FACULDADE DE ENGENHARIA DA UNIVERSIDADE DO PORTO

Comparision between traditional network reinforcement and the use of DER flexibility

Tiago José Pires de Almeida Torres

Mestrado Integrado em Engenharia Eletrotécnica e de Computadores

Supervisor: Doutor Ricardo Jorge Gomes Sousa Bento Bessa

Second Supervisor: Professor Doutor Manuel António Cerqueira da Costa Matos

October 30, 2020

Resumo

Historicamente, o planeamento de redes de distribuição (PDP) consiste em determinar quais os investimentos a executar garantindo a satisfação de consumos previstos, obedecendo a restrições técnicas. Se até agora, o PDP se centra numa gestão passiva da rede, na qual existe um grau mínimo de monitorização e controlo dos parâmetros da rede, atualmente o principal desafio do planeamento da rede de distribuição é a integração contínua dos recursos energéticos distribuídos (DER), especialmente das fontes de energia renováveis (RES).

Esta nova tendência nos sistemas de distribuição, devido à incerteza e produção variável de energia por parte dos DER, exige mudanças nos mercados de electricidade e o desenvolvimento de novos modelos e metodologias para o PDP.

Por conseguinte, o PDP entra na era das Redes Inteligentes (SGs). O planeamento da metodologia tradicional para operação e gestão da rede de distribuição deve transitar para uma metodologia de gestão activa da rede (ANM).

Dentro deste contexto, esta tese apresenta uma metodologia PDP que inclui as duas metodologias de tomada de decisão do operador da rede de distribuição (DSO): o planeamento do reforço tradicional da rede de distribuição, onde os problemas técnicos são resolvidos através do reforço dos activos existentes, e a gestão preditiva da rede (planeamento ANM) que permite ao DSO contratar flexibilidade de consumo/geração (com antecedência) aos DER para ajudar na gestão e operação da rede em caso de problemas de congestionamento/tensão.

Primeiramente, é criado um cenário de base para o PDP. Depois, é desenvolvida a metodologia PDP com ambas as soluções de planeamento da rede (reforço e ANM) que é aplicada a um caso de teste através de um horizonte de planeamento definido e com crescimento de consumo e geração proveniente de fontes renováveis (RES) definido em cada ano.

De seguida, é desenvolvida uma metodologia de análise custo-benefício (CBA) para determinar o custo total de cada solução de planeamento. Ainda na mesma metodologia, é realizada uma análise de sensibilidade para estimar o custo máximo que o planeamento ANM pode assumir como sendo rentável (ponto de equilíbrio), e estabelece-se uma avaliação dos indicadores-chave de desempenho (KPIs) para determinar os benefícios técnicos e económicos da mudança de um planeamento passivo (reforço da rede) para um planeamento moderno (ANM).

Finalmente, para o horizonte de planeamento, o paradigma chave desta tese pode ser revelado: se activar os serviços de flexibilidade distribuídos (planeamento ANM) é a solução óptima em termos de custos para a resolução de problemas técnicos e melhoria de aspetos da rede, sendo que o planeamento de reforço tradicional da rede oferece uma solução alternativa.

Palavras-chave: Planeamento da Rede Distribuição, Planeamento do Reforço da Rede, Redes Inteligentes, Gestão Preditiva da Rede, Recursos Energéticos Distribuídos, Flexibilidade, Análise de Custo-Benefício, Ponto de Equilíbrio, Indicadores-Chave de Desempenho

Abstract

Historically, power distribution planning (PDP) consists of determining which investments to be made, supplying the expected demand and restricted to technical constraints. If up to now, the PDP focuses on a passive network management, in which there is a minimum degree of monitoring and control of network parameters, today the key challenge of distribution planning is the continuous integration of distributed energy resources (DER), specially renewable energy sources (RES).

This new trend in the power distribution systems, due to the uncertainty nature and variable power production of DER, requires changes in the electricity markets and development of new models and methodologies for PDP.

Hence, the PDP enters in the Smart Grids (SGs) era. The traditional methodology planning for operation and management of the distribution grid must transit to an active network management (ANM) methodology.

Within this context, this thesis presents a PDP methodology which includes the two distribution system operator (DSO) decision-making methodologies: traditional power distribution reinforcement planning, where technical problems are solved by reinforcing existing assets, and the predictive grid management (ANM planning) that allows the DSO to contract power consumption/generation flexibility (ahead in time) from DER to assist in the management and operation of the grid in case of congestion/voltage problems.

Firstly, a base case scenario for the PDP is created. Then, the PDP methodology with both network planning solutions (reinforcement and ANM) is developed and each planning alternative is applied to a test case through a defined planning horizon and with an established load and RES capacity growth for each year.

Secondly, a cost-benefit analysis (CBA) methodology is developed to determine the total cost of each planning solution. Still in the same methodology, a sensitivity analysis is performed to estimate the maximum cost that the ANM planning can assume to be cost-effective (break-even point), and a key performance indicators (KPIs) assessment is established to determine technical and economical benefits of shifting form a passive (grid reinforcement) planning to a modern (ANM) planning.

Finally, for the defined planning horizon, the key paradigm of this thesis can be disclosed: whether activate distributed flexibility services (ANM planning) is the cost-optimal solution for solving network technical problems and improving network technical aspects, as the traditional reinforcement planning offers an alternative solution.

Key words: Power Distribution Planning, Power Distribution Reinforcement Planning, Smart Grids, Predictive Grid Management, Active Network Management, Distributed Energy Resources, Flexibility, Cost-Benefit Analysis, Break-Even Point, Key Performance Indicators

Acknowledgements

First of all, I would like to start thanking Doctor Ricardo Bessa, Senior Research at INESC TEC, for accepting me under his supervision and allowing me the opportunity to work in such interesting subject. His visionary and rigorous thinking opened my mind to new perspectives and had a great influence throughout the development of this work. Without his guidance and advises this thesis would be a very tough journey.

To my second supervisor Professor Manuel Matos, Full Professor at the Faculty of Engineering of the University of Porto (FEUP) for all the inspiration and encouragement during the development of this work, and without whom this collaboration with INESC TEC would not be possible.

I cannot forget Luís Brito, Research at INESC TEC, for all his confidence and willingness to help during the most troubled moments, and for always motivating me to keep moving forward.

To all my colleagues and friends, specially Afonso, Pedro, Francisco, Manuel and Miguel for their friendship and continuous encouragement. All of your support during the last years helped me to get to this point and accomplish this goal. Thank you all!

Finally, I would like to express my sincere gratitude to my family, specially my parents and sister, for their unconditional support, patient and guidance during my academic journey. To them I owe all my success and accomplishments.

