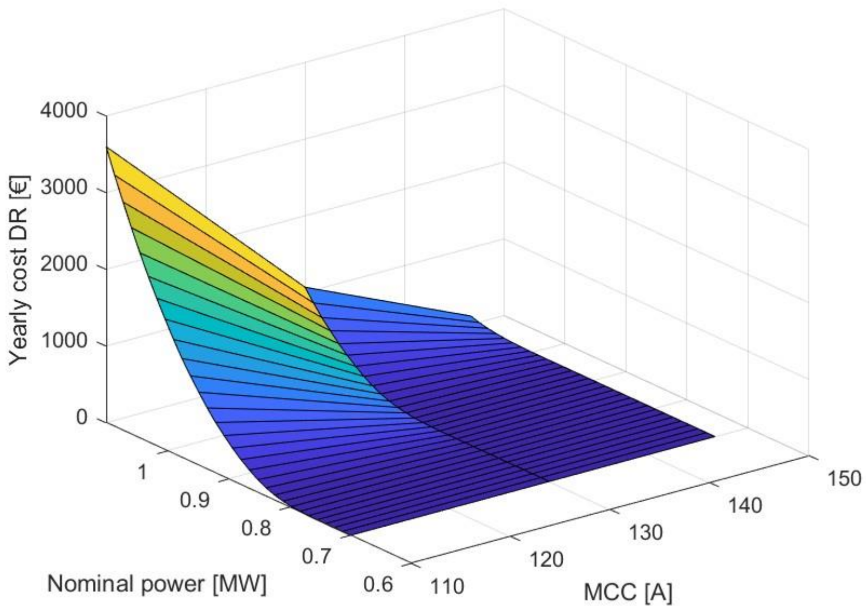


Figure 4.7 it is possible to see all the variables of the previous case but plotted in only one graph to be able to see their relationships. The maximum prices for the DR solution are reached for low value of MCC and high nominal power (frequent and broad congestions). On the other hand, the minimum prices are reached in the opposite situation: high value of MCC and low nominal power (rare and not intense congestions). This matches exactly what is intuitively expected, thus confirming the validity of the model.

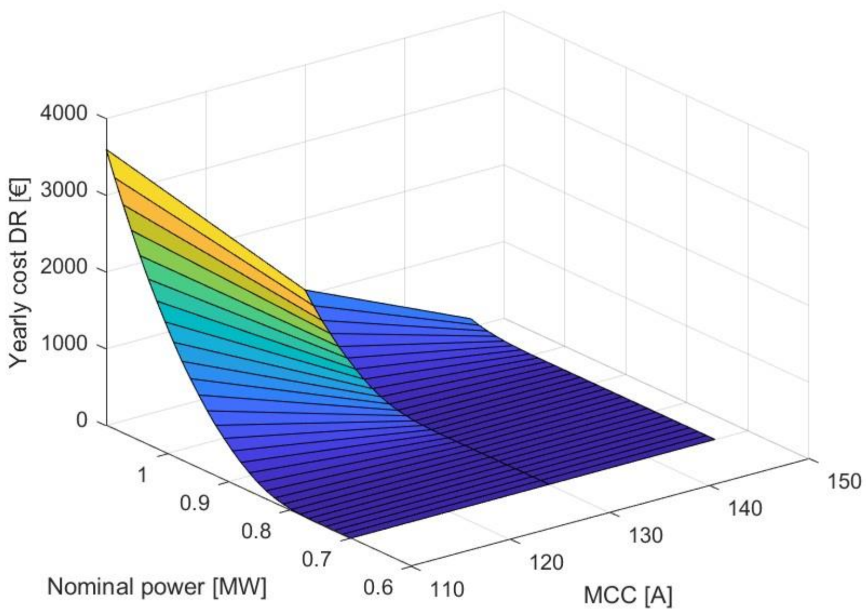


Figure 4.7: Case 2

4.3. Case 3: variable length

The objective of this case is to analyze the effect of the length of the lines. In each of the thirty simulations every parameter remains constant, except for the length (and it is constant between each sub-case), as can be seen in Table 4.3. The MCC and the nominal power are constant in the simulations in order to have a fixed number of congestions, and they both increase between the sub-cases. The input data can be visualized in Figure 4.8 and Figure 4.9.

	In-between simulations	**In-between sub-cases**
Nominal Power	Constant	Increasing
MCC	Constant	Increasing
Branches length	Increasing	Constant
Bids price	Constant	Constant

Table 4.3: Data of case 3

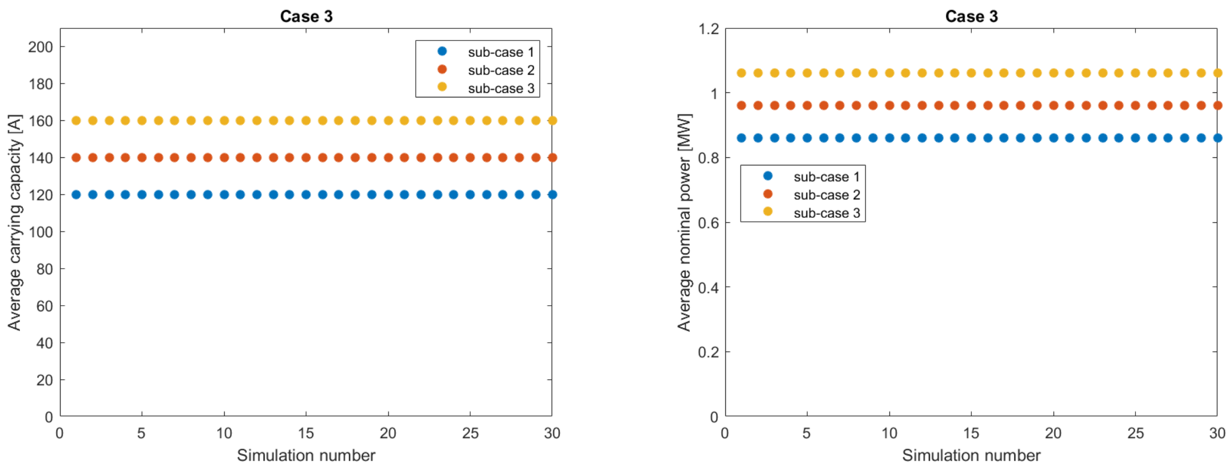


Figure 4.8: Data for testing variable length

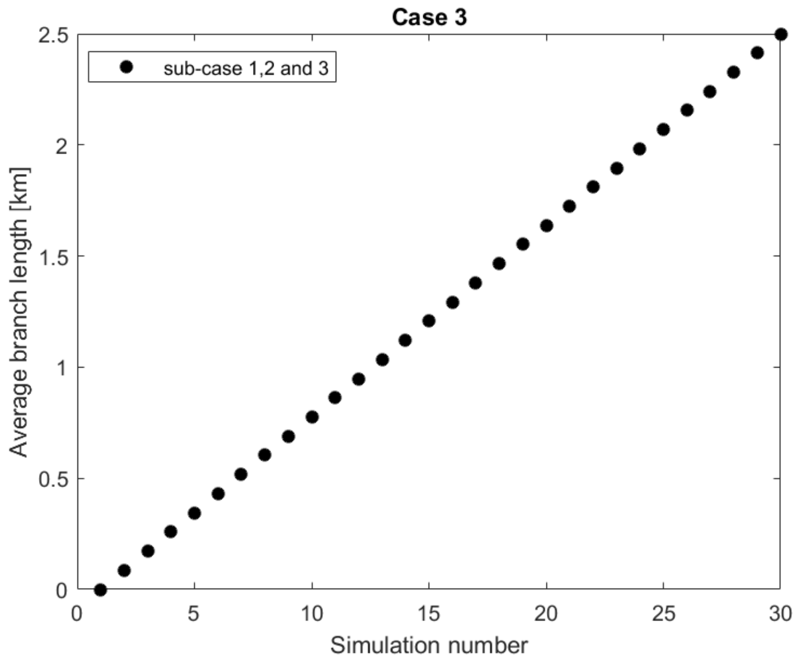


Figure 4.9: Testing variable length data

By looking at equation (3.13) it is possible to see that the branch length is one of the main parameters which constitutes the final GE price. There is therefore a break-even value between the two solutions, analogously to the nominal power in Case 1 and Case 2. What is really interesting about this case is the fact that the annual congestions increase with the length of the branch. Intuitively, the number of congestions should depend mainly on the MCC and the nominal power. But when the lines increase in length, also the power losses increase due to Joule effect increase. Since the active power demand has to satisfied with the actual active power going into a node (the "to" value), that value remains fixed. On the other hand, the "from" value has to increase to compensate the major losses. And since the algorithm to be conservative considers the highest value, the number of congestions increases. However, the rate of increase of the GE is much higher than the one of the DR. Moreover, the congestions graph (on the right) has a "step" shapes, meaning that in some simulations the number of congestions is constant, therefore the DR price, but not the GE one, because the lines keep increasing in length in each iteration. These trends can be seen in Figure 4.10, Figure 4.11and Figure 4.12.

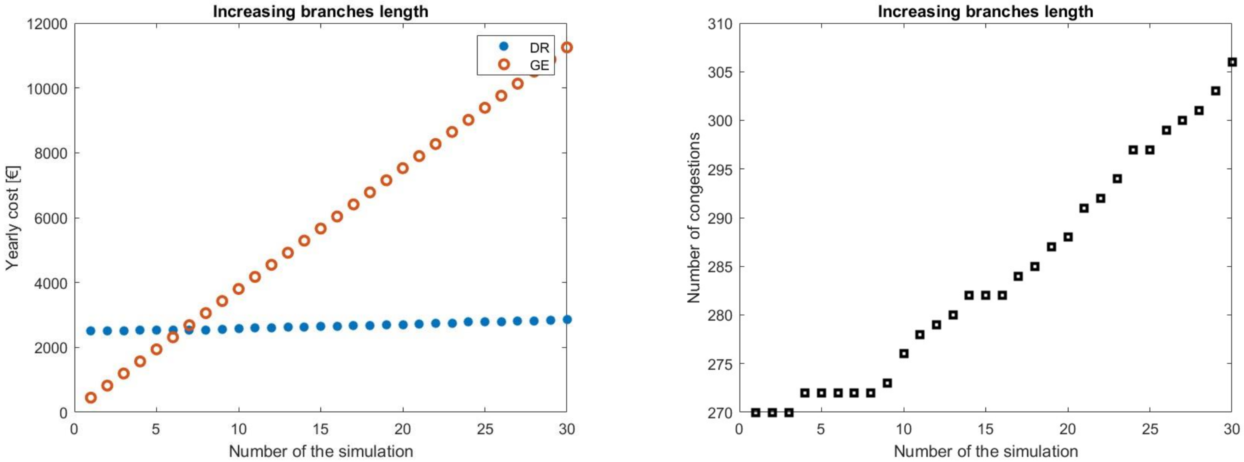


Figure 4.10: Case 3.1: increasing the length of the branches

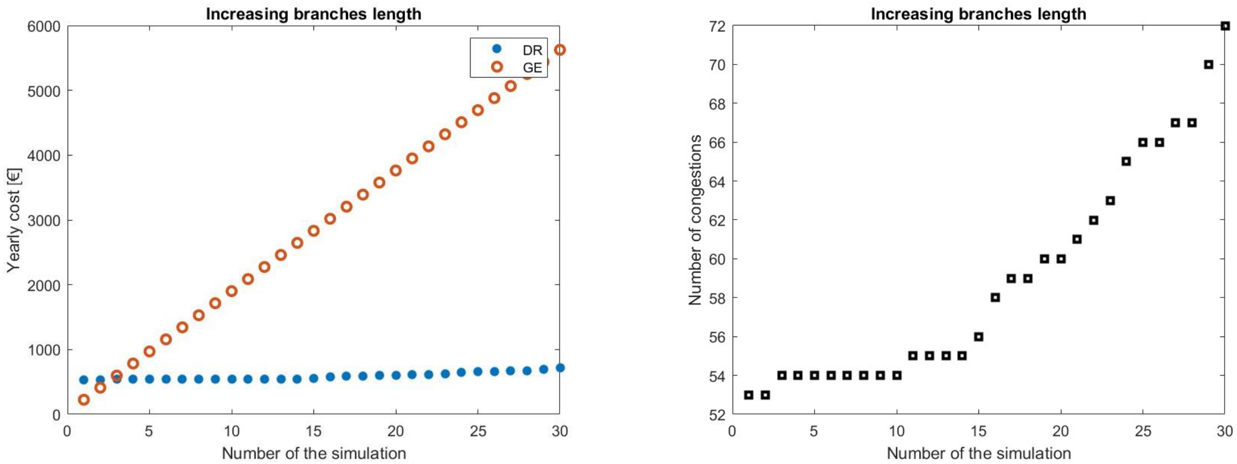


Figure 4.11: Case 3.2: increasing the length of the branches

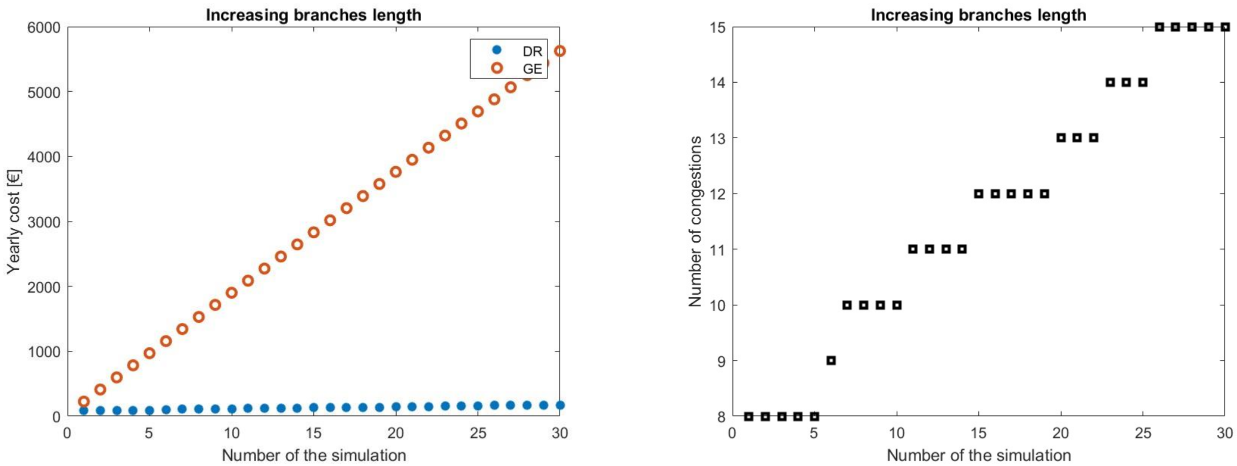


Figure 4.12: Case 3.3: increasing the length of the branches

Moreover, it is possible to plot on the same graph the dependency between GE and DR, the MCC and the branch length, as in Figure 4.13. The most important difference is the one along the y-axis showing the branches lenghth, in particular on the slope of the two graphs. It is clear how the GE solutions increase more steeply. And as already seen before, the DR solution is much more sensitive to a reduction of the MCC with respect to the GE.

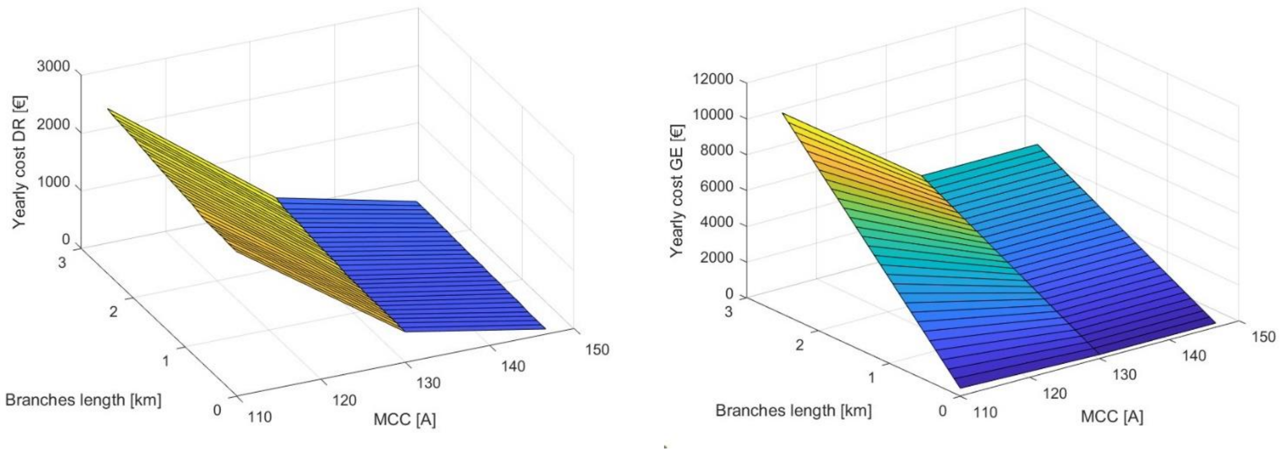


Figure 4.13: 3D plot

4.4. Case 4: variable prices

In this case the focus is on the price of the active resource's bids, which is the only parameters which change between a simulation and the other, as shown in Table 4.4. Therefore, for each simulation the grid and the load are constant, and thus the number of congestions. The MCC changes between one sub-case and the other to test different grid configurations. The data can be visualized in Figure 4.14.

	In-between simulations	**In-between sub-cases**
Nominal Power	Constant	Increasing
MCC	Constant	Increasing
Branches length	Increasing	Constant
Bids price	Increasing	Increasing

Table 4.4: Data of case 4

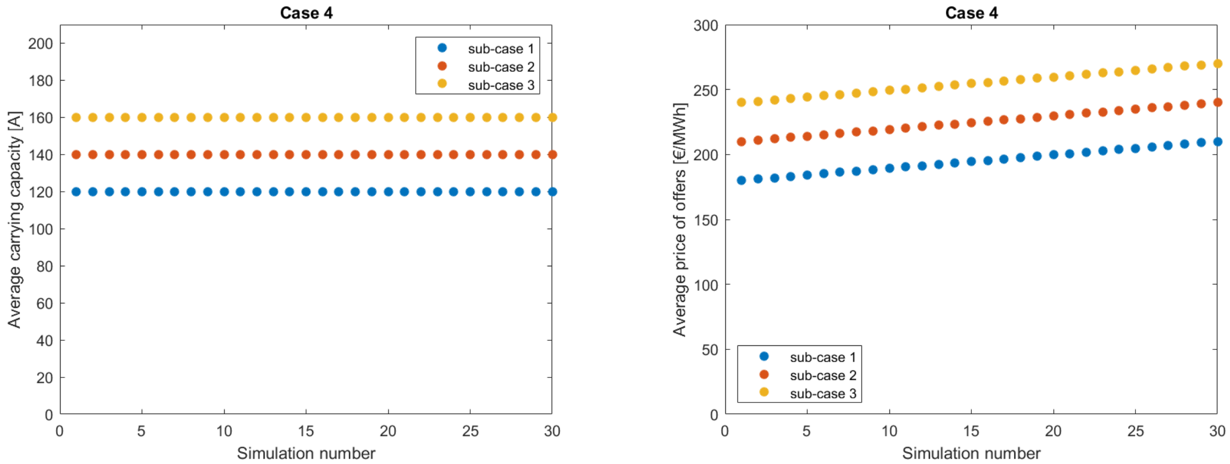


Figure 4.14: Testing variable prices data

The main insight from Figure 4.15, Figure 4.16 and Figure 4.17is that for any grid topology and condition, there is an average price of offers which makes indifferent for the DSO to pursue one solution or the other. In a real case study, the classical GE price is the benchmark in respect to which the DSO can manage to select the appropriate offers which can be accepted, preserving the stability of the grid and at the same time saving costs.

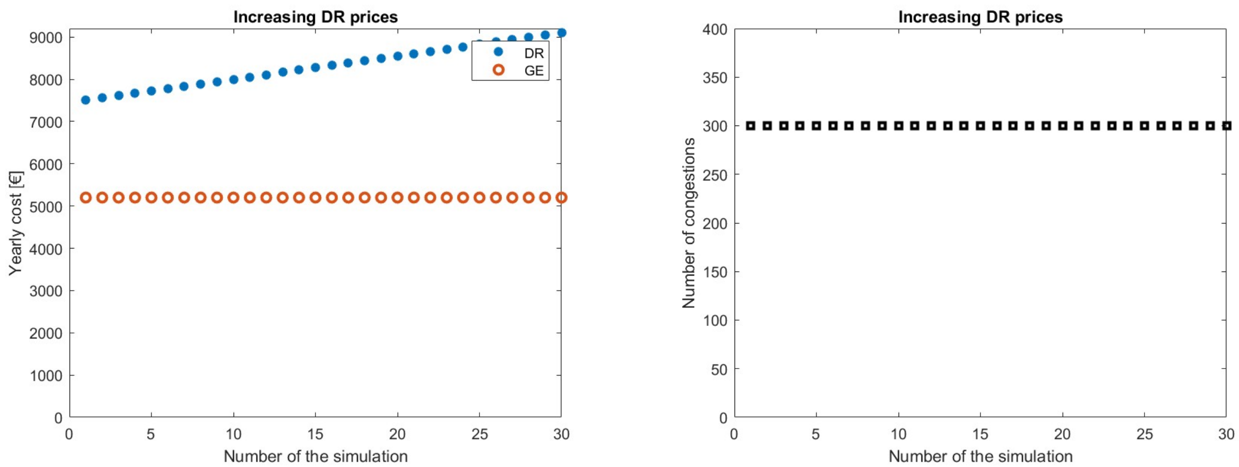


Figure 4.15: Case 4.1: increasing the price of the bids

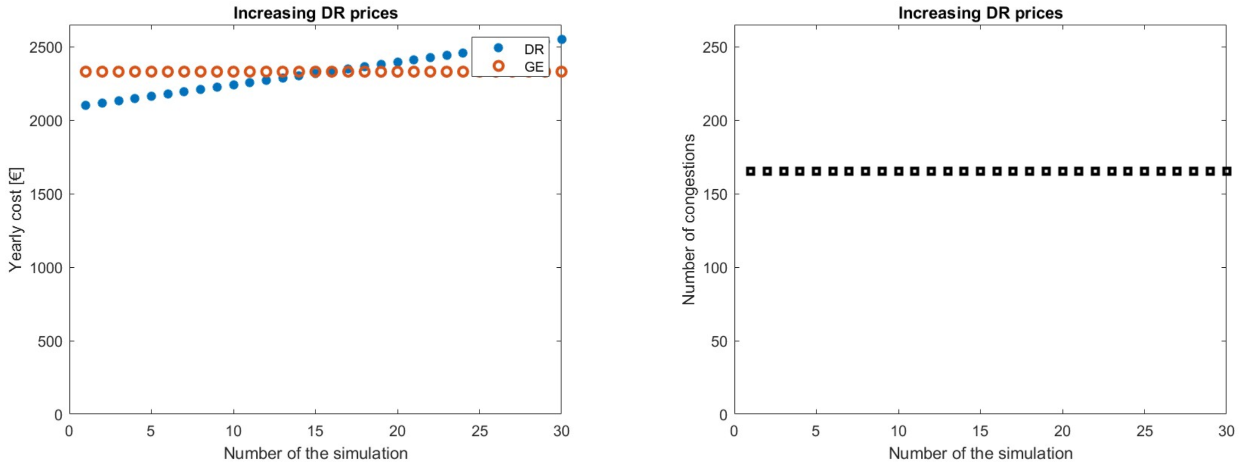


Figure 4.16: Case 4.2: increasing the price of the bids

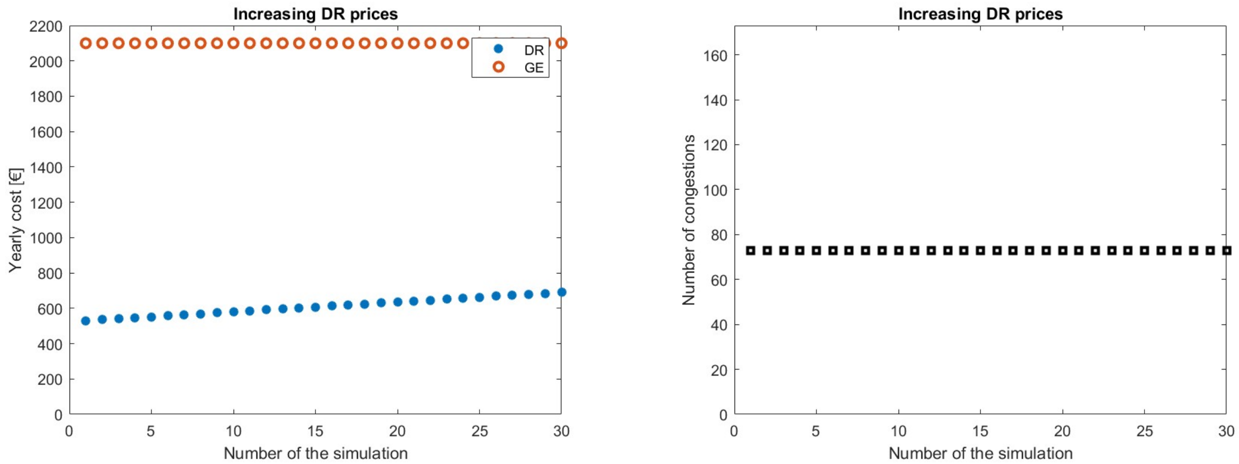


Figure 4.17: Case 4.3: increasing the price of the bids

4.5. Test conclusions

The previous simulations have had a dual purpose: test the solidity and validity of the algorithm, and take the first insights about the comparison of GE and DR.

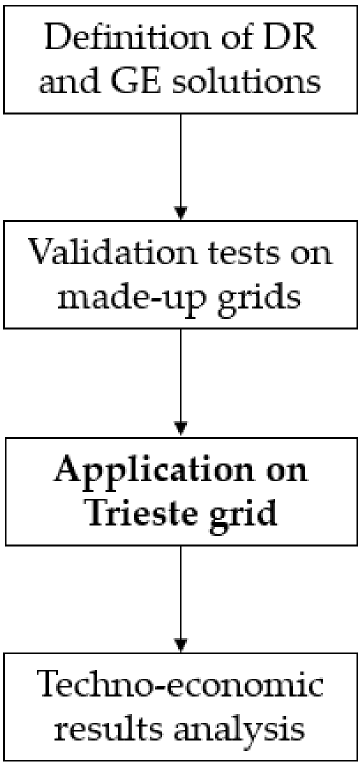
The first objective has been reached: the simulations show a strong coherence with a multitude of different initial input and the results do not contradict any assumptions or physical principle. This demonstrate the principle of working of the two algorithms which can subsequently be applied to a real distribution grid with real potential active resources to be exploited.

Furthermore, the previous simulations have shown that the comparison between the two solutions (i.e., GE and DR) is strongly dependent on the initial condition, and therefore each analysis is very case specific.

From these tests it is possible to infer some qualitative trends and conditions in which each solution is better than the other. These trends will be then verified or invalidated with the application of the algorithms to the real case of Trieste distribution grid. The DR solutions is usually convenient when the MCC is high and the nominal power low, which translates in having a low number of congestions each year and with a limited amplitude in term of current differential. This advantages the DR solutions because with a small differential the GE solution would create a new grid which is strongly over-dimensioned (and real distribution grid in regular conditions are already over-dimensioned) and thus expensive. And since the DR need to be paid for each time the flexible resources are activated, rare congestions favor this solution. The length of the lines is also a crucial factor since it is one of the main drivers of the cost of the GE. Thus, in a real grid a different position of the congestion could strongly affect the results, with all the other parameters being constant. And lastly, the energy prices are the main driver for the price of the DR (but not the only one, since there is also the power component), and with the real grid of Trieste the main objective will be to find out which values break-evens the two solutions.

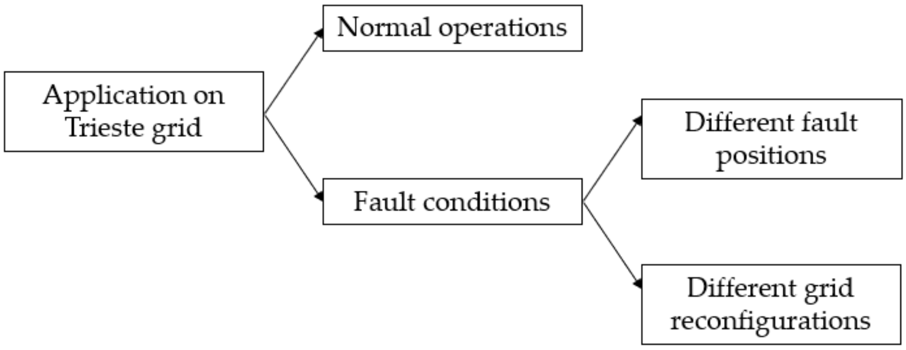
5 Application to Trieste grid

After having done the validation of the models and the algorithm, it is possible to proceed further and not just limit the application to fictitious grids. The third part of this thesis work, as shown in Flowchart 5.1 consists of the application of the developed grid extension (GE) and demand response (DR) solution to a real distribution grid, the one of Trieste (Italy), limitedly to the medium voltage (MV) distribution.



Flowchart 5.1: Thesis structure

Firstly, the grid structure is described, and then different scenarios both in normal working and fault conditions are simulated, as shown in Flowchart 5.2.



Flowchart 5.2: Application of the solutions on the grid of Trieste

5.1. Distribution grid description

The electricity distribution in the city of Trieste is exercised and managed by the distribution system operator (DSO) “AcegasApsAmga” through a concession issued by the "Ministry of Economic Development" expiring in the year 2030, providing services to users connected to the electricity grid. In the municipality of Trieste, the electrical energy is distributed both in low voltage (230/400 V) and in medium voltage (2.000, 10.000, 20.000, 27.500 V), to domestic, non-domestic and industrial users [59]. The DSO is responsible for ensuring the safety and continuity of supply, providing for the management and maintenance of the entire electricity network and the systems connected to it. Since several years AcegasApsAmga has been making all the new medium voltage lines exclusively with the underground cable, to eliminate the electric fields and to significantly reduce the magnetic fields. At the same time the impact is reduced: the environmental disfigurement and the disfigurement of the landscape almost completely disappears.

In 2016 (most recent data) the distribution line of Trieste was made by:

- Medium voltage: 640 km of cables (98% underground, 2% aerial) [60].
- Low voltage: 1141 km of cables (50% underground, 50% aerial) [60].

In the territory of the Municipality of Trieste there are four primary HV/MV substations connected to the national electricity transmission grid, characterized as in Table 5.1 [61]:

Primary substation name	HV [kV]	MV [kV]
Broletto	132	27.5
Altipiano	132	20
Rozzol	132	27.5
Valmartinaga	132	27.5

Table 5.1: Primary HV/MV substations in Trieste

The MV/MV electrical substations present on the territory of the Municipality of Trieste are the following, shown in Table 5.2:

Primary substation name	HV [kV]	MV [kV]
Centro	27.5	10
Stoppani	27.5	10
San Giovanni	27.5	10
Cacciatore	27.5	10
Ippodromo	27.5	10
Flavia	27.5	10
Opicina	27.5	10

Table 5.2: Primary MV/MV substations in Trieste

In this work the DR is applied only to the loads directly connected to the MV loads. They are 86, with a power factor between 0.89 and 0.92 and a nominal power between 0.057 and 3.5 MW. The complete list of loads can be found in the Appendix.

There are in total 792 branches and 88 different nodes. The difference in the order of magnitude between branches and nodes is due to the fact that there is not only one conductor connecting two consecutive nodes, but a series of a conductor.

For example, in Figure 5.1 it is possible to see two branches connecting radially three nodes.

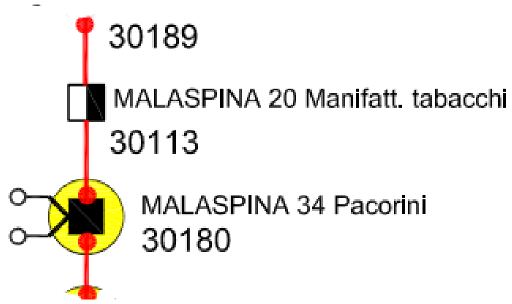


Figure 5.1: Example of nodes in the grid

The two branches connecting node 30189-30113 and node 30113-30180 are subsequently made of 10 distinct branches:

Branch name	Type of cable	Node name "from"	Electrical node number "from"	Node name "to"	Electrical node number "from"	Length [km]	Nominal current [kA]	Resistance [Ω/km]	Susceptance [Ω/km]
R1118	CU 3x(1x150)	30189_1A1	8781566		7966217	0.00599	0.321	0.11704	0.13
R1117	CU 3x(1x150)		7966218	30189_1A1	8781567	0.004492	0.321	0.11704	0.13
R1116	CU 3x(1x160)		7971595		7966218	0.078985	0.321	0.11704	0.13
R897	CU 3x(1x160)	30113_1A1	8781572		7971595	0.064523	0.321	0.11704	0.13
R905	CU 3x(1x160)		7968044	30113_1A1	8781573	0.02704	0.321	0.11704	0.13
R1008	CU 3x(1x160)		7968045		7968044	0.026444	0.321	0.11704	0.13
R224	CU 3x(1x160)		7965864		7968045	0.191239	0.342	0.11704	0.13
R791	CU 3x(1x160)		7967889		7965864	0.109974	0.342	0.11704	0.13

R257	CU 3x(1x150)	30180_1A1	8781643		7967889	0.036994	0.321	0.11704	0.13
R793	CU 3x(1x150)		7967888	30180_1A1	8781648	0.042747	0.321	0.11704	0.13

Table 5.3: Conductors between two nodes

The branches can be merged in branches connecting just two nodes by adding their length, since they are made with the same conductor (with thus same specific resistance and susceptance) and considering the minimum carrying capacity. When the merging has been done for all the branches, the medium voltage distribution grid of Trieste is reduced to 88 nodes and 91 branches. In regular conditions the grid is perfectly radial, with each node/load being served by one of the substations previously mentioned. The whole grid can be represented in a simplified version as in Figure 5.2 in order to better understand the relative position of the primary substation, the main branches, and the interchange nodes.

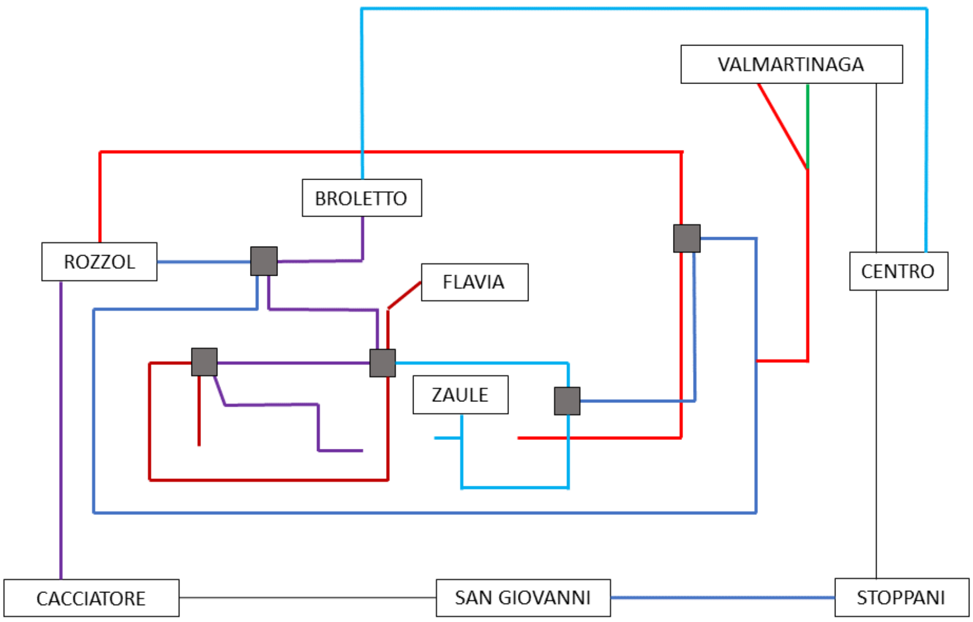


Figure 5.2: Trieste distribution grid simplified version

In the figure the branch lengths are not in scale. Each color represents a different path that starts from a given substation. The branch colored in black are branches which do not have any loads on them. The black squares represents the node in which different path meet, which are used for the counter-feeding in case of failure. There are a total of 5 interconnection points. The 86 loads are served as follows:

- 20 by the substation Flavia
- 19 by the substation Broletto
- 12 by the substation Zaule

- 17 by the substation Rozzol
- 15 by the substation Valmartinaga
- 1 by Cacciatore and Rozzol
- 1 by San Giovanni and Stoppani
- 1 by Centro and Rozzol.

The grid detailed topology and the distribution of the loads in the grid is reported in the Appendix.

5.2. Smart metering

Among the innovative tools put in place to realize the transition to a smart grid, there are the second-generation electricity meters (2G smart meters). Thanks to them, the electricity user of the grid will be able to count on tools that will enable new services and features to be activated, like the real time monitor of the consumption. Such devices are a key enabling technology in order to setup a DR scheme. The renewal of the meter fleet of the distribution grid of Trieste is part a national scale project [62], which was activated in order to achieve the energy transition activated at the European level from the beginning of 2000s [63]. The "Commissioning Plan of smart metering" by AcegasApsAmga [64] shows the project to bring the new meters in the Gorizia and Trieste municipalities, planning the replacement of over 162,000 meters starting in April 2022 until 2036. However, the majority of meters will be installed in a concentrated massive replacement in the first 4 years. The new Remote Management System can enable services to the Market, support advanced management of the electricity network and infrastructure of electrical vehicles recharge and distributed energy resources (DER), make the technical and commercial processes more efficient and effective. Among the benefits for the user of the distribution grid are the possible active participation of customers/prosumer to the local and global ancillary services market, the possible reduction of consumption through a greater awareness and/or the participation to DR pilot projects, new opportunities for business through the services of Energy Service Company (ESCO) or aggregators. Benefits are also provided to the DSO for in the form of advantages for the planning and operation of the distribution service. The 2G meters can help to improve the continuity of service reporting in real time the critical state of any meter due to lack of power or voltage following a fault on the network or in the primary/secondary cabin. Furthermore, the new meters enable the data collection to improve accuracy of analysis and forecasts for the purposes of planning the distribution network management and infrastructure, also in the presence of high rates of distributed generation. To support the massive replacement plan, AcegasApsAmga will implement a multi-channel engaging campaign ghat will have the customer at the center and will adapt to the peculiarities of the area served, to obtain the maximum success of the installation of the new meters. AcegasApsAmga will promote a first strong engagement of the territory through a massive campaign based above all on advertising that announces to customers, institutions, mass media and stakeholders the arrival on the territory of the new meter and the consequent replacement of the old one. This could be also a potential occasion to engage potential customers and inform the grid user about the possibility and advantages of starting a DR scheme.

5.3. Grid in normal conditions

The first thing to do is analyzing the distribution grid of Trieste during normal operations. In order to do so, real data of active and reactive power has been updated. The data has an hourly time frame and spans from 01/01/2018 until 31/12/2019. To keep the length of the simulation to one year, the average for each hour has been calculated.

In Figure 5.3 it is possible to see the active and reactive power load curves. Regarding the power curve, the maximum is at around 40 MW and it is reached three times in one year. Regarding the reactive power, the maximum is at about 30 MVar and it is reached twice in one year. As expected, in a normal situation there is no risk of congestions in the grid, since it has been over-dimensioned to prevent them. As it possible to see in Figure 5.5, out of 91 branches, only 1 has a loading degree higher than 70%: it is the branch connecting node 30008 and 30154 on the line starting from Broletto. As expected, the most congested branches are the one upstream in the line and the closest to the primary substation. The loads have more or less the same order of magnitude regarding the active and reactive power withdrawals, with the exception of five loads (with ID 1,2,22,23,40,41, 63,) which are two to four times bigger than the average, as it is possible to see in Figure 5.4.