Tiago Torres

"Kites rise highest against the wind, not with it"

Winston Churchill

Contents

List of Figures

List of Tables

List of Acronyms and Abbreviations

AC	Alternating Current
ACS	Ant-Colony Search
ADN	Active Distribution Network
AIS	Artifical Immune Systems
ANM	Active Network Management
BaU	Business as Usual
CAES	Compressed Air Energy Storage
CAPEX	Capital Expenditure
CBA	Cost-Benefit Analysis
DDCI	Deferred Distribution Capacity Investment
DER	Distributed Energy Resources
DG	Distributed Generation
DNO	Distribution Network Operator
DP	Dynamic Programming
DSO	Distribution System Operator
DTDCI	Deferred Transmission and Distribution Capacity Investment
ENS	Energy Not Supplied
ERSE	Entidade Reguladora dos Serviços Energéticos
GA	Genetic Algorithm
GEFCom	Global Energy Forecasting Competition
HC	Hosting Capacity
HV	High Voltage
KPI	Key Performance Indicator
MIP	Mixed Integer Programming
MILP	Mixed Integer Linear Programming
MINLP	Mixed Integer Non-Linear Programming
LP	Linear Programming
LV	Low Voltage
MIBEL	Mercado Ibérico de Electricidade
MV	Medium Voltage
NLMIP	Non Linear Mixed Integer Programming
NPC	Network Planning Case
NPV	Net Present Value
OPEX	Operational Expenditure
OPF	Optimal Power Flow
PDIRD	Plano de Desenvolvimento e Investimento na Rede de Distribuição
PDP	Power Distribution Planning
PF	Power Flow
PLF	Probabilistic Load Flow
PSO	Particle Swarm Optimization
PV	Photovoltaic
QMIP	Quadratic Mixed Integer Programming
REC	Renewable Energy Curtailment
RES	Renewable Energy Sources
SG	Smart Grid
TOTEX	Total Expenditure
TS	Tabu Search
TSO	Transmission System Operator

Chapter 1

Introduction

In this chapter, a brief synopsis about the addressed problem will be discussed. First, the context to the development of this thesis will be presented, referring the change of power systems paradigm and the importance of modern approaches to cope with new challenges. Then, the objectives of this work will be detailed. Finally, the structure of the thesis will be exposed.

1.1 Context

The traditional power distribution planning (PDP) represents the reinforcement of distribution network, by determining which investments (up rating transformers and lines/cables capacity) are necessary to perform in the network in order to increase the overall network capacity, ensure that all network assets do not exceed their nominal ratings, avoid voltage and congestion problems and to supply the expected demand. With this type of management it was expected for the grid to work with the minimum amount of control and without facing constraints in the long term horizon. This would result in investments that would only make effect after a long period of time.

A core element of the current transformation of energy systems around the world is the rapid and massive integration of distributed energy resources (DER), especially renewable energy sources (RES), into the network. The sharp increase of DER into the grid makes it extremely expensive to continue with the traditional PDP policy, because of the fast deployment of DER and due to the uncertainty nature and variable power production of DER. Therefore, it is required changes in the electricity markets, development of new models and methodologies for the PDP and additional efforts to balance the system.

In this context, the operation and management of the power system, namely in distribution grids with high penetration of DER, will have to cope with congestion and voltage problems due to the continue increase in the electricity consumption as well as high intermittent power output of RES. Therefore, adequate support tools for preventive operation and management of distribution grid must be taken into account. The traditional PDP of the network must transit to an active network management (ANM) - Smart Grid paradigm.

Part of this paradigm includes the opportunity to use distributed flexibility from DER instead of reinforcement to solve distribution network constraints, balance the system demand and generation and to postpone investment actions that otherwise would be performed in the network. Furthermore, distributed system operators (DSOs) will contract power flexibility from DER to manage technical problems in real time, depending on various conditions such as location, upward and downward flexibility, operating cost, among others. The modern PDP will be defined in order to identify the best technical and economic balance between the innovative active network management and the traditional network reinforcement.

In this thesis, the modern PDP problem will be addressed by comparing the two DSO decision-making planning alternatives: power distribution reinforcement planning and active distribution grid management. Both network planning solutions will be applied to a test case throughout a defined planning horizon to seek the investments performed in the network and the amount of activated flexibility services by DSO from DER. Also, the total cost of each solution will be disclosed, likewise the technical and economical benefits of shifting from traditional reinforcement planning to a predictive grid management planning. Finally, a sensitive analysis will be performed to access the maximum total cost that DSO is willing to pay for the ANM strategy to be cost-effective.

The development of the both PDP methodologies, reinforcement planning methodology and ANM methodology, was carried out using the software Pandapower.

1.2 Objectives

The main objective of this work is to develop a cost-benefit analysis (CBA) between the predictive grid management (ANM planning with activation of flexibility services) and the traditional grid reinforcement. To achieve this goal, it is necessary to define the following sub-objectives:

- Define a base case scenario, which represents the year zero and is the planning baseline for the defined planning horizon;

- Develop a PDP methodology embedded with the two DSO decision- making methodologies and applied to a test case. DSO will use, separately, the traditional grid reinforcement and predictive grid management (with flexibility activation) methodologies to solve technical problems that may occur over the planning horizon. Furthermore, an alternating current (AC) optimal power flow (OPF) is used to estimate the amount of energy not supplied by loads and/or energy not injected by RES in the reinforcement planning and the activated/contracted flexibility from loads and distributed generation (DG) units (from RES) by the DSO in the ANM planning;

- Develop a CBA methodology to determine the total cost of each network planning solution and with a sensitivity analysis estimate the maximum cost that DSO is willing to pay for ANM planning solution to be cost-effective (break-even point). Also, establish a key performance indicators (KPIs) assessment to reveal some important points: network investment deferral (monetary value and number of years) and reduction in network power losses, from adopting a predictive grid management as the planning solution for technical problems.

1.3 Structure

In addition to chapter 1, this thesis is organized in four more main chapters.

In chapter 2, is presented the relevant work that has already been made within the scope of this work. First, the traditional distribution grid planning and reinforcement is analysed, with special attention to grid reinforcement, current methods applied to address the PDP problem and the drawbacks of traditional planning approaches. Then, the modern power distribution planning is investigated, with particular consideration for the modern methods applied to PDP problem, the concept of flexibility and the impact of ANM. Also, data modelling is analysed to seek the changes when passing from traditional to current to modern planning. Finally, some relevant information is given regarding the process of a CBA between the business as usual (BaU) scenario and smart grid (SG) scenario, with some detailed topics about establishing the baseline, the concept of discount rate, identification of costs and benefits (with definition of relevant KPIs).

In chapter 3 the modelling of a PDP problem is addressed by comparing and explaining two DSO decision-making methodologies: power distribution reinforcement planning and active distribution grid management. First, it will be exposed and explained some important features of the two possible DSO planning solutions. Then, the PDP methodology that includes both planning solutions methodologies will be presented and some important methodology steps will be detailed. Finally, a CBA methodology will be outlined to estimate the total cost of each DSO planning solution, the break-even point and with an additional KPIs assesment to determine some technical and economical benefits of shifting from a traditional reinforcement planning to an active network management planning.

In chapter 4, the PDP methodology embedded with reinforcement and ANM planning methodologies depicted in chapter 3 is applied to a real medium voltage (MV) German power distribution network. Therefore, the suitability of both DSO planning solutions will be evaluated by giving important comments about each strategy and sustained by relevant results about technical and economical appraisal over the defined period. First, the system test data along with a study about system's current stage and some notes will be given, before addressing the PDP over the next years. Then, a technical analysis throughout the planning horizon will be verified, presenting some relevant information regarding the critical years. Next, the data used to perform the CBA will be pointed out. Finally, the results information regarding technical and monetary aspects from both planning solutions will be exposed along with the sensitivity analysis and KPIs results.

In chapter 5 is mentioned the main conclusions of this work in relation to the PDP exercise and the two possible planning solutions to solve network technical problems, taking into account annual consumption increases and high penetration of DG. Also, future complementary perpectives are given.

Finally, appendix A and appendix B are added to the work with complementary information about the test system and results.

Chapter 2

State of the Art

2.1 Traditional Distribution Grid Planning and Reinforcement

In the beginning, the main paradigm in PDP was the electrification. The goal was to encourage consumption and the investments guided the power distribution costs.

With the succeeded connection of all consumers, the electrification rate decreased and the power quality became the main purpose of PDP. The emergence of regulatory instruments to improve DSOs' power quality was caused by the need to increase the quality of energy supply in terms of economic consequences for the consumers, regarding distribution network failures [8].

Traditionally, network distribution planning points out where will be necessary to invest in network, as well as when will network investments be needed and the type of investment that is required [9, 10].

In 1997, the authors in [4, 11] summarized the main topics considered in the traditional distribution grid planning:

- Optimal location of the feeders and optimal individual feeder design;
- Optimal allocation of load;
- Optimal allocation of substation capacity;
- Optimal mix of transformers by substation.

Therefore, the classic PDP consists of finding the most economical solution with the optimal location and size of new substations and/or feeders, as well as the reinforcement of existing ones in order to supply the future demand [8, 12].

The main goal of the classic PDP refers to the minimization of an economic cost function (e.g. the investment cost, reinforce/replace substations and/or feeder, as well as the energy loss cost), restricted to a set of technical and operational factors (e.g. voltage fluctuation) [12].

Demo-graphic aspects of a region like the geographic barriers or the population growth have a tremendous impact on distribution grid investment and operational costs [8].

Historically, distribution networks have been designed to distribute the electric energy generated in the conventional power plants to the loads connected to the distribution networks - unidirectional power flow [13, 14]. For this reason, the network process used a network planning case (NPC) that describes the critical load conditions to dimension the network.

Therefore, distribution network planning is mainly based on load demand forecasting whereas DG is often excluded, reflecting that these network analyses are conducted on passive distribution networks [1, 15].

When it comes to connecting DG in traditional distribution grid planning, the "fit and forget" approach is also applied [16]. The DG units operate under a constant power factor and are treated like negative loads. If the integration of DG is less common and geographically dispersed, the planning process is not influenced by the DG. On the contrary, if DG integration is high in a given geographical area, many challenges crop up [2]. Hence, there is a need to consider important aspects such as voltage arise, reverse power flows and congestion.

Although the passive way of planning and operating distribution grids has proven cost-effective in the past several years, it turns out to be a barrier for increasing the penetration of DG [14, 16].

Traditional PDP is known as a "predict and provide" process and is accomplished by the DSOs. Taken into account the predicted load growth, the performance criteria (e.g., voltage, reliability and protection), the geographic information along with other constraints, network planners aim to find engineering achievable and economic enlightened network solutions for meeting the electric demands distributed over a distinct area [13].

In general, distribution networks are sized to handle with the worst-case scenario (mostly in terms of loads and voltage drops, along with certain security constraints) of a given load forecast and in a way that minimum or no active operation is required, even though these generally occur only a few hours a year. These approach is known as "fit and forget" and is carried out in a deterministic way, which means no uncertainties are considered [17, 18].

The "fit and forget" strategies historically employed took most electricity utilities to execute their grid analysis based on load demand forecasting, underlining the importance of this concept for the NPC and neglecting the integration of DG.

Load Forecasting

In the traditional grid planning, forecasts tend to be for load demand while limited evidence is available of forecasts for DG. Most eletricity utilities focus on power demand and DG is mostly not visible to the network operators, nor it is considered in forecasts [1, 2]. The lack of forecasts for DG appears to be a compromise for the accuracy of the demand forecasting and could be a major drawback for the planning of ADNs.

The load growth of a geographical area is an important factor that impacts the expansion and reinforcement of the distribution grid. The inputs for load forecasting are the social economic indicators, demographic and weather data, and land use plans. The output for the load forecasting methods are the load densities [1] as they are used to properly design the distribution network.

Long-term forecasting (time horizon of 15-20 years) and short-term forecasting (time horizon up to 5 years) are the two common time scales regarding the load forecasting.

Grid Reinforcement

Accordingly to [19, 20], the traditional grid investment/reinforcement practice method consists of replacing the transformers with higher capacity ones and hanging cables with large cross-sectional area conductors, avoiding voltage, capacity and load supply problems. A cable with larger cross-sectional area presents low impedance (Z) and consequently produces smaller voltages variations.

Reinforcement of distribution grids has usually been planned through a set of worst-case scenarios and it corresponds to the BaU network solutions (e.g., line/transformer refurbishment), appealing to the "fit and forget" approach [10, 18].

With this type of management, it was expected for the grid to operate with the minimum amount of control and without facing constraints in long-term horizon, resulting in investments that only make effect after a long period of time [21].

2.1.1 Current Methods

During the process of PDP, some assumptions are made to simplify the work plan at each stage [13], including:

- Electrical load can be taken as passive demand;
- DG units are treated as negative loads and operate under constant power factor;
- The load flow is unidirectional;
- Distribution grid operation has a small impact on distribution grid planning.

These assumptions lead to a sizeable consequence, that many utilities choose to have "peak planning" method in the planning process. To that end, the best alternative is found when it meets the expected peak load at a minimum cost [10, 13].

Traditional PDP is commonly based on a static load flow computation (snapshot) that takes into account the maximum coincident load to determine the grid infrastructure dimensioning [22].

The conventional distribution network planning process, currently chased by many distribution utilities, is illustrated in Figure 2.1.

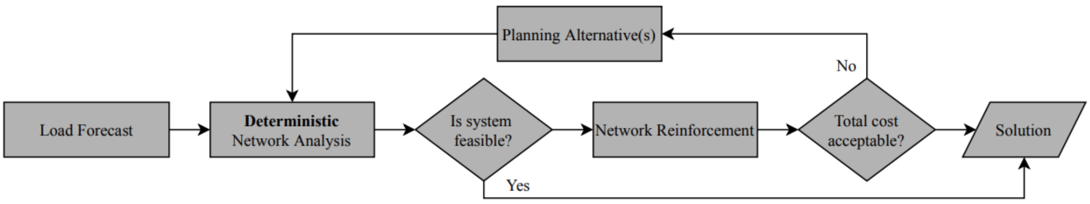


Figure 2.1: Flowchart of the traditional PDP process, adaptaded from [1]

This process is repeated for each year of a long-term planning horizon (15-20 years). The load forecasting rules the load conditions for the corresponding planning horizon. Once load demand is known, steady state power flows and short circuit analysis are executed to calculate the power flow in the distribution lines, the voltage fluctuations and the short circuit current flows.

If the system is not technically feasible (particularly for the design of the feeders), the distribution network does not comply with the power systems technical and operating constraints. Thus, distribution network has to be reinforced with new components (e.g., new conductor sizes, transformers, feeders, capacitor placement, etc.) or new HV/MV substations to meet the future demand [1, 2, 16].