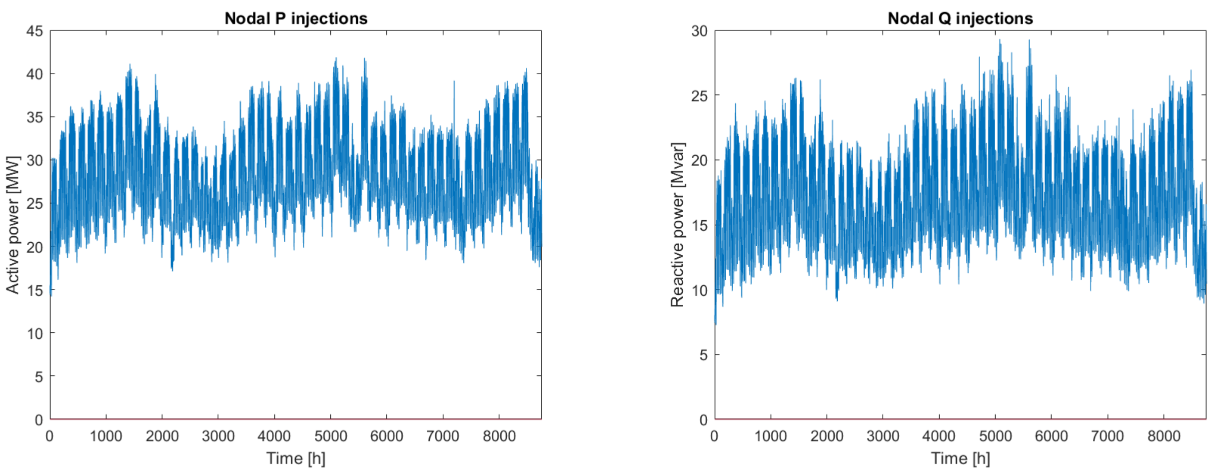


Figure 5.3: Nodal P and Q injections in Trieste grid, normal operations

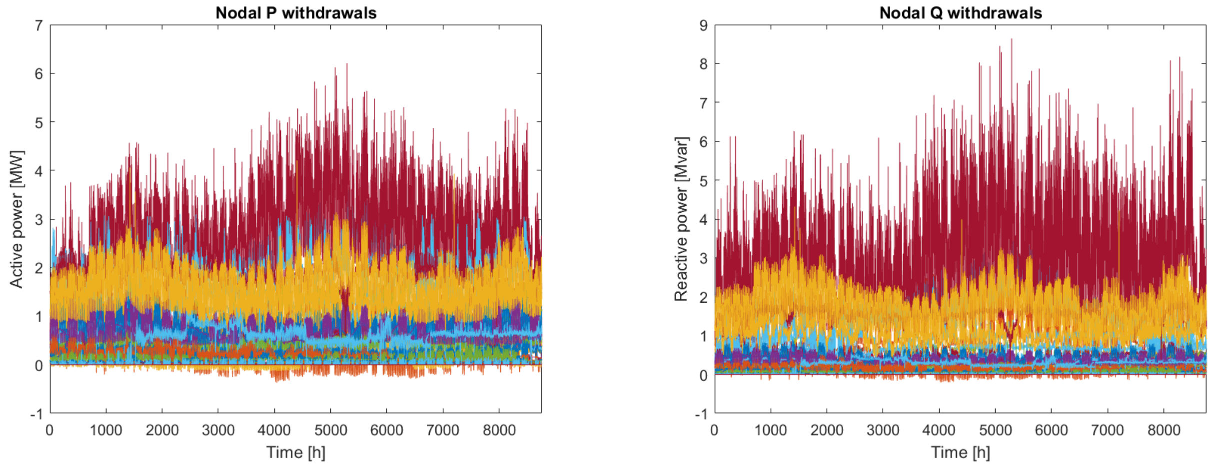


Figure 5.4: Nodal P and Q withdrawals in Trieste grid, normal operations

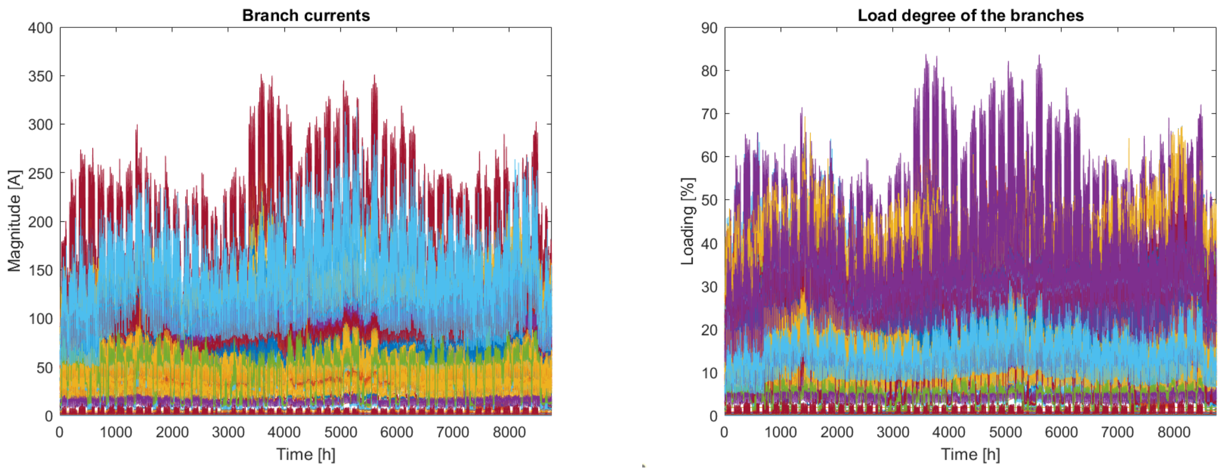


Figure 5.5: Branch currents and loading in Trieste grid, normal operations

Since in regular conditions there are no congestions, being the maximum loading of the branches 80%, the algorithm cannot be applied. Thus, simulations with progressively increasing nominal power are conducted, giving the following results, reported in Table 5.4.

Nominal power increment	**Number of annual congestions**	**Maximum loading**	**Number of congested branches**	**Annual cost of GE solution [€]**
+ 5%	0	86.8%	0	0
+10%	0	92.2%	0	0
+15%	0	96.5%	0	0

+20%	5	101%	1	949.56
+25%	55	105%	2	2269.77

Table 5.4: Nominal power increment

In Figure 5.6 the comparison between the DR and GE solution is shown, for the last two cases of Table 5.4. 15 different simulations are done for each price range of each Case. In each simulation the result is the sum of the cost of the DR solution for each hour along the year, assuming that the flexibility is activated by the DSO every time it is needed. The 15 results for each case are reported in the graphs of this section through the use of a box chart. A box chart, also known as a box plot, is a graphic depiction of the summary statistics for a sample of data. The box chart for numeric data shows the median, lower and upper quartiles, any outliers if present and the minimum and maximum values (that are not outliers). When the data points are organized in ascending order, 25% of them are found in the lower quartile. On the other hand, the value below which 75% of them can be found is known as the upper quartile.

It is possible to see that when the electric demand increase of +20%, the DR solutions is almost always convenience with respect to the GE solution. The economic convenience of the DR solution can be achieved if the DSO always accepts only the bids that are lower than 350 €/MWh. The situation is different when the demand increases by 25%. Even though the GE price has raised with respect to the following cases, for all the possible price ranges the DR solution is more expensive than the DR.

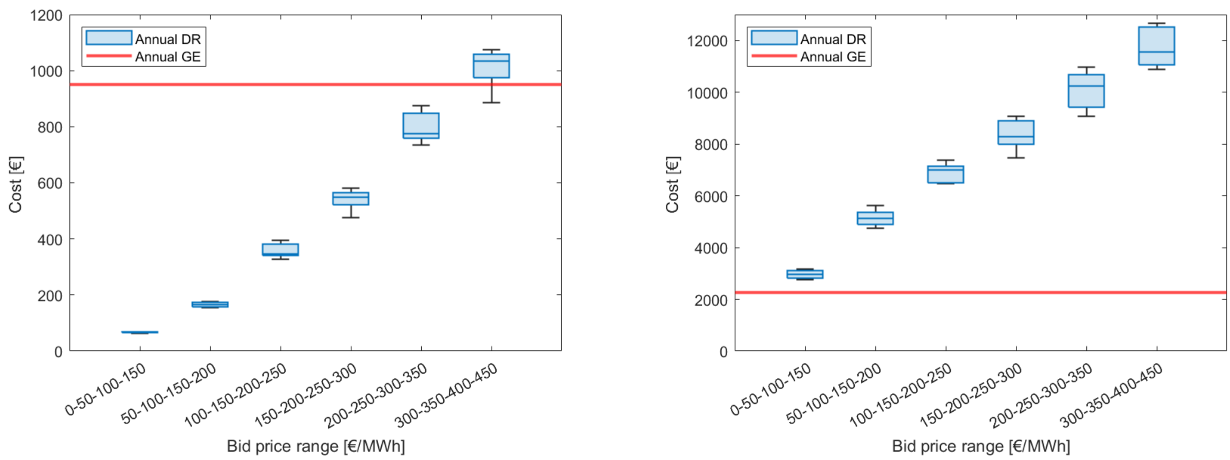


Figure 5.6: cost comparison for demand increase of +20% (left) and +25% (right)

As demonstrated, for the first congestion to appear the nominal load has to be increased by 20%, This is already a quiet high increase in electricity demand considering a short-term temporal horizon. In fact, for example, between December 2019 and December 2021 the electrical energy demand in Regione Friuli Venezia Giulia has been raised +7.9% [65]. The forecast for the national electricity demand in Italy goes from 320 TWh in 2020, to 331.4 TWh in 2025, to 380.6 TWh in 2040 [66], meaning an increase respectively of 5% and almost 19%. Therefore, assuming the same rate of increase for Friuli Venezia Giulia and Trieste municipality, the grid operating in normal conditions should be safe from congestions for at least 15 years. Thus, neither of the solutions is requested in the short time.

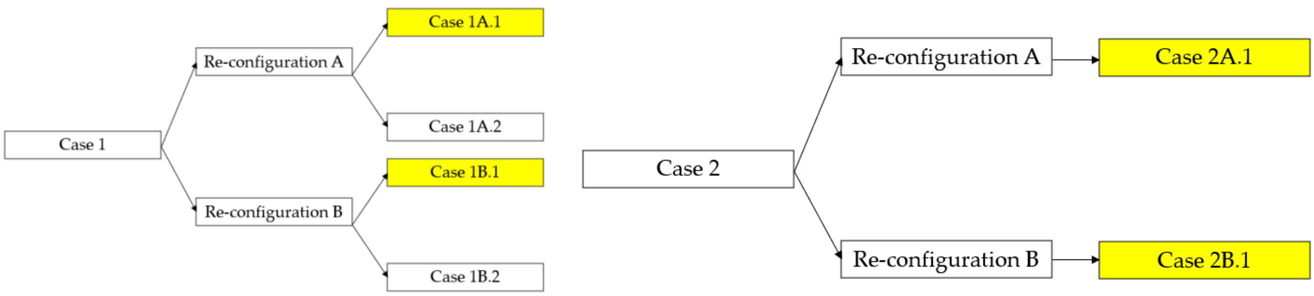
5.4. Fault conditions

In this section four different faults conditions will be analyzed. Of course, all the branches in the grid could run into a fault, but not all the faults lead to a reconfigured grid which is affected by congestion. Thus, in this section only the faults leading to an actual congested grid are analyzed. It is important to remember that the fault timing is unknown, and it will last the time needed to repair it or solve what have caused it. The pictures in this section report simulations done along a whole year with the presence of the fault. The aim is not to literally simulate what would happen if a fault would happen for the whole year, since it is not a realistic situation, impossible to happen in a real distribution grid. This is just to simulate the potential effect on the branches that fault would have in any given hour, to see when it would lead to a congestion and with which intensity. The graphs on this chapter have to be interpreted as independent snapshots of the grid one hour long, and not as a simulation lasting one year, as in the previous chapter.

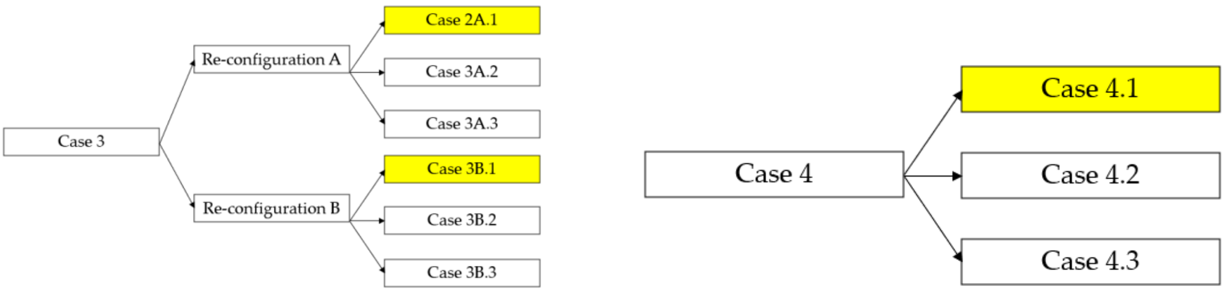
In some cases, more than one grid reconfiguration can be done, if there is one more than one interconnection between the path where the fault is located and the other paths. When possible, different grid reconfiguration are tested to see which is the one which leading to the fewer number of congestions and to a total lower cost of applying the DR and GE solution. In case 1 the worst cases are simulated, leading to the highest number of congestions and branch loading, since the fault is simulated as close as possible to the given sub-station. This is shown in part 1.

Finally, when the best reconfiguration is found, different positions of the fault are simulated, to see how the currents, the congestions and the costs of the solutions change. This is shown in part 2.

The structure of each case is represented in the following flowcharts. In each graph the worst case, described in part 1, is represented in yellow. A total of 15 different sub-cases have been identified.



Flowchart 5.1: Case 1 and Case 2 description



Flowchart 5.2: Case 3 and Case 4 description

5.5. Part 1: different grid reconfigurations

5.5.1. Case 1

In case 1 there is a simulation of a failure in the line served by the substation Broletto. Due to this failure, the substation Broletto cannot serve its line anymore.

In case 1A, thanks to the interconnection in node 30140, the loads are then taken by the substation Flavia (represented in red). The worst congestions are present when there is a simulation of a failure between nodes 30008 and 30145 (Case 1A.1).

In Figure 5.7, but also in all the other Figures representing the schematic view of the grid in this chapter, the branches highlighted in yellow are the ones that can incur in a congestion at least once along the year.

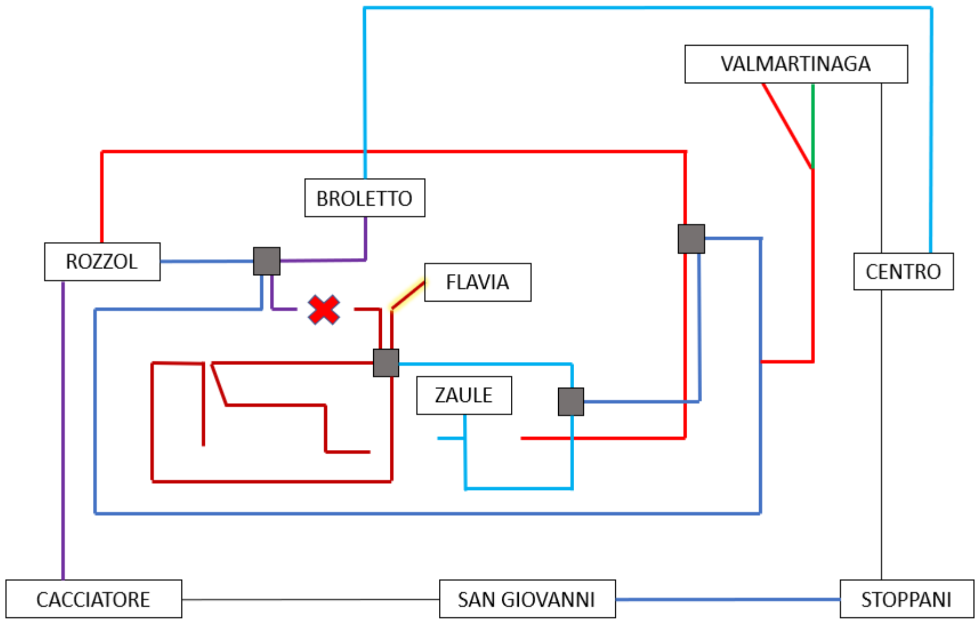


Figure 5.7: Grid with failure, case 1A.1

In Figure 5.8 the electrical results are shown. Keeping the nominal load at 100%, when there is a fault the branch between the node 30140 and the substation Flavia is congested. This is due to the fact that all the current serving the loads located from node 30140 to 30110 now has to flow through the congested branch.

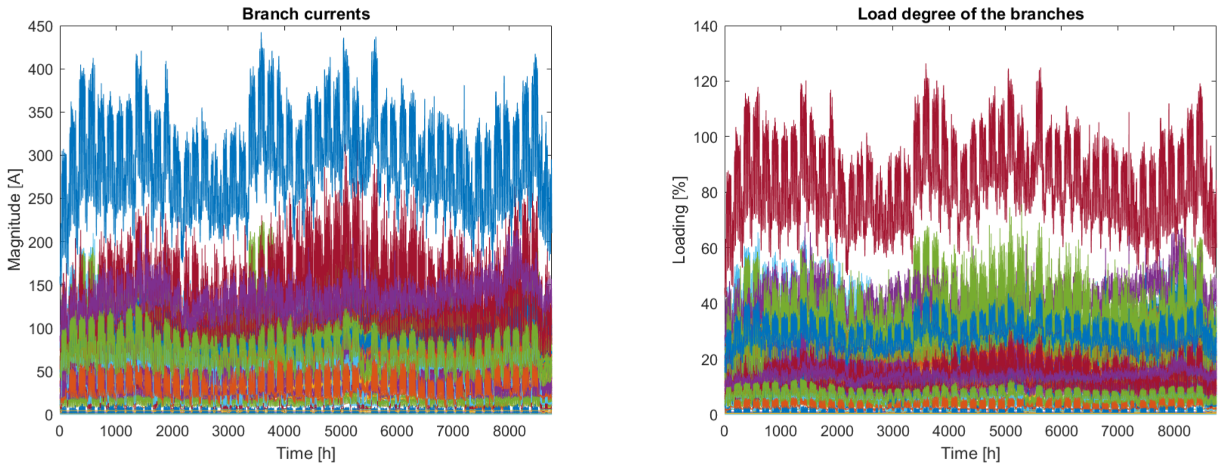


Figure 5.8: Electrical results of Case 1A.1

In case 1.B there is a simulation of the same line as the previous case, thus a failure on the line served by Broletto sub-station, as represented in Figure 5.9. However, in case 1B there is a different counter-feeding, exploiting the interconnection in node 30102. The loads are therefore taken by the substation Flavia (represented in red). The worst congestions are present when there is a simulation of a failure between nodes 30008 and 30145 (Case 1B.1).

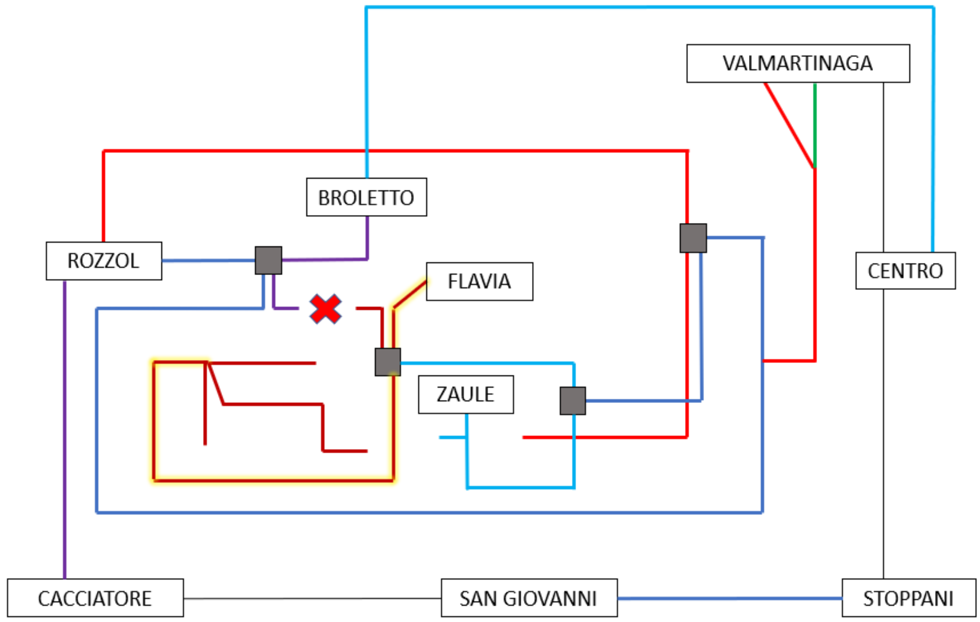


Figure 5.9: Grid with failure, case 1B.1

In Figure 5.10 the electrical results are shown. Keeping the nominal load at 100%, when there is a fault, the following branches are congested: between nodes 30144 and 30102, 30192 and 30144, 30143 and 30192, 30141 and 30143, 30140 and 30141, node 30140 and substation Flavia.

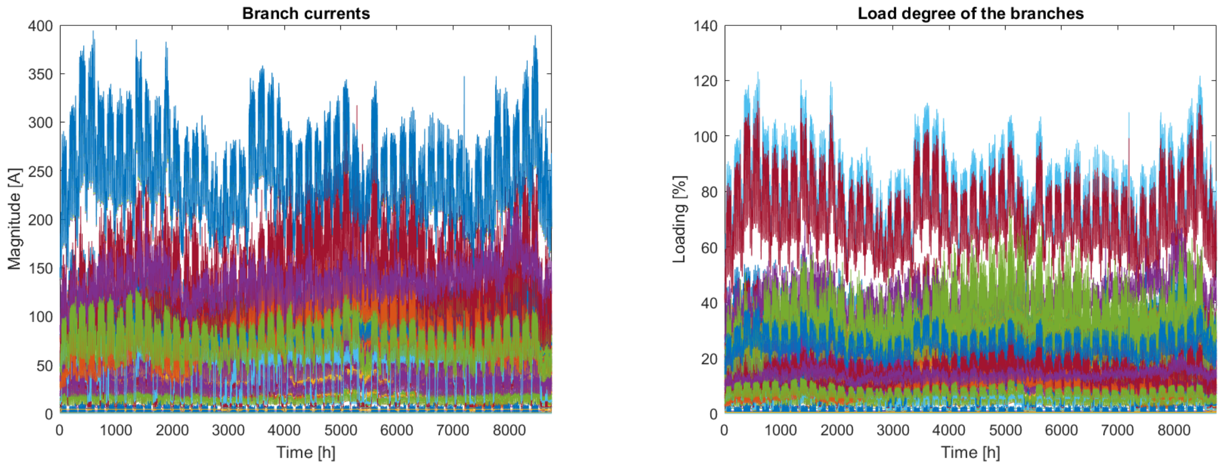


Figure 5.10: Electrical results of Case 1B.1

Regarding case 1, it is immediate to see that the configuration 1.A1 is the best one according to all parameters: fewer potential congestions, less congested hour, lower maximum loading of the branches, lower number of congested branches and congestions with an average fewer intensity. The results of case 1 are summarized in Table 5.5.

Case number	Number of potential annual congestions	Number of hours with congestion	Maximum loading [%]	Number of congested branches	Average congestion intensity [A]	Annual cost of GE solution [€]
1A.1	1495	1495	126.39	1	26	349
1B.1	3286	790	123.22	6	17	6510.50

Table 5.5: Case 1 summary of results

5.5.2. Case 2

In case 2 there is a simulation in the line served by the sub-station Flavia. Due to this failure, the substation Flavia cannot serve its line anymore, as represented in Figure 5.10. In case 2A thanks to the interconnection in node 30140, the loads are then taken by the substation Broletto (represented in purple). The worst congestions are present when there is a simulation of a failure between nodes 30008 and substation Flavia (Case 2A.1).

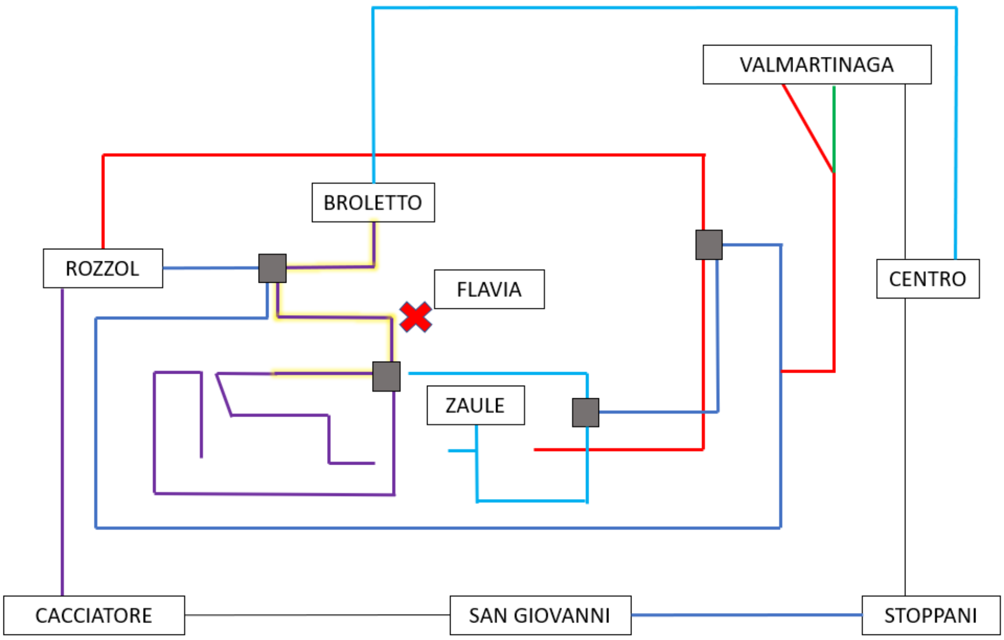


Figure 5.11: Grid with failure, case 2A.1

In Figure 5.12 the electrical results are shown. Keeping the nominal load at 100%, when there is a fault, the following branches are congested: between nodes 30188 and 30102, 30101 and 30188, 30140 and 30101, 30145 and 30140, 30008 and 30145, 30007 and 30008, 30007 and substation Broletto.

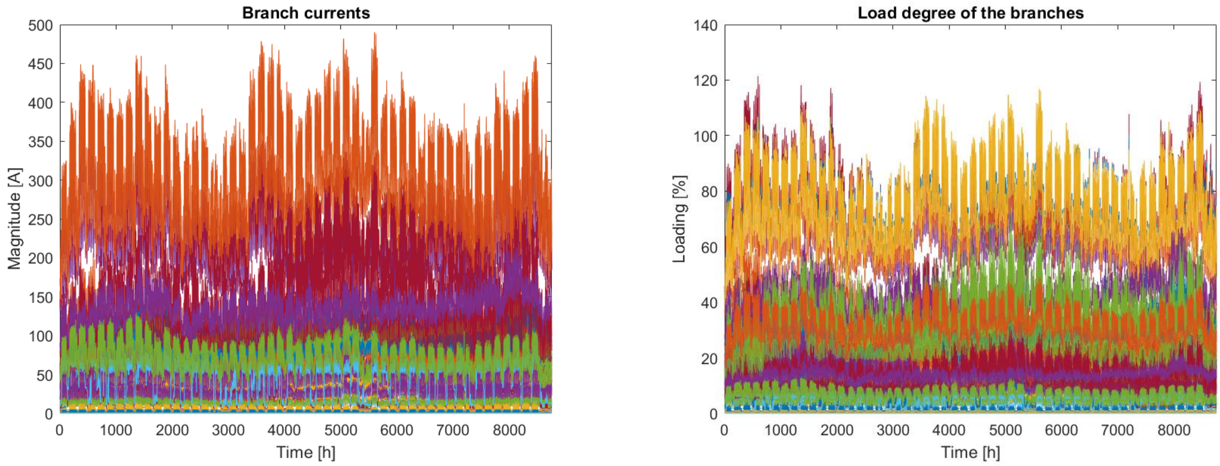


Figure 5.12: Electrical results of Case 2A.1

In case 2B there is a simulation of the same line as the previous case, thus a failure on the line served by Flavia sub-station. However, in case 2B there is a different counter-feeding, exploiting the interconnection in node 30140, as represented in Figure 5.13. The loads are therefore taken by the substation Broletto (represented in purple). The worst congestions are present when there is a simulation of a failure between nodes 30008 and substation Flavia (Case 2B.1).

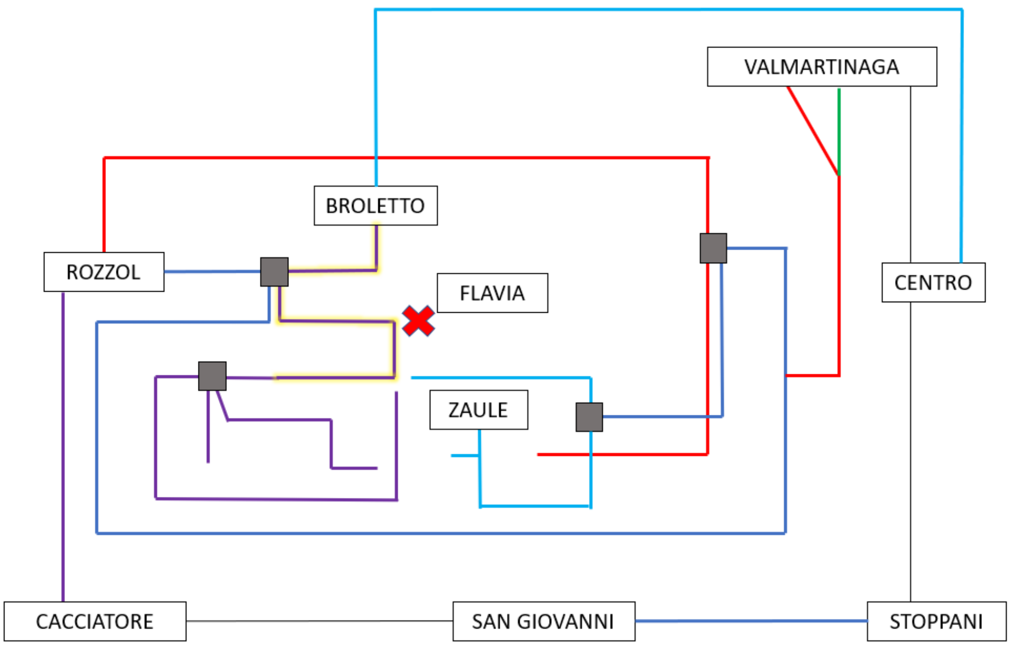


Figure 5.13: Grid with failure, case 2B.1

In Figure 5.14 the electrical results are shown. Keeping the nominal load at 100%, when there is a fault, the following branches are congested: between nodes 30188 and 30102, 30101 and 30188, 30140 and 30101, 30145 and 30140, 30008 and 30145, 30007 and 30008, 30007 and substation Broletto.

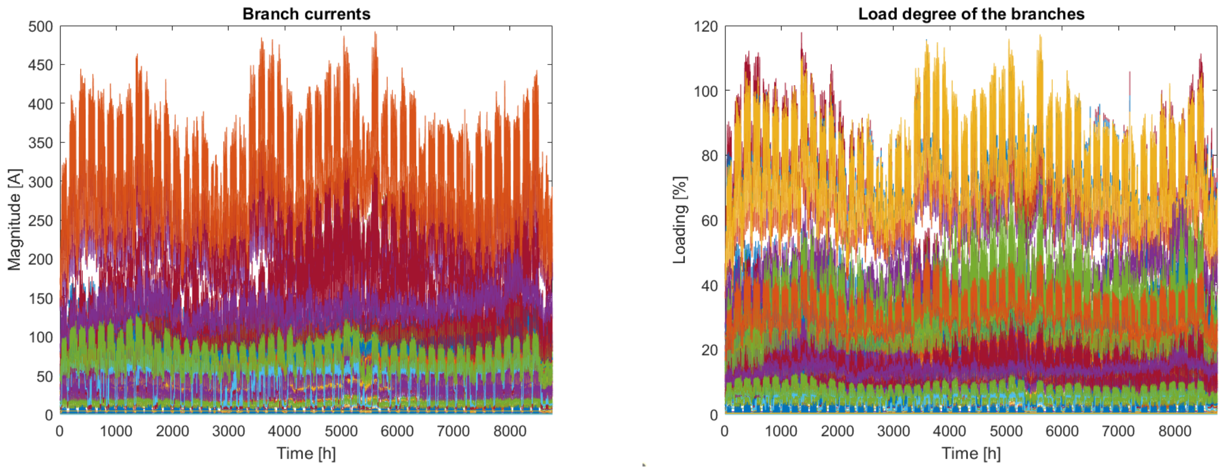


Figure 5.14: Electrical results of Case 2B.1

For case 2 the situation is more difficult to read. Configuration 2A.1 has more potential congestions, a higher loading and a slightly average intensity, but a lower number of congested branches. Both configurations will then be analyzed in detail. The results of case 2 are summarized in Table 5.6.

Case number	Number of potential annual congestions	Number of hours with congestion	Maximum loading [%]	Number of congested branches	Average congestion intensity [A]	Annual cost of GE solution [€]
2A.1	1467	737	122.85	7	20	10597.36
2B.1	1299	600	117.9	7	17	14348.95

Table 5.6: Summary of case 2 results

5.5.3. Case 3

In case 3 there is a simulation in the line served by the sub-station Zaule. Due to this failure, the substation Zaule cannot serve its line anymore. In case 3A thanks to the interconnection in node 30146, the loads are then taken by the substation Rozzol (represented in blue), as represented Figure 5.15. The worst congestions are present when there is a simulation of a failure between nodes 30146 and substation Zaule (Case 3A.1).

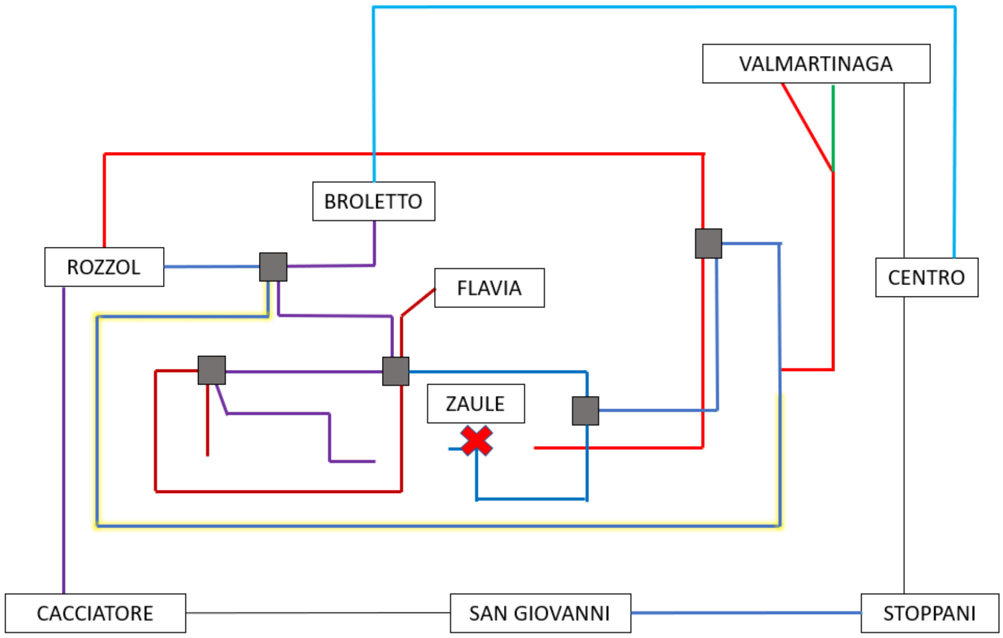


Figure 5.15: Grid with failure, case 3A.1

In Figure 5.16 the electrical results are shown. Keeping the nominal load at 100%, when there is a fault, the following branches are congested: between nodes 30008 and 30154, 30154 and 30176, 30176 and 30155, 30155 and 30181.

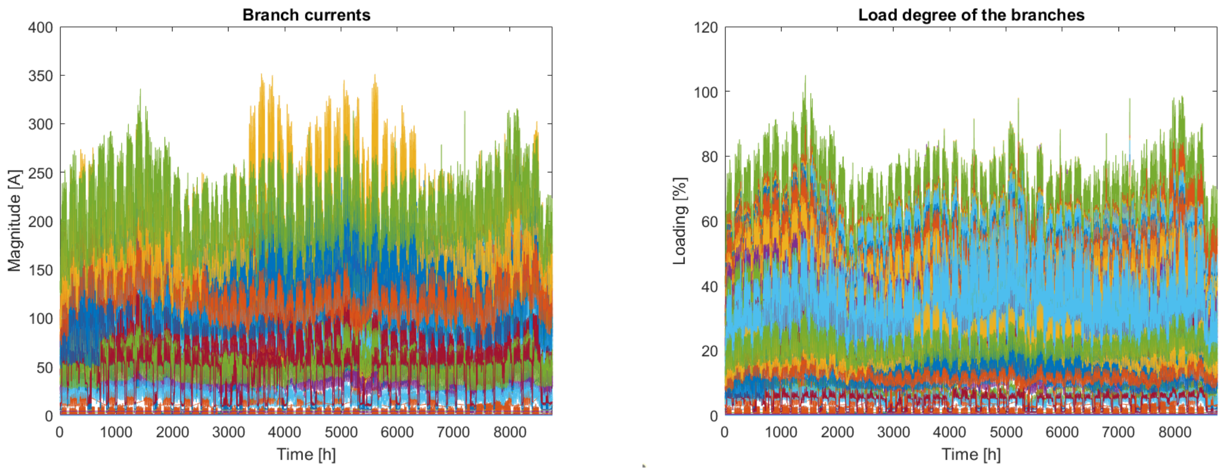


Figure 5.16: Electrical results of Case 3A.1

In case 3B there is a simulation of the same line as the previous case, thus a failure on the line served by Zaule sub-station. However, in case 3B there is a different counter-feeding, exploiting the interconnection in node 30140. The loads are therefore taken by the substation Flavia (represented in red), as represented in Figure 5.17. The worst congestions are present when there is a simulation of a failure between nodes 30122 and substation Zaule (Case 3B.1).

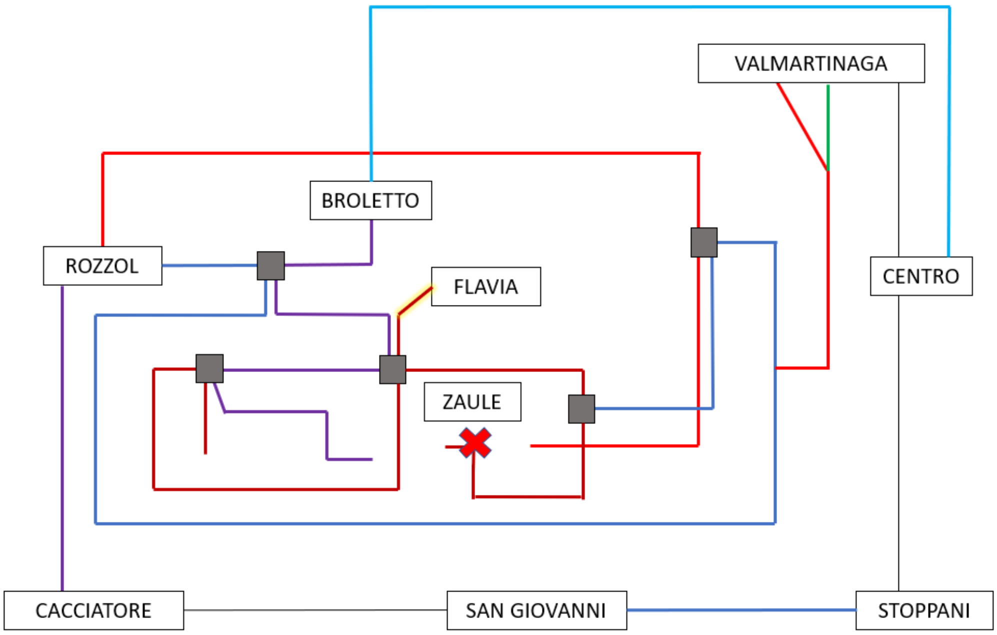


Figure 5.17: Grid with failure, case 3B.1

In Figure 5.18 the electrical results are shown. Keeping the nominal load at 100%, when there is a fault, the branch between nodes 30140 and Flavia is congested.