For example, if a given distribution cable or line becomes overloaded at specific year of the planning horizon, it will be needed to replace immediately in next following year. In order to do that, the physical characteristics of the cable/line to be replaced, in specific its nominal voltage and cross-sectional area, must be taken into account. Despite of that, if the cross-section of the overloaded cable or line is already very high (240 mm^2 or more), the load of the distribution grid may have to be redistributed through the distinct feeders connected to the primary HV/MV substations [1].

In case that the corresponding cost of this solution is too high or the reinforcement practice cannot accomplish satisfactory performance, then the initial solution is reexamined and an alternative solution will be prepared. The procedure ends when a satisfactory solution is reached to meet the future distribution network requirements with the minimum cost, i.e., the most cost-effective solution [1, 16].

PDP problem

The planning problem can be solved using static (single stage) or dynamic (multi-stage) planning model. The static planning model is used to meet the network's immediate needs, i.e., determines the planning requirements in only one single time over the planning horizon. The dynamic planning determines the planning requirements in successive expansion plans over several periods (smaller time frames of the overall period). That is, the necessary investments for the initial steps are carried out while the investments for the subsequent stages are reassessed in the future, with the adoption of updated forecasts [12, 23, 24].

The methods that are used to solve the PDP problem can be divided into two categories: mathematical (numerical) optimization and heuristic planning methods.

Numerical Methods

Some of the methods of mathematical optimization to solve the PDP problem include linear programming (LP), the class of mixed integer programming (MIP) and dynamic programming (DP) [25, 26, 27, 28]. In this approach, it is possible to represent the major constraints explicitly (power flow equations, voltage drops, equipment capacities and budget) and to minimize fixed (investment) and variable (operating and maintenance) costs arising form installation and replacement of equipment. These methods guarantee to find optimum solution [23, 27].

MIP is the most used method with continuous and binary/integer variables. The continuous variables of the problem are the power flows in all branches of the distribution grid, and the binary/discrete variables contain the decision variables associated with the installation of new substations/feeders branches and with the replacement/capacity of existing substations/feeders branches.

The goal of the optimization process is to find a set of binary decision variables linked to a set of continuous variables that minimize the objective function (total installation and operational cost) and meet the constraints demanded on the problem [29, 30]. There are different types of MIP methods to be adopted: mixed-integer linear programming (MILP) [30, 31], quadratic mixed integer programming (QMIP) [32], Branch and Bond [33] and Benders Decomposition [25, 31, 34].

Heuristic Methods

Since 1980, much effort has been pointed toward solving the PDP problem using heuristic algorithms, which have become an alternative to mathematical programming. Heuristic methods gained attention because they can operate in a straightforward fashion with nonlinear constraints and objective function. These methods are based on intelligent searches that have no guarantee of finding an optimal solution, but cope with local optimal solutions [8, 23]. This approach also introduce aspects, such as losses, reliability and uncertainties.

The heuristic approaches used so far are based on expert systems, network flow programming and evolutionary algorithms, i.e., ant-colony search (ACS), genetic algorithm (GA) [31, 35, 36], particle swarm optimization (PSO) , tabu Search (TS) [8, 26, 37, 38] and artificial immune systems (AIS), etc. [12, 30, 31, 39].

Qualitative Evaluation

- Numerical methods find the optimal solution accurately and the time to compute the optimal solution is low. On the other hand, these methods have difficult to manage power system equations into an optimization model [12] and require non acceptable computational effort for large scale realistic networks [14];

- Heuristic methods are usually robust and provide near-optimal solutions for complex large-scale PDP problems, however there is no guarantee that they will find a global optimum solution. Generally, these methods require high computational effort [28, 31].

2.1.2 Drawbacks of Traditional Planning Approaches

The fast technological developments, deregulation of energy markets and the policies motivated by economic, environmental and societal drivers lead to a tremendous increase in DG [8]. The integration of DG gain major interest among electric power systems planners and operators, energy policy makers and regulators, as well as developers, therefore this concept will play a significant role in reaching environmental and development targets [38, 40].

The strong DG penetration rises challenges in the distribution systems, because these systems were designed assuming that electric energy would be carried unidirectional from HV/MV substations downstream to consumers [8]. The high penetration of DG units from RES may lead to various problems and operational limit violations if exceeds a particular limit known as the systems's hosting capacity (HC) [41]. When the total capacity of RES increases, RES investments start to interact with demand driven investments and distribution network should not be reinforced only due to load demand growth, but also to host connected renewable generation [1].

Historically, network expansion planning has been based on maximum load scenarios, but in the case of a high DG penetration, the grid is dimensioned to deal with maximum generation [31]. The high penetration rate of DG leads to two worst case conditions: the heavy load flow (maximum load and no generation) and the reverse power flow (minimum load and maximum generation). These extreme parameters do not consider the time variability of demand and generation, and these conditions may only apply for a few hours per year [31, 40].

In addition, the intermittent characteristics of many RES may accentuate any dynamic issues of the new generators present in the network [9, 10]. Thus, the "fit and forget" approach will result in massive network investments only motivated to deal with worst-case scenarios that may have an extremely low probability of occurrence [17]. The uncertainties in planning concepts and financial support surrounding DG investments pose DSOs with major challenges as to what, where and when to reinforce the system, in order to facilitate the transition towards a low-carbon economy, without the risk of stranded assets [16]. Furthermore, DSOs are committed to integrate, at reasonable costs, all this new DG into their distribution networks without jeopardizing the existing quality of service [4, 38].

The high penetration of DG, driven by the increasing investment in low carbon generation, often triggers network reinforcement (investment in network components such as lines, cables, transformers , etc.). The "fit and forget" approach to network investment, arising from DG connection, leads to sub optimal solutions causing over investment in networks with high connection costs but low utilization. In addiction, these high costs and the uncertainty of future connection costs can make the financial risk of generation investment unattractive to developers. Instead of reinforcing the network using only traditional network solutions, alternative lower-cost solutions have been explored [42, 43].

Therefore, there is a general consensus that the "fit and forget" approach is no longer suitable to modern distribution planning because of the high and not necessary expenditures caused by its application [4]. Consequently, DSOs need to move form the planning of the passive distribution grid towards a distribution network in which the active management of the DG is taken into account, as well as the application of novel concepts [1, 40].

In Figure 2.2 is depicted the potential changes paving the transition towards a so called low-carbon economy. This transition will change the way electric power systems are planned and operated. Other changes in generation, load and the electricity infrastructure itself (such as the use of electricity storage) are part of the vision behind the need of a more intelligent power system [2].

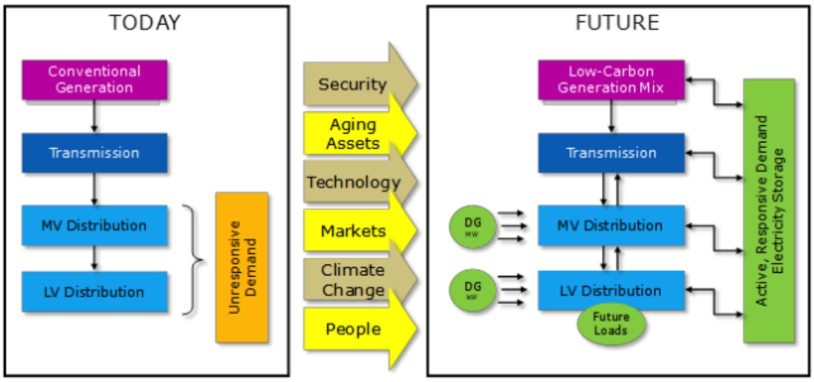


Figure 2.2: Agents of change [2]

2.2 Modern Power Distribution Planning

In order to overcome the limitations previously stated and to facilitate the integration of the low-carbon technologies, the use of an active approach for managing distribution networks (including both network elements and participants) has been proposed by academia and industry [17, 44]. Due to the increasing penetration of DG connected to MV, particularly in Europe, significant interest was first given to coordinated control approaches that could mitigate voltage or congestion issues.

When DG penetration has reached certain levels and cannot be neglected any more, the distribution planning and operation practices should be more oriented to active power flow management [15]. Therefore, in order to avoid potentially prohibitive network reinforcements costs, several ANM strategies have been recently proposed as alternatives to the "fit and forget" approach [42]. A plenty of smart grids (SGs) demonstrations and deployment projects is worldwide ongoing to show that a convenient operation of the grid with DER do not entail capital expenditures as much as the "fit and forget" does [17]. DSOs need to take into account the integration of DER, not simply the connection, thus enhancing the capacity of DER that can be connected into an existing distribution system, in direct contrast to the current "fit and forget" approach [40].

2.2.1 Modern Methods

The key feature of a modern planning tool for ADNs is the integration of future network operation practices in the set of feasible planning alternatives, in order to identify the best technical and economic balance between an innovative solution (that tends to maximize asset utilization) and traditional network expansion [16]. The operation influences the planning stage of the modern distribution system and more attention has already been paid to operating strategies that bridge the transition from passive to active/smart networks.

The integration of DGs of intermittent power generation (eg., PV and wind) have significant uncertainties in spatial and temporal distribution. These uncertainties bring many challenges to the system operation and planning and put forward the exploration of different active management strategies that have standard requirements for operational flexibility of DER (e.g., demand and generation) [21].

To allow for different active network management strategies, DSO needs to rely on flexible resources. The flexibility of DER to provide different ancillary services in the system will become crucial to help in the network management and offer an alternative solution for the traditional network expansion [45]. Therefore, the SG paradigm considers the integration of several DER and also cater for the active participation of consumers and producers in system operation, offering their loads and DG units as flexibility services [16].

Flexibility - A New Service

The introduction of DER (mainly RES) into the power system makes system planners and operators recognize the need for new ways of balancing supply and demand. In fact, the developments in DER technology enable them to contribute to this new era of services to maintain the system security and reliability. Thus, the concept of DER flexibility in the literature gains importance for the future management of power system, especially in distribution systems [45].

The operational flexibility is an important property of electric power systems and plays a crucial role for the transition of today's power systems towards power systems that can efficiently accommodate high shares of DER, especially RES. The availability of sufficient operational flexibility in a given power system is a necessary prerequisite for the effective grid integration of large shares of fluctuating power in-feed from variable RES, especially wind power and PV [3, 46].

In the remainder of this thesis, the concept of flexibility refers as the amount of power provided by DER that can help the system operator managing the system, by modifying generation injection and/or consumption in reaction to an activation by the DSO. This concept includes upward flexibility from RES/demand resources to reduce/increase the power availability in the system and downward flexibility from RES/demand resources for increase/reduce the power in the system. Upward and downward flexibility services from DER are activated/contracted by DSO to use in real-time to manage the grid and solve congestion/voltage problems, accounting for the uncertainty of renewable sources [45, 46]. Furthermore, with this new preventive management of distribution grids it is possible to differ network reinforcement.

Sources of Operational Flexibility

Operational flexibility can be obtained on the generation-side and on the demand-side. In addiction, stationary storage capacities (e.g., hydro storage, Compressed Air Energy Storage (CAES), stationary battery or fly-wheel systems) as well as time-variant storage capacities (e.g., electric vehicle fleets) are well- suited for providing operational flexibility [3].

The different sources of power system flexibility in distribution networks are illustrated in Figure 2.3.

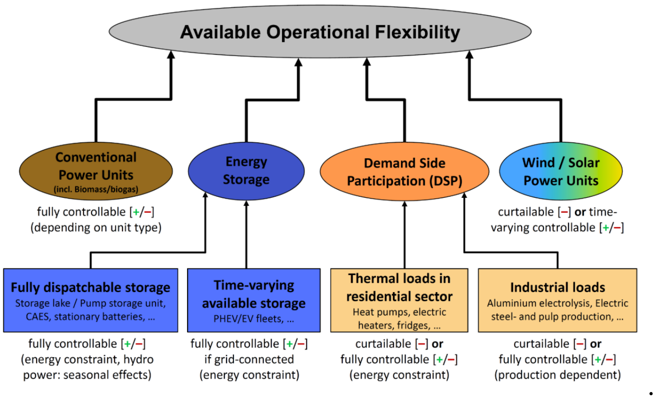


Figure 2.3: Sources of operational flexibility in power systems [3]

For instance, the generation curtailment of RES and/or the load shedding of responsive loads can help to relief network congestions and solve voltage problems, and therefore they are valuable planning alternatives to the classical network reinforcement/expansion [4, 46].

All these ways of controlling and integrating DER impact the system operation, playing a significant role in the optimal development of the system, in other terms, the active network operation significantly contaminates the planning [4].

2.2.1.1 Stochastic Algorithms

The intermittent characteristic of RES led to the investigation of stochastic methods for the analysis of power systems [21]. Modern planning should consider probabilistic methods in order to adequately consider DER and other sources of uncertainty, which implies the creation of stochastic models and the introduction of risk concepts for the assessment of constraint violations. Decision-making under uncertain scenarios causes risks that should be explicitly dealt with by planning tools in order to allow objectivity and transparency [16].

One of the main sources of uncertainty in MV distribution network calculations is the renewable generation because of the unpredictability of the primary energy sources (e.g., wind speed, solar radiation, and water flow). Also, the load exhibits natural random variations that can increase in presence of residential PV installations and uncontrolled recharge of electric vehicles. These uncertainties can be modelled by suitable probabilistic density functions (pdfs) if the probabilistic data for the input are available. Depending on the adopted stochastic distributions (i.e., Gaussian, Beta, Rayleigh, etc.), network calculations can be performed by tailored probabilistic load flow (PLF) algorithms or the more general Monte Carlo simulation approach. The results of these calculations are the stochastic representation of the nodal voltage and branch current variables, through which the technical constraints can be verified with a relative confidence (acceptable risk of violation) [4, 16].

The application of stochastic programming optimization techniques to the traditional distribution network expansion planning problem is difficult, as the nature of the planning problem does not consist of many effective recourse decisions. Rather, it is based on investment planning where the traditional "passive" nature of networks means that there is little control over operational variables.

Following the introduction of dynamic flexible network control technologies, a new recourse characteristic is added to the network planning model. Such "active" control measures are regarded as relatively (in comparison to network reinforcement) inexpensive solutions for overcoming network issues and when the problem is modelled as a multi-stage program, at each stage an optimal decision will be made whether to accept the solution, or to invest in long-term reinforcements. One of the benefits of multi-stage stochastic programming is that technologies can become available for use at different stages of the model, as they become available for deployment in the future. Ultimately, the accuracy of stochastic programming as a decision support tool for network planners will be reliant on the accuracy (or suitability) of the probability distributions for stochastic parameters [9].