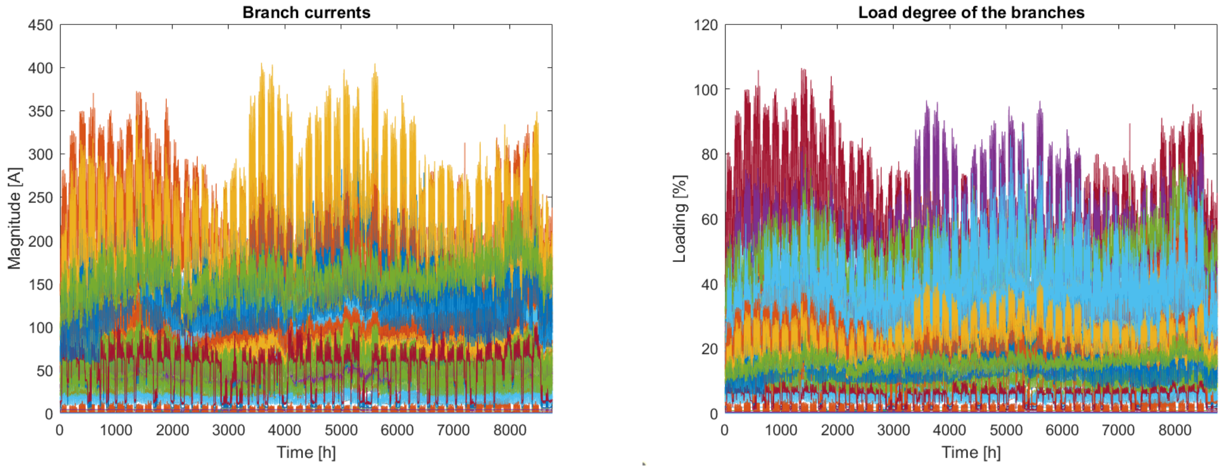


Figure 5.18: Electrical results of Case 3B.1

For case 3 the situation is similar to case 2. Configuration 3A.1 has better numbers than 3B.1 in all categories, except for the number of congested branches. Both configurations will then be analyzed in detail. The results are summarized in Table 5.7.

Case number	Number of potential annual congestions	Number of hours with congestion	Maximum loading [%]	Number of congested branches	Average congestion intensity [A]	Annual cost of GE solution [€]
3A.1	12	3	105	4	9	4244.40
3B.1	28	28	106.44	1	10	349.50

Table 5.7: Summar of Case 3 results

5.5.4. Case 4

In case 4 there is a simulation of a failure in the line served by the substation Valmartinaga. Due to this failure, the substation Valmartinaga cannot serve its line anymore. Therefore, thanks to the interconnection in node 30156, the loads are then taken by the substation Rozzol (represented in blue), as represented in Figure 5.19. This is the only possible reconfiguration. The worst congestions are present when there is a simulation of a failure in the substation Valmartinaga. (Case 4.1).

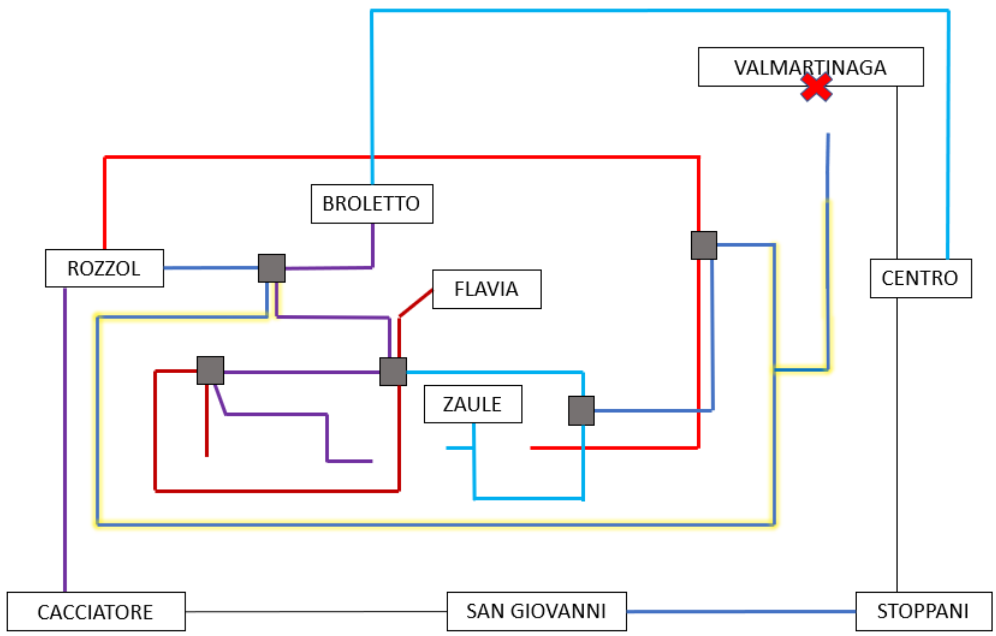


Figure 5.19: Grid with failure, case 4.1

In Figure 5.20 the electrical results are shown. Keeping the nominal load at 100%, when there is a fault, the following branches are congested: between nodes 30008 and substation Rozzol, 30008 and 30154, 30154 and 30176, 30176 and 30155, 30155 and 30181, 30181 and 30156, 30172 and 30156, 30171 and 30172, 30170 and 30171, 30170 and 30169, 30168 and 30169, 30165 and 30166, 30164 and 30165, 30196 and 30164, 30195 and 30196.

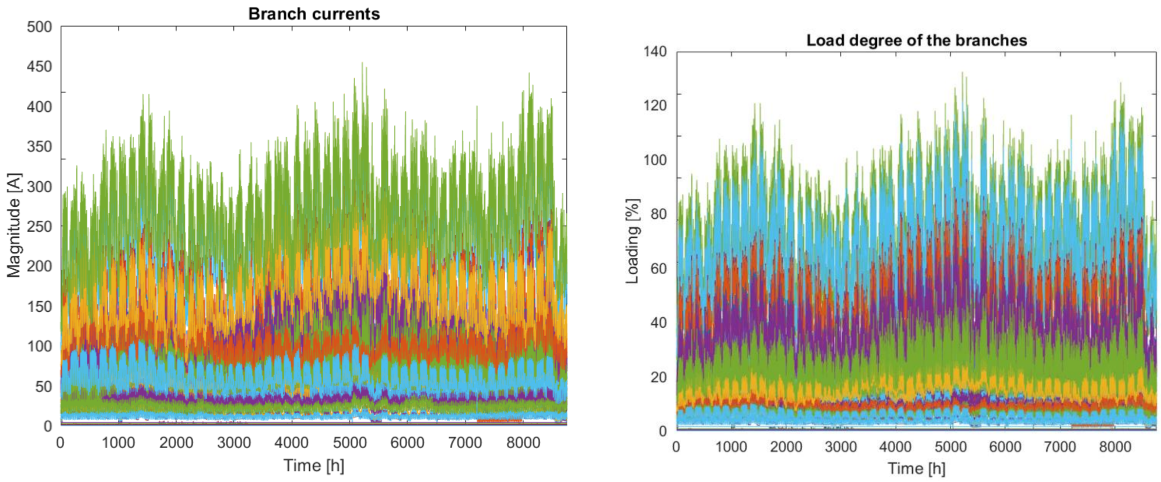


Figure 5.20: Electrical results of Case 4.1

Regarding case 4, this is the only possible grid reconfiguration. The results are summarized in Table 5.8.

Case number	Number of potential annual congestions	Number of hours with congestion	Maximum loading [%]	Number of congested branches	Average congestion intensity [A]	Annual cost of GE solution [€]
4.1	22724	4209	129.5	14	51	23048.564

Table 5.8: Case 4 results

5.6. Part 2: fault simulations at different locations

Starting from the reference cases of Part 1, different subcases are simulated in which the position of the fault slightly changes along the line, meaning that the intensity and the frequency of the congestion change, but also the availability of flexibility. In fact, when the fault moves downstream with respect to the primary substation there are less loads that need to be counterfed. The electrical results of each sub-case can be found in the Appendix.

5.6.1. Case 1

Case 1A.2: fault between nodes 30145 and 30140. There are 2 less loads that need to be counterfed. The new fault position is represented in Figure 5.21.

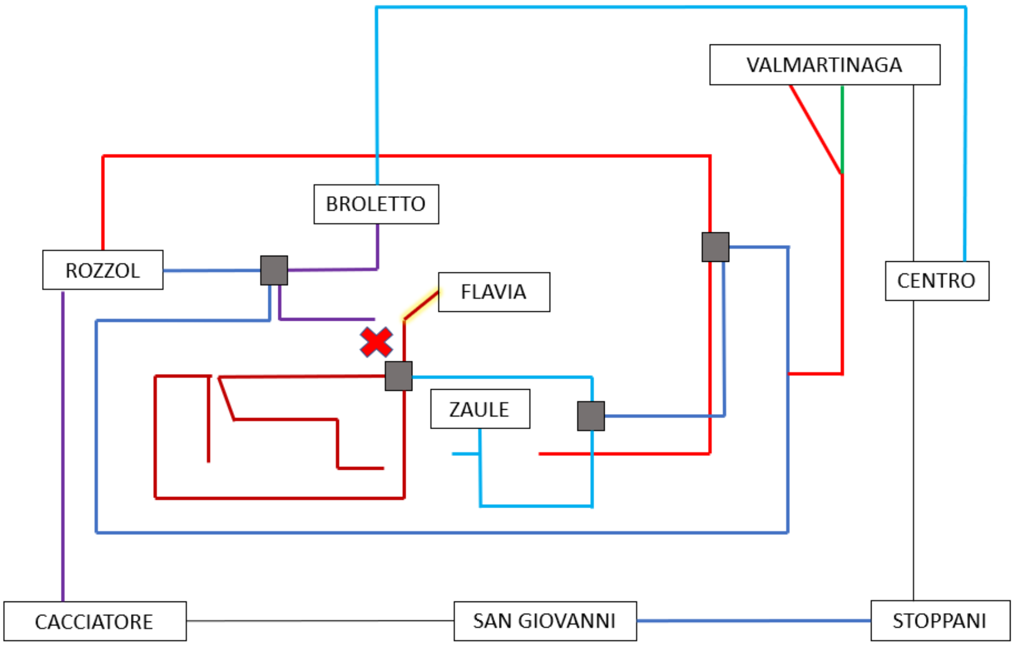


Figure 5.21: Grid with failure, case 1A.2

Keeping the nominal load at 100%, when there is a fault, the branch between nodes 100 and substation Flavia is congested.

Case 1B.2: fault between nodes 30102 and 30188. When the fault is downstream to node 30140 (one of the two interconnection points of the two lines) reconfiguration as Case 1A is not feasible. Therefore, the reconfiguration as in Case 1B is applied. The new fault position is represented in Figure 5.22.

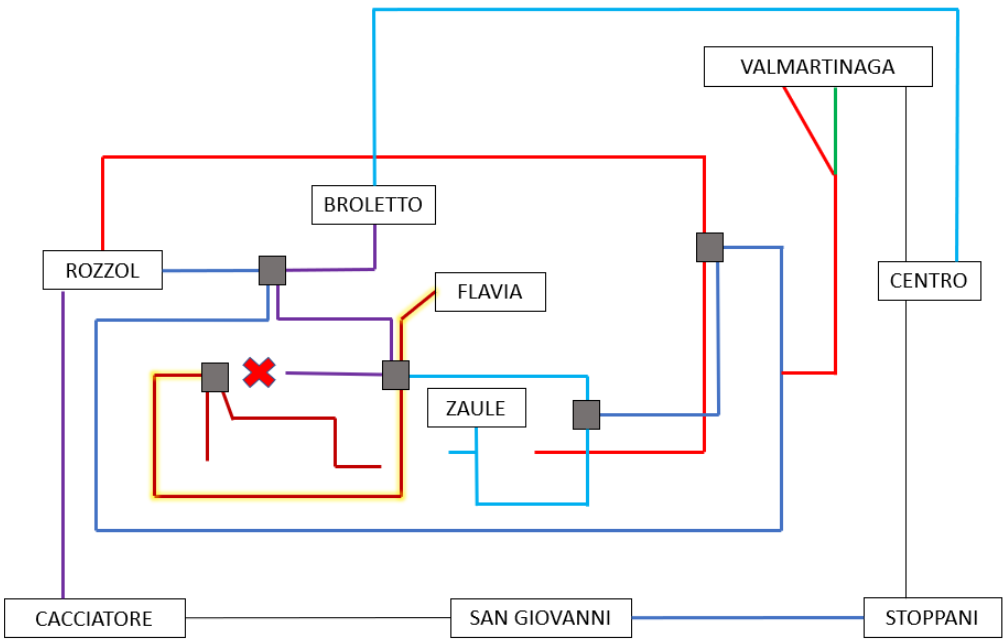


Figure 5.22: Grid with failure, case 1B.2

Keeping the nominal load at 100%, when there is a fault, the following branches are congested: between nodes 30144 and 30102, 30192 and 30144, 30143 and 30192, 30141 and 30143, 30140 and 30141, substation Flavia and 30140.

5.6.2. Case 2

In this case a different position of the fault cannot be simulated, since there is only one branch between the interconnection point and the primary substation Flavia.

5.6.3. Case 3

Case 3A.2: there is a fault between nodes 30122 and 30194. There are 3 less nodes that need to be counterfed. The new fault position is represented in Figure 5.23.

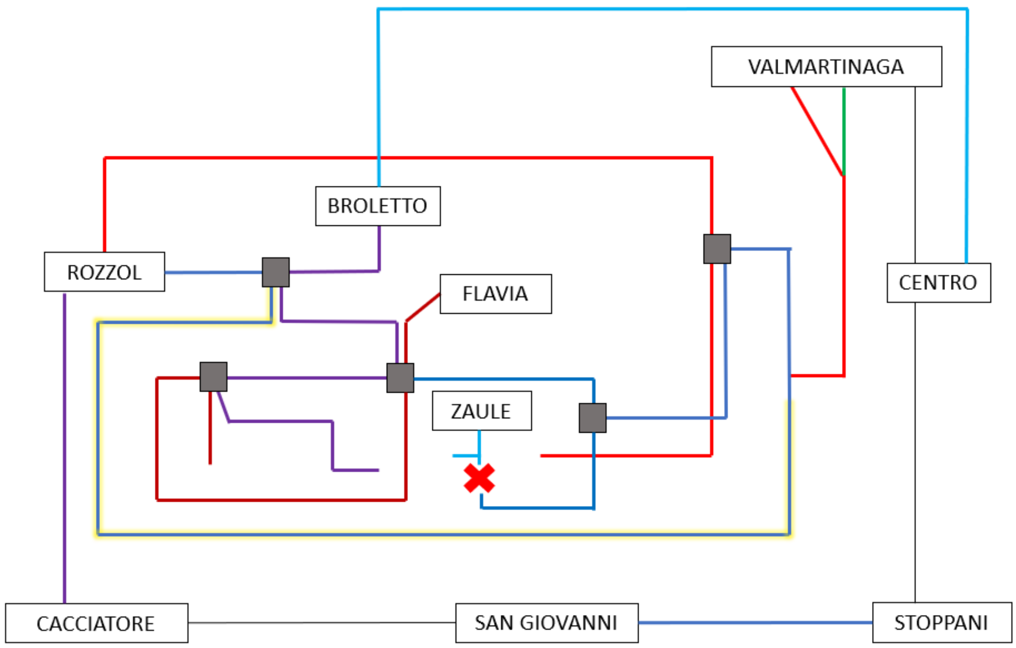


Figure 5.23: Grid with failure, case 3A.2

Keeping the nominal load at 100%, when there is a fault, the following branches are congested: between nodes 30008 and 30154, 30154 and 30176, 30176 and 30155, 30155 and 30181.

Case 3B.2: analog to Case 3A.2, but with the different reconfiguration. The new fault position is represented in Figure 5.24.

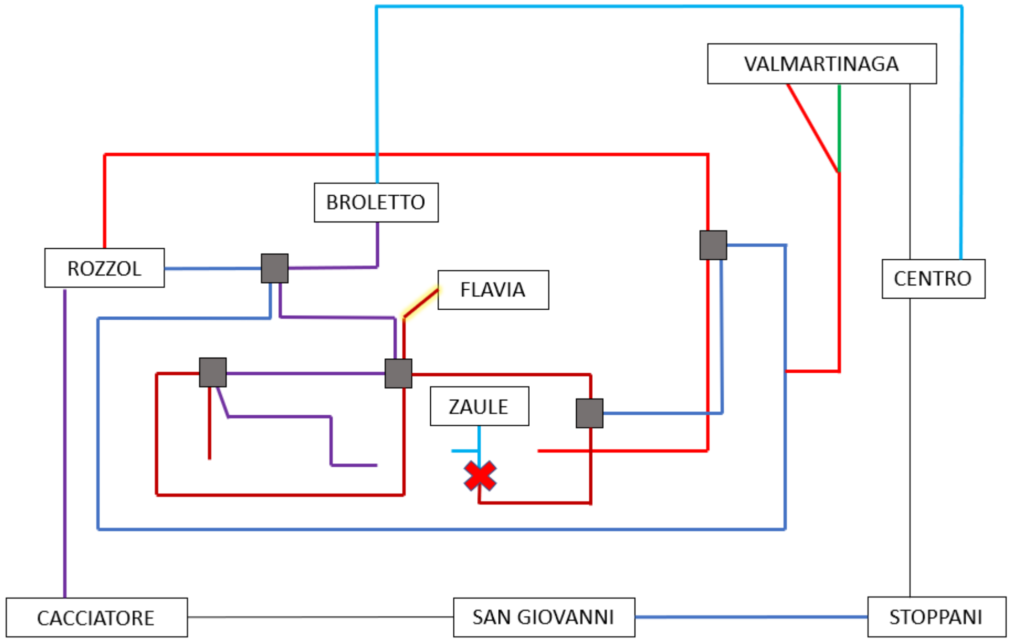


Figure 5.24: Grid with failure, case 3B.2

Keeping the nominal load at 100%, when there is a fault, the branch between nodes 30140 and substation Flavia is congested.

In case 3A.3 and 3B.3 there is a fault between nodes 30125 and 30194. Since only 1 less load need to be counterfed, and with a nominal power of just 0.7 MW, the results are very similar respectively to case 3A.2 and 3B.2. Thus, to avoid redundancy all the images are not shown, but only the results in Table 5.9. If the fault is moved downstream (i.e. between nodes 30125 and 30126 and further from the substation Zaule) there are not any more congestions in the grid.

5.6.4. Case 4

Case 4.2: fault between nodes 30164 and 30165. There are 5 less loads that needs to be counter-fed. The new fault position is represented in Figure 5.25.

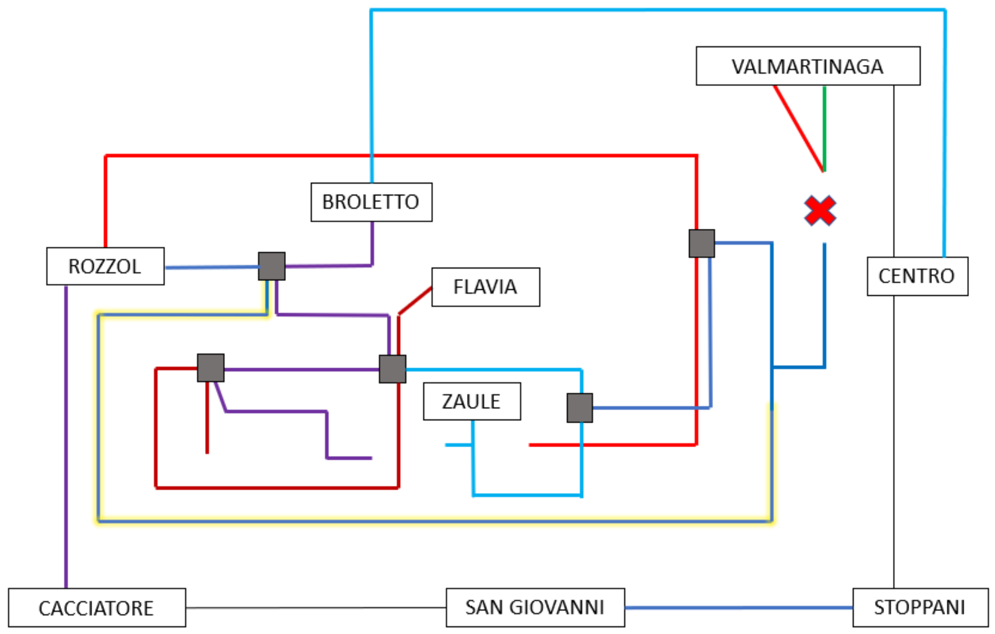


Figure 5.25: Grid with failure, case 4.2

Keeping the nominal load at 100%, when there is a fault, the following branches are congested: between nodes 30008 and substation Rozzol, 30008 and 30154, 30176 and 30155, 30155 and 30181, 30181 and 30156.

Case 4.3: fault between nodes 30165 and 30166 (4.2). Two less loads that need to be counterfed. The new fault position is represented in Figure 5.26.

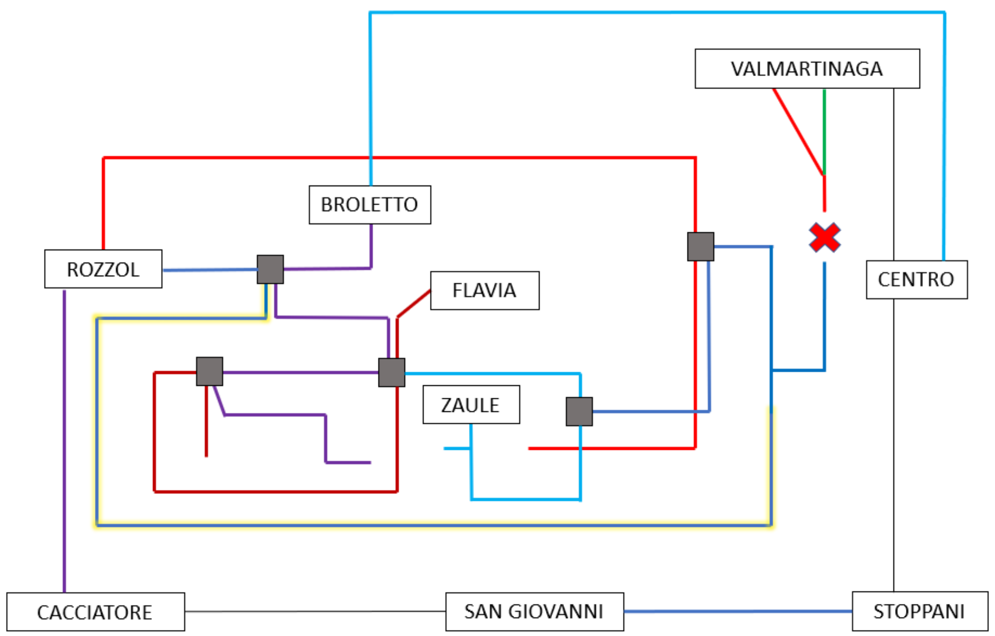


Figure 5.26: Grid with failure, case 4.3

Keeping the nominal load at 100%, when there is a fault, the following branches are congested: between nodes 30008 and substation Rozzol, 30008 and 30154, 30176 and 30155, 30155 and 30181, 30181 and 30156.

5.6.5. Results

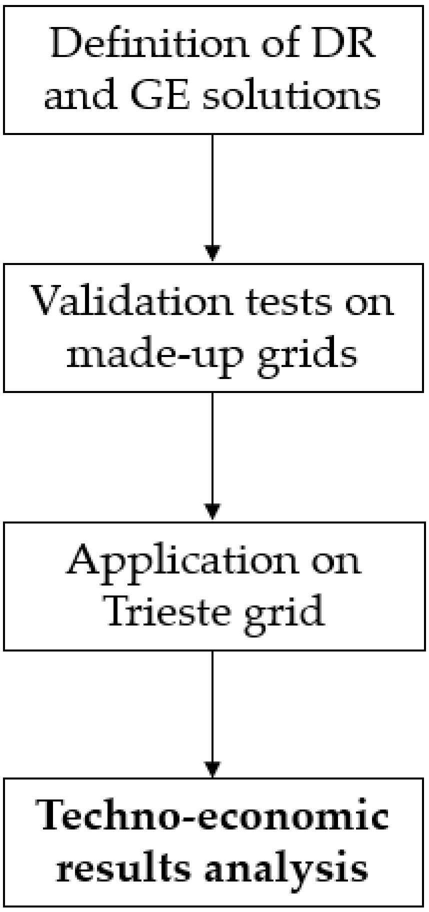
Case number	Number of potential annual congestions	Number of hours with congestion	Maximum loading [%]	Number of congested branches	Average congestion intensity [A]
1A.2	179	179	112.4	1	13
1B.2	868	193	114.22	6	12
3A.2	12	3	104.73	4	8
3A.3	12	3	104.56	4	8
3B.2	26	26	106.35	1	10
3B.3	26	26	106.15	1	10
4.2	2240	492	124	5	15
4.3	279	175	108.45	5	11

Table 5.9: Summary of part 2 results

In every case all the parameters have reduced. This is due to the fact that in each of them, the fault is located more downstream than the reference case, and thus the counterfeeding needs to serve less loads, with a decrease of the current and apparent power following through the branches. In the next chapter it will be analyzed how the different position of a fault along the same line influences the DR solution and how the loads that can actively help to reduce the congestion change.

6 Results of the simulations: economic comparison of the solutions

As shown in Flowchart 6.1, in chapter 6 and 7 the last part of the thesis work is dedicated to showing and analyzing the results of different yearly simulations based on the cases shown and described in Chapter 5.



Flowchart 6.1: Thesis structure

The aim of this chapter is to analyze the yearly price of the DR solution in case of different faults and re-configurations. In this chapter only the variable price related to the energy is considered. The part relative to the capacity will be analyzed in the next chapter. The economic results of the DR solution are strongly linked by mainly two factors. The first is the prices of the bids offered by the active resources. As seen in paragraph 3.5.2, each resource can bid at three different price level, and by changing the value of these levels, the final cost of the DR solution changes, with the rest being equal. The second factor is the frequency of the fault itself. This factor is more difficult to control and predict, since no precise historic data are present, and it is the main difficulty when analyzing the results. Thus, in order to compare the two solutions a probabilistic analysis needs to be conducted.

When comparing the different re-configurations possible for each case it is important to remind the different time frame of applicability of the various solutions. The GE solutions must be planned in advance, since the construction work takes time. The DR on the other hand can be applied when the actual congestion is present. At the same hours, for the same fault, it is possible that the congestions would be present in one reconfiguration and not in another. If the DSO has direct control on the re-configurations, some congestions might be prevented by choosing one instead of the other. The comparison between each sub-case makes sense if there is an overlap between the different re-configurations in the hours when a congestion might happen in the simulation along the year. Actually, this is the case most of the times in the simulations of the distribution grid of Trieste.

For sake of completeness, when there is more than one configuration, all of them are analyzed in this chapter. This is done to provide a complete vision, just in case that one of the re-configurations studied cannot actually be applied in real life for any reason. Thus, to have a thorough analysis a double confrontation needs to be made:

- Between the DR and GE solution for each re-configuration (indicator I, II, III and IV)
- Between different re-configurations within the same fault (Indicator V).

Regarding the active power reduction offered by the flexible resources, the extremes of the ranges for the random generation of the offers are fixed. Since in the worst case analyzed the loading of the most congested line does not overcome the value of 130% and that there are three offers for each load, the following extremes have been used: first offer between 5 and 15% of the nominal power, second offer between the previous one and 25%, third offer between the previous one and 35%.

6.1. I: congestion distribution along the year

Firstly, it is possible to analyze the cost for each hour in a year of the DR solutions, remembering that the GE solution price is a constant, given the results obtained in

Chapter 5. As in the previous chapter, a fault happening the whole year is simulated, just to see the potential effect on each hour, and not meaning that the fault would happen for the whole year.

The graphs in this section are useful to have a first and immediate image of the situation for each different case, and to have a first comparison between the two solutions. In some cases, a further analysis will be needed. However, in some cases it is clear by a first look that the DR is less convenient than the GE solutions, especially when the latter is particularly cheap.

It is possible to draw different graphs for each case, in function of the ranges of prices set for the active resource's bids. Three different price ranges for the bids have been set-up: each price range is in turn divided in three sub-ranges, one for each of the offers biddable by the active resources. The ranges considered are:

- Price range 1:
  - First offer: between 50 and 100 €/MWh
  - Second offer: between 100 and 150 €/MWh
  - Third offer: between 150 and 200 €/MWh.
- Price range 2:
  - First offer: between 150 and 200 €/MWh
  - Second offer: between 200 and 250 €/MWh
  - Third offer: between 250 and 300 €/MWh.
- Price range 3:
  - First offer: between 250 and 300 €/MWh
  - Second offer: between 300 and 350 €/MWh
  - Third offer: between 350 and 400 €/MWh.

Thus, for each load and for each bid, the price of the offer is randomly generated between the price range defined in the considered case. Since there are three different price ranges, three different annual simulations for each case are done.

- The horizontal red line represents the annual cost for the DSO to pursue the classical GE solution.
- Each blue point represents the sum of the cost of all the congested branch with the DR solution for each hour of the year, calculated with equation (6.1).

$$Hourly\ cost_t = \sum_{i=1}^{Number\ of\ brances} Cost_{i,t} \tag{6.1}$$

Thus, there is the same number of blue points as number of hours with congestion, and not as number of potential annual congestions (since more than one congestion can happen on different branches in the same time step).

Since the prices are randomly generated, the operation described is carried 5 times for each price range and for each case, in order to have different data inputs. Thus, the figures in this section represent the average of the results obtained. Each of the three figures represented for each case refers to a specific price range.

Case 1A.1: in this case there is a failure on the line served by the substation Broletto leading to one branch to be potentially congested (branch between the node 30140 and the substation Flavia). As shown in Figure 6.1, in this case the annual cost for the GE solution is quiet low, since only one cable can become congested and needs to be substituted. Furthermore, the cable is quite short being 0.2 km long with an average length in the grid of about 1 km per branch. The blue points are very dense, meaning that a congestion could happen at different times during the year, if a fault is present. In this case, even at first glance, it appears that the DR solution on many occasions is not more convenient than the GE solution. Even in the case when the bids are offered in the lowest price range, there are already many points above the red line. This means that even if a congestion happens once in a year, but in those given hours, the yearly cost of the DR solution is higher than the yearly cost of the GE solution. It is not possible to predict when and where a fault, and consequently a congestion, will happen but the more points are present above the red line, the more probable is for the DR solution to be less convenient. The trend consolidates when bids in higher price ranges are simulated, increasing the density of points above the line.

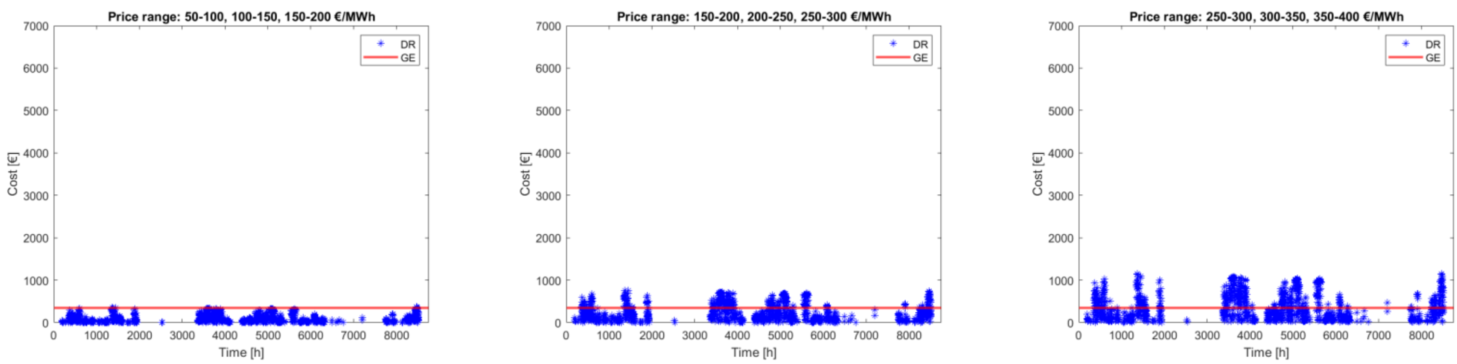


Figure 6.1: simulation hour by hour of case 1A.1

Case 1B.1: in this case there is a failure on the line served by the substation Broletto leading to six branches to be potentially congested (between nodes 30144 and 30102, 30192 and 30144, 30143 and 30192, 30141 and 30143, 30140 and 30141, node 30140 and substation Flavia). As shown in Figure 6.2, in this case the annual cost for the GE solution is much higher than in Case 1A.1, because the different grid reconfiguration causes 6 different cables to potentially be congested, with an average of 0.85 km. For this reason, there are much more congestions and thus the cost of the DR solution increase with respect to Case 1A.1. Regarding just case 1B.1 the DR solution has the potential to be more convenient that the respective GE. In fact, in all the three price ranges, even the most congested hours have a total cost much lower than the GE solution. This means that in each hour, taken individually, the DR is more convenient.

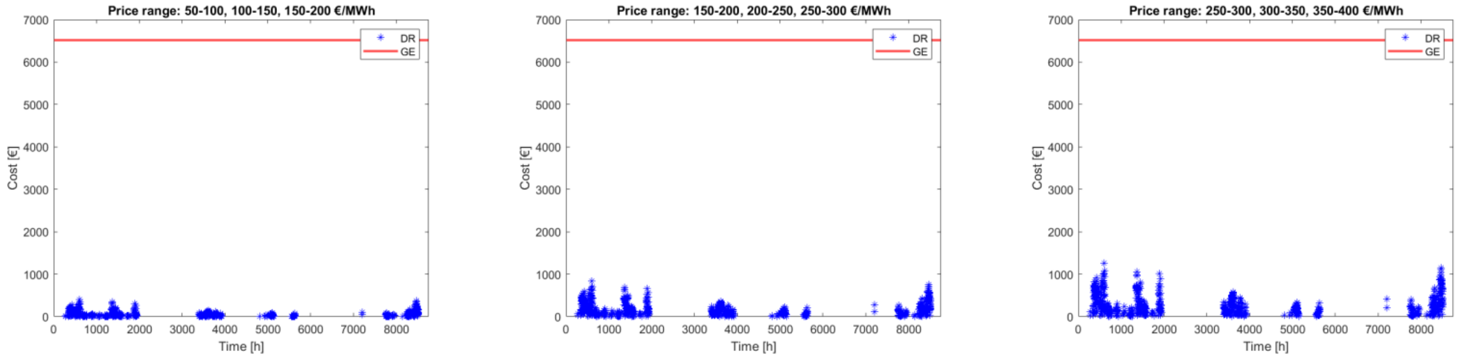


Figure 6.2: simulation hour by hour of case 1B.1

Case 2A.1: in this case there is a failure on the line served by the substation Flavia leading to seven branches to be potentially congested (between nodes 30188 and 30102, 30101 and 30188, 30140 and 30101, 30145 and 30140, 30008 and 30145, 30007 and 30008, 30007 and substation Broletto). As shown in Figure 6.3, in this case there are 4 congested branches with an average of 0.93 km, leading to a quiet high cost for the GE solution. The possible congestions are not distributed evenly along the whole year and seems to concentrate in 4 macro-periods. The cost of the DR solution is abundantly lower in all the hours and in all the possible price ranges, maintaining a big margin from the GE solution even when the bids are offered at the highest prices.

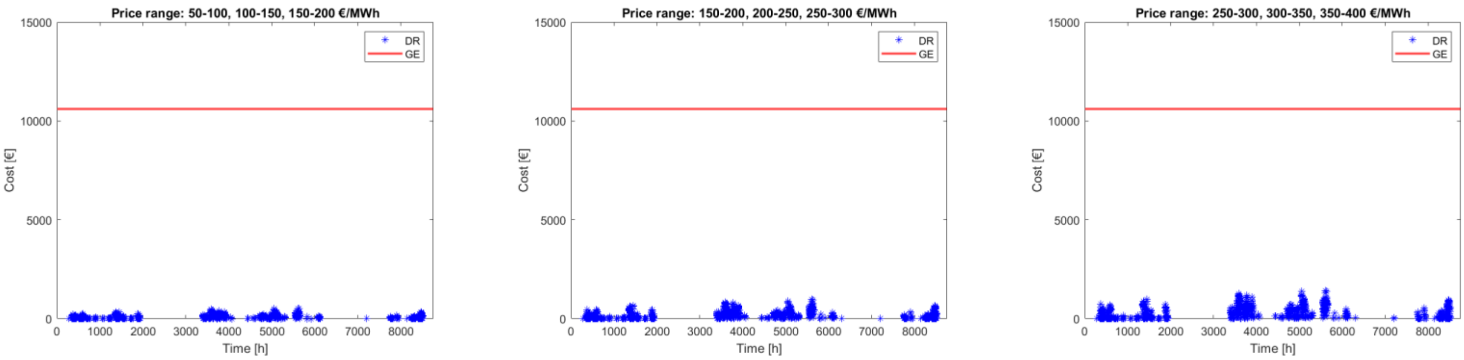


Figure 6.3: simulation hour by hour of case 2A.1

Case 2B.1: in this case there is a failure on the line served by the substation Flavia leading to seven branches to be potentially congested (between nodes 30188 and 30102, 30101 and 30188, 30140 and 30101, 30145 and 30140, 30008 and 30145, 30007 and 30008, 30007 and substation Broletto). As Figure 6.4 shows, with respect to Case 2A.1 there are more congested branches, but for a lower number of hours and with less strong congestions, with a similar average length of 0.91 km. Thus, with this configuration it is obvious that the cost of the GE solution increase with respect to the previous one. Regarding the DR, the effect of having more congested branch is stronger than the fact of having congestions which are less intense, leading to higher prices than the previous case. Also in this case, the cost of the DR solutions seems lower for each hour than the GE solution with a strong margin.

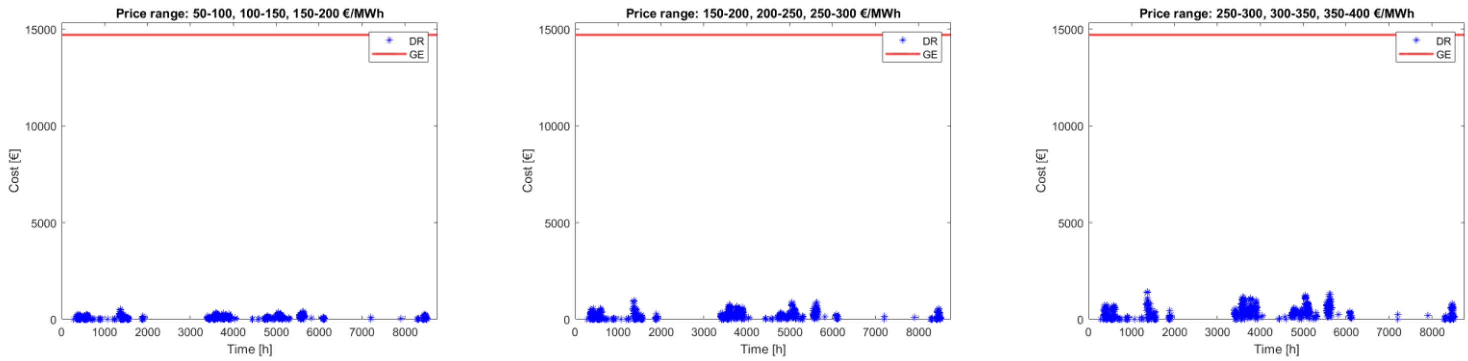


Figure 6.4: simulation hour by hour of case 2B.1

Case 3A.1: in this case there is a failure on the line served by the substation Zaule leading to four branches to be potentially congested (between nodes 30008 and 30154, 30154 and 30176, 30176 and 30155, 30155 and 30181). As shown in Figure 6.5, in this case 4 cables can be congested, but for a maximum of just 4 hours in a whole year, a much smaller number in comparison with all the other cases. The average length of the congested cables is 0.75 km. Thus, there is a high cost for the GE solution and quiet a low cost for the DR, given the very short time of applicability. In this Case, even if the fault for absurdity would last the whole year, the DR solution would be the most convenient one.