2.2.2 The Impact of Active Network Management

An active distribution network is defined by a shared global definition: “Active distribution networks (ADNs) have systems in place to control a combination of distributed energy resources (DER), defined as generators, loads and storage. Distribution system operators (DSOs) have the possibility of managing the electricity flows using a flexible network topology. DER take some degree of responsibility for system support, which will depend on a suitable regulatory environment and connection agreement.” [2]

The distribution grid operation planning was traditional limited to network elements, but with the employment of ADN, emerged some control of network participants (demand and generation). Ergo, the full implementation of ADN will lead to a future where DNOs will manage the networks in a very similar way to the TSOs for the transmission systems, so becoming DSOs [4, 16, 17].

The future distribution network planning will be defined with less network investment, since technical operation issues can be fixed with the so called no-network solutions [16]. The novel planning approach is capable to benefit the integration of RES, by incorporating no-network solutions as valid planning alternatives [4]. For these reasons, it is imperative that modern planning tools for the ADN integrate network operation practices in the set of feasible planning alternatives, in order to identify the best technical and economic balance between the innovative ANM and the traditional network expansion [16].

The possibility of ADN will represent an alternative way (no-network solutions) to solve the most typical issues faced with BaU network solutions, such as line/transformer refurbishment. It is important to highlight that traditional investments will be always needed at some point in the planning horizon, but it is indisputable that no-network planning alternatives have the potential to handle many grid issues in short/mid term [17] and therefore deferral the reinforcement actions in the network.

Table 2.1 presents some approaches (network and no-network solutions) to deal with the network technical concerns.

Challenge	Current Solution	Future Alternatives
Voltage rise	Reinforcement Operational p.f. 0.95 lagging Generation tripping	Volt/VAR control Storage Generation curtailment Online reconfiguration
Voltage drop	Reinforcement Fixed capacitor banks	Volt/VAR control Storage Demand side response Online reconfiguration
Network capacity	Reinforcement	Storage Generation curtailment Demand side response Online reconfiguration
Network power factor	Limits/bands for demand and generation	Storage Unity power factor generation
Sources of reactive power	Transmission network Fixed capacitor banks	Storage SVC Volt/VAR control
Network asset loss of life	Strict network designs specifications based on technical and economic analyses	Dynamic protection settings Asset condition monitoring

Table 2.1: BaU (network) and ADN (no-network) solution in modern distribution planning with high shares of RES to cope with technical issues [4]

2.3 Data Modelling

Traditionally, techniques of load analysis were applied to generate characteristic load profiles used to categorize customers into different classes. The results of the load analysis were used to produce suitable approximations of peak demand, based on annual energy consumption [4].

This traditional representation was used in PDP by assuming unique yearly values of demand and generation. Peak values were estimated to identify worst-case conditions and used, with a constant annual growth rate, in the "fit and forget" approach to plan network expansion for a given planning horizon. Average values (if necessary) were considered for estimating technical losses and for reliability analyses [2, 16].

Currently, PDP takes into account the penetration of large shares of RES and is greatly influenced by factors such as the uncertainty of load demand and the output power of RES. Therefore, adequate knowledge about demand, wind and PV generation profiles is crucial in two planning features [1, 2]:

- The identification of the maximum stress conditions: maximum load and no generation and minimum load and maximum generation. Any distribution system should be planned in order to ensure that the resulting system configuration will be adequate and on the basis that further reinforcement will not be required during the given long-term planning period;

- The determination of power losses. The annual power losses constitute the main component of the DSO's operating cost, i.e. annual power losses increase the DSO's Operational Expenditure (OPEX) costs.

However, the deterministic "fit and forget" approach is still used by DSO, now identifying the previous defined worst-case conditions. The main drawback of this deterministic approach is that the distribution grid is designed and planned assuming the worst conditions as certain, even if they have a very low probability of occurrence [16].

These simplified representations are unsuitable for the planning studies of the future ADNs. In order to capture the operational aspects that can affect the PDP, the time variability of demand, PV and wind generation has to be explicitly represented in the planning calculations [4].

Therefore, two possible options can be followed to represent the hour variability of demand and generation [2, 16]:

- Classification of all the demand-generation states in a year, by grouping them in some typical conditions - clustering periods. With this approach, considering annual time-series profiles of power consumption and generation, different operating conditions can be recognised and clustered in order to decrease the computational burden of the planning calculations.

  For better estimation of the probability of occurrence of each state, this analysis has to be extended to several years of historic data. However, due to the recent introduction of RES generation, the amount of historic data available may not be enough to extend this methodology, so new techniques of forecasting need to be explored to compensate the lack of data.

  In Figure 2.4, it is possible to observe some clustering examples of demand and generation conditions;

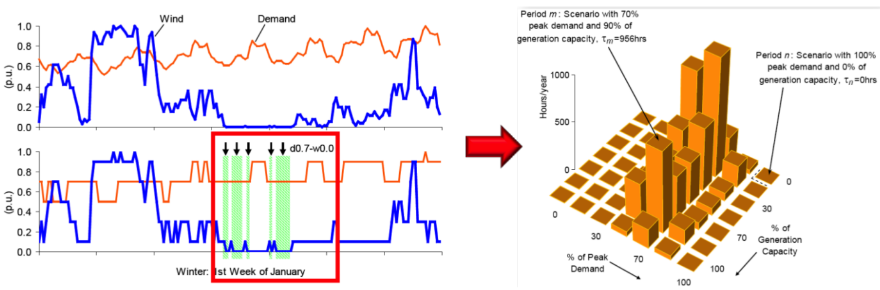


Figure 2.4: Clustering of demand and generation variability [2]

- Adopt distinctive daily profiles for the whole year to represent the behaviour of distributions network consumers and producers in a year (representative scenarios). These days are divided into hourly intervals and the network calculations are repeated for each of them.

  In this case, to capture the uncertainties of demand and generation, loads and DG units are modelled with suitable probabilistic density functions (e.g. normal, beta, etc.), as shown in Figure 2.5.

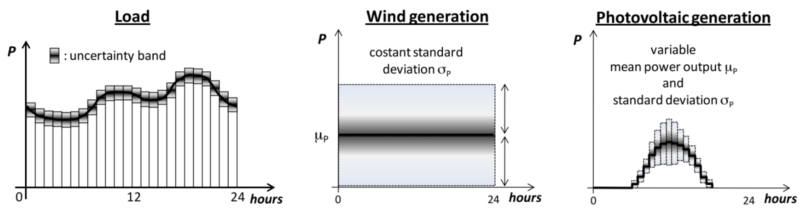


Figure 2.5: Representation examples of daily load and generation profiles [4]

In addition, load demand, wind and solar generation are considered independent variables, having different probabilistic density functions [1]:

- Each load of the system is represented by an appropriate daily profile, divided into 24 hourly-time intervals, with specific mean values and standard deviations. Each load interval follows a Gaussian/normal distribution;
- The output power of a wind generation unit depends on the wind speed. The variability of the wind speed follows the Weibull distribution;
- The output power of a PV generation unit relies on the solar irradiance. To describe the random behaviour of the solar irradiance, the Beta distribution is used.