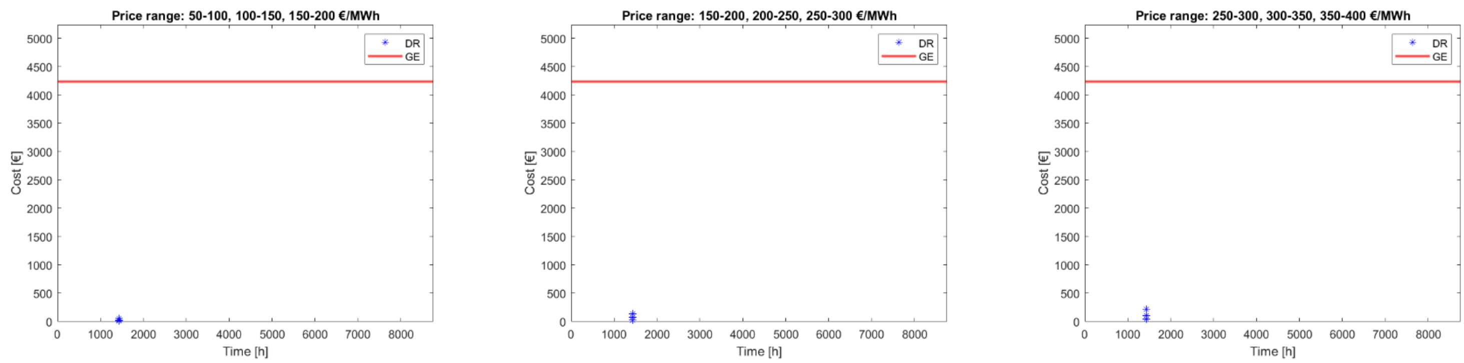


Figure 6.5: simulation hour by hour of case 3A.1

Case 3B.1: in this case there is a failure on the line served by the substation Zaule leading to only one branch to be potentially congested (between nodes 30140 and Flavia). As shown in Figure 6.6, as opposed to the previous one, in Case 3B.1 there is only one congested cable, but potentially for more hours and with higher intensity, with a length of 1 km. Thus, the DR and GE are closer to each other being the DR more expensive and the GE cheaper. For the highest price range, there are even some hours in which the cost of the DR solution overcome the annual cost of the GE.

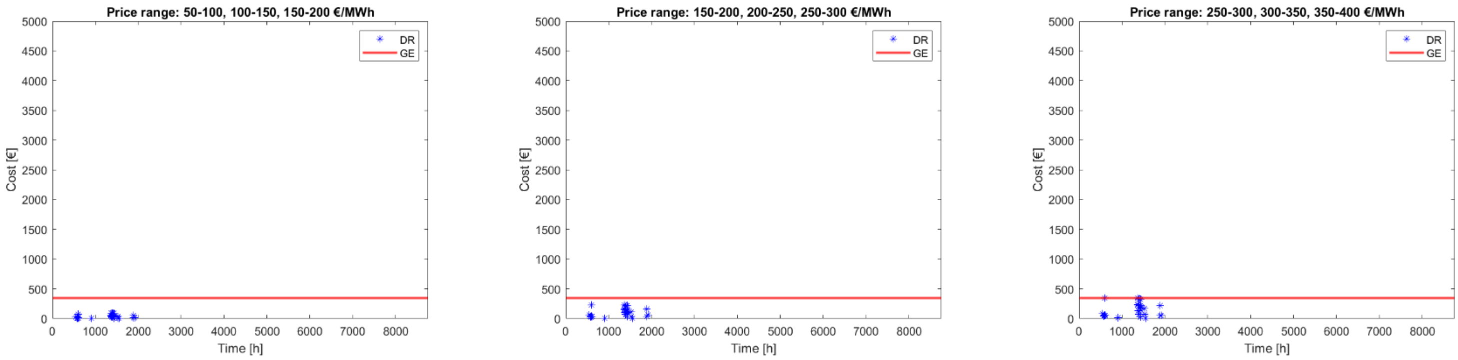


Figure 6.6: simulation hour by hour of case 3B.1

Case 4.1: in this case there is a failure on the line served by the substation Valmartinaga leading to 14 branches to be potentially congested (between nodes 30008 and substation Rozzol, 30008 and 30154, 30154 and 30176, 30176 and 30155, 30155 and 30181, 30181 and 30156, 30172 and 30156, 30171 and 30172, 30170 and 30171, 30170 and 30169, 30168 and 30169, 30165 and 30166, 30164 and 30165, 30196 and 30164, 30195 and 30196). As shown in Figure 6.7, this Case is the one with the highest cost for the GE solution, the one with the most congested cable and the one with the highest number of hours with a potential congestion. Furthermore, the one proposed is the only possible re-configuration. Given the high density of possible congestion, which are distributed evenly along the whole year, further analyses are necessary. Said so, even in the case with the highest prices there is still a huge margin between the two solutions. As already this, given the grid topology this is the only possible re-configuration.

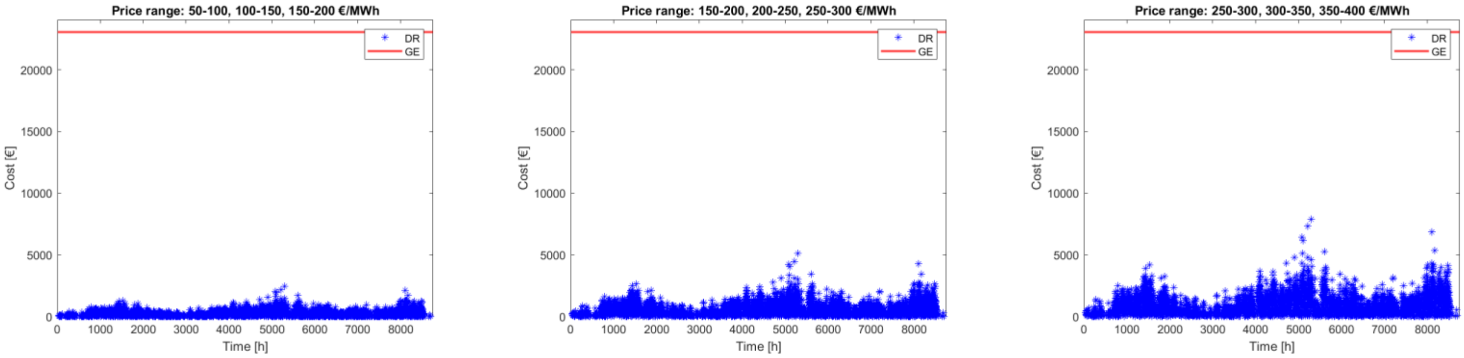


Figure 6.7: simulation hour by hour of case 4.1

Assuming that the probability of a failure is the same among all the different hours in the year, the probability of a congestion given that a failure will happen once in a year can be calculated with equation (6.2).

$$P_{congestion\,|\,failure} = \frac{Number\ of\ hours\ with\ congestion}{Hours\ in\ a\ year} \qquad (6.2)$$

This probability depends only on the grid topology and the power demand forecast, therefore it is not a variable number. The smaller this probability is, the more it is convenient to rely on the flexibility options that require less CAPEX investments than the investments in the grid.

Furthermore, the probability that the DR solution is more convenient than the GE solution can be calculated, assuming that one congestion event for 1 hour happens once a year, using equation (6.3):

$$P_{DR\ better\,|\,congestion} = \frac{Number\ of\ hours\ DR\ cheaper\ than\ GE}{Potentially\ congested\ hours\ in\ a\ year} \qquad (6.3)$$

This second probability depends on the price ranges and the offers, therefore it changes at every iteration. In Table 6.1:, an average among 5 cases for each price range and case is considered.

Case	$P_{congestion\,|\,failure}$	$P_{DR\ better\,|\,congestion}$ **Price range 1: 50-100-150-200 €/MWh**	$P_{DR\ better\,|\,congestion}$ **Price range 2: 150-200-250-300 €/MWh**	$P_{DR\ better\,|\,congestion}$ **Price range 3: 250-300-350-400 €/MWh**
1A.1	17%	96%	69%	53%
1B.1	9%	100%	100%	100%

2A.1	8%	100%	100%	100%
2B.1	7%	100%	100%	100%
3A.1	0.03%	100%	100%	100%
3B.1	0.3%	100%	100%	93%
4.1	48%	100%	100%	100%

Table 6.1: different probabilities for different price ranges

From these first results it is possible to see that the probability that a failure leads to a congestion (first column) is quiet low for the majority of cases. Furthermore, the actual probability should keep in consideration the fact that even the failure itself has a low probability of happening, although it is difficult to quantify. Thus, this analysis is already conservative since it assumes the presence of a fault every year for 1 hour. The second, third and fourth columns shows the eventual link between the convenience of the DR solution and price range sets for the bids. In case 1A.1 the probability of the DR solution to be more convenient to the GE is almost halved. In Case 1B.1, Case 2B.1, Case 3A.1 and Case 4.1 being the GE extremely expensive since more cables needs to substitute, the price does not influence the final percentage. In two cases, Case 1A.1 and 3B.1, the price influences the probability that the DR would be better than the GE solutions, being the two solutions much closer in term of cost.

6.2. II: average yearly cost of DR solution

The previous analysis only focused on analyzing the cost of the DR solution considering singularly each hour of the year. It would be useful to find some indicators to summarize along the whole year each case and solution, in order to make comparisons. When there is a failure, the calculation cannot be done by summing all the DR cost along the year, because that would imply that the failure would last for the whole year. A useful indicator is the average along one year of the cost for solving an hour-long congestion, calculated with (6.4):

$$cost_{average,DR} = \frac{\sum_{i=1}^{number\ of\ congestions} cost_i}{number\ of\ congestions} \qquad (6.4)$$

In this way, since an equal probability for the failure to happen in every hour along the year is assumed, it is possible to get a mean expected value for the total cost of the

DR solution. If this operation is done with different price range for each iteration, a break-even average price of offers can be found, which makes indifferent for the DSO to pursue the DR or the GE solution. The lowest the break-even is, the less is probable for the DR solution to be more convenient, since that will be the case only if the average of the offers made by active resources is lower than the break-even price. Contrarily, the highest the break-even, the higher the probability that DR is convenient (probability which could become certainty if the price overcomes 400 €/MWh, the strike price for the UVAM pilot projects, taken as reference). It is important to remember that this indicator needs to be paired with the probability of congestion seen in the previous section. In fact, the same average price with different probability of happening can lead to different decisions regarding the solution to pursue.

15 different simulations are done for each price range of each case. The 15 results for each case are reported in the graphs of this section through the use of a box chart. In this section, this approach was chosen because the distribution of data values may be skewed or because there might be clear outliers, whereas the mean is usually used when the data are close to being symmetrical. The value of the mean, and all the other numerical results, are reported for completeness in the tables in the Appendix. Actually, it is possible to see that the values of the mean and the average for each case are not very different. This happens because the range chosen for the price is not big, being 50 €/MWh for each offer. And secondly there are 86 nodes, so the fluctuation in the price offers by the active resources are likely to compensate each other. The graphs are reported using a logarithmic scale in the y-axis, because in some cases the value of the GE solution is much higher than the DR. In this way the visibility of the graph is improved.

Figure 6.8 shows that in Case 1A.1 there is a point where the average cost of the DR intercepts the annual cost of the GE solution. Since it is an average, it means that statistically when the price of the bids is higher than the range 200-250-300-350 €/MWh, the expected annual cost is higher with the DR rather than the traditional solution. This can be a signal of a potential problem: if there is not much liquidity in the market when needed, the DSO might be forced to select offers that are higher than the mentioned threshold. If the GE solution had been already discarded priorly, the DSO has to accept these offers, causing an economic loss. Regarding Case 2A.1, this issue is not brought up, since the average costs of the DR solutions are always much lower than the cost of the GE solution.

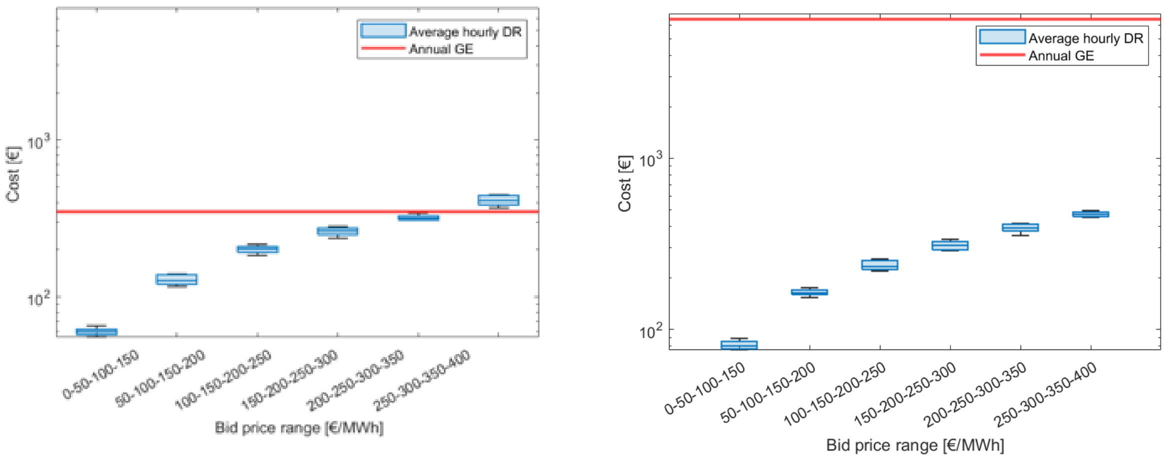


Figure 6.8: average yearly cost for case 1A.1 (left) and 1B.1 (right)

As Figure 6.9 shows, in both case 2A.1 and 2B.1 there is not a point in which the average price for the DR solution intercepts the line of the GE cost. Furthermore, there is quiet a big margin between the cost of the two solutions. Therefore, independently on the type of reconfiguration chosen by the DSO in case of a fault, the DR solution appears more convenient.

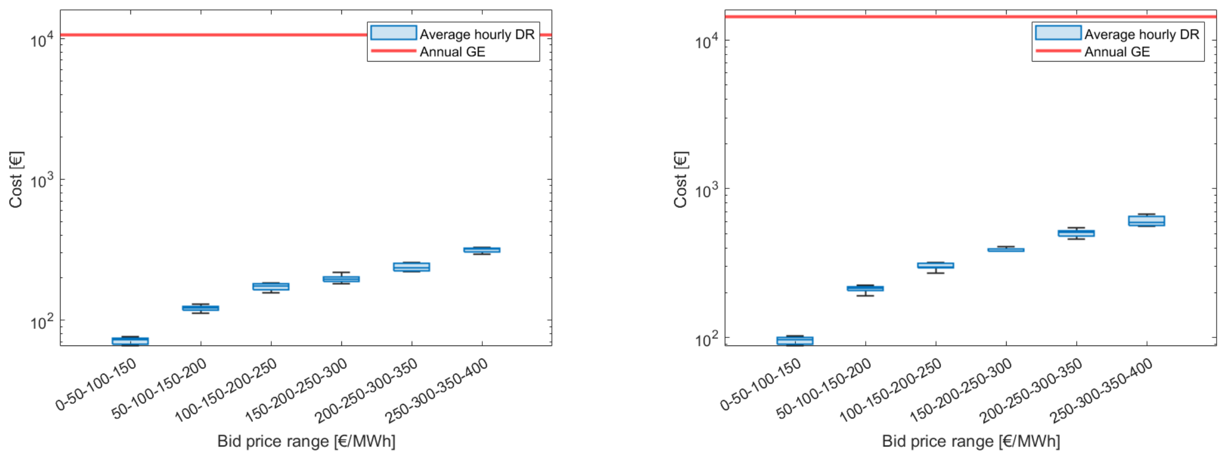


Figure 6.9: average yearly cost for case 2A.1 (left) and 2B.1 (right)

As Figure 6.10 shows, in both case 3A.1 and 3B.1 there is not a point in which the average price for the DR solution intercepts the line of the GE cost. In case 3B.1 the difference between the two solutions is quiet low, not giving a lot of margins.

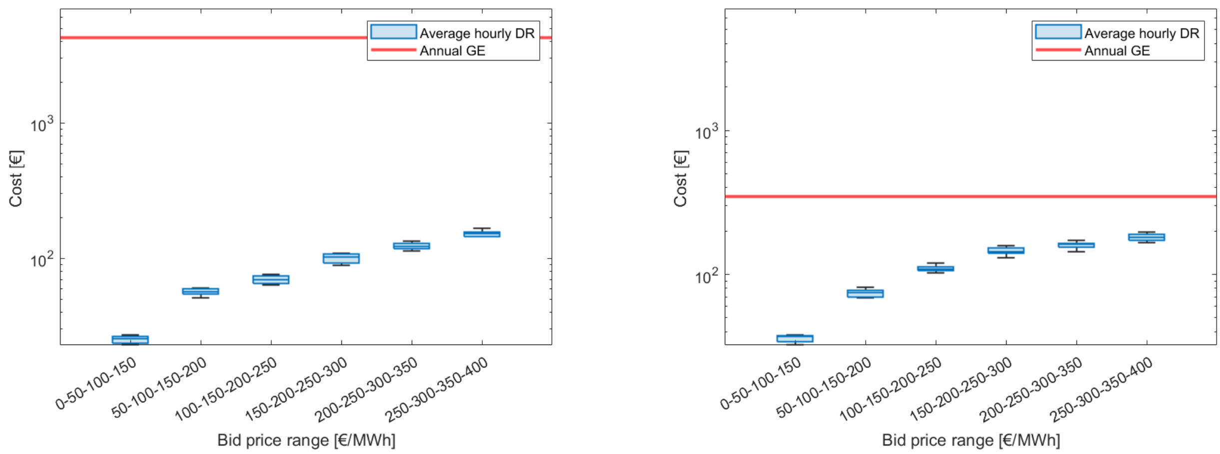


Figure 6.10: average yearly cost for case 3A.1 (left) and case 3B.1 (right)

Figure 6.11 shows that Case 4.1 is the one with the highest average prices among all cases. Nevertheless, this is due to the incredibly high number of congestions that the fault and the re-configuration cause. In fact, the DR solutions seems extremely more convenient than the GR, with the highest margin with respect to all other cases.

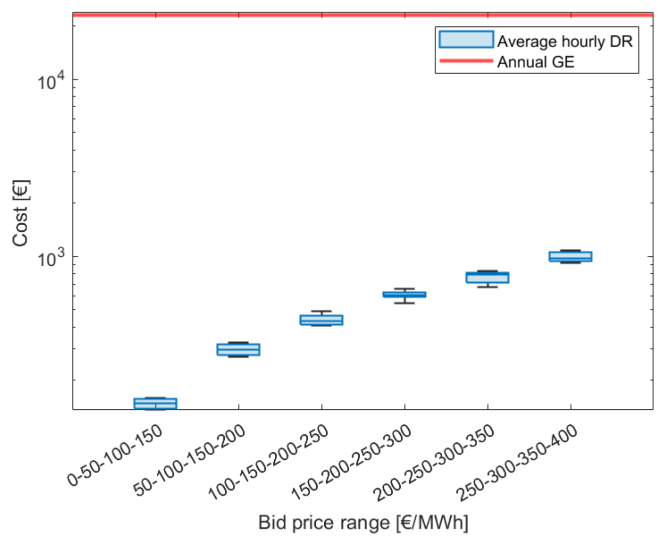


Figure 6.11: average yearly cost for case 4.1

Among all the cases considered, only in case 1A.1 there is a break-even point between the cost of the GE solutions and the DR solutions, reached with a price range for the bids of 200-250-300-350 €/MWh. In all the other cases, a break-even is never reached considering the chosen price ranges, which have an upper limit of 400 €/MWh. In fact, it is very unlikely for a DSO to accept a bid with a price much higher than 400 €/MWh (the UVAM project strike price [35]), and thus it has not been considered. Hence, for all the other cases on average the DR solution is more convenient than the GE solution, assuming an hour-long congestion each year.

6.3. III: congestion event with variable length

In this section the assumption that the congestion lasts only one hour is relaxed. If a fault is not solved within one hour, the congestion will last also for the following hour. If the fault is still not solved, the congestion continues to be present until one of two conditions is verified: the demand spontaneously decreases, or the fault is finally fixed. The maximum period of consecutives hours from when the congestion is present until when it is spontaneously solved is given the name of “congestion event”, within this thesis. Hence, it is more conservative to assume that the DR solution would be activated for the whole duration of the congestion event. Thus, the longer the congestion is, the more likely it is for the DR solution to be less convenient, since the cost grows both with the duration and with the amplitude of the congestion itself (in terms of current or energy). On the other hand, the cost of the GE solution is only linked to the intensity, regardless of the duration, since it is dimensioned on the worst case (the 90th percentile).

The cost of each congestion event is calculated as in equation (6.5):

$$cost\ congestion\ event\ [€] = \sum_{j=1}^{length\ of\ event\ [h]} hourly\ cost_j \qquad (6.5)$$

The difference with the previous case is that before the cost was calculated for each hour, and now it is calculated grouping the consecutive congestion in one event, assuming that the event is as long as it can possibly be. Thus, if equation (6.5) is applied instead of equation (6.1) the average cost changes and increases, since the average duration of the congestions have also increased. Hence, in this section a more conservative approach is done, since the probability that the GE solution is more convenient than the DR increases.

The following analysis is done carrying out 5 simulations with the same price ranges of Chapter 6.1 and is conceptually the same analysis, but calculating for the DR solution the average on each congestion event, and not on each hour. Obviously, the cost for the GE solution does not change. The following graphs are conceptually very similar to the ones of section 6.1, but on the x-axis are present only the congestion events, whereas previously there were all the hours in the year. Each blue dot represents the average cost for the given event, the red line as before is the yearly cost for the GE solution. Since the results found show similar trends, in the following graphs the results for each of the three price ranges are not reported, to avoid redundancy. Instead, an average between the three price ranges is shown for every case.

As Figure 6.12 shows, the trend seen in the previous chapter are confirmed. In case 1A.1 the GE solution is extremely cheap and thus is more convenient in more than two thirds of the times. In case 1B.1 being the GE solution much more expensive, the DR one is more convenient in all the cases considered.

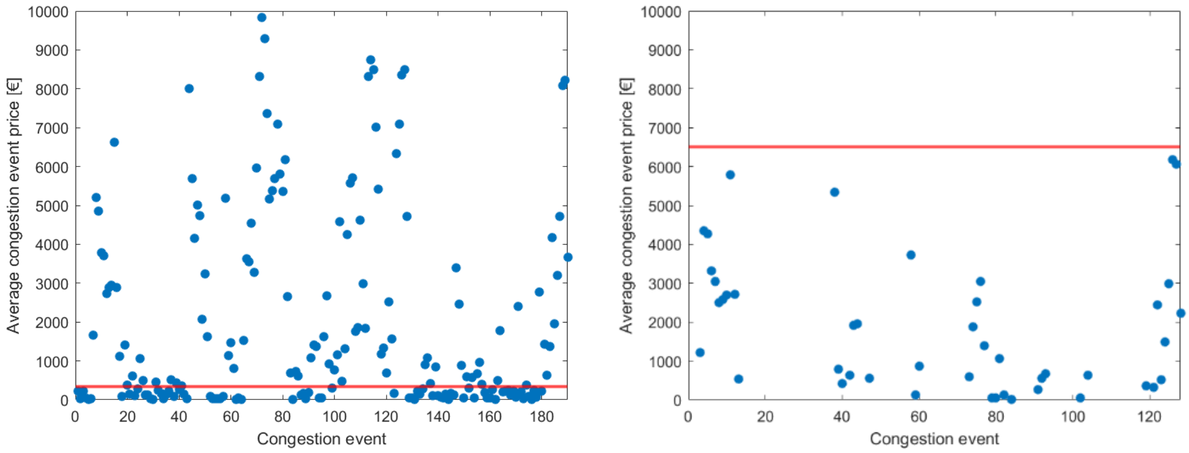


Figure 6.12: congestion events cost for case 1A.1 (left) and case 1B.1 (right)

Figure 6.13 shows that in Case 2, in both the re-configurations the situation is similar, since the cost for the GE solution is quite high. Only in a few events in Case 2A.1 the DR solution happens to be more expensive. The price of the DR solution in the two cases are comparable, both in term of frequency and average cost.

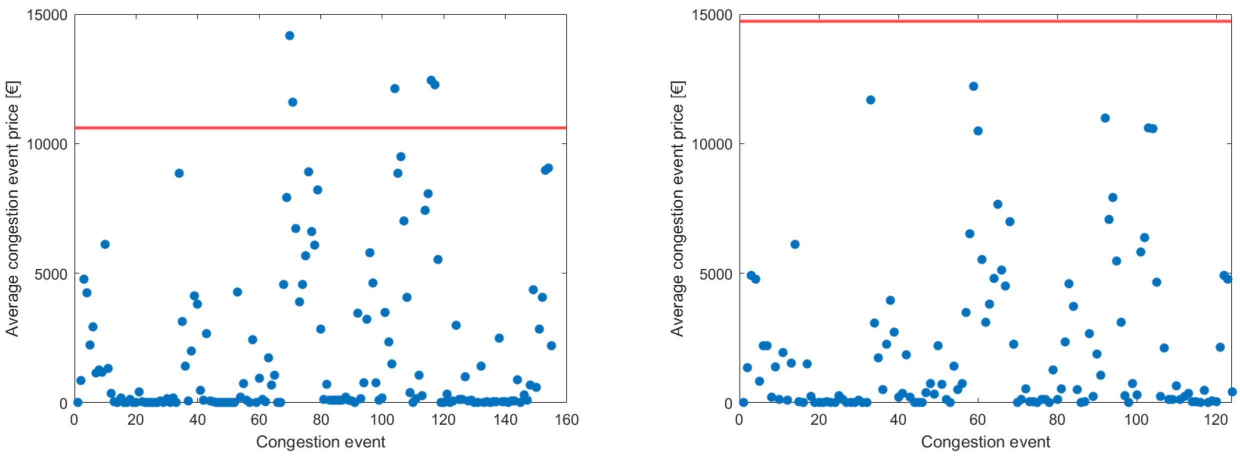


Figure 6.13: congestion events cost for case 2.A1 (left) and case 2B.1 (right)

As Figure 6.14 shows, in case 3A.1 the DR response is extremely more convenient than the GE, also considering the fact that the congestion events are very rare to happen along the year. This is a peculiar case due to the very limited amount of congestions event in both sub-cases. In case 3B.1 the situation is less clear, being the GE solution less expensive. It seems that the DR solution of case 3A.1 is cheaper even than the GE solution of case 3B.1

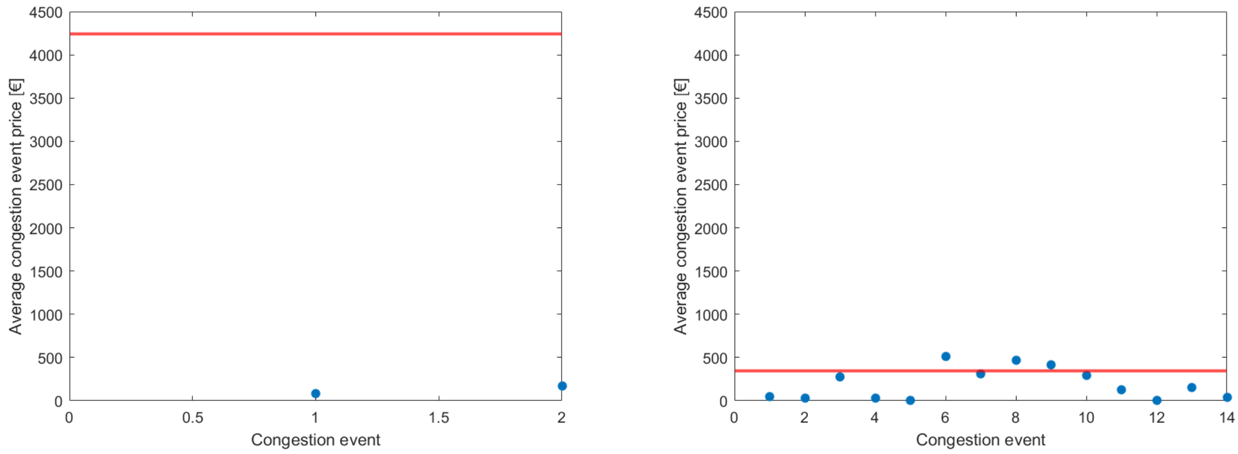


Figure 6.14: congestion events cost for case 3A.1 (left) and case 3B.1 (right)

Case 4 is the most difficult to analyze, due to the high number of potential congestions, and the absence of other re-configurations. As Figure 6.15 shows, for the most congestions events, the DR is more convenient than the GE. The issue is that in the cases where it is not, the annual price can nearly double with respect to the GE solution. This type of trend has been seen previously only in Case 1A.1

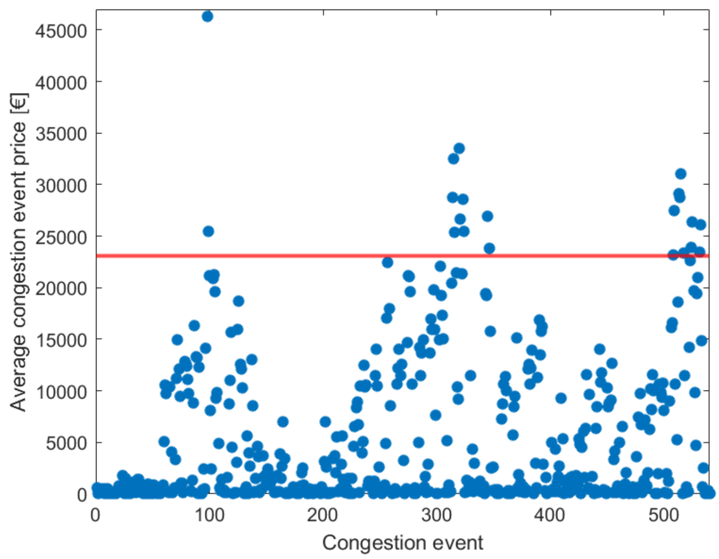


Figure 6.15: congestion events cost for case 4.1

To summarize the graphs shown, it is possible to define as an indicator the average conveniency of DR against GE, assuming that only one congestion event happens in each year. It is the ratio between the number of congestion events which are less costly than the GE solution, and the total number of congestion events. This indicator is calculated for each of the 5 simulations, and a final average is shown in Table 6.2.

Case	**Possible congestions**	**Congestion events**	**Average duration of the event [h]**	**Average convenience of DR against GE**
1A.1	1495	189	7.9	31.74%
1B.1	3286	128	6.17	100%
2A.1	1467	155	6.18	96.77%
2B.1	1299	124	5.61	100%
3A.1	12	2	1.5	100%
3B.1	28	14	2	57%
4.1	22724	540	7.7	90%

Table 6.2: summary of the average congestion event

In Cases 1B.1, 2B.1, 3A.1 all the congestion events, taken individually, are on average cheaper than the GE solution. For Case 2A.1 this is true respectively for 96.77% and 90% of the events, thus a great majority. On the other hands, in Cases 1A.1 and 3B.1 the GE solution is on average cheaper. In almost every case the average congestion event duration is between 5 and 8 hours, thus leading to a number of congestion events which is much smaller than the total number of congestions. The minimum number of congestions events is in Cases 3A.1 and 3B.1, respectively with 2 and 14 event, whereas the maximum is in case 4.1, with 540 events. All the other cases have a number of congestion events between 124 and 189.

The same conceptual operation of Chapter 6.2 can be done. The average along one year of the cost for solving a congestion event can be calculated with equation (6.6).

$$cost_{average,DR\ congestion\ event} = \frac{\sum_{i=1}^{number\ of\ congestion\ events} cost_i}{number\ of\ events} \quad (6.6)$$

By applying the same price ranges as in Chapter 6.2, a break-even average price of offers can be found, which makes indifferent for the DSO to pursue the DR or the GE solution. The result are summarized in Table 6.3.

Case	**Break-even price range [€/MWh]**
1A.1	50-100-150-200
1B.1	/
2A.1	/
2B.1	/
3A.1	/
3B.1	250-300-350-400
4.1	/

Table 6.3: summary of congestion events break-even costs

From the table it is possible to see that compared to Chapter 6.2 the break-even price range has decreased by 150 €/MWh in Case 1. Furthermore, also for case 3B.1 it is now possible to see that there is a break-even within the price ranges simulated. This means that if the DR is applied for the whole duration on the congestion event, the DSO on average needs to accept bids with lower price, in order to not incur in an economic loss with respect to the GE solution.

6.4. IV: worst case scenarios

It is very difficult to predict when, where and for how long a fault will be present in the grid. Nevertheless, these three parameters, beyond the bid prices, have a great influence on the prices of DR. It is not possible to calculate a priori the total cost for the DR solutions without doing assumptions on the frequency and duration of the failure. If a failure is present when the power demand is low, even in a counter-feeding disposition there might be not even one congestion. Thus, the total price of the DR solution is not fully predictable but depend on the time where the fault is present and on the power demand in that given time. If a budget for the DR solution it is fixed, is not possible to see a priori the number of congestions which might be solved, since the price is unknown until the fault (and therefore the congestion) actually happens. On the other hand, by definition the GE solution is able to cover (almost) all the potential solutions along all the year. This happens because the cable dimensioning is done already on the 90th percentile of the possible worst case and the costs are already sunk.

That is why to compare the two solutions is useful to consider the worst case, defined as the fault happening when the power demand is at the maximum, and then leading to a congestion with the highest branches' loading with respect to the whole year. This operation can be done not just on the worst case in absolute, but for any given number of congestions, starting from the worst one. For example, the 5 worst congestions are defined as the 5 timesteps leading to the 5 highest average loading of the branches. By summing the costs of the DR solution for each hour, it is possible to obtain the cost that the DSO would pay if 5 faults happened in one year, in the moments of highest demands, leading to the 5 worst congestions.

For any given price ranges, it is possible to calculate how many congestions it is possible to solve with the same annual expense as the GE solution, considering before the worst congestions. The acceptable threshold is up to the risk attitude of the DSO. It is important to note that there is a minimal likelihood that failures will coincide with high power demand, therefore it can be more cost-effective to rely on flexibility solutions with much smaller CAPEX investments. Thus, even if not strictly quantifiable the probability of even 1 congestion is already low, and the probability of 5-10-15 yearly congestions is exponentially lower. Furthermore, by considering the worst congestions before, the approach is very conservative. Also, the GE costs indicate only an inferior limit, and it is likely higher in reality, to have an even more conservative approach. All the numerical values are reported for completeness in the Appendix.

Case 1A.1

By looking at Figure 6.16 it is immediate to see that the DR solution is much riskier than the GE, since only 1 yearly congestion, in the range with the lowest bid prices, could be solved using the same budget as the GE solution. And even in the best case when the DR is more convenient, the maximum savings is only up to 53%. If two congestions happened in the same year, not having invested priorly in the GE would mean an increase of cost for the DSO. Thus, it would be convenient for the DSO to proceed with the cable substitution between node 30140 and Flavia.

Case 1B.1

From Figure 6.16 it is clear to see that in the most probable cases (1 and 5 congestions) the DR solution is always more convenient than the GE. Regarding the least probable cases (10 and 15 congestions) it depends on the prices. In the first 2-3 price bands, the DR solution remains more convenient. In the best case for the DR, the yearly savings for the DSO would be up to 97% with respect to the GE solution, clearly showing the DR solution to be more convenient than the GE. Thus, it would not be convenient for the DSO to proceed with the cables' substitution.

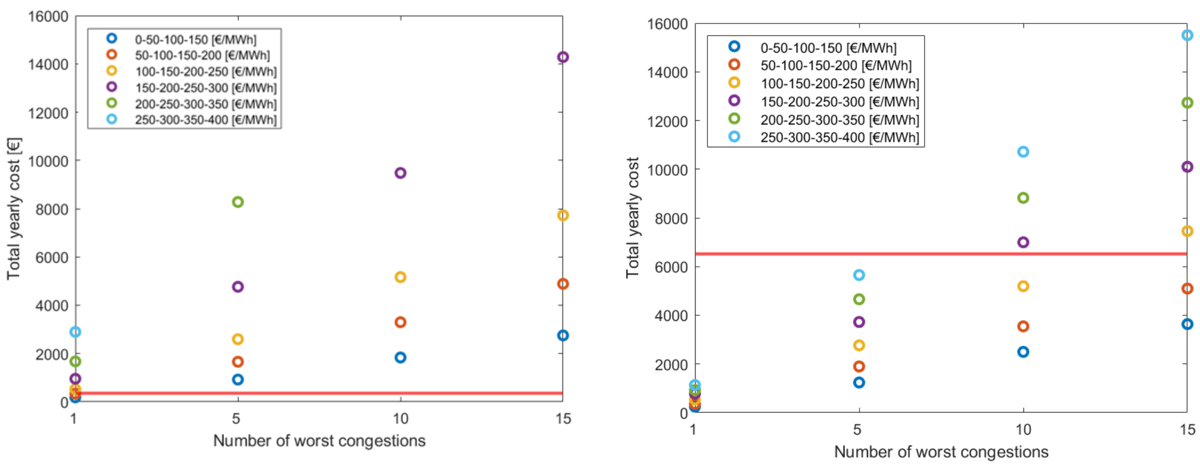


Figure 6.16: Worst case scenarios for Case 1A.1 (left) and Case 1B.1 (right)

Case 2A.1

In this case it is very clear to see from Figure 6.17Table A.10 that almost in all cases analyzed and for almost all the price ranges the DR solution is more convenient. Applying the DR solution would also give to the DSO quiet a high margin, since these are the worst cases possible along the year.

*Case 2B.1*This case is very similar to the previous, with the GE being more convenient than the DR only in the very worst case analyzed and with the highest prices, as Figure 6.17 shows.

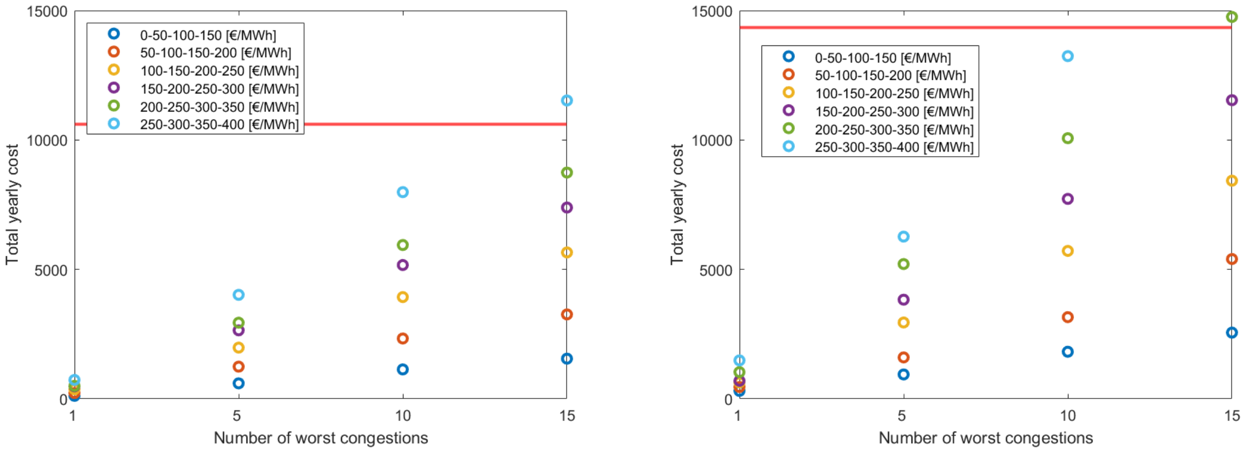


Figure 6.17: Worst case scenarios for Case 2A.1 (left) and Case 2B.1 (right)

Case 3A.1

In this case only in 3 hours along the year a congestion can happen, thus it does not make sense to analyze the case with 5 and 15 congestions. In this case, even in the worst scenario and with the highest prices the DR solution is more convenient than the GE, as shown by Figure 6.18.

Case 3B.1

Figure 6.18 shows that in this case the DR solution is more convenient considering all price ranges, but just considering the worst congestion. In all the other situations, the GE is more convenient, being extremely cheap. Thus, proceeding with the DR solution would not give a high margin of safety and the DSO would risk incurring in an economic loss if there is more than one congestion.

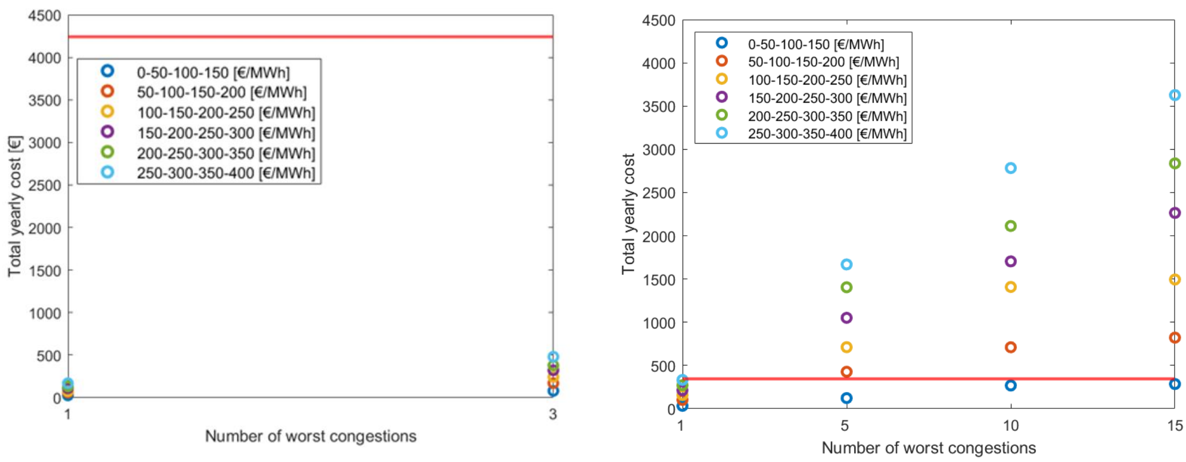


Figure 6.18: Worst case scenarios for Case 3A.1 (left) and Case 3B.1 (right)

Case 4.1

As shown in Figure 6.19 in this case in almost exactly half of the situations analyzed the DR solution is more convenient, whereas in the other half the GE is more convenient. Up to 5 congestions the DR is still convenient, except the very last price range simulated. Thus, according to the risk degree of the DSO, it might be more convenient to apply the DR solution.

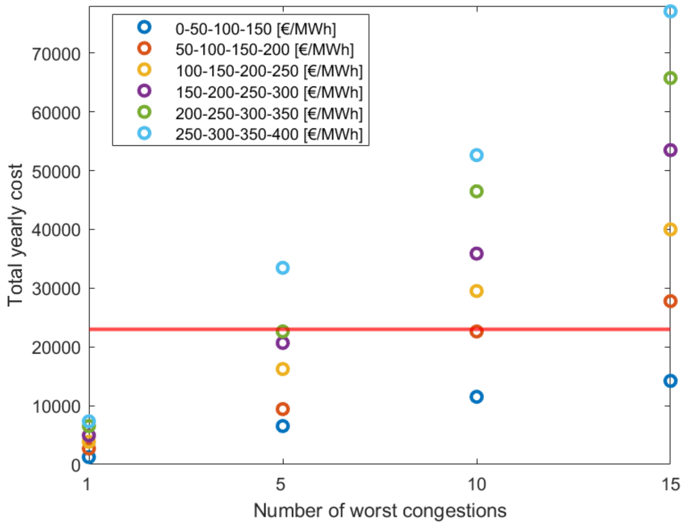


Figure 6.19: Worst case scenarios for Case 4.1

6.5. V: more than one congestion

The strong assumption until now was that only congestion of one hour happens in a whole year due to a fault. To calculate the average cost with more than one hourly congestion per year the following equation can applied,

$$cost_{n\ congestions,} = cost_{1\ congestion} \times n \tag{6.7}$$

Where n is the number of congestions assumed in the year and the average cost for 1 congestion is the one simulated in chapter 6.2

Since the cost for 1 hourly congestion is an average for one hourly event along the year, and the cost for different congestions with the DR solution is cumulative (contrarily to the GE solution) the average cost for 2 congestions is twice the cost for 1 congestion, and so on. This means that the average cost is strongly related to the number of expected faults in one year, which cannot be forecast with the data in possession. Thus, the inclination of the DSO to pursue a DR scheme or a classical GE solution is strongly dependent with the risk profile of the DSO, and the data it is able to collect to predict when and where a fault in the grid could happen in the future.

In this section, for each Case, it is considered the minimum cost for each re-configuration, and not the respective cost, as it has been done in the previous section. This is done in order to find the most cost-effective solution overall. In fact, as seen before, a DR scheme might be more convenient when compared to the GE of one re-configuration, but less convenient when compared to the GE of another re-configuration. In this section, a number of congested hours between 0 and 10 is considered. It is important to remember that, even if not quantifiable, a higher number of congestions is less probable, since in order to have multiple congestions along the year, the same fault should happen in different moments. Another aspect to consider is the fact that in this chapter every simulation is done along one year, whereas the useful life of the new cables is 30 years. Thus, it can happen that in one year the annual cost for the DR solution is higher than the annual cost for the GE simulation. However, the presence of a fault is aleatory, and to create a congestion it needs to coincide with the peak of the demand, meaning that the probability of happening is already low, as seen in Chapter 6.2. Thus, it is even less probable that the same conditions verify in multiple years along the time frame considered (30 years).

For each a case of plot showing the price of the DR solution is shown, depending on the number of annual congestions and the different price range. All the numerical values are reported for completeness in the Appendix.

In both plots in Figure 6.20 the GE is plotted considering re-configuration 1A.1, being the cheapest one. Now the comparison made on Case 1B.1 seems definitely less convenient than before. The choice depends on the risk profile of the DSO, since there are still conditions with a low number of congestions and a low price offered which make the DR solution more convenient. The DR applied to re-configuration 1A.1 is more convenient in 18% of the cases considered (although the cases are not equiprobable), whereas re-configuration 1B.1 on 13% of the cases. The potential economic savings are theoretically up to 100% if no congestions is formed during the year. With one congestion the savings are up to 82% of the GE expenses with re-configuration 1A.1 and 76% with re-configuration 1B.1. It does not make much sense to calculate the potential economic loss since is depends on the number of the congestions and can conceptually tend to infinite. To adopt a conservative approach, the DSO should choose the GE solution applied on re-configuration 1A.1.

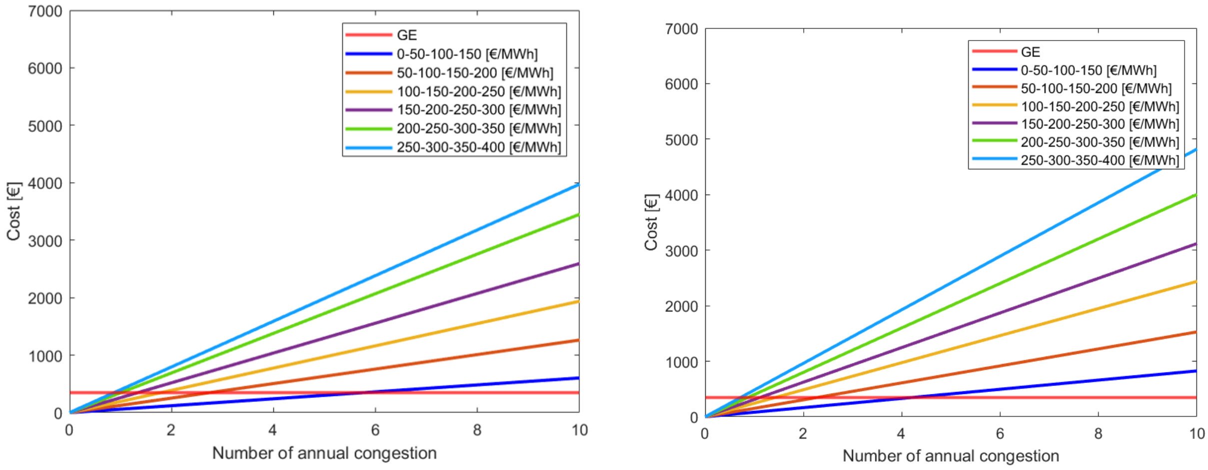


Figure 6.20: increasing number of congestions for case 1A.1 (left) and case 1B.1 (right)

In Case 2 the reference GE is the one of re-configuration 2A.1, being the cheapest, as shown in Figure 6.21. It is quite straightforward to see that in all the simulations conducted, the DR with both reconfiguration is the most convenient solution. The potential gain for the DR solution with re-configuration 2A.1 is higher than the one of 2A.1. Thus, the former is the suggested solution to pursue. With one congestion the savings are up to 97% of the GE expenses with re-configuration 2A.1 and 96% with re-configuration 2B.1.

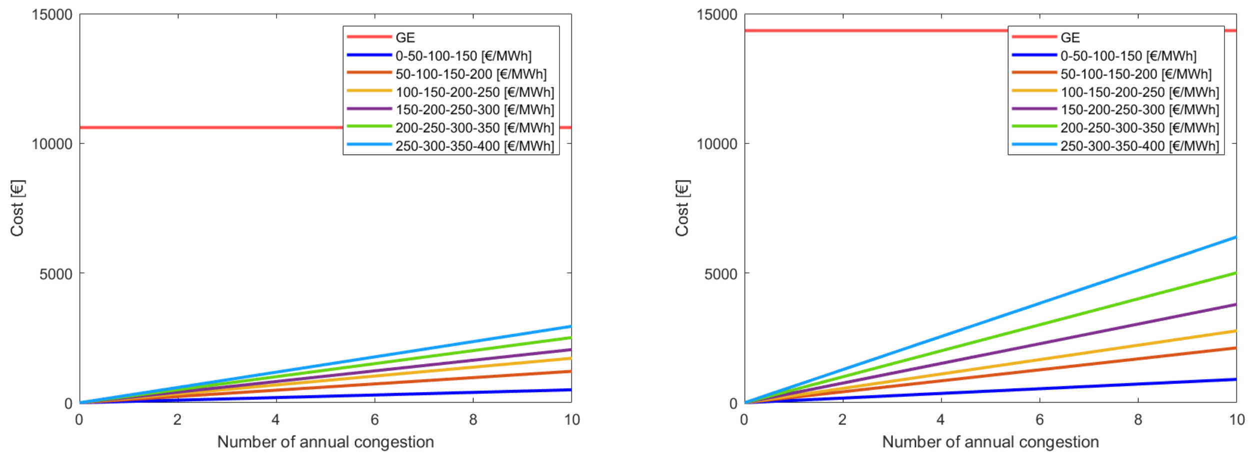


Figure 6.21: increasing number of congestions for case 2A.1 (left) and case 2B.1 (right)

In Case 3 the reference GE is the one of case 3B.1, being much cheaper than case 3A.1. The results are depicted in Figure 6.22. This case is very similar to Case 1. The DR solutions can be cheaper than the GR, but it strongly depends on the number of congestions and price of the offers. Thus, the choice is up to the DSO and its risk profile. It the DSO wants to proceed with a more conservative approach the GE solution with reconfiguration 3B.1 might be the more suitable solution. With one congestion the savings are up to 92% of the GE expenses with re-configuration 3A.1 and 90% with re-configuration 3B.1.

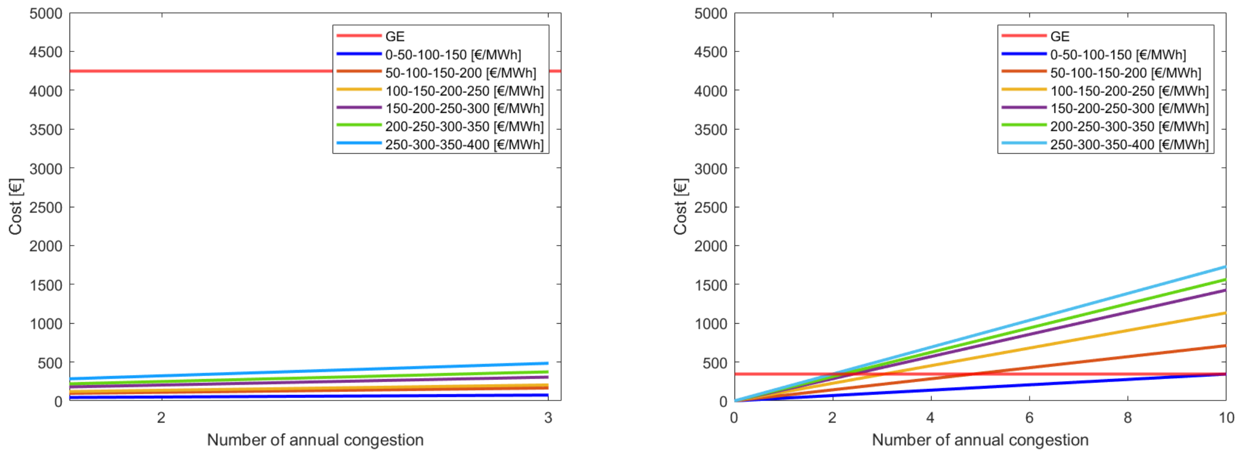


Figure 6.22: increasing number of congestions for case 3A.1 (left) and case 3B.1 (right)

In case 4there is only one possible re-configuration, so there is not the need to choose a GE as the reference case. The results are depicted in Figure 6.23. It is possible to see that in all the simulations the DR is cheaper than the GE. Since the GE solution in this case very high, due to the high number of cables congested, the potential economic gain by pursuing the DR solution are the highest with respect to all other cases. With one congestion the savings are up to 95% of the GE expenses.

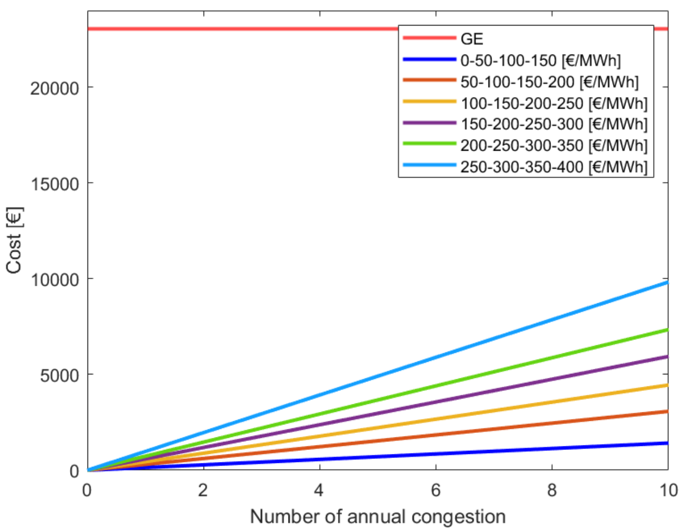


Figure 6.23: increasing number of congestions for case 4.1

6.6. Key findings

In this section, 5 different indicators have been proposed in order to compare the DR and GE solutions when a fault is present in the grid and a re-configuration needs to be done in order to counterfeed the loads. Two major issues emerged. The first is that, given a congestion, the cost of the DR is strongly linked to the ranges in which the offers are bided by the active resources. Thus, different simulations with different ranges have been done in order to cover different cases. Statistical instruments like the mean, average and the quantiles have been used in order to unify the different simulations for each case. The second major issue is that with the available data it is not possible to estimate quantitatively the frequency of the fault. Thus, different hypotheses need to be done, which can be more or less conservative. Since the GE is the conventional solution, there needs to be a certain arbitrary margin that makes the DSO want to pursue a different and innovative solution. Otherwise, business-as-usual with the conventional grid planning is more likely to be chosen. It has to be underlined that the solutions are not strictly mutually exclusive: the DR can also be used as a tool to postpone the network expansion, or as a way to not mine the grid safety and increase the resilience when an unexpected fault shows up. The fact that to implement a DR scheme require much less investments that the GE, and that the DR can be applied almost at real time when the flexibility is needed are important factors that favors this solution. In particular, in this section 4 different cases are analyzed: there are the faults more upstream possible in each line, thus representing the worst situation in terms of formation of congestions in the branches. Each case has its own peculiarity and the indicators shown before are here summarized.

- Case 1: in case 1A.1 the GE solutions costs only 349 €/year, since only one cable needs to be substituted and it is shorter than the average. As indicator I shows, there are many hours in which the DR solution already overcomes the price of the GE. In case 2A.1 the DR hourly costs are similar, but the GE is much more expensive (6510 €/year, almost twenty times more) since 6 different cables need to be substituted. Indicator I also shows that the formation of a congestion when there is a fault in the grid is not a remote event, being the probability respectively 17% and 9% for the two sub-cases. Indicator II confirms this trend. The average hourly cost along the year can overcome the GE costs in case 1A.1, but it is fairly distant in case 1B.1, assuming one average congestion of one hour per year. With Indicator III this assumption is relaxed, and the cost is calculated not for the congestion in a single hour, but assuming that it lasts until the demand spontaneously decrease. Then the same operation of Indicator I is conducted, leading to much higher average prices. Thus, the trend is confirmed: in case 1A.1 the GE is more convenient, in case 1B.1 is not. With indicator IV a simulation of the worst congestion in terms of loading degree is done, in order to see the costs of the DR solution in the conditions that make the price the highest. For case 1A.1 the cost is almost always higher than the GE. In case 1B.1 the DR gets higher only for at least 10 congestions, which is improbable to happen. In Indicator V two different operations are conducted. Firstly, using the average yearly cost as the starting point, it is calculated the price of up to 10 annual congestions. And secondly, the comparison is done not only within the same sub-case but taking the lowest GE cost among the different sub-cases as the reference point. The costs of the two different DR solutions are not very distant from each other, but there are many situations in which they overcome the cost of the GE. In this case it is probably better to stick with the conventional GE, applied to re-configuration 1A.1, and thus reinforcing the conductor in the branch between the node 30140 and the substation Flavia.

- Case 2: case 2A.1 and 2B.1 are quite similar in term of cost of the DR solutions. the re-configuration 2A.1 needs 4 cables to be reinforced leading to a GE of 10597.36 €/year, almost 30% less than the 14348.95 €/year needed for re-configuration in case 2B.1, since there are 3 more cables to substitute. Indicator I shows that considering the single hour congestions in both cases the cost of the DR solution is much smaller than the respective GE, also leaving a high margin. Indicator I also shows that the formation of a congestion when the fault is present is possible, even if rare with a probability respectively of 8% and 7% for the two sub-cases Indicator II confirms the trend, since the average annual prices never intercepts the line representing the annual cost for the GE, also when the prices of the bids are set at the maximum. In the Indicator III for the first time, it is simulated a scenario in which the case 2A.1 leads to a higher price for the DR solution, which still has a 97% probability of being more convenient than the GE, depending on when the fault happens. For case 2B.1 the DR is still more convenient for all the congestions event, being the annual GE cost quite high. Indicator IV simulating the worst-case scenario shows almost an absolute convenience for both the DR solutions, excluding the very most unlucky cases. Finally, indicator V gives the almost certainty that both the solution are cheaper even than the reference GE, leaving a high margin even with an average of 10 yearly congestions. Furthermore, the indicator III, IV and V together shows that the DR solution applied to the re-configuration 2A.1 is the cheapest. In this case then, this is the solution that the DSO should pursue.

- Case 3: this case is similar to Case 1, since the two re-configurations lead to very different prices for the GE solution. In case 3A.1 4 branches are congested, leading to a price of 4244.40 €/year. In case 3A.1 only 1 branch is congested, thus leading to the annual price of 349.50 €. This case is peculiar because of the very low number of hours which can be congested, 3 and 28 respectively, which means that the formation of a congestion is very unlikely, since the fault should synchronize with the high demand load curve, as it is shown by the probabilities of Indicator I. Regarding the hourly cost, in case 3A.1 the DR solution is always convenient, whereas in case 3B.1 there is an overlapping in the costs when the highest price ranges are set. Indicator III shows that for both cases the average hourly cost of the DR is lower than the GE, even though in the second case there is a very little margin. As for Indicator IV the trend is confirmed for case 3A.1, for which the DR solutions remains more convenient even for all the possible congestions summed. The same is not true for case 3B.1: there is the certainty of convenience for the DR solution only considering the worst case, leaving a risk of incurring in an economic loss if more congestions happen in the high demand peaks. Indicator V, in which both DR solutions are compared with the same GE, confirms this trend. In fact, the cost for the DR in case 3A.1, overcome the cost of GE when all 3 congestions appear, and the highest bids are offered. Thus, in case 3 the indicators do now all lead to the same conclusion. The probability of actually incurring in a congestion are extremely low, but if it happens the DR might not be the optimal solution. This, and the fact that the GE solution is cheap and practical considering than only 1 branch needs to be reinforced, may lead the DSO to pursue the conventional solution.

- Case 4: in case 4 only one re-configuration is possible. The peculiarity of this case is that there is the highest probability of a fault leading to a congestion, the highest number of branches that should be reinforced and consequently the highest cost for the GE solution, which is 23048.564 €/year. Indicator I shows that the hourly cost of the DR solution is always lower than the GE one, with a substantial margin. This trend is also confirmed by Indicator II, the average price of the DR is always lower. Indicator III gives different results, since in 10% of the cases the GE is more convenient, if the congestion lasts for many hours. The probability of happening are still a low, but in the unluckiest cases the cost for the single congestion event can double the annual price of the GE solution. Indicator IV, as the III, does not give clear results, since in different conditions the DR solution could lead both to an important economic gain or loss. In more than half of the cases it leads to a gain though. Finally, Indicator V shows that on average even 10 different congestions, even with the highest price ranges, are solved in a more economical way through the DR rather than the GE. Thus, as in Case 3 it is difficult to understand clearly which is the most convenient solution. The big difference is that in case 4 the initial investment is relevant, being the total for the construction work 720.000 €. Hence, in this case it might initially be more convenient to rely on the DR solution, to defer the start of the construction, and consequently the investment.

7 Results of the simulations: flexible resources utilization

In this chapter the analysis is done on the resources which are able to give flexibility through DR, firstly starting from the cases in chapter 5.1 as a reference, and then doing the comparison with the cases described in chapter 5.2, moving the position of the fault downstream for each reference case. It is important to do a preliminary analysis on the possible flexible resources, to understand how the distribution of probability of being activated for each resource for each case is. In fact, if a resource has a much higher probability of being used by the DSO to solve the congestion, it will be more enticed to participate in the DR scheme, having a high probability of being remunerated energy-wise. This preliminary analysis is also important to help the DSO design its tariff structure. In fact, in chapter 6.1 only the price of the offers in term of energy have been analyzed. As seen in chapter 2.1.1, also the power availability of the flexible resources could be remunerated. The DSO could pursue different strategies. Since the amount of money for the energy remuneration is not fixed and forecastable in an accurate way, as demonstrated in the previous chapter, it could indirectly influence also the capacity part of the remuneration. In fact, the loads which are less likely to intervene to solve the congestion could be less prone to participate in the DR scheme since their probability of being remunerated is lower than other loads. Thus, the DSO could incentivize them by offering a higher price in term of €/MW. On the other hand, the price offered to loads which are more probable to intervene cannot be much lower, because if they do not participate in the DR the DSO risks to lose important resources and liquidity in its local market. The DSO could offer a fixed capacity price for all the resources, and an extra remuneration component at the end of each year, or at the end of a multi-year time lapse. In fact, as shown in the previous chapter, depending on if, where and when the fault(s) in the grid happens, the DSO can make huge potential savings with respect to the traditional GE solution. A part of this savings could be re-distributed among the resources which have given their availability, but have not been selected in the reference period, in order to incentive them to keep participating in the program.

It is important for the understanding of the chapter to remember how the DR algorithm works and how the flexible resources are chosen. When a congestion is detected, the flexibility can be activated only by the loads which respect two main conditions. They share the same path to the primary sub-station with the congestion and are downstream to it with respect to the sub-station. Thus, given the position of the congestion in the grid, different situation are possible. There might be only a sub-set of resources that can be activated among the ones located on the line, and the more the congestion is downstream in the line, the more the sub-set is reduced, since all the loads upstream cannot be helpful in solving the congestion. The opposite situation occur when the congestion is upstream, close to the primary sub-station: potentially all the loads present on the given line could reduce their active power and solve the congestion. When this latter situation occurs, the only discriminating factor for the DSO to choose between the offers, is the price.

In this chapter the objective is to quantify which is the probability for each resource to be activated along the year for each congested hour. However, the approach of chapter 6.1 cannot work. In chapter 6.1 in fact different simulations have been done changing each time the value of the price of the offer, because the focus of study was the total final (or average) cost in one year, and not how this cost was distributed among the different resources. The approach cannot be replied in this chapter, because when two or more resources are suitable to be selected since they meet the 2 criteria aforementioned, only the one with the lowest specific cost is chosen by the algorithm (and hence by the DSO). Thus, the simulation would not give any indication about the different probability of each resource to be activated, since it only depends on the price which is randomly generated before the simulation starts. What can be done, is to count in how many occasions each resource have the two necessary conditions aforementioned to have its flexibility activated. The probability of the resource to be activated along one year is proportional to the count. Thus, each flexible resource can potentially be activated a number of times between 0 and the total number of congestions that can happen in one year (second column of Table 5.9). Depending on the amount of active power that needs to be reduced, it is theoretically possible that all the resources that are suitable are activated.

For example, considering a simplified grid as in Figure 7.1:

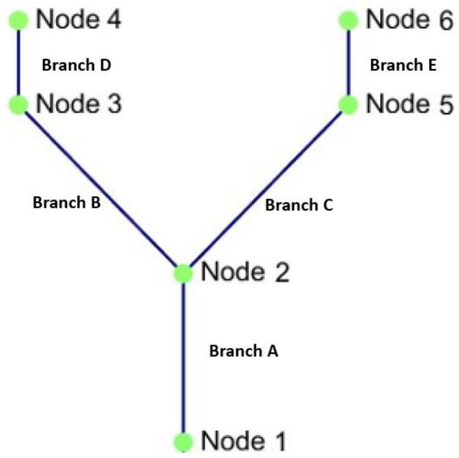


Figure 7.1: example grid with different loads

- If there is a fault on branch A, all the loads can potentially activate the DR. In fact, they all are downstream the congestion. If they offer different prices, the cheapest one would be activated. Then, if the congestion is still present, the second cheapest one would be activated and so on. It would be possible to do different simulations with different offers also in term of percentage of reduction, but this would influence the results too much, similarly to the costs. Thus, in this case all the loads would be counted as potentially activable.
- If there is a fault on branch B, only the loads on node 3 and 4 could be activated, and not the loads on node 5 and 6. Thus, in this case only the loads on node 3 and 4 would be counted as potentially activable. The same reasoning as before can be done, since both the loads on node 3, or 4, or both could be activated, but this would only depend on the result of random assignation of prices and percentage of reducible power. However, the aim of chapter is to assess which are the most probable resources to be selected only based on the grid topology, the branches carrying capacity, and the demand along the year. Of course, the same reasoning could be done similarly if the congestion was present on branch C.
- If there is a congestion on branch D, only the loads on node 4 would be counted as potentially activable. Analogously, if there is a congestion on branch E, only the loads on node 6 would be counted.

In the following pages, for each case the count will be done, in order to assess how the results change when the fault changes position along the line.

In the graphs of this section, in the x-axis, each load is reported with its load ID and they are plotted from the most upstream (on the left) to the most downstream (on the right). Since in many cases there are sub-paths, to maintain the graphic representation of increasing distance from the substation, the graph is split on the sub-paths.

Then, it is possible to calculate the percentages of congestions that each load could potentially calculated as in (7.1).

$$Percentage_{solvable\ congestions,load\ i} = \frac{Congestion\ solvable_{load\ i}}{Total\ number\ of\ congestions\ along\ the\ year} \qquad (7.1)$$

The y-axis represent the average of the percentage for each load, calculated along all the sub-cases.

The count of congestions solvable for each load and case is reported in the Appendix.

7.1. Case 1

In Figure 7.2 is possible to see precisely where the position of the fault is simulated for each case, and the position of all the loads involved for all the configurations of Case 1.

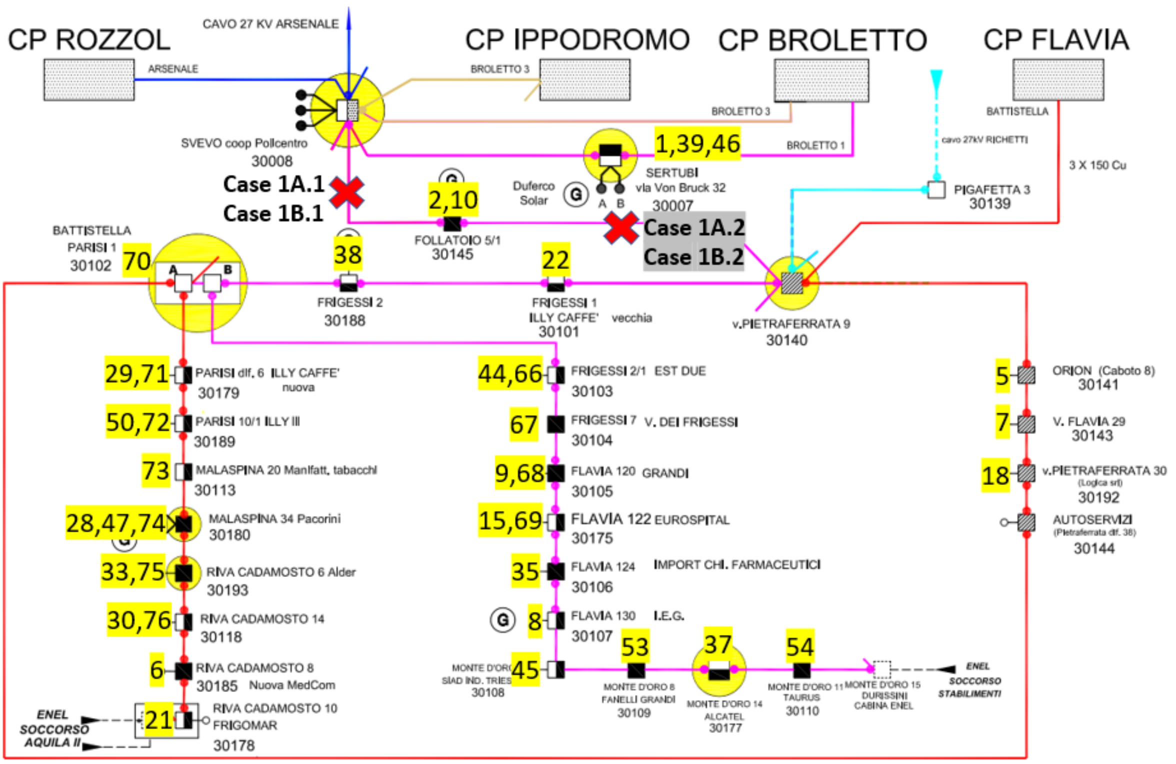


Figure 7.2: different position of the faults in Case 1

Case 1A.1

In this case there is only one congested line, and it is located before the crossroads on node 30140, where three different paths diverge (30140-30145, 30140-30110, 30140-30178). This case is quite straightforward to analyze, since all the loads meet the two necessary conditions in order for their flexibility to be activated. In fact, they all are downstream the congestion, which is upstream the crossroad (on branch 30140-Flavia). Thus, all loads have the same probability to be chosen. The flexibility activated depends only on the price offered.

Case 1A.2

This case is conceptually identical to the previous, from the point of view of the loads' availability in providing flexibility. The only difference is that in this case the loads 2 and 10 are excluded, because they are now being served by substation Broletto, and not Flavia, in this scenario, since the fault is downstream with respect to them.

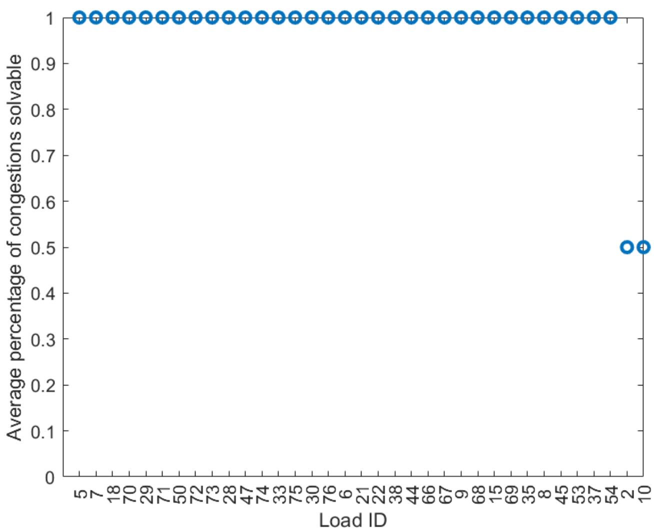


Figure 7.3: probability of activation of case 1A

Since the results in this care are very homogenous, all the three paths have plotted on the same graph, shown in Figure 7.3. Given the particular topology of this re-configuration, almost all the loads have the same probability of being chosen to offer the flexibility service. The only exception is load 2 and 10, which have their probability halved by the fact that in the re-configuration 1A.2 they are not able to provide a service useful to solve the congestion.

Case 1B.1

In this case the differences in the results involve just the loads upstream to the crossroad point, in node 30102. This case is more heterogenous than the previous, since there are loads both upstream and downstream the congested branches. The loads involved (loads 5, 7 and 10) are the one with the lowest probability of being activated, whereas the others share the same results.

Case 1B.2

In this case in it is more appropriate to analyze separately the two paths, since the results are strongly dependent on which path the load is located. In fact, only the congested branch between the node 30102 and substation Flavia is common to both paths. Regarding the path that goes from node 30102 to node 30110, the situation is very similar to case 1A.1, since all the loads are downstream the congestion, and hence all of them are potentially eligible to be selected to provide the flexibility service. Regarding the path that goes from node 30140 to node 30102, the situation is more similar to case 1B.1. In fact, loads 5, 7 and 18 are on the congested branches and thus they can offer the service limitedly to the congestion upstream to their location.

In this case it is possible to notice two separate trends for the two different paths. In the picture on the left in Figure 7.4 it is possible to see an increasing trend, which then stabilizes since all the loads become downstream to the congestion. In the picture on the right in Figure 7.4, there is only the flat part of curve, since all the loads present in the path are not directly linked to the congested branches.

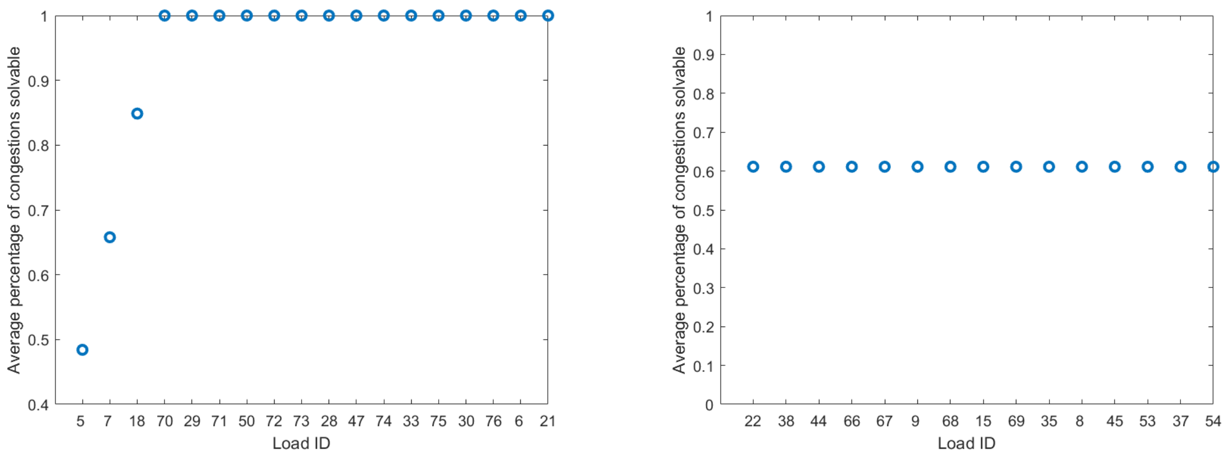


Figure 7.4: probability of activation of case 1B

7.2. Case 2

In Figure 7.5 it is possible to see precisely where the position of the fault is simulated for each case, and the position of all the loads involved for all the configurations of Case 2.

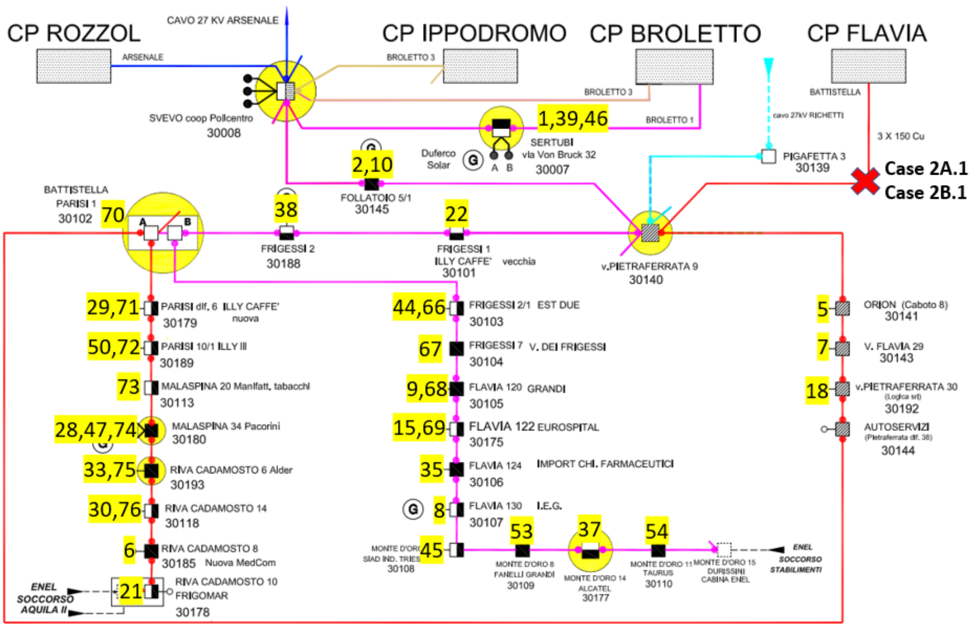


Figure 7.5: different position of the fault in Case 2

Case 2A.1
In this case the congestions are both in the common path upstream to the crossroad node (node 30140) and downstream. Thus, it is appropriate to analyze the two paths in a separate way, as it has been done for the previous case. In this case the trends on both paths are the same as case 1B.1, even though with different values, as it is possible to see in Figure 7.6. There is an increasing trend for the loads that are located in the middle of branches which are congested, and then a stabilization when all the loads happen to be all downstream than the congestions.

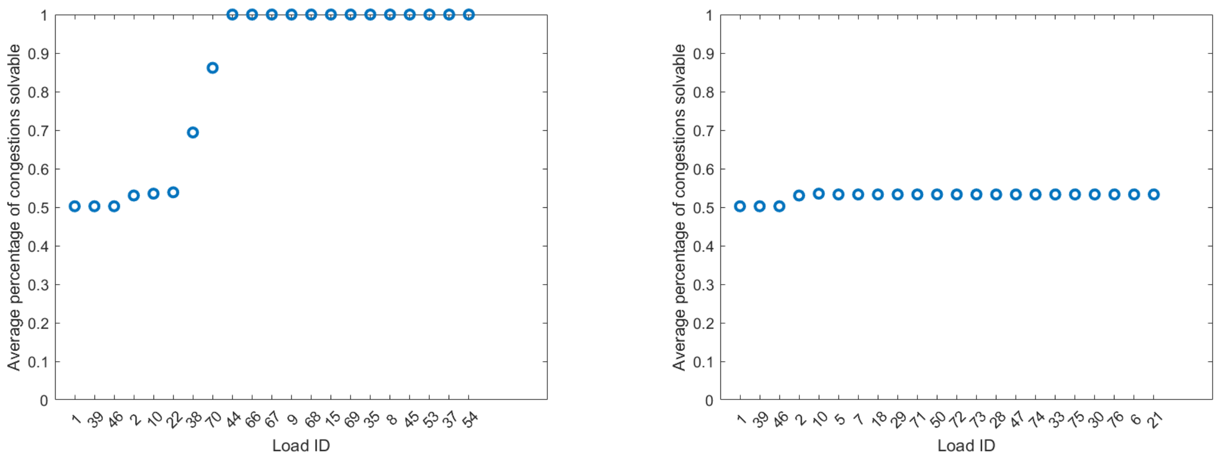


Figure 7.6: probability of activation of case 2A

Case 2B.1

In this case there is a common path until node 30102, and then a division in three different sub-paths: 30102-30178, 30102-30141, 30102-30110, which are represented from left to right in Figure 7.7. As expected, the congestions are all present on the common path, since all the power flowing to the three sub-paths need to flow through there. Thus, there will be a different behavior of the resource on the common path, and a common behavior for all the three sub paths. The results confirm the trend expected, similarly to the previous cases.