According to [2, 16], the uncertainties that are inherent to current and future distribution networks suggest both the use of probabilistic models to better represent planning data and the introduction of the risk concept in the selection of planning alternatives. Thus, in Table 2.2 is underlined the evolution undergone in data modelling for PDP since the traditional to the modern planning.

Traditional	Current	Modern
Daily load curves were collected to classify several categories of loads and used to identify the worst condition: maximum demand (coincidence factors). Constant/predictable generation considered as negative load. Unpredictable generation (RES) was considered only for the estimation of technical losses.	Due to a higher penetration of DG, all generation technologies are considered. However, uncertainties of RES are not represented. Two worst-case conditions are defined: 1) Max Load – No generation, 2) Min Load – Max generation. These conditions are considered as certain even if they will appear rarely (particularly for renewables).	Daily load curves and daily generation curves have to be explicitly modelled. Some typical operating conditions need to be recognized together with their relative probability of occurrence. Importance of chronological representation.

Table 2.2: Data modelling for power distribution planning studies [2]

2.4 Cost-benefit Analysis (CBA)

SGs are a key component of the European strategy towards a low-carbon energy future. Given the economic potential of SG, there is a need for a methodological approach to estimate the costs and benefits of such network [5].

Before assessing the CBA for SG, it is important to underline the meaning of the concept Smart Grid by presenting some valid definitions [47]:

- "A network efficiently integrating the behaviour and actions of all users connected to it – generators, consumers and those that do both – in order to ensure an economically efficient, sustainable electricity system with low losses and high quality and security of supply and safety."
- "Any equipment or installation, both at transmission and medium voltage distribution level, aiming at two way digital communication, real-time or close to real-time, interactive and intelligent monitoring and management of electricity generation, transmission, distribution and consumption within an electricity network."

The proposed approach is cognizant that the impact of SG projects goes beyond the monetary terms. Thus, the general approach aims to integrate an economic analysis (monetary appraisal of costs and benefits on behalf of society) with a qualitative impact analysis (non-monetary appraisal of non-quantifiable impacts and externalities) [5], as observed in Figure 2.6.

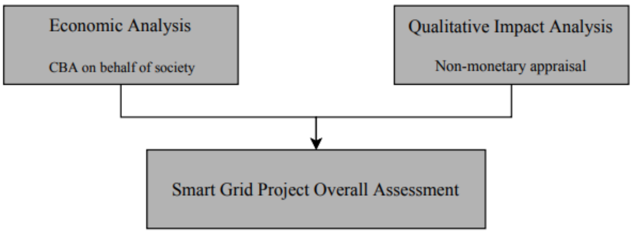


Figure 2.6: Framework of Smart Grid projects, including economic and qualitative evaluations [5]

According to [5, 47], the economic analysis takes into account all costs and benefits expressed in monetary terms, considering a societal perspective. That is, the analysis tries to include all costs and benefits from the Smart Grid project into the electric system (e.g, allowing future integration of DER) and into a society at large (e.g., environmental costs).

The qualitative impact analysis consider externalities that are not quantifiable in monetary terms. This includes the costs and benefits derived from broader social impacts like security of supply, consumer participation and improvements to market functioning.

2.4.1 Establishing the Baseline

The purpose of establishing the project baseline is to define the "control state" that reflects the system condition that would have occurred if the project had not taken place. Therefore, the CBA is based on the difference between the costs and benefits associated with the "Business as Usual" scenario and those associated with the implementation of a SG project [5, 48].

Therefore, all the assessment shall be carried out considering the two following scenarios [17, 48]:

- BaU scenario (without SG deployment) representing the traditional network planning, in which solutions such as line and transformers reinforcements are used to solve many network issues. This is the reference scenario to assess the impact of the Smart Grid project;

- SG scenario in which, for example, an ADN planning will represent an alternative way to solve most common issues faced. With the employment of ADN, some control of network participants (demand and generation) emerged, which allows to use DER flexibility resources to solve many network problems.

2.4.2 Discount Rate

According to [49], costs and benefits from CBA methodology rarely occur within a short time period. As the value of money changes over time due to some effects such as inflation, the value of a cost or benefit in the future may not be representative of the actual worth of that cost or benefit in present terms. For this reason, it is necessary to discount the future values of costs and benefits occurring over time to a common metric - present values. This allow the researchers to calculate the net present value of total costs and net present value of total benefits.

A key concern is the value assigned to the discount rate. An incorrect value could easily result in an inaccurate estimate of the present value of a future cost of benefit [48].

Often government agencies provide a suggested discount rate to use when performing discounting [49]. Although, different values may be proposed as long as they are justified in the light of a specific country's macro-economic circumstances and its capital constraints [48].

2.4.3 Identification of Costs

One of the common methods of annually cost estimation is the Total Expenditure (TOTEX) logic, that results from the following indicators: Capital Expenditure (CAPEX) costs related to network investments (reinforcement costs) and Operational Expenditure (OPEX) costs related to operation network costs, such as power losses costs and DER flexibility resources activation costs (costs presented in ADN scenario) [48]. The TOTEX is calculated for each considered scenario.

2.4.4 Identification of Benefits

According to [48, 50], the benefits (technical and/or economical) are the difference between the reference case (scenario) and the application case (SG scenario), over the defined planning horizon.

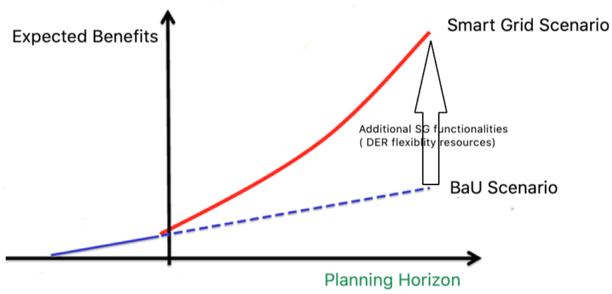


Figure 2.7: Expected benefits comparison between BaU and SG scenarios, adapted from [6]

Each criterion, category or group of benefits will have its own form of quantification, whether it is monetary or not. One reliable way to identify in a quantified manner the benefits that can be obtained from the adoption of the SG scenario (ADN functionality) are the key performance indicators (KPIs) [47, 50].

According to Figure 2.8, for the described reference case (BAU scenario) and the Smart Grid scenario, the KPIs are computed based on a four-step approach [6]:

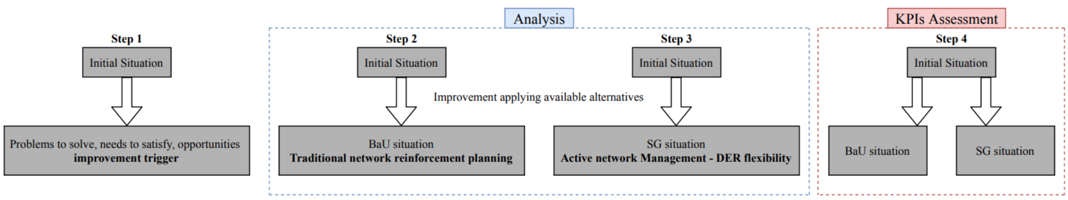


Figure 2.8: Process for calculating the KPIs, adapted from [6]

1. Identification of the network problems (congestion/voltage) that need to be solved or the situation that needs to be improved;
2. Selection of the scenario as an action to the previous step, i.e., use traditional network reinforcement planning to solve congestion/voltage problems or improve operation aspects of the network. Then, estimate the results and the progress made after applying this approach;
3. Selection of the SG scenario as an action to the fist step, i.e., enable an ANM with active participation of demand and generation (DER flexibility) to solve technical problems or improve operation aspects of the network (e.g., power losses). Then, estimate the results and the progress made after implementing this modern planning approach;
4. Calculation of KPIs in order to assess the technical and economical benefits of shifting from a traditional planning (BaU scenario) to a modern planning (SG scenario), by applying the proposed formula for each KPI.