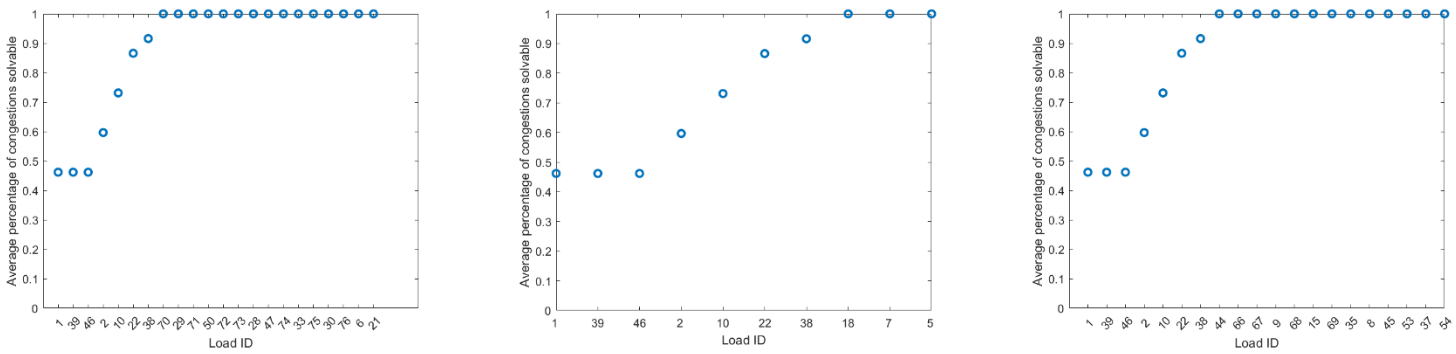


Figure 7.7: probability of activation of case 2B

7.3. Case 3

In Figure 7.8 it is possible to see precisely where the position of the fault is simulated for each case, and the position of all the loads involved for all the configurations of Case 3.

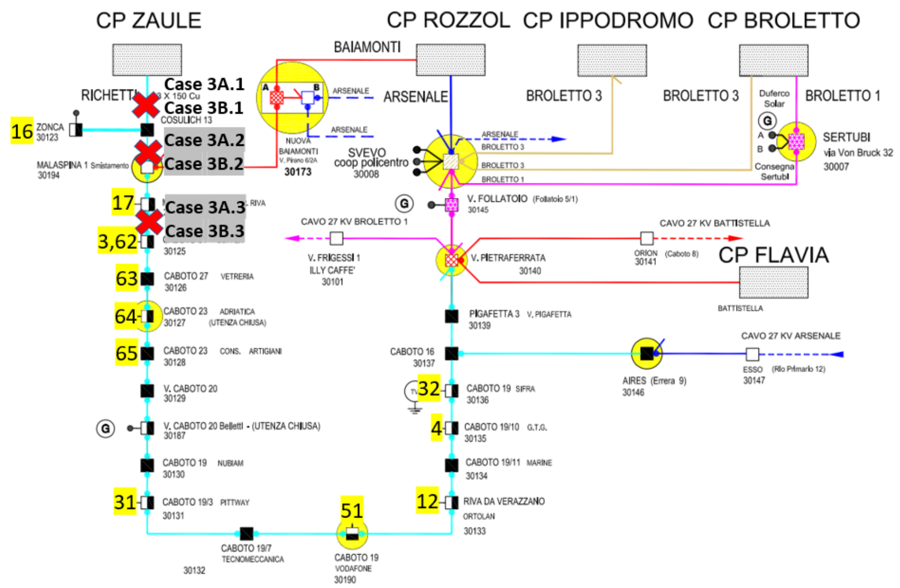


Figure 7.8: different position of the fault in Case 3

Cases 3A

In this case there is only a single path, since no crossroads are present, thus all the three sub-cases are represented on the same graph, shown in Figure 7.9. The congestions are present, as always, in the most upstream branches. In this case the counter-feeding is done in a way that flips completely the order of the loads. The ones that were the most upstream, closest to substation Zaule, are in the re-configuration the ones that are the most downstream, the furthest from substation Rozzol.

In this case two things can be noticed. The first one is that the same trend shown in the other cases is confirmed. In fact, there maximum solvable congestions are increasing the more the load is downstream, until a plateau is reached when all the resources are downstream to the congestion. The second thing is that in this case even the number of available resources changes, when the fault changes its position. In fact, in case 3A.2 the load 16 is still served by the original sub-station Rozzol, and therefore is not able to provide flexibility services. The same thing happens also to load 17 in re-configuration 3A.3. This trend would potentially go on, if it were not for the fact that if the fault is simulated even more downstream, with respect to sub-station Rozzol, than case 3A.3 no congestions are present in the grid.

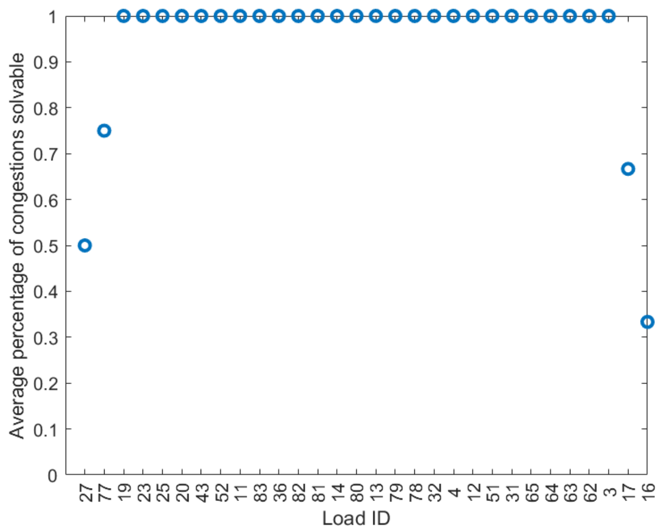


Figure 7.9: probability of activation of case 3A

The average percentages of congestions solvable in shows a different trend between the previous cases, in which the maximum values were reached for loads at the very beginning or end of line. In this case in fact the maximum values are reached in the middle. This is due to the fact that the closest loads to the substation in the re-configuration cannot solve the congestion downstream their location, as seen already. On the other hand, the furthest loads, depending on the position of the fault, could not even be part of the counter-feeding, and still be served by the original substation of

Rozzol. But given that the fault could separate the two lines, these loads are excluded from the possibility of providing flexibility to solve the congestions close to the sub-station Rozzol.

Cases 3B

In this case two different paths originates in node 30140: 30140-30185 and 30140-30122. In both paths, all the loads are downstream to the congested branch. Regarding the path that start from node 30140 and continues towards 30122, it is conceptually identical to the previous case, with the only difference that the re-configuration is done by another sub-station, and the numbers of the congestions are different. Only the most downstream loads do not meet the conditions to be available to offer the flexibility service (load 16 in case 3B.2 and loads 16, 17 in case 3B.3). This is shown on Figure 7.10 (left). Regarding the path that start from node 30140 and continues towards the node 30185, the distribution of resources for all the 3 cases is the same. In fact, no loads are present in congested branch, and the different position of the fault do not influence the loads in no way. Thus, also the average percentage of congestions solvable is 1 for all the loads). This is shown on Figure 7.10 (right).

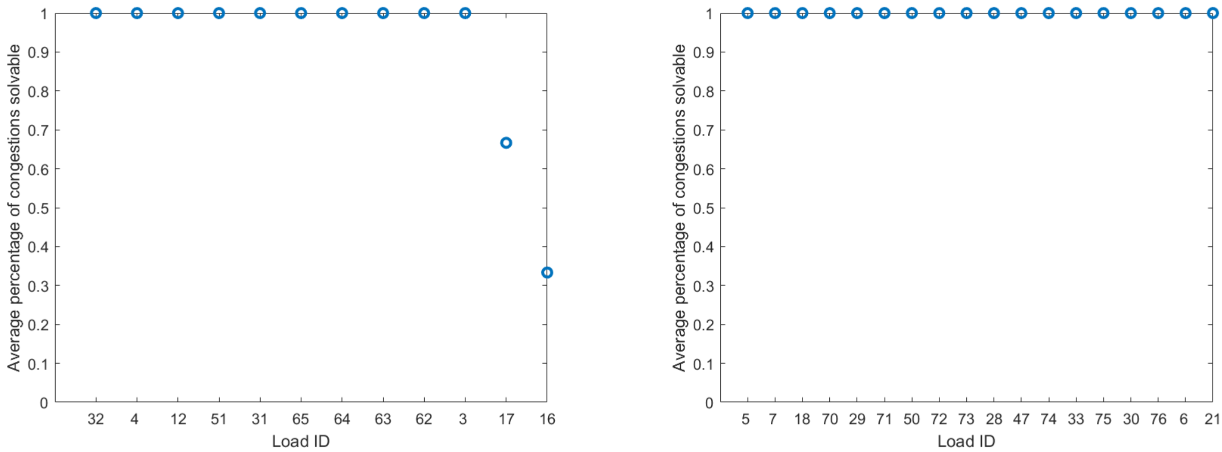


Figure 7.10: probability of activation of case 3B

This case is similar to the previous one, since the furthest loads from the counter-feeding (17,16) have the lowest percentages of congestion solvable. Contrarily, in the graph there is not any upward trend since all the congestions are downstream to the only congested branch.

7.4. Case 4

In Figure 7.11 it is possible to see precisely where the position of the fault is simulated for each case, and the position of all the loads involved for all the configurations of Case 4.

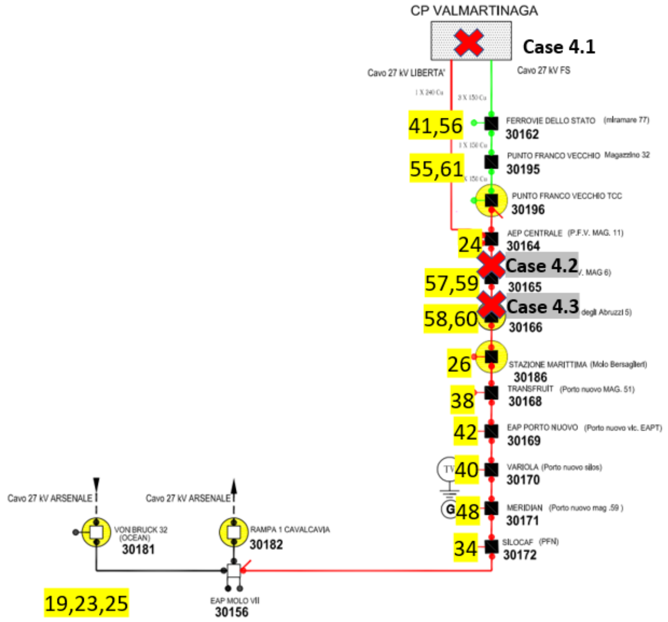


Figure 7.11: different position of the fault in Case 4

Case 4.1

In this case it is possible to see that the line separate in two different paths at node 30156 (30156-30147 and 30156-30162), and the congestions are only present in the second of the two paths. Thus, it is expected that the loads present on the congested path will have more potential activations, since they are the only ones influencing the congestions themselves. In particular, the most downstream load on such path, will potentially be able to intervene to any single congestion which may happen. In fact, the flexible resources on this path are technically able to solve both the congestion upstream and downstream the crossroad point (node 30156). Instead, the opposite is not true for path 30156-30147, since the resources can only solve the congestions upstream node 30156. This is also the reason why all the resources downstream to load 20 have the same possibility of being used. On the other hand, on the congested path the probability raises going more downstream, since for each branch there are less resources potentially capable of reducing the congestion. The extreme case are loads 41-56 and 27. The former can potentially be activated to solve each congestion, since the power and the current that they demand need to flow through all the congested branches. The latter has the lowest probability of being activated since it is downstream of just 3 branches, out of 14 which can incur in a congestion.

Case 4.2
In this case, contrarily to the previous one, the congestions can be present only before the crossroad at node 30156. This happens since in this case the substation Valmartinaga is able to loads 41, 56, 55 and 61, which were previously served by substation Rozzol. In this way also the congestions between the crossroad and the fault are not present, since the four loads aforementioned have all a nominal power above the average of the line (in particular load 41 is the one with the highest).

In this case the results are more homogeneous than in the previous case. Since the congestions are all potentially formed before the crossroad, there is no need to represent the two paths in two different figures. In fact, all the loads except for 27, 77, 19, 23 and 25 are technically able to intervene to all congestions which might occur along the year. As before, the most upstream loads, which are the closest to the substation, have the lowest count since there are congestions also downstream to them.

Case 4.3
This case is conceptually very similar to the previous one. In fact, the congestions are formed in the same branches. The only difference is on the number of hours along the year in which they could happen (and also the amplitude of the congestion, but it is out of the scope of this chapter). With respect to the previous case, there are 2 less loads that need to be counterfed. Also, the distribution of the possible congestion solvable is very similar to the previous case. Of course, what changes is the relative percentage of the congestions solvable by each load with respect to the maximum number of congestions that can be present in one year. This is due to the fact that, even if there are less congestions, there are fewer loads, and thus flexible resources, which can bid and offer the service with respect to the previous case.

As Figure 7.12 shows, the two paths follow the same trend in the first part, with an increase in the percentages and then a plateau. In the first case though, the percentage decreases when the fault moves, since the loads closer to the Valmartinaga station are served by the original substation and do not need to be counterfed, and thus cannot provide the flexibility.

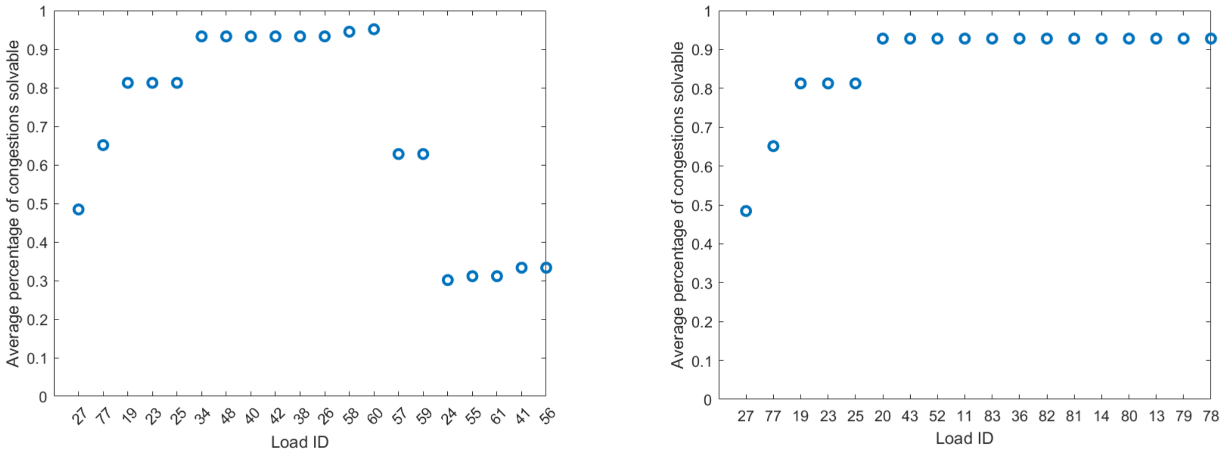


Figure 7.12: probability of activation of case 4

7.5. Key findings

The aim of this chapter was to investigate the different situations caused by the presence of a fault in different part of the line. Depending on its position on the line, and on the type of re-configuration used, each load has a different probability of being able to be selected for its flexibility service. Said so, the results do not show a great variability. This is due to the fact that most of the congestions are only in the very first branch in the line, close to the substation which is counter-feeding the entire line. Thus, all the loads that are located downstream the congested branch, even if there are crossroads, often meet the technical constraints to be able to alleviate the congestion with the DR. Furthermore, it is possible to identify three macro-trends in the results just shown.

The first one is the one of Case 1A and Case 3B. In both the cases, the shape of the percentage of availability in function of the distance from the counter-feeding substation is a non-decreasing curve. This is due to the fact that all the loads are downstream to the congested branch and have the same the availability for solving the congestions, thus shaping the first part of the curve as a plateau. The decreasing part of the curve is due to the fact that when the fault moves, the loads which were the furthest from the counterfeeding substation, can be fed by the original sub-station. Since their availability goes down to zero in all this cases, the average percentage of solvable congestions also decreased.

The second possible trend is the one of case 1B, and case 4 (only the non-congested path). In this case, there is firstly an increasing curve, and then a plateau. The increasing part is due to the fact that the first few branches in the line, starting from the counter-feeding substation, are congested. Thus, for all the loads located in these branches, the availability of offering flexibility services increase with the distance, since the more downstream the load is, the more congested branches are present upstream to the load itself. Then the plateau is reached for all the loads located downstream to the last congested branch. In this case the plateau does not finish, since due to the grid topology, the furthest loads are not connected to any other substation.

The third trend is the one of cases 3A and 4 (only the congested path), which substantially is the merger of the two previous cases. In this case the shape of the curve is hence a parabola with the concavity pointing downwards. In this case all the conditions described before are met. Starting from the substation, there is a series of branches in which the congestions are located (increasing part of the curve). Then there is a series of loads which are load located downstream to the last congested branch, with the highest potential availability (plateau). And finally, there are some loads which can be fed by their original substations when the fault is moved, which thus are not available in the aforementioned cases (decreasing part of the curve).

As said before, studying the probability of each case to being selected for the flexibility and the number of hours in which a load is technically able to offer the service, is useful in setting up the eventual part of the tariff based on the capacity. In fact, by not paying the availability for the loads which have the lowest probability of being useful in providing services to the grid the DSO would lower its cost. In the literature it was seen that DR schemes can have or not have a fixed remuneration based on the capacity made available. In the previous analyses in chapter 6 and 7 the tariff part has always been set to 0 €/MW, to investigate and isolate the effect of the bids prices on the final result. In this final part, the fixed remuneration will be investigated. The quantification of this part of the tariff should be a trade-off between two extremes. The first one is that if the remuneration is too low the risk is not having enough participants in the DR, a low liquidity and an insufficient number of flexible resources to solve the congestions. On the other hand, the verification of a fault leading to a congestion is still a rare event, and in most cases, it is not needed the intervention of all the possible resources. Thus, a lot of money would be invested in a capacity availability which is never requested. Furthermore, a load could already be participating in an UVAM project, and be already remunerated by the TSO. This is also another reason why the collaboration and communication between the TSO and DSO should be enhanced and improved. If the capacity was remunerated using the average of the two last procurement procedures of the UVAM project, which is about 28000 €/MW for the evening product [67] [68], the total amount of investment done by the DSO to remunerate only the capacity would already be higher than the cost of all the identified grid extensions altogether. Since the DR could provide a huge savings for the DSO in term of annual expenses, this could be the source of liquidity to remunerate the capacity, since the less the DR is used during the year the less energy needs to be remunerated. The only issue is that, as it was highlighted in chapter 6, this cannot be done a priori, but only at the end of the year. The DSO could redistribute a part of the money saved, calculated as the difference between the avoid annual expense for the grid extension and the money actually spent for the DR, to all the resources which participated in the project. In this way the participation would be enhanced, the resources could increase their earning and the DSO would spend less money with respect to the conventional solution.

To quantify the remuneration for the availability of the capacity, it is possible to use the results from chapter 6.5, in which the average DR price has been calculated for various price ranges and number of yearly congestions. For each number of yearly congestions, an average between the different price ranges is done to merge the sub-cases. The difference between the cost of the GE and the cost simulated for the DR for each case is the yearly potential savings of the DSO. As said, a part of this avoided expense could be use at the end of the year to remunerate all the resources that offered their flexibility, even though their offers have not been accepted or if any congestion has happened. Different percentages of the money saved are assumed to be redistributed. The final remuneration expressed in €/MW is calculated dividing the money to be redistributed by the total capacity made available, assuming that all the resources present in the grid agree to participate in the project. This value is calculated as the 35%, since this is the maximum value biddable, of the sum of the active power of all loads. The result is 24.14 MW if all loads are considered. As said before, the DSO could decide to exclude the loads who are less likely to be selected to offer the flexibility. If this would be the case, the capacity remuneration for the other loads would hence increase. In Figure 7.13 the results have been depicted for Case 2 and Case 4, the two cases in which the DR gave the most promising results, as seen in chapter 6.

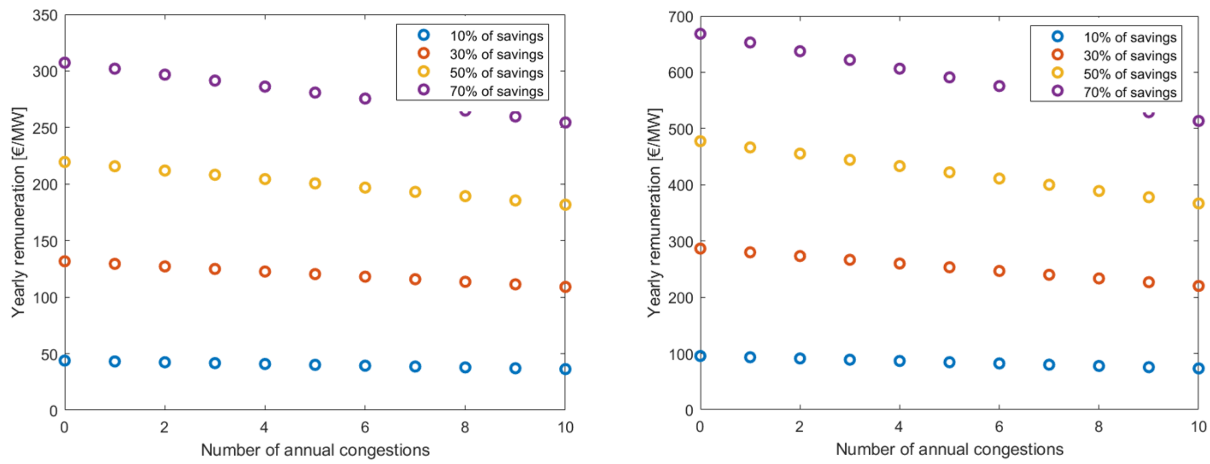


Figure 7.13: Capacity remuneration for Case 2 (left) and Case 4 (right)

The first thing to be noticed is that the value of the remuneration is much lower than the one of the UVAM pilot projects. This is due to the fact that the annual budget is intrinsically limited by the annual expense needed for the cable construction. Even if theoretically all the money saved would be redistributed by the DSO and there were no congestions in one year, the maximum amount reachable would be 441 €/MW in Case 2 and 960.33 €/MW in Case 4. Increasing furtherly the remuneration beyond these thresholds would not make any sense, since the DR would be at the point more expensive than the GE.

Conclusion and future developments

Renewable energy sources (RES) that rely on wind and solar photovoltaic energy are becoming more important in the process of moving towards a decarbonized energy system. The latter in fact formerly depended on massive, centralized power plants. The recent emergence of dispersed, small or medium-sized, and variable sources capable of injecting electricity in a bidirectional power flow grid is posing several new obstacles. Furthermore, behind-the-meter energy sources are getting more and common, called distributed energy resources (DER). Energy demand is also experiencing many changes as a result of the electrification of new uses, particularly in the field of mobility with the development of electric vehicles (EV), as well as in the residential and industrial sectors. These changes are occurring simultaneously to the supply-related challenges mentioned above. To improve the electricity system's capacity to handle these difficulties, flexibility development is essential. The International Energy Agency (IEA) defines flexibility as a power system's capacity to safely and economically handle demand and supply variability and uncertainty over different time scales, to guarantee immediate system stability and to promote long-term supply security. The DSOs are actively called to emerge into a more active role to procure the necessary resources for the flexibility in distribution grids.

A specific way through which flexibility resources can be found is called demand response: it is measure for reducing energy load in response to supply limitations, typically during periods of peak demand. Demand response is a potential tool for congestions management. The grid incurs in a congestion when the current (or apparent power) flowing through a branch to meet demand exceeds the branch's maximum carrying capacity. It is a responsibility of the DSO to prevent and resolve congestions. The traditional solution to do so is by enhancing the redundancy of the distribution grid through grid extension (GE) initiatives. The aim of the thesis work was to verify the technical feasibility of DR to solve congestions in the distributions grid, simulating different scenarios using both fictitious and real data and comparing the economic costs of the two solutions in order to identify the most convenient for the DSO to pursue.

The two solutions have been analyzed and three main conceptual differences emerged. The first one is the time frame of applicability. The DR scheme is built to be operated very close to the real time, when a congestion is being detected on the grid or has just been forecasted to show up in the near future. On the other hand, the GE solution is based on forecasts of the evolution of the electricity demand and supply profiles. In fact, in order to be executed, important construction works needs to be done, which must be planned and projected years priorly to the possible formation of the congestion. The second main difference is the fact that the DR solution is intrinsically limited by the active participation of the loads, and by the amount of active power that they are willing to reduce. The GE solution instead is theoretically always effective, since the DSO can arbitrarily increase the capacity of the grid.

The other operative difference relies in the cost structure of the solutions. The DR has none or very little CAPEX, and a variable amount of OPEX. The latter is not rigorously predictable since it depends on the frequency of activation of the flexibility. Symmetrically, the GE solution has a very high and fixed CAPEX, but none or very little OPEX, which are mainly related to the cost of the faults repair.

The chosen model to implement the DR scheme is a local ancillary services market in which the active loads can offer a standardize product and the counterpart, the DSO, can select the bids starting from the cheapest until the congestion is solved. The yearly cost of the DR solutions needs to be compared with the yearly cost of the GE, considering the useful life of the cables.

The distribution grid of Trieste has been modeled, using real data about the topology and real energy profiles as the input, limiting to users connected at the medium voltage level. The electrical results have been calculated considering 1 year of grid operation without faults, and the two solutions have been compared based on the obtained results. The simulations showed that the grid is oversized with respect to the real needs. For this reason, using the energy profiles as-is the congestions never appear. When the simulations are done by increasing the electric demand, the results changes. The congestion appear when a +20% increase is simulated. In this case the GE solutions costs almost 950 €/year, whereas the DR solution never overcomes 870 €/year, if only bids lower than 350 €/MWh are accepted. On the other hand, when a demand increase of +25% is simulated, the GE is always more convenient than the DR. According to the TERNA scenarios, a demand increase of +20% is not expected for at least the next 15 years. Thus, in normal operating conditions neither of the two solutions should be requested in the short time.

Then, different scenarios of fault in the grids have been simulated, identifying four macro cases. For each one of the cases, a worst-case fault position has been identified when it is the closest to the primary sub-station, leading to the highest number of congested branches, for the most hours and with the highest magnitudes of congestions. In some cases, more than one possible re-configuration to counterfeed the loads have been identified. The biggest issues was the impossibility to determine the probability of a fault happening in each position, since the related data were not available. Different indicators based on a probabilistic approach have been identified and for each sub-case the comparison between the DR and GE solutions has been carried out, assuming different price ranges for the bids offered by the flexible resources. The simulations showed that in 2 of the 4 cases outlined the DR solutions have a higher probability to be cheaper than the GE, with an economic savings that in principle could be up to 100% of the annual expenses. For Case 2 the conventional GE solution would cost at least 10597 €/year to be pursued, whereas the DR solution could cost up to 7985 €/year to solve 15 annual congestions, considering the least conservative grid conditions, demand profiles and with the highest prices. For Case 4 the GE solutions would cost at least 23048 €/year, whereas the DR solution could cost up to 7329 €/year to solve the worst congestion in the same conditions aforementioned. In the other 2 cases, it may be more reliable to pursue the traditional GE solution, but a DSO with a high-risk profile could still choose the DR solution and save money, depending on whether a congestion occurs or not.

A probabilistic analysis of the flexible resources have been conducted in order to determine, based on their position on the grid, the probability that each one of them has to have its bid accepted by the DSO along one year. The results shows that in each Case there is one or more resources with a higher probability of having the bids accepted, compared to the others. Knowing these trends is important for the DSO in decision of letting or not a flexible resource to participate in the DR scheme. In fact, if a capacity-based part of the tariff is set up, also the loads which at the end of the year have not been selected for the flexibility still needs to be remunerated. The simulations showed that the tariff have a structural limit of 441 €/MW in Case 2 and 960.33 €/MW in Case 4, due to the fact that the maximum budget is constrained by the yearly price of the alternative GE solution.

This work is intended to be a first approach to design a DR scheme on a distribution grid. Given the novelty and the innovativeness of the topic, there is a huge margin for improvement and for future developments. The main flaw of the work is the impossibility to estimate the probability of fault for each branch of the grid. Thus, a potential improvement could be the analysis of the single components that constitutes a grid, investigating the probability of faults of each one of them using historical data series or data provided by the manufacturer. A potential improvement can also be done in how the flexibility resources behavior in the market is modeled. In this thesis work the price of the bids is randomly generated and kept constant through the year, without considering the actual typology of the loads. Industrial or aggregated domestic users could behave in a different way and change behavior in different moments of the day or the year. These different attitudes can be furtherly investigated, to see how they reflect in the DR scheme. A further improvement could be also the study of how the flexible resources can recover the reduced power in a future moment in time, thus applying a load shifting strategy instead of a simple load cutting. The new load profile curve can be studied to verify the risk of just moving the formation of the congestion to another time.

Bibliography

[1] IPCC - Intergovernmental panel on climate change, Climate Change 2021, The Physical Science Basis, Summary for Policymakers, 2021.

[2] United Nations Environment Programme, Emission gas report 2020, 2020.

[3] UNCC - United Nations climate change, Key aspects of the Paris agreement, 2015.

[4] UNCC - United Nation Climate Change, Glasgow Climate Pact COP26, 2021.

[5] World Energy Council, World Energy Trilemma Index, 2021.

[6] European Commission, "2020 climate & energy package," 2009. [Online]. Available: https://climate.ec.europa.eu/eu-action/climate-strategies-targets/2020-climate-energy-package_en.

[7] European Commission, "A European Green Deal - Striving to be the first climate-neutral continent," 2019. [Online]. Available: https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal_en.

[8] European Commission, "2030 climate & energy framework," 2019. [Online]. Available: https://climate.ec.europa.eu/eu-action/climate-strategies-targets/2030-climate-energy-framework_en.

[9] REN21, Renewables 2021- Global status report, 2021.

[10] IRENA, Electrification with renewables - Driving the transformation of energy services, 2019.

[11] IEA, "Distributed energy resources for net zero: An asset or a hassle to the electricity grid?," 2021. [Online]. Available:

https://www.iea.org/commentaries/distributed-energy-resources-for-net-zero-an-asset-or-a-hassle-to-the-electricity-grid.

[12] IEA, "Unlocking the Potential of Distributed Energy Resources - Power system opportunities and best practices," 2022.

[13] EEA - European Environmenal Agency, Decommissioning fossil fuel power plants between now and 2030 essential for Europe’s low carbon future, 2016.

[14] A. Alarcon-Rodriguez, G. Ault and S. Galloway, "Multi-objective planning of distributed energy resources: A review of the state-of-the-art," *Renewable and Sustainable Energy Reviews*, vol. 14, pp. 1353-1366, 2010.

[15] A. Saint-Pierre and P. Mancarella, "Active Distribution System Management: A Dual-Horizon Scheduling Framework for DSO/TSO Interface Under Uncertainty," *IEEE Transactions on Smart Grid,* vol. 8, pp. 2186-2197, 2017.

[16] S. R. Lopez, G. Gutierrez-Alcaraz, M. S. Javadi, G. J. Osório and J. P. S. Catalão, "Flexibility Participation by Prosumers in Active Distribution Network Operation," in *2022 IEEE International Conference on Environment and Electrical Engineering and 2022 IEEE Industrial and Commercial Power Systems Europe (EEEIC / I&CPS Europe)*, 2022.

[17] L. Van Halewyck, J. Verstraeten, M. Strobbe and C. Develder, "Economic evaluation of active network management alternatives for congestion avoidance — the DSO perspective," in *IEEE PES Innovative Smart Grid Technologies, Europe*, 2014.

[18] JRC - Joint research center, The European Commission science and kwowledge service - Annual report, 2017.

[19] CAPENERGIES, Interoperable solutions for implementing holistic FLEXIbility services in the distribution GRID, 2020.

[20] IEA - International energy agency, "The who and how of power system flexibility," [Online]. Available: https://www.iea.org/commentaries/the-who-and-how-of-power-system-flexibility.

[21] ENTSO-E WGAS, "Survey on ancillary services procurement, balancing market design," 2018.

[22] IRENA, Future role of distribution system operators - Innovation landscape, 2019.

[23] C. Madina, I. Gómez-Arriola, M. Santos-Mugica, J. Jimeno, K. Kessels, D. Trakas, J. Pablo Chaves and Y. Ruwaida, "Flexibility markets to procure system services. CoordiNet project," in *2020 17th International Conference on the European Energy Market (EEM)*, 2020.

[24] Coordinet consortium, Evaluation of combinations of coordination schemes and products for grid services based on market simulatios, 2020.

[25] B. Olek and M. Wierzbowski, "Local Energy Balancing and Ancillary Services in Low-Voltage Networks With Distributed Generation, Energy Storage, and Active Loads," *IEEE Transactions on Industrial Electronics,* vol. 62, pp. 2499-2508, 2015.

[26] EcoGrid, EcoGrid EU – A Prototype for European Smart Grids, 2016.

[27] Interflex, Interactions between automated energy systems and Flexibilities brought by energy market players, 2020.

[28] PLATform for Operation of distribution NEtworks, Overview of regulatory aspects that impact the solutions tested in the demos in European, 2021.

[29] EUROPEAN PARLIAMENT AND COUNCIL, *DIRECTIVE (EU) 2019/944,* 2019.

[30] M. Miletić, M. Gržanić, I. Pavić, H. Pandžić and T. Capuder, "The effects of household automation and dynamic electricity pricing on consumers and suppliers," *Sustainable Energy, Grids and Networks,* vol. 32, p. 100931, 2022.

[31] N. Savvopoulos, T. Konstantinou and N. Hatziargyriou, "TSO-DSO Coordination in Decentralized Ancillary Services Markets," in *2019 International Conference on Smart Energy Systems and Technologies (SEST)*, 2019.

[32] G. Migliavacca, M. Rossi, D. Six, M. Džamarija, S. Horsmanheimo, C. Madina, I. Kockar and J. Morales, "SmartNet: H2020 project analysing TSO–DSO interaction to enable ancillary services provision from distribution networks," *CIRED - Open Access Proceedings Journal,* vol. 2017, pp. 1998-2002, October 2017.

[33] ARERA, *Deliberazione 5 maggio 2017 300/2017/r/eel,* 2017.

[34] ARERA, *Documento per la consultazione 322/2019/Reel,* Milano, 2019.

[35] ARERA, *Deliberazione 352/2021/R/EEL,* 2021.

[36] "IEEE Standard Dictionary of Electrical and Electronics Terms," *IEEE Transactions on Power Apparatus and Systems,* Vols. PAS-99, pp. 37a-37a, 1980.

[37] S. Mohagheghi, F. Yang and B. Falahati, "Impact of demand response on distribution system reliability," in *2011 IEEE Power and Energy Society General Meeting*, 2011.

[38] S. Shao, M. Pipattanasomporn and S. Rahman, "Grid Integration of Electric Vehicles and Demand Response With Customer Choice," *IEEE Transactions on Smart Grid,* vol. 3, pp. 543-550, 2012.

[39] G. B. e. al, "A Survey of Utility Experience with Real time pricing," *Energy (Norwalk, Connecticut),* vol. Volume 30, no. Issue 1 , pp. Pages 14 - 18, 2005.

[40] Enel X, *Demand Response: Opportunity For Circular Economy,* 2020.

[41] M. H. Albadi and E. F. El-Saadany, "Demand Response in Electricity Markets: An Overview," in *2007 IEEE Power Engineering Society General Meeting*, 2007.

[42] P. Bradley, M. Leach and J. Torriti, "A review of the costs and benefits of demand response for electricity in the UK," *Energy Policy,* vol. 52, pp. 312-327, 2013.

[43] *Legislative Decree 102/2014 (transposing the European Directive 2012/27 / EU on energy efficiency).*

[44] Department of Energy and Climate Change (DECC), *Smart meter roll-out for the domestic and small and medium and non domestic sectors,* 2014.

[45] e-Distribuzione, Piano di Sviluppo annuale e pluriennale delle infrastrutture di e-Distribuzione, 2018.

[46] *Art. 18 del Decreto Legislativo 3 marzo 2011, n. 28.*

[47] Enel Distribuzione, Guida per le connessioni alla rete elettrica di enel distribuzione, 2014.

[48] Unareti S.p.A., Reti Elettriche - Tabella dei valori unitari medi di riferimento corrispondenti alla realizzazione di ciascuna soluzione tecnica convenzionale, 2016.

[49] Areti S.p.A., Modalità e condizioni contrattuali per l'erogazione del servizio di connessione alle reti elettriche con tensione nominale superiore ad 1 kV, 2006.

[50] Edison, Capitolato e preziario per lavori elettrici, 2011.

[51] DEA - Distribuzione Elettrica Adriatica, Costi Standard per la realizzazione degli impianti di rete per le connessioni in MT e BT, 2012.

[52] C. R. H. Z. X. J. L. H. Xu Lizhou, "Dynamic Reconfiguration of Distribution Network Containing Distributed Generation," in *Proceedings - 2016 9th International Symposium on Computational Intelligence and Design*, 2016, pp. Volume 1, Pages 3 - 7.

[53] Next-kraftwerke, Our platform for your Virtual Power Plant, 2019.

[54] Next-kraftwerke, "What does Peak shaving mean?," [Online]. Available: https://www.next-kraftwerke.com/knowledge/what-is-peak-shaving.

[55] R. D. Zimmerman, C. E. Murillo-Sánchez and R. J. Thomas, "MATPOWER: Steady-State Operations, Planning, and Analysis Tools for Power Systems Research and Education," *IEEE Transactions on Power Systems,* vol. 26, pp. 12-19, 2011.

[56] ARERA, "TILP- load profiling per fasce per il sistema profiling per fasce per il sistema - Deliberazione n. 278/07," 2007.

[57] Prysmian group, Low and medium voltage cables and accessories catalogue, 2018.

[58] La Triveneta cavi SpA, Catalogo cavi, 2018.

[59] AceagasApsAmga, "Impianti di distribuzione a trieste e gorizia," [Online]. Available: https://www.acegasapsamga.it/attivita_servizi/energia_elettrica/ee_impianti/ee_impianti_trieste/pagina1.html.

[60] AceagasApsAmga, "Numeri chiave," [Online]. Available: https://www.acegasapsamga.it/attivita_servizi/energia_elettrica/ee_numeri_chiave/.

[61] Aegasapsamga, Piano per lo sviluppo delle reti di distrubuzione dell'energia elettrica, 2020.

[62] ARERA, Smart metering di seconda generazione - Le novità della regolazione, 2017.

[63] European Commission, Benchmarking smart metering deployment in the EU-28, 2019.

[64] AcegasApsAmga, Piano di Messa in servizio del sistema di smart metering 2G (PMS2), 2021.

[65] Terna, Rapporto mensile sul sistema elettrico, 2021.

[66] Terna, Snam, Scenario National Trend Italia, 2021.

[67] TERNA, "PROCEDURA DI APPROVVIGIONAMENTO A TERMINE DI RISORSE DI DISPACCIAMENTO PER UVAM - CAPACITÀ ASSEGNATA PER IL PERIODO NOVEMBRE 2022," November 2022. [Online]. Available: https://www.terna.it/it/sistema-elettrico/pubblicazioni/news-operatori/dettaglio/esitiastauvamnovembre2022.

[68] TERNA, "PROCEDURA DI APPROVVIGIONAMENTO A TERMINE DI RISORSE DI DISPACCIAMENTO PER UVAM - CAPACITÀ ASSEGNATA PER IL PERIODO AGOSTO 2022," August 2022. [Online]. Available: https://www.terna.it/it/sistema-elettrico/pubblicazioni/news-operatori/dettaglio/esitiastauvamagosto2022.

[69] G. Xu, W. Yu, D. Griffith, N. Golmie and P. Moulema, "Toward Integrating Distributed Energy Resources and Storage Devices in Smart Grid," *IEEE Internet of Things Journal,* vol. 4, pp. 192-204, 2017.

Appendix

The following table represents the full list of loads located in the medium voltage distribution grid of Trieste, described in **Chapter 5.1.**

Nominal power [MW]	Node	Power factor
1.983	9	0.899997
3.51	48	0.899999
0.36	28	0.899924
0.057	38	0.901908
0.489	45	0.899868
0.152	84	0.901343
0.198	46	0.899794
0.04	19	0.924517
0.162	17	0.899983
0.174	48	0.90113
0.271	56	0.900036
0.282	36	0.90487
0.215	52	0.90169
0.217	53	0.910113
0.152	74	0.899608
0.08	26	0.902797
0.094	27	0.909367
0.191	90	0.910708
0.358	80	0.907639
3.805	61	0.899999
0.231	77	0.900333
1.69	12	0.900006
1.548	80	0.900001
0.531	64	0.899994
0.894	80	0.899985
0.288	85	0.899974
0.072	75	0.900769
0.258	79	0.900009
0.319	78	0.899889
0.809	24	0.899934
0.581	34	0.90001

1.092	39	0.9
1.562	91	0.90006
0.583	71	0.899597
0.688	18	0.899997
0.438	55	0.900013
1.937	76	0.9
0.151	67	0.900079
0.717	9	0.900026
3.172	69	0.900047
3.358	63	0.899921
0.828	68	0.901949
0.404	82	0.900148
0.087	15	0.899946
0.058	20	0.905218
0.603	9	0.947227
0.571	79	0.970127
0	70	0.955288
0.132	87	1
0.198	88	0.901995
0.151	89	0.900018
1.216	97	0.900107
1.5	21	0.9
1.5	22	0.9
0.49	94	0.900006
1.62	63	0.899997
1.72	94	0.9
1.43	63	0.899999
1	94	0.9
1.98	63	0.899999
1.23	94	0.9
1.53	28	0.899996
0.41	29	0.899631
1.5	30	0.899999
1.45	31	0.9
1.23	15	0.899982
1.87	16	0.9
1.64	17	0.899994
1.45	74	0.9
1.78	14	0.900002
1.5	78	0.9
1.34	88	0.9
0.55	23	0.899958
0.55	79	0.899741
1.5	91	0.9
1.47	24	0.900008

1.51	58	0.9
1.43	51	0.9
1.56	52	0.9
1.94	53	0.899999
1.48	54	0.9
1.34	55	0.899999
1.84	56	0.899999
1.48	29	0.92
1.93	34	0.93
4.2	67	0.91

Figure A.1: loads connected to the medium voltage grid of Trieste

The following pictures show the Trieste grid detailed representation, described in **Chapter 5.1.**

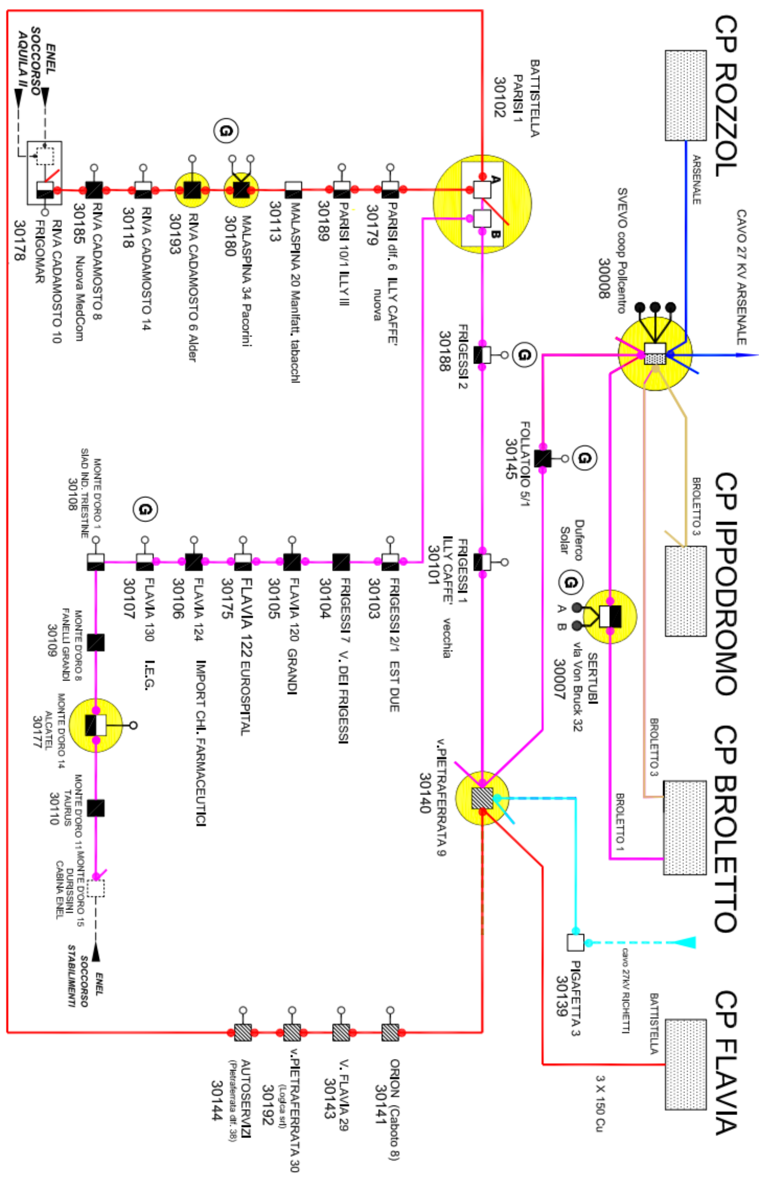


Figure A.2: Trieste grid page 1

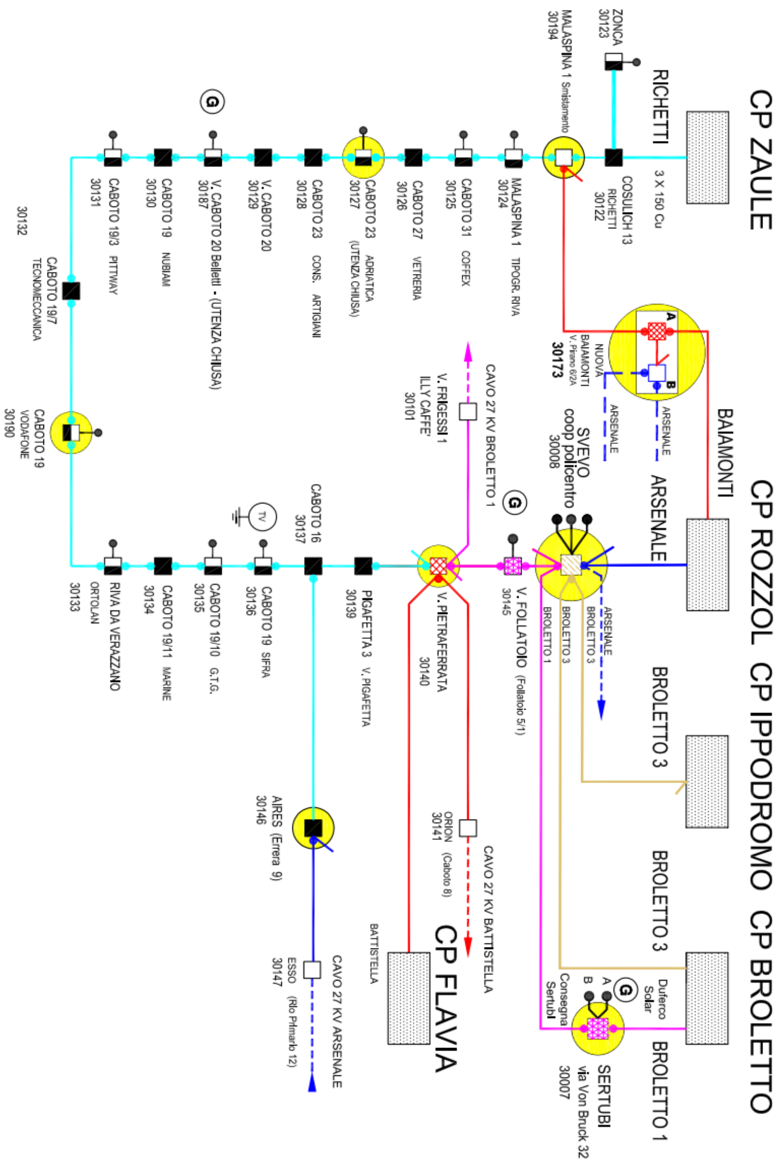


Figure A.3: Trieste grid page 2

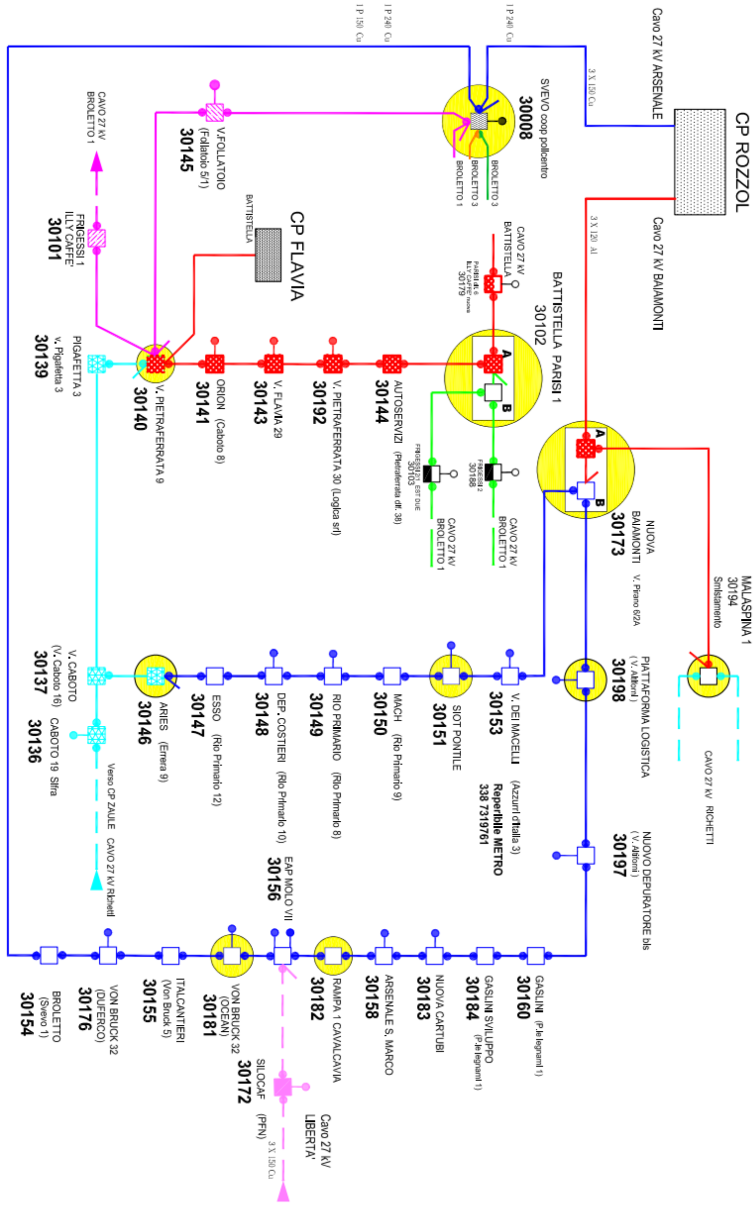


Figure A.4: Trieste grid page 3

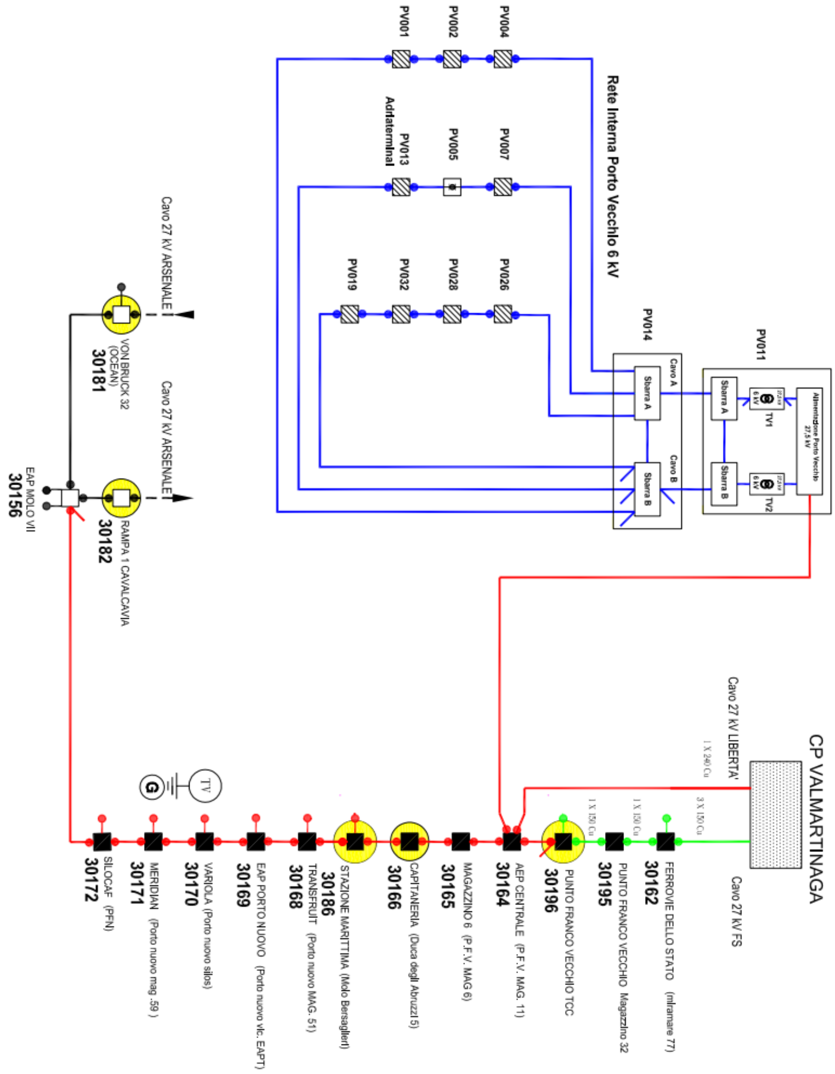


Figure A.5: Trieste grid page 4

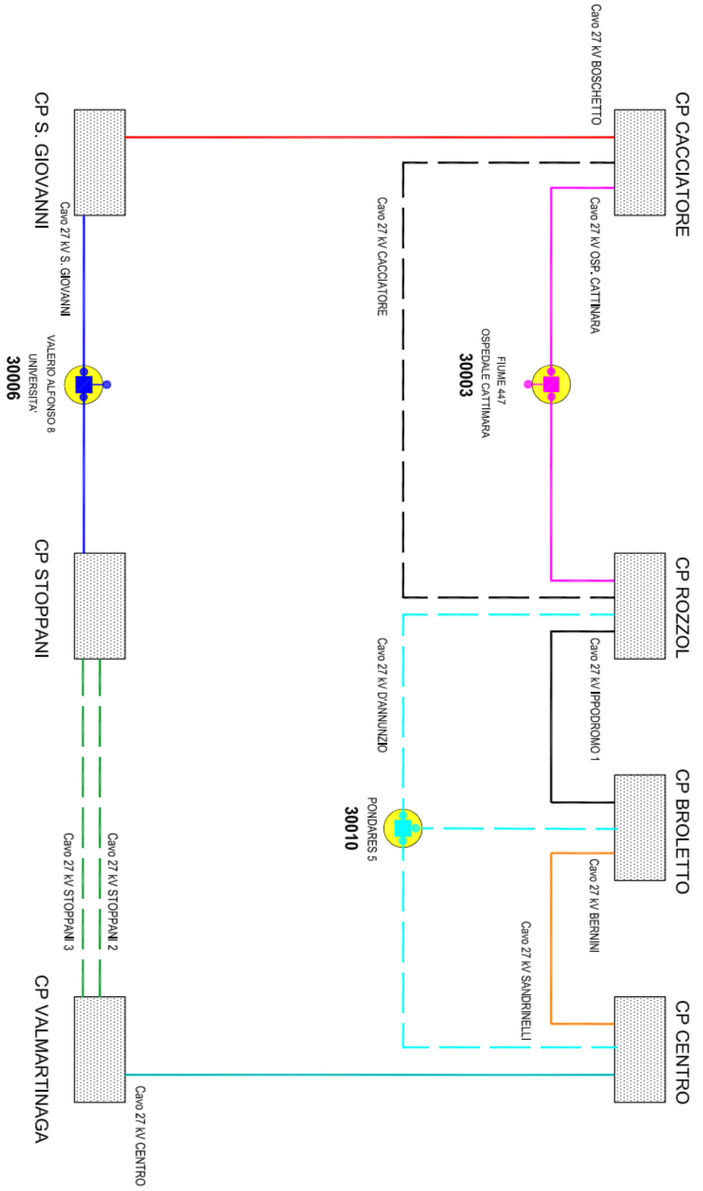


Figure A.6: Trieste grid page 5

The following images represent the electrical results of the cases described in **Chapter 5.6.**

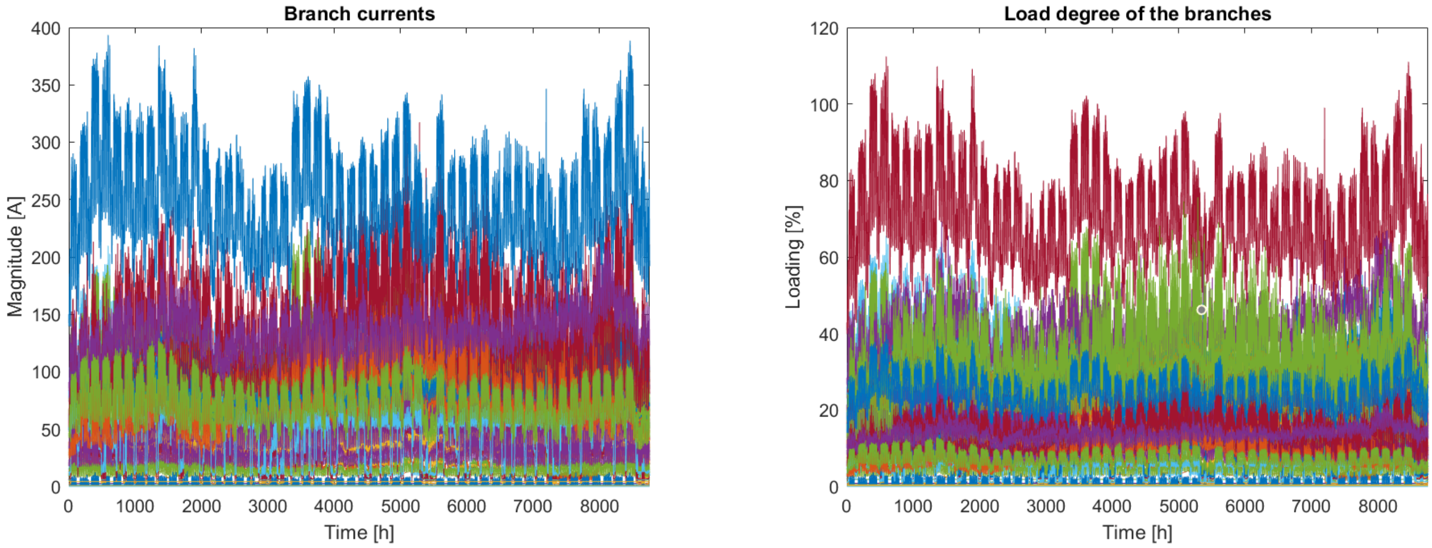


Figure A.7: Electrical results of Case 1A.2

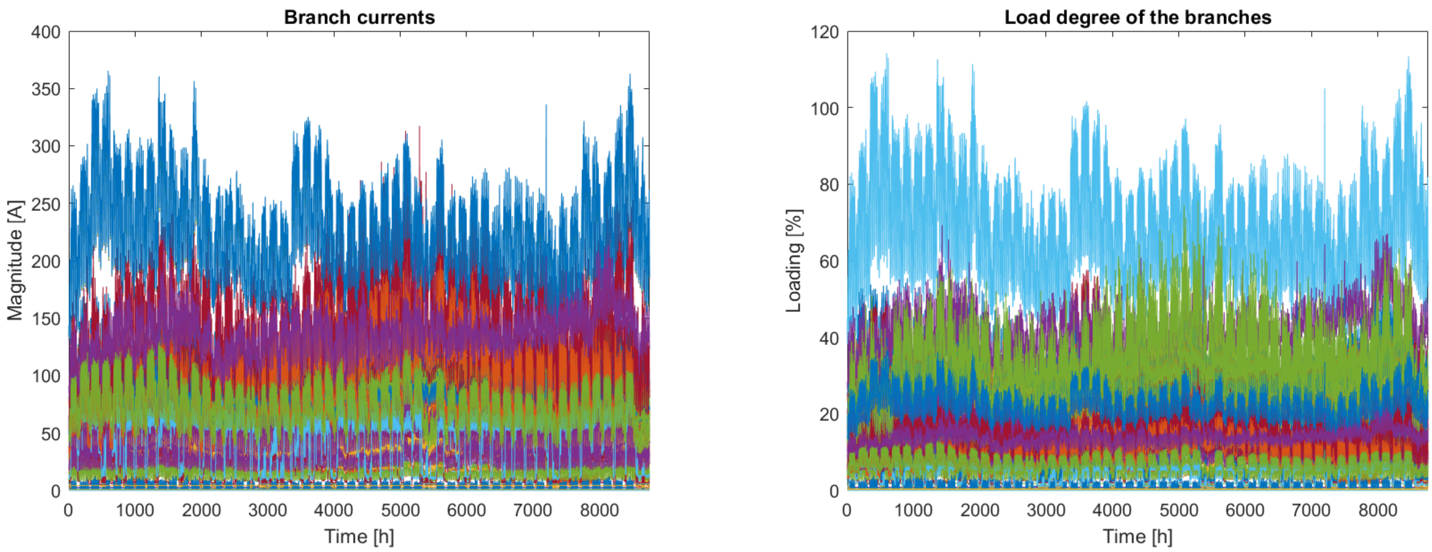


Figure A.8: Electrical results of Case 1B.2

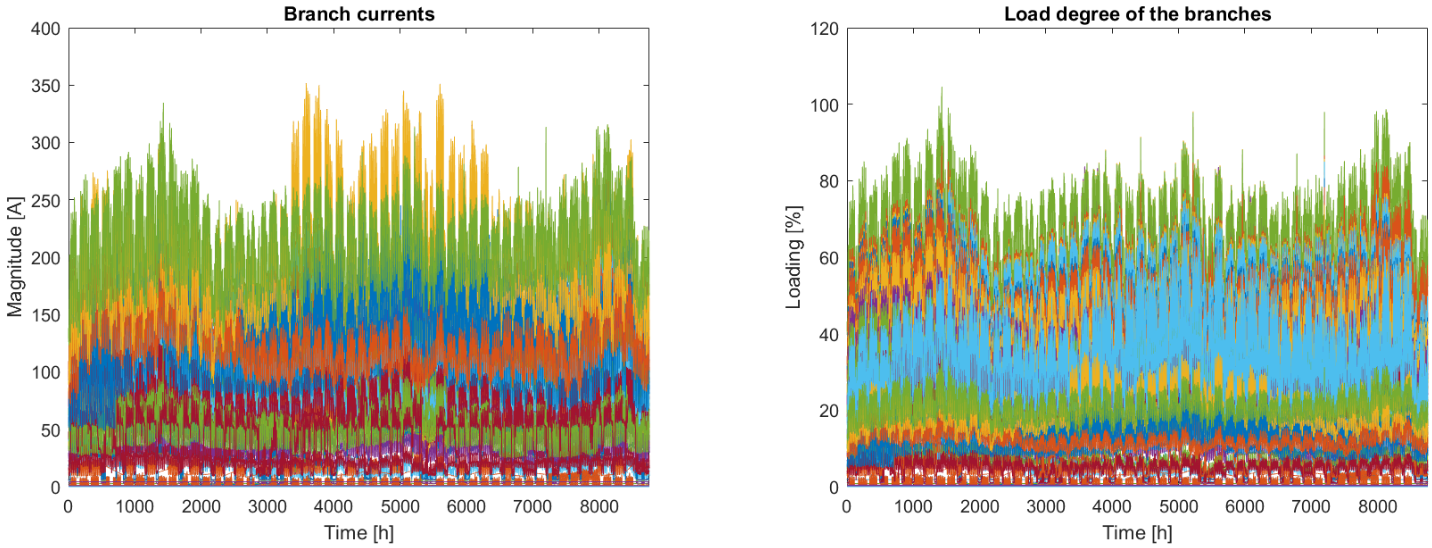


Figure A.9: Electrical results of Case 3A.2

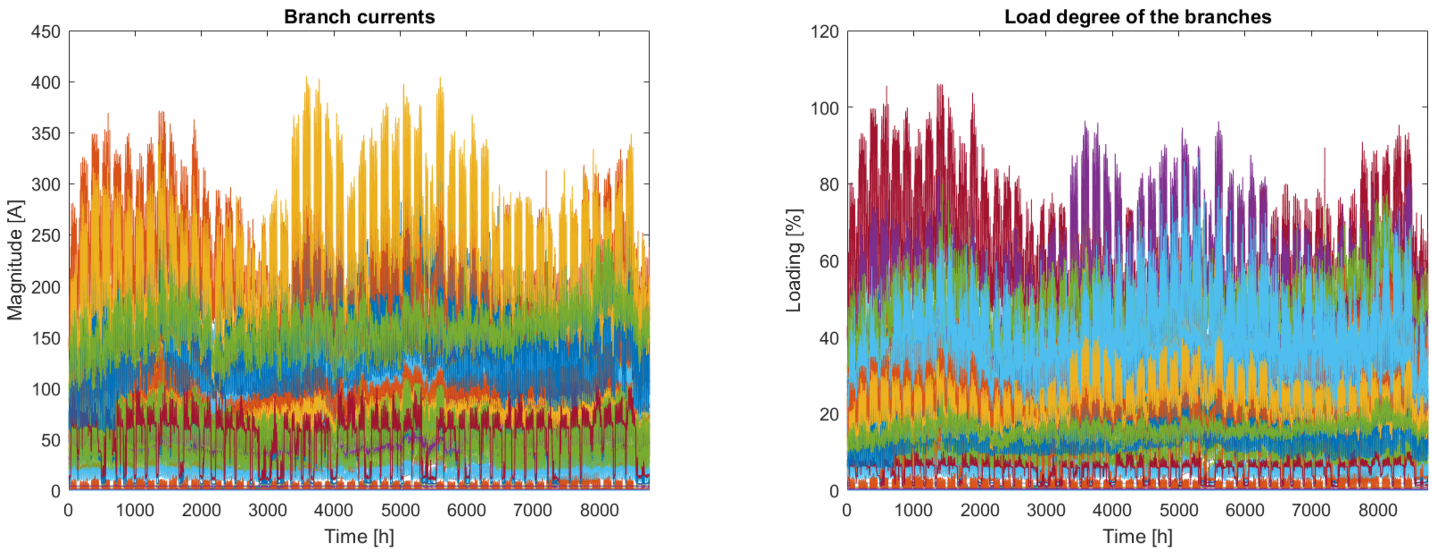


Figure A.10: Electrical results of Case 3B.2

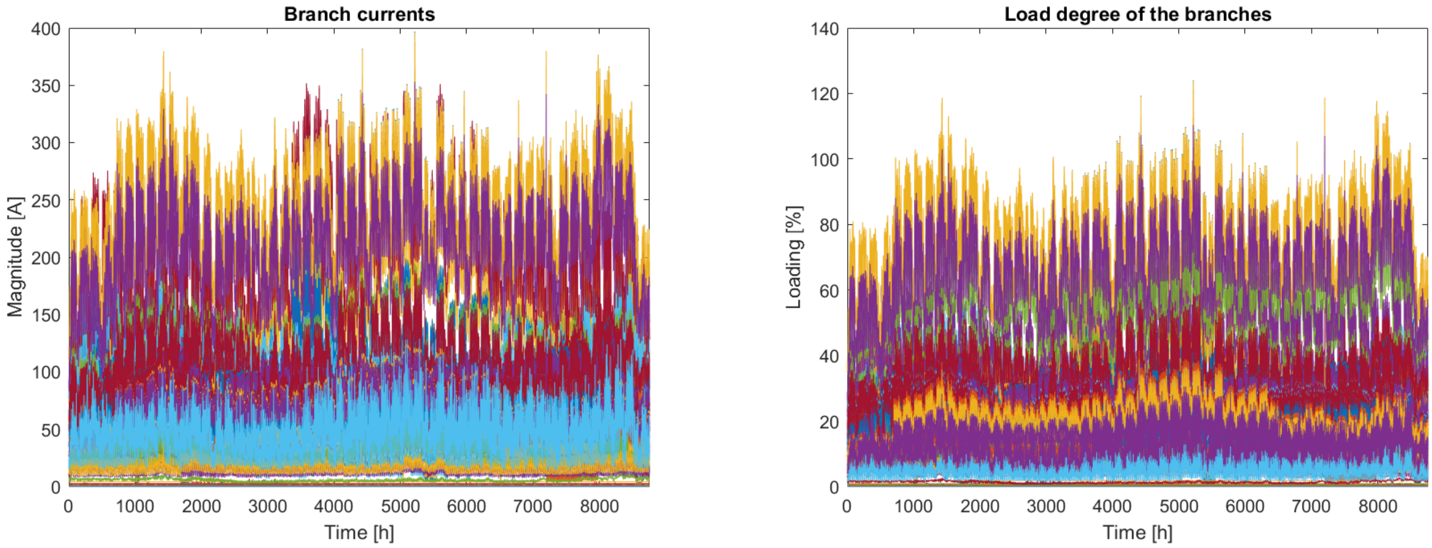


Figure A.11: Electrical results of Case 4.2

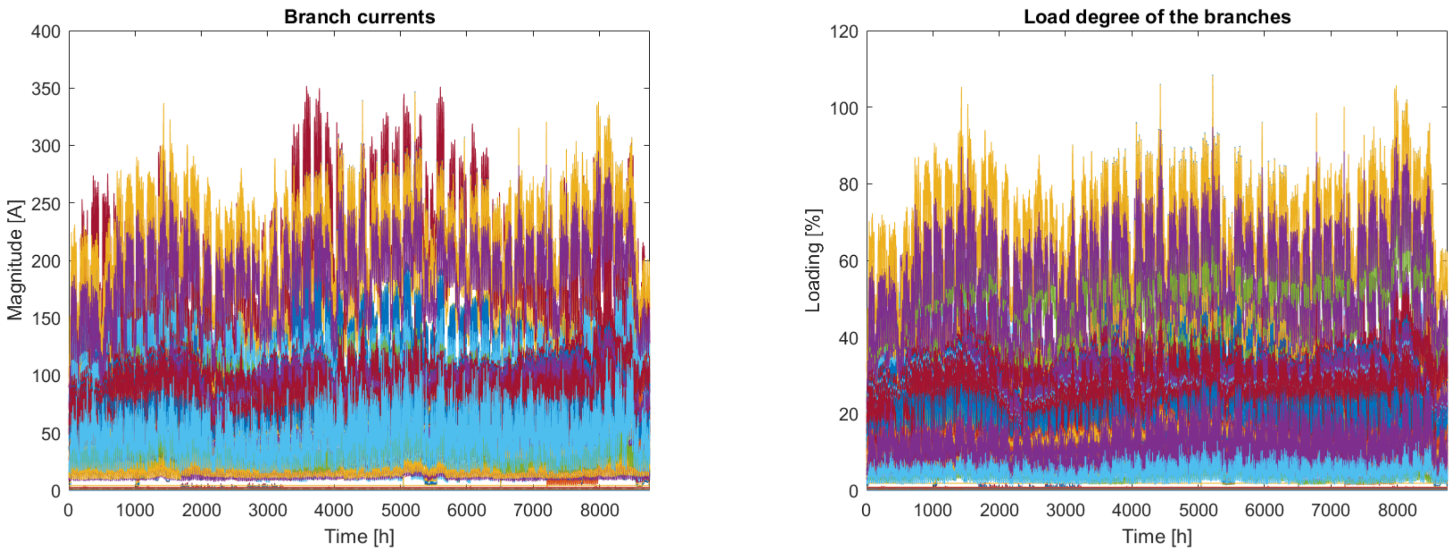


Figure A.12: Electrical results of Case 4.3

The following tables report the data represented in the figures of **Chapter 6.2**. The results are expressed in [€].

	Lower quartile	Median	Upper quartile	Mean
0-50-100-150	58.66	60.24	63.66	60.91
50-100-150-200	122.61	126.30	136.95	128.82
100-150-200-250	189.85	193.77	202.78	195.30
150-200-250-300	244.55	259.39	271.06	254.13
200-250-300-350	324.64	345.03	354.02	338.56
350-300-350-400	381.53	397.50	420.74	402.02

Table A.1: average yearly cost for case 1A.1

€/MWh	Lower quartile	Median	Upper quartile	Mean
0-50-100-150	79.05	82.67	88.62	83.25
50-100-150-200	146.47	152.87	161.60	153.72
100-150-200-250	235.51	243.82	259.22	245.55
150-200-250-300	301.80	311.95	344.74	319.10
200-250-300-350	377.01	400.44	412.79	394.97
350-300-350-400	464.62	482.19	489.91	477.49

Table A.2: average yearly cost for case 1B.1

	Lower quartile	Median	Upper quartile	Mean
0-50-100-150	47.47	49.90	51.00	49.90
50-100-150-200	116.51	121.20	125.61	120.79
100-150-200-250	165.18	171.53	184.44	172.56

150-200-250-300	183.86	204.94	214.90	202.16
200-250-300-350	241.41	251.45	252.36	249.07
350-300-350-400	275.42	294.91	303.25	293.02

Table A.3: average yearly cost for case 2A.1

	Lower quartile	Median	Upper quartile	Mean
0-50-100-150	87.98	90.15	97.07	92.47
50-100-150-200	203.16	211.67	220.29	211.23
100-150-200-250	272.31	277.45	300.78	285.15
150-200-250-300	358.40	379.43	395.60	379.20
200-250-300-350	485.89	501.20	504.52	495.76
350-300-350-400	588.60	639.47	655.14	624.29

Table A.4: average yearly cost for case 2B.1

	Lower quartile	Median	Upper quartile	Mean
0-50-100-150	23.50	24.87	25.37	24.65
50-100-150-200	51.36	55.12	56.18	54.16
100-150-200-250	67.55	68.25	70.77	69.10
150-200-250-300	96.03	101.91	107.30	101.87
200-250-300-350	118.94	124.49	132.12	125.45
350-300-350-400	148.31	161.35	172.48	160.41

Table A.5: average yearly cost for case 3A.1

	Lower quartile	Median	Upper quartile	Mean
0-50-100-150	32.99	34.48	35.26	34.32

50-100-150-200	69.51	71.16	73.33	73.33
100-150-200-250	106.66	113.40	115.82	111.60
150-200-250-300	138.62	142.72	145.32	143.04
200-250-300-350	148.26	156.46	169.13	159.01
350-300-350-400	167.99	173.01	187.41	177.37

Table A.6: average yearly cost for case 3B.1

	Lower quartile	Median	Upper quartile	Mean
0-50-100-150	139.43	142.03	153.51	146.1
50-100-150-200	286.01	307.58	322.46	303.16
100-150-200-250	413.16	445.00	475.04	445.78
150-200-250-300	557.75	594.28	640.61	597.73
200-250-300-350	707.64	734.54	772.41	744.57
350-300-350-400	925.11	982.89	1032.06	988.68

Table A.7: average yearly cost for case 4.1

The following tables report the data shown in the pictures of **Chapter 6.4.** The results are expressed in [€].

Price range	First bid range	Second bid range	Third bid range	Worst congestion	Sum of 5 worst congestions	Sum of 10 worst congestions	Sum of 15 worst congestions
1	0-50	50-100	100-150	185.87	922.06	1836.32	2751.37
2	50-100	100-150	150-200	340.69	1660.58	3298.39	4886.79
3	100-150	150-200	200-250	523.59	2594.64	5166.59	7726.11
4	150-200	200-250	250-300	957.09	4765.98	9479.98	14280.54

5	200-250	250-300	300-350	1674.90	8276.98	16680.54	24765.38
6	250-300	300-350	350-400	2897.58	14401.50	28880.65	43449.34

Table A.8: worst congestions for case 1A.1

Price range	First bid range	Second bid range	Third bid range	Worst congestion	Sum of 5 worst congestions	Sum of 10 worst congestions	Sum of 15 worst congestions
1	0-50	50-100	100-150	250	1239	2498	3637
2	50-100	100-150	150-200	360.65	1897.93	3545.68	5098.65
3	100-150	150-200	200-250	543.76	2765.28	5194.35	7458.00
4	150-200	200-250	250-300	783.76	3725.64	6998.01	10098.12
5	200-250	250-300	300-350	928.54	4658.16	8822.02	12732.60
6	250-300	300-350	350-400	1134.97	5653.77	10717.33	15504.11

Table A.9: worst congestions for case 1B.1

Price range	First bid range	Second bid range	Third bid range	Worst congestion	Sum of 5 worst congestions	Sum of 10 worst congestions	Sum of 15 worst congestions
1	0-50	50-100	100-150	117.33	599.72	1137.49	1553.18
2	50-100	100-150	150-200	225.89	1243.96	2331.71	3262.38
3	100-150	150-200	200-250	370.99	1978.82	3932.45	5656.20
4	150-200	200-250	250-300	483.04	2647.76	5169.95	7390.39
5	200-250	250-300	300-350	501.66	2941.92	5943.14	8741.69
6	250-300	300-350	350-400	732.82	4018.71	7985.36	11525.85

Table A.10: worst congestions for case 2A.1

Price range	First bid range	Second bid range	Third bid range	Worst congestion	Sum of 5 worst congestions	Sum of 10 worst congestions	Sum of 15 worst congestions
1	0-50	50-100	100-150	308.77	943.56	1819.98	2559.17
2	50-100	100-150	150-200	459.28	1600.44	3157.17	5401.76
3	100-150	150-200	200-250	634.61	2950.60	5715.03	8427.36
4	150-200	200-250	250-300	695.63	3831.37	7725.12	11537.03
5	200-250	250-300	300-350	1033.08	5208.08	10068.17	14753.15
6	250-300	300-350	350-400	1485.43	6267.44	13239.17	18097.67

Table A.11: worst congestions for case 2B.1

Price range	First bid range	Second bid range	Third bid range	Worst congestion	Sum of 3 worst congestions
1	0-50	50-100	100-150	27.45	79.93
2	50-100	100-150	150-200	59.95	173.38
3	100-150	150-200	200-250	75.57	244.33
4	150-200	200-250	250-300	110.38	322.42
5	200-250	250-300	300-350	131.93	379.49
6	250-300	300-350	350-400	165.12	481.81

Table A.12: worst congestions for case 3A.1

Price range	First bid range	Second bid range	Third bid range	Worst congestion	Sum of 5 worst congestions	Sum of 10 worst congestions	Sum of 15 worst congestions

1	0-50	50-100	100-150	33.52	123.27	268.96	285.56
2	50-100	100-150	150-200	102.34	427.53	711.01	821.99
3	100-150	150-200	200-250	158.58	712.00	1408.15	1494.49
4	150-200	200-250	250-300	214.00	1051.68	1703.75	2264.41
5	200-250	250-300	300-350	272.23	1404.82	2113.39	2837.56
6	250-300	300-350	350-400	333.50	1668.54	2783.13	3626.78

Table A.13: worst congestions for case 3B.1

Price range	First bid range	Second bid range	Third bid range	Worst congestion	Sum of 5 worst congestions	Sum of 10 worst congestions	Sum of 15 worst congestions
1	0-50	50-100	100-150	1254.24	6536.23	11508.29	14215.88
2	50-100	100-150	150-200	2706.88	9415.53	22624.67	27788.24
3	100-150	150-200	200-250	3854.22	16233.36	29503.46	39982.70
4	150-200	200-250	250-300	4930.87	20671.95	35867.72	53472.38
5	200-250	250-300	300-350	6532.81	22634.53	46465.12	65738.44
6	250-300	300-350	350-400	7329.05	33448.43	52623.94	77086.41

Table A.14: worst congestions for case 4.1

The following images report the data shown in the graphs of **Chapter 6.5.** The results are expressed in [€].

	1 cong.	2 cong.	3 cong.	4 cong.	5 cong.	6 cong.	7 cong.	8 cong.	9 cong.	10 cong.
0-150 €/MWh	288.76	228.52	168.28	108.04	47.8	-12.44	-72.68	-132.92	-193.16	-253.4
50-200 €/MWh	222.7	96.4	-29.9	-156.2	-282.5	-408.8	-535.1	-661.4	-787.7	-914
100-250 €/MWh	155.23	-38.54	-232.31	-426.08	-619.85	-813.62	-1007.39	-1201.16	-1394.93	-1588.7

150-300 €/MWh	89.61	-169.78	-429.17	-688.56	-947.95	-1207.34	-1466.73	-1726.12	-1985.51	-2244.9
200-350 €/MWh	3.97	-341.06	-686.09	-1031.12	-1376.15	-1721.18	-2066.21	-2411.24	-2756.27	-3101.3
250-400 €/MWh	-48.5	-446	-843.5	-1241	-1638.5	-2036	-2433.5	-2831	-3228.5	-3626

Table A.15: difference between the DR of case 1A.1 and the reference GE

	1 cong.	2 cong.	3 cong.	4 cong.	5 cong.	6 cong.	7 cong.	8 cong.	9 cong.	10 cong.
0-150 €/MWh	266.33	183.66	100.99	18.32	-64.35	-147.02	-229.69	-312.36	-395.03	-477.7
50-200 €/MWh	196.13	43.26	-109.61	-262.48	-415.35	-568.22	-721.09	-873.96	-1026.83	-1179.7
100-250 €/MWh	105.18	-138.64	-382.46	-626.28	-870.1	-1113.92	-1357.74	-1601.56	-1845.38	-2089.2
150-300 €/MWh	37.05	-274.9	-586.85	-898.8	-1210.75	-1522.7	-1834.65	-2146.6	-2458.55	-2770.5
200-350 €/MWh	-51.44	-451.88	-852.32	-1252.76	-1653.2	-2053.64	-2454.08	-2854.52	-3254.96	-3655.4
250-400 €/MWh	-133.19	-615.38	-1097.57	-1579.76	-2061.95	-2544.14	-3026.33	-3508.52	-3990.71	-4472.9

Table A.16: difference between the DR of case 1B.1 and the reference GE

	1 cong.	2 cong.	3 cong.	4 cong.	5 cong.	6 cong.	7 cong.	8 cong.	9 cong.	10 cong.
0-150 €/MWh	10547.1	10497.2	10447.3	10397.4	10347.5	10297.6	10247.7	10197.8	10147.9	10098
50-200 €/MWh	10475.8	10354.6	10233.4	10112.2	9991	9869.8	9748.6	9627.4	9506.2	9385
100-250 €/MWh	10425.47	10253.94	10082.41	9910.88	9739.35	9567.82	9396.29	9224.76	9053.23	8881.7
150-300 €/MWh	10392.06	10187.12	9988	9777.24	9572.3	9367.36	9162.42	8957.48	8752.54	8547.6
200-350 €/MWh	10345.55	10094.1	9842.65	9591.2	9339.75	9088.3	8836.85	8585.4	8333.95	8082.5
250-400 €/MWh	10302.09	10007.18	9712.27	9417.36	9122.45	8827.54	8532.63	8237.72	7942.81	7647.9

Table A.17: difference between the DR of case 2A.1 and the reference GE

	1 cong.	2 cong.	3 cong.	4 cong.	5 cong.	6 cong.	7 cong.	8 cong.	9 cong.	10 cong.
0-150 €/MWh	10506.85	10416.7	10326.55	10236.4	10146.25	10056.1	9965.95	9875.8	9785.65	9695.5
50-200 €/MWh	10385.33	10173.66	9961.99	9750.32	9538.65	9326.98	9115.31	8903.64	8691.97	8480.3

100-250 €/MWh	10319.55	10042.1	9764.65	9487.2	9209.75	8932.3	8654.85	8377.4	8099.95	7822.5
150-300 €/MWh	10217.57	9838.14	9458.71	9079.28	8699.85	8320.42	7940.99	7561.56	7182.13	6802.7
200-350 €/MWh	10095.8	9594.6	9093.4	8592.2	8091	7589.8	7088.6	6587.4	6086.2	5585
250-400 €/MWh	9957.53	9318.06	8678.59	8039.12	7399.65	6760.18	6120.71	5481.24	4841.77	4202.3

Table A.18: difference between the DR of case 2B.1 and the reference GE

	1 cong.	2 cong.	3 cong.	4 cong.	5 cong.	6 cong.	7 cong.	8 cong.	9 cong.	10 cong.
0-150 €/MWh	324.13	299.26	274.39	249.52	224.65	199.78	174.91	150.04	125.17	100.3
50-200 €/MWh	293.88	238.76	183.64	128.52	73.4	18.28	-36.84	-91.96	-147.08	-202.2
100-250 €/MWh	280.75	212.5	144.25	76	7.75	-60.5	-128.75	-197	-265.25	-333.5
150-300 €/MWh	247.09	145.18	43.27	-58.64	-160.55	-262.46	-364.37	-466.28	-568.19	-670.1
200-350 €/MWh	224.51	100.02	-24.47	-148.96	-273.45	-397.94	-522.43	-646.92	-771.41	-895.9
250-400 €/MWh	187.65	26.3	-135.05	-296.4	-457.75	-619.1	-780.45	-941.8	-1103.15	-1264.5

Table A.19: difference between the DR of case 3A.1 and the reference GE

	1 cong.	2 cong.	3 cong.	4 cong.	5 cong.	6 cong.	7 cong.	8 cong.	9 cong.	10 cong.
0-150 €/MWh	314.52	280.04	245.56	211.08	176.6	142.12	107.64	73.16	38.68	4.2
50-200 €/MWh	277.84	206.68	135.52	64.36	-6.8	-77.96	-149.12	-220.28	-291.44	-362.6
100-250 €/MWh	235.6	122.2	8.8	-104.6	-218	-331.4	-444.8	-558.2	-671.6	-785
150-300 €/MWh	206.28	63.56	-79.16	-221.88	-364.6	-507.32	-650.04	-792.76	-935.48	-1078.2
200-350 €/MWh	192.54	36.08	-120.38	-276.84	-433.3	-589.76	-746.22	-902.68	-1059.14	-1215.6
250-400 €/MWh	175.99	2.98	-170.03	-343.04	-516.05	-689.06	-862.07	-1035.08	-1208.09	-1381.1

Table A.20: difference between the DR case 3B.1 and the reference GE

	1 cong.	2 cong.	3 cong.	4 cong.	5 cong.	6 cong.	7 cong.	8 cong.	9 cong.	10 cong.
0-150 €/MWh	22905.97	22763.94	22621.91	22479.88	22337.85	22195.82	22053.79	21911.76	21769.73	21627.7
50-200 €/MWh	22740.42	22432.84	22125.26	21817.68	21510.1	21202.52	20894.94	20587.36	20279.78	19972.2
100-250 €/MWh	22603	22158	21713	21268	20823	20378	19933	19488	19043	18598

150-300 €/MWh	22453.72	21859.44	21265.16	20670.88	20076.6	19482.32	18888.04	18293.76	17699.48	17105.2
200-350 €/MWh	22313.46	21578.92	20844.38	20109.84	19375.3	18640.76	17906.22	17171.68	16437.14	15702.6
250-400 €/MWh	22065.11	21082.22	20099.33	19116.44	18133.55	17150.66	16167.77	15184.88	14201.99	13219.1

Table A.21: difference between the DR of case 3B.1 and the reference GE

The following pictures express the maximum congestions solvable for each load, described in **Chapter 7.**

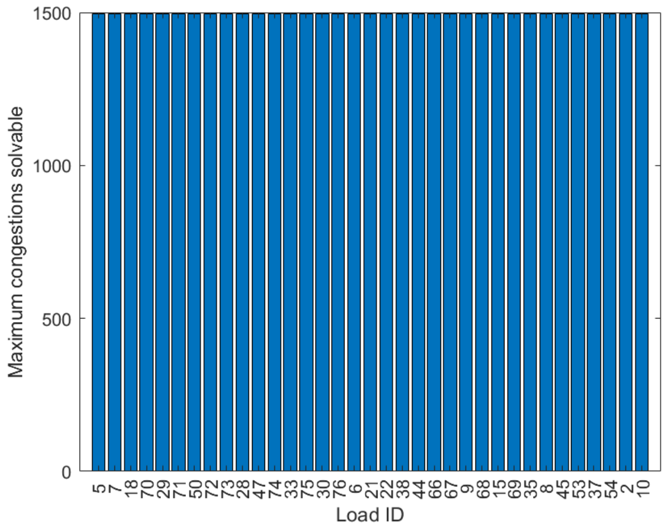


Figure A.13: congestions solvable in Case 1A.1

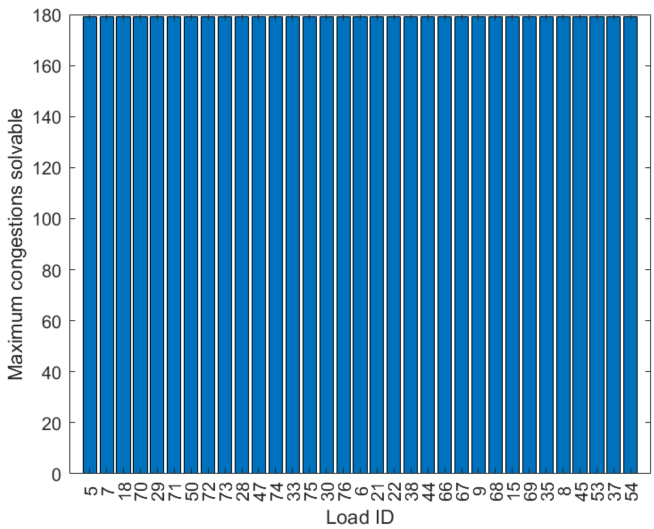


Figure A.14: congestions solvable in Case 1A.2

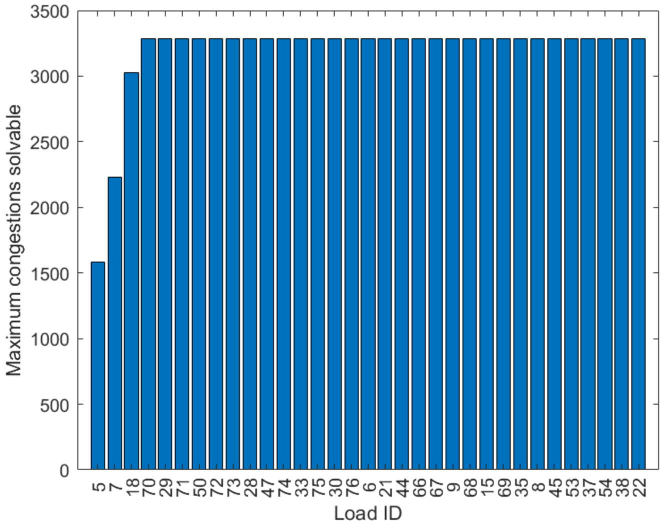


Figure A.15: congestions solvable in Case 1B.1

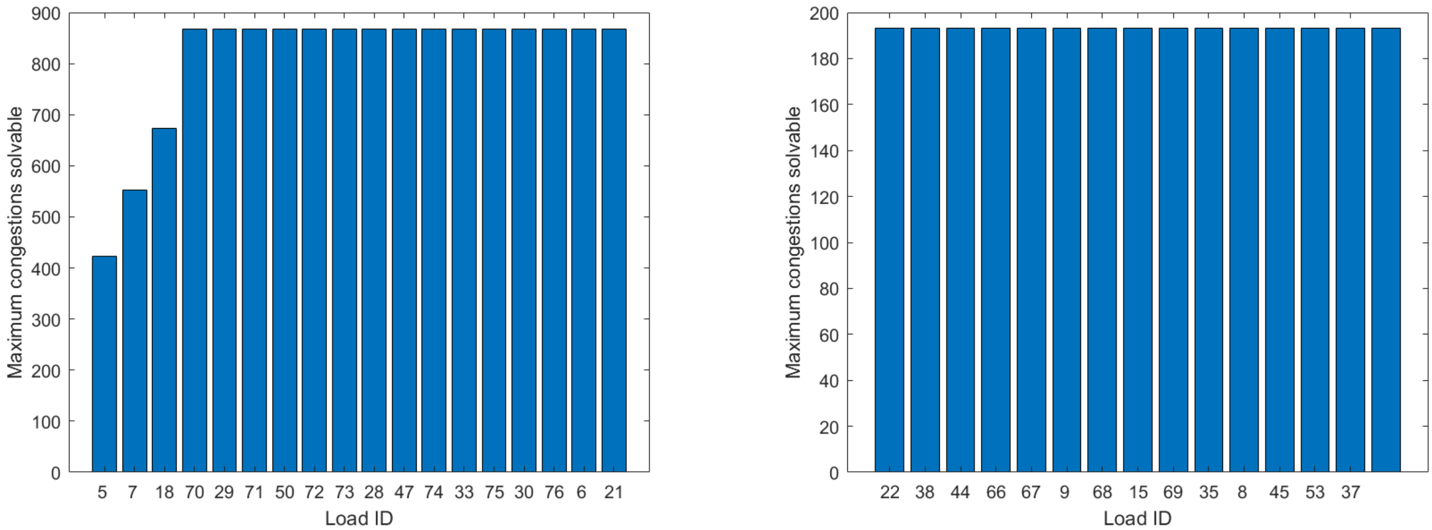


Figure A.16: congestions solvable in Case 1B.2, congested path (right) and non-congested path (left)

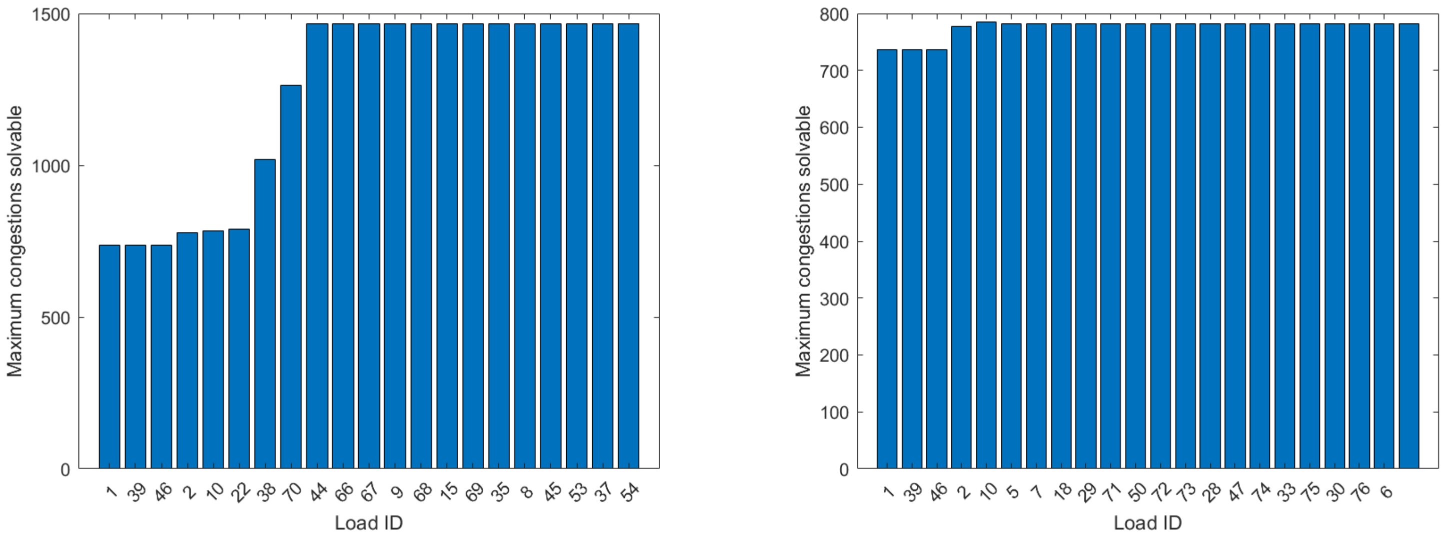


Figure A.17: congestions solvable in Case 2A.1

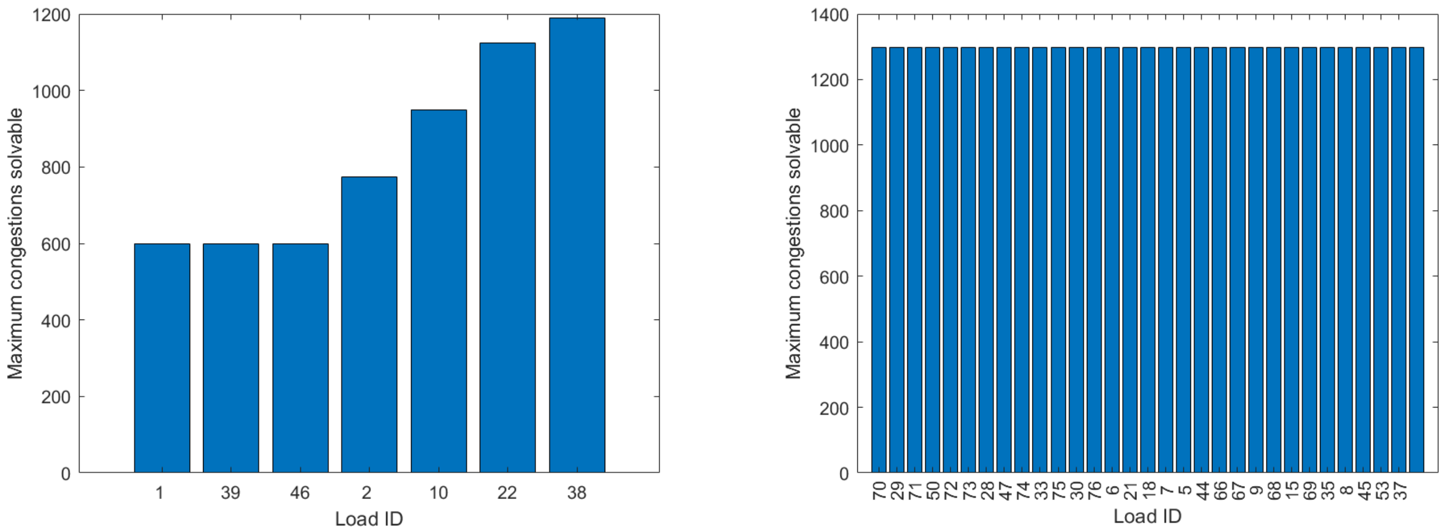


Figure A.18: congestions solvable in Case 2A.2

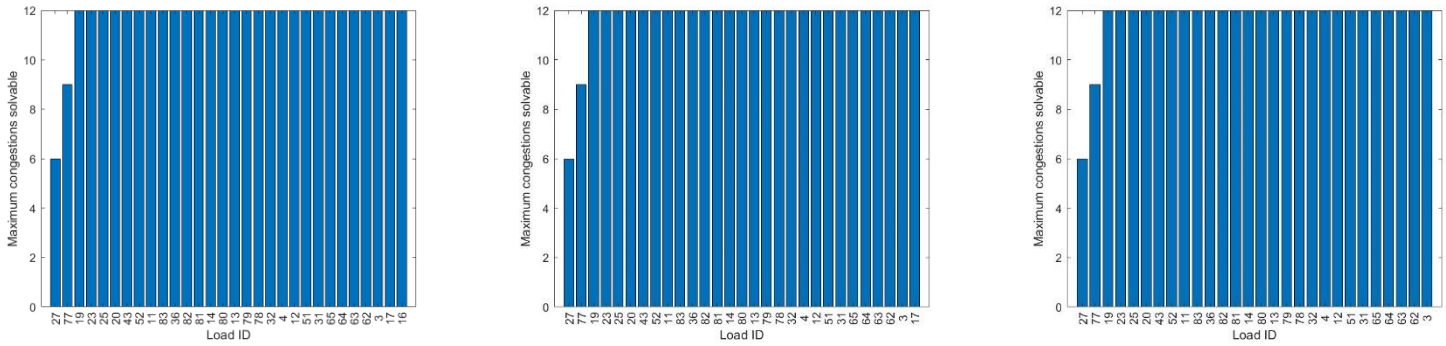


Figure A.19: congestions solvable in Case 3A.1 (left), 3A.2 (center) and 3A.3 (right)

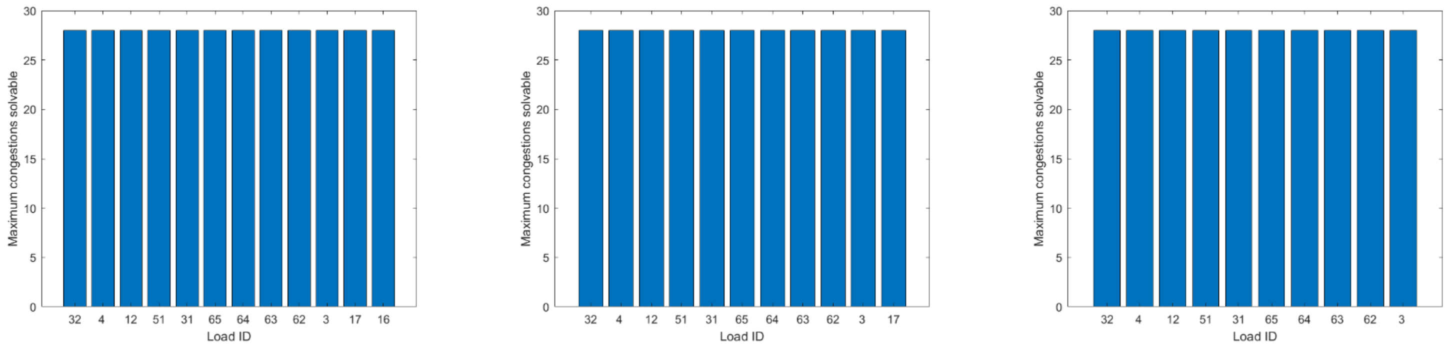


Figure A.20: congestions solvable in Case 3B.1 (left), 3B.2 (center) and 3B.3 (right)

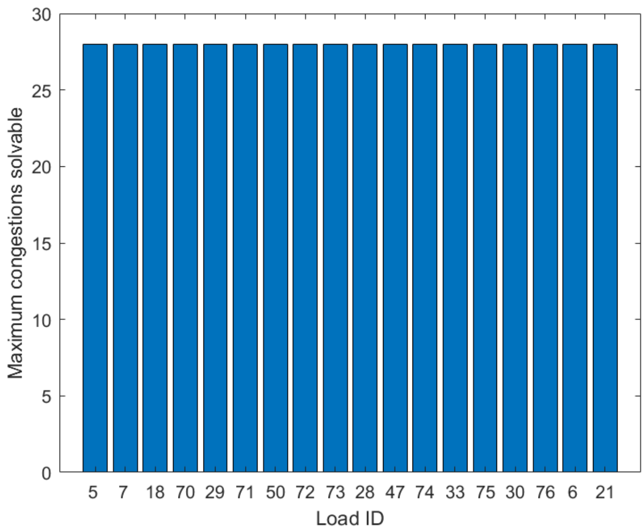


Figure A.21: congestions solvable in Case 3B.1, 3B.2 and 3B.3

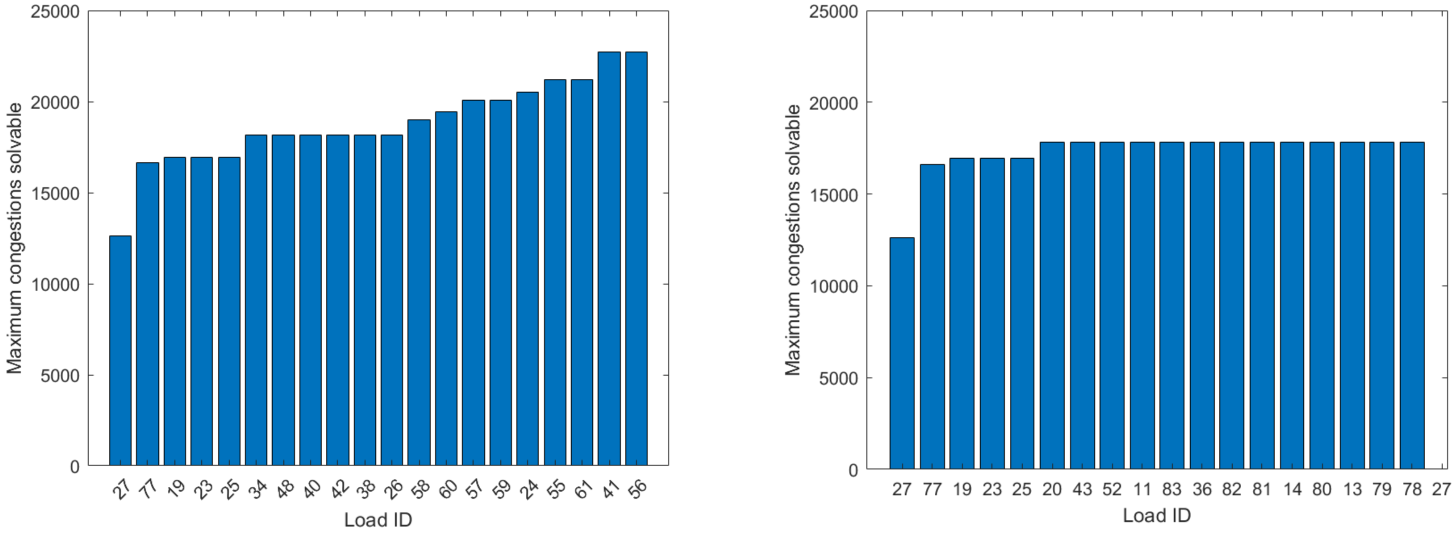


Figure A.22: congestions solvable in 4.1, congested path (left) and non-congested path (right)

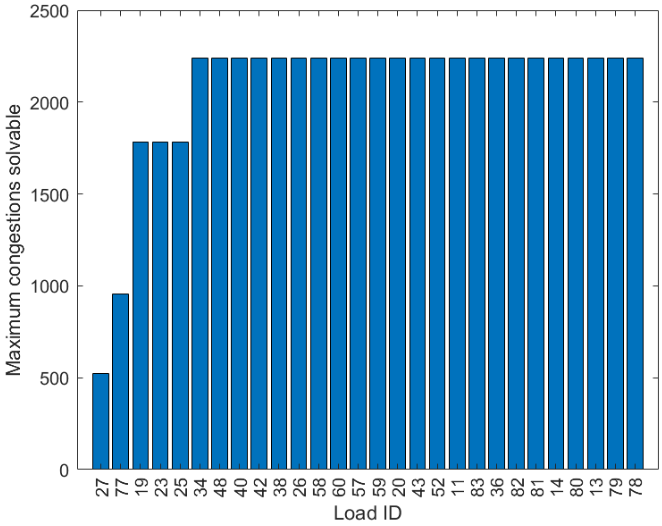


Figure A.23: congestions solvable in Case 4.2

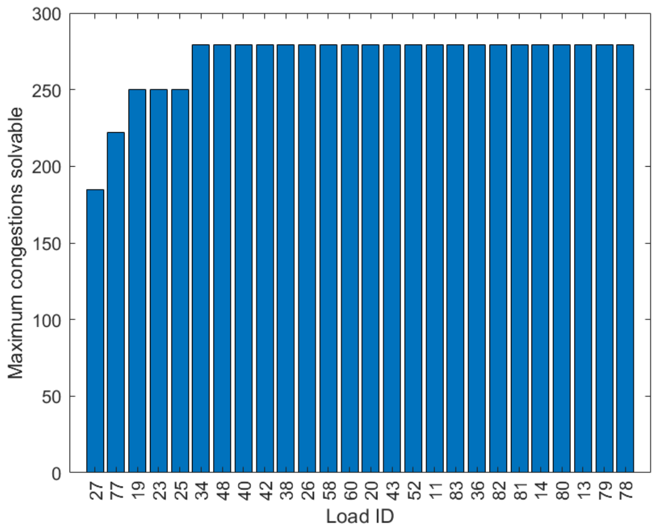


Figure A.24: congestions solvable in Case 4.3

List of Figures

Figure 1.1: summary of local ancillary services [25] 8
Figure 1.2: EcoGrid new real-time market [26] 10
Figure 2.1: A classification of DR programs 21
Figure 2.2: A classification of DR benefits 23
Figure 2.3: A classification of DR setups costs 24
Figure 3.1: Load cutting (left) and load shifting (right) profiles [54] 30
Figure 3.2: Grid network with different paths 35
Figure 3.3: Grid network with different paths and crossroads 35
Figure 3.4: Grid with failure and counterfeeding 36
Figure 3.5: Example of bids by active resource 43
Figure 3.6: Admissible apparent power diagram with a congestion 43
Figure 3.7: Admissible apparent power diagram without congestions (DR) 44
Figure 3.8: Admissible apparent power diagram without congestions (GE) 52
Figure 4.1: topology of the test grid 56
Figure 4.2: Testing variable power data 58
Figure 4.3: Case 1.1: increasing nominal power 59
Figure 4.4: Case 1.2: increasing nominal power 60
Figure 4.5: Case 1.3: increasing nominal power 60
Figure 4.6: Testing variable power 2 data 62
Figure 4.7: Case 2 63
Figure 4.8: Data for testing variable length 63
Figure 4.9: Testing variable length data 64
Figure 4.10: Case 3.1: increasing the length of the branches 65
Figure 4.11: Case 3.2: increasing the length of the branches 65
Figure 4.12: Case 3.3: increasing the length of the branches 65
Figure 4.13: 3D plot 66

Figure 4.14: Testing variable prices data........ 67
Figure 4.15: Case 4.1: increasing the price of the bids........ 67
Figure 4.16: Case 4.2: increasing the price of the bids........ 68
Figure 4.17: Case 4.3: increasing the price of the bids........ 68
Figure 5.1: Example of nodes in the grid........ 73
Figure 5.2: Trieste distribution grid simplified version........ 74
Figure 5.3: Nodal P and Q injections in Trieste grid, normal operations........ 76
Figure 5.4: Nodal P and Q withdrawals in Trieste grid, normal operations........ 77
Figure 5.5: Branch currents and loading in Trieste grid, normal operations........ 77
Figure 5.6: cost comparison for demand increase of +20% (left) and +25% (right)........ 78
Figure 5.7: Grid with failure, case 1A.1........ 81
Figure 5.8: Electrical results of Case 1A.1........ 81
Figure 5.9: Grid with failure, case 1B.1........ 82
Figure 5.10: Electrical results of Case 1B.1........ 82
Figure 5.11: Grid with failure, case 2A.1........ 83
Figure 5.12: Electrical results of Case 2A.1........ 84
Figure 5.13: Grid with failure, case 2B.1........ 84
Figure 5.14: Electrical results of Case 2B.1........ 85
Figure 5.15: Grid with failure, case 3A.1........ 86
Figure 5.16: Electrical results of Case 3A.1........ 86
Figure 5.17: Grid with failure, case 3B.1........ 87
Figure 5.18: Electrical results of Case 3B.1........ 87
Figure 5.19: Grid with failure, case 4.1........ 88
Figure 5.20: Electrical results of Case 4.1........ 89
Figure 5.21: Grid with failure, case 1A.2........ 90
Figure 5.22: Grid with failure, case 1B.2........ 90
Figure 5.23: Grid with failure, case 3A.2........ 91
Figure 5.24: Grid with failure, case 3B.2........ 92
Figure 5.25: Grid with failure, case 4.2........ 93
Figure 5.26: Grid with failure, case 4.3........ 93
Figure 6.1: simulation hour by hour of case 1A.1........ 98

Figure 6.2: simulation hour by hour of case 1B.1 99

Figure 6.3: simulation hour by hour of case 2A.1 99

Figure 6.4: simulation hour by hour of case 2B.1 100

Figure 6.5: simulation hour by hour of case 3A.1 100

Figure 6.6: simulation hour by hour of case 3B.1 101

Figure 6.7: simulation hour by hour of case 4.1 102

Figure 6.8: average yearly cost for case 1A.1 (left) and 1B.1 (right) 105

Figure 6.9: average yearly cost for case 2A.1 (left) and 2B.1 (right) 105

Figure 6.10: average yearly cost for case 3A.1 (left) and case 3B.1 (right) 106

Figure 6.11: average yearly cost for case 4.1 106

Figure 6.12: congestion events cost for case 1A.1 (left) and case 1B.1 (right) 108

Figure 6.13: congestion events cost for case 2.A1 (left) and case 2B.1 (right) 108

Figure 6.14: congestion events cost for case 3A.1 (left) and case 3B.1 (right) 109

Figure 6.15: congestion events cost for case 4.1 109

Figure 6.16: Worst case scenarios for Case 1A.1 (left) and Case 1B.1 (right) 113

Figure 6.17: Worst case scenarios for Case 2A.1 (left) and Case 2B.1 (right) 114

Figure 6.18: Worst case scenarios for Case 3A.1 (left) and Case 3B.1 (right) 114

Figure 6.19: Worst case scenarios for Case 4.1 115

Figure 6.20: increasing number of congestions for case 1A.1 (left) and case 1B.1 (right) 117

Figure 6.21: increasing number of congestions for case 2A.1 (left) and case 2B.1 (right) 117

Figure 6.22: increasing number of congestions for case 3A.1 (left) and case 3B.1 (right) 118

Figure 6.23: increasing number of congestions for case 4.1 118

Figure 7.1: example grid with different loads 125

Figure 7.2: different position of the faults in Case 1 126

Figure 7.3: probability of activation of case 1A 127

Figure 7.4: probability of activation of case 1B 128

Figure 7.5: different position of the fault in Case 2 129

Figure 7.6: probability of activation of case 2A 129

Figure 7.7: probability of activation of case 2B 130
Figure 7.8: different position of the fault in Case 3 130
Figure 7.9: probability of activation of case 3A 131
Figure 7.10: probability of activation of case 3B 132
Figure 7.11: different position of the fault in Case 4 133
Figure 7.12: probability of activation of case 4 135
Figure 7.13: Capacity remuneration for Case 2 (left) and Case 4 (right) 137
Figure A.1: loads connected to the medium voltage grid of Trieste 151
Figure A.2: Trieste grid page 1 152
Figure A.3: Trieste grid page 2 153
Figure A.4: Trieste grid page 3 154
Figure A.5: Trieste grid page 4 155
Figure A.6: Trieste grid page 5 156
Figure A.7: Electrical results of Case 1A.2 157
Figure A.8: Electrical results of Case 1B.2 157
Figure A.9: Electrical results of Case 3A.2 158
Figure A.10: Electrical results of Case 3B.2 158
Figure A.11: Electrical results of Case 4.2 159
Figure A.12: Electrical results of Case 4.3 159
Figure A.13: congestions solvable in Case 1A.1 168
Figure A.14: congestions solvable in Case 1A.2 168
Figure A.15: congestions solvable in Case 1B.1 169
Figure A.16: congestions solvable in Case 1B.2, congested path (right) and non-congested path (left) 169
Figure A.17: congestions solvable in Case 2A.1 170
Figure A.18: congestions solvable in Case 2A.2 170
Figure A.19: congestions solvable in Case 3A.1 (left), 3A.2 (center) and 3A.3 (right) 171
Figure A.20: congestions solvable in Case 3B.1 (left), 3B.2 (center) and 3B.3 (right). 171
Figure A.21: congestions solvable in Case 3B.1, 3B.2 and 3B.3 171

Figure A.22: congestions solvable in 4.1, congested path (left) and non-congested path (right)........ 172

Figure A.23: congestions solvable in Case 4.2........ 172

Figure A.24: congestions solvable in Case 4.3........ 173

List of Tables

Table 2.1: eDistribuzione construction work for MV connections 26
Table 2.2: Unareti construction work for MV connections 27
Table 3.1: Cable catalogue merged 51
Table 4.1: Data of Case 1 58
Table 4.2: Data of Case 1.2 61
Table 4.3: Data of case 3 63
Table 4.4: Data of case 4 66
Table 5.1: Primary HV/MV substations in Trieste 72
Table 5.2: Primary MV/MV substations in Trieste 72
Table 5.3: Conductors between two nodes 74
Table 5.4: Nominal power increment 78
Table 5.5: Case 1 summary of results 83
Table 5.6: Summary of case 2 results 85
Table 5.7: Summar of Case 3 results 88
Table 5.8: Case 4 results 89
Table 5.9: Summary of part 2 results 94
Table 6.1: different probabilities for different price ranges 103
Table 6.2: summary of the average congestion event 110
Table 6.3: summary of congestion events break-even costs 111
Table A.1: average yearly cost for case 1A.1 160
Table A.2: average yearly cost for case 1B.1 160
Table A.3: average yearly cost for case 2A.1 161
Table A.4: average yearly cost for case 2B.1 161
Table A.5: average yearly cost for case 3A.1 161
Table A.6: average yearly cost for case 3B.1 162
Table A.7: average yearly cost for case 4.1 162

Table A.8: worst congestions for case 1A.1 163
Table A.9: worst congestions for case 1B.1 163
Table A.10: worst congestions for case 2A.1 163
Table A.11: worst congestions for case 2B.1 164
Table A.12: worst congestions for case 3A.1 164
Table A.13: worst congestions for case 3B.1 165
Table A.14: worst congestions for case 4.1 165
Table A.15: difference between the DR of case 1A.1 and the reference GE 166
Table A.16: difference between the DR of case 1B.1 and the reference GE 166
Table A.17: difference between the DR of case 2A.1 and the reference GE 166
Table A.18: difference between the DR of case 2B.1 and the reference GE 167
Table A.19: difference between the DR of case 3A.1 and the reference GE 167
Table A.20: difference between the DR case 3B.1 and the reference GE 167
Table A.21: difference between the DR of case 3B.1 and the reference GE 168

List of Acronyms

ANM	Active network management
AS	Ancillary services
BESS	Battery energy storage system
BSP	Balance service provider
CAPEX	Capital Expenditure
COP	Conference of Parties
DSO	Distribution system operator
DER	Distributed energy resources
DR	Demand response
ESCO	Energy service company
EV	Electric vehicles
EU	European Union
GE	Grid extension
GHG	Greenhouse gases
HP	Heat pump
HV	High voltage
HVAC	Heating, ventilation and air conditioning
IBP	Incentive based program
ICT	Information and communication technology
IEA	International Energy Agency

IEEE	Institute of Electrical and Electronics Engineers
LV	Low voltage
MCC	Maximum carrying capacity
MV	Medium voltage
OPEX	Operating Expenditure
PU	Per unit
PBP	Price based program
PV	Photo voltaic
RES	Renewable energy sources
TIDE	Testo integrato dispacciamento elettrico
TSO	Transmission system operator
UVAM	Unità virtuali abilitate miste

Acknowledgments

I would like to thank Professor Davide Falabretti for all the help and advice that he has patiently provided me during these last months. The opportunity of working on this thesis led me to focus and deepen a topic of my interest from an interdisciplinary point of view. I would also like to thank Francesco Gulotta who accompanied me in the whole duration of the thesis helping me in times of difficulty and solving all my doubts. And finally, I would like to thank Professor Enrico Cagno for agreeing to supervise my work.