Definition of relevant KPIs

Deferred Transmission and Distribution Capacity Investment (DTDCI)
In the scenario, it is necessary capital investments to solve technical problems and improve network operational aspects. However, with the Smart Grid scenario, DSO contracts DER flexibility services to solve the same problems and by that reduces the need of network reinforcements [51]. Therefore, after introducing an ANM, a decrease in investment costs are observed and it is important to access the potential of investment deferral caused by ANM [52].

Therefore, the DTDCI KPI for the functionality of network reinforcement planning considering management of distributed flexibility will be computed by the following formula [50]:

$$DTDCI = \frac{NRC_{BaU} - NRC_{SG}}{NRC_{BaU}} * 100\% \tag{2.1}$$

where NRC_{BaU} is the net present value of total cost of the baseline scenario (BaU scenario) and is computed by the traditional network reinforcement planning tool. The NRC_{SG} is the net present value of the total cost for the SG scenario (ADN planning) and is computed by the traditional network reinforcement planning tool considering an ANM (DER flexibility).

Reduction of technical power losses
Smart Grid functionality using DER flexibility resources can locally balance energy production and consumption (reduction in power flows, thereby lowering power losses. However, in some cases, the reverse power flow related to increased energy production during low load periods increases power losses [50, 51].

The KPI that is associated with the reduction of power losses is computed as follows [50]:

$$\Delta PL = \frac{L_{BaU} - L_{SG}}{L_{BaU}} * 100\% \tag{2.2}$$

where L_{BaU} is the amount of energy losses (MWh) in baseline scenario (BaU scenario) evaluated in a defined period and L_{SG} is the amount of energy losses (MWh) in SG scenario (ADN planning) evaluated in a defined period.

Smart Grid including the use of system flexibility services have a major contribution to the creation of a future energy system. The expected costs and benefits from the implementation of a SG scenario with the use of DER flexibility resources are summarized in Table 2.3.

Type of effects	Cost	Benefit
Direct	Investments in Smart Grids	Avoided grid investment
	Smart Grid operation and maintenance	Avoided grid losses
	Cost on location for equipment	Avoided investments in central generation capacity
		Avoided investments in storage
		More efficient use of central generating capacity
		Additional energy savings
		Reduced imbalance
Indirect and External	Welfare losses due to adaptation to new energy demand patterns	Welfare gain due to new services
		Reduced CO2 emissions
		Reduced outage time
		Reduced curtailment of distributed generation
		Increased grid hosting capacity for distributed generation

Table 2.3: Comparison of potential costs and benefits of developing smart grids and flexibility, adapted from [7]

Chapter 3

Network Planning Methodologies

In this chapter, the modelling of a PDP problem will be addressed by comparing and explaining two different DSO decision-making methodologies:

1. **Power Distribution Reinforcement Planning** as the traditional grid planning framework;

2. **Active Distribution Grid Management** as the predictive grid planning that considers the management of distributed flexibility.

First, it will be exposed and explained some important features of the two possible DSO planning solutions. Then, the PDP methodology embedded with both planning solutions will be presented and some important methodology steps will be detailed.

In a second phase, a CBA methodology will be outlined to mark some important points:

1. The total cost of each DSO planning solution;

2. The break-even point, referring to the maximum total cost that the DSO is willing to pay for the active distribution grid management to be profitable;

3. The KPIs to assess some technical and economical benefits of shifting from a traditional reinforcement planning to an active network management planning.

3.1 Power Distribution Reinforcement Planning

Network reinforcement planning aims to guarantee a sufficient network capacity for accommodating the electricity supply, in conformity with the producers and consumers requirements.

This planning exercise has two strands, one technical and other economic, which objectively implements and quantifies the generic obligation of network planning, to which the DSO is linked. Both of these aspects are logically connected and are inseparable, since the judgement resulting from the technical analysis will dictate the actions to perform in the network, represented by a quantifiable financial investment and formulation of a corresponding budget.

Therefore, the power distribution reinforcement planning determines which investments should be made to meet the load growth demand and host large shares of RES, within a given planning horizon.

3.1.1 Power Distribution Reinforcement Investments

There are four major types of network reinforcement investments: mandatory, urgent, programmable and structural.

For the reinforcement planning methodology, the investments that will be executed in the grid are related to technical problems such as overcurrent and voltage limits violation, due to load and DG growth. Thus, the focus on the traditional planning to be carried out refers to the urgent investments.

The urgent reinforcement requirements are the investments that will be necessary to maintain a certain level of overall reliability, taking into account network component outages. All loads must be supplied if an outage occurs at one of the feeders at HV level or HV/MV transformers.

These type of investments cannot be defined in advance, but are essentially aimed at resolving incidents that jeopardize the security or supply of electrical energy. In most cases, they lead to the replacement/reinforcement of network elements, when obsolete, thus reducing operating costs and contributing to the improvement of operational efficiency.

These investments tend to be the most standard: up rating substation transformers capacity and/or up rating distribution lines/cables capacity, in order to increase the overall network capacity. Therefore, power capacity reinforcements aim to ensure that all transformers and lines/cables do not exceed their nominal ratings, avoiding voltage and capacity problems, while supplying the load.

$$Reinforcement\ action = \begin{cases} \text{Increase line/cable cross-sectional area,} & \text{if } I_{L_j} \geq I_{L_j}^{max} \\ \text{Increase transformer rated apparent power,} & \text{if } I_{T_k} \geq I_{T_k}^{rat} \\ \text{Keep the original size,} & \text{otherwise} \end{cases} \tag{3.1}$$

where,

I_{L_j} is the current on distribution line/cable j [A]

$I_{L_j}^{max}$ is the maximum allowed current of distribution line/cable j [A]

I_{T_k} is the current on substation transformer k [A]

$I_{T_k}^{rat}$ is the rated current of substation transformer k [A]

As to the increase of line/cable cross-sectional area, if the cross-section of the overloaded line/cable is already very high (240 mm^2 or more), the load of the distribution grid may have to be redistributed through the distinct feeders connected to the primary HV/MV substations.

It is important to notice that the reinforcement action regarding increasing transformers rated power is a decision that is not as common to happen as increasing lines/cables cross-sectional area, and only happen after long years of planning (e.g., 15 years). Therefore, in this thesis, the replacement of substation HV/MV transformers will not be considered.

Furthermore, the planning process will take into account a logistical perspective, i.e, when a building crew is sent to a specific location in the network it should solve all the technical problems associated with that location, in order to avoid sending crews to the same site year after year.

When choosing the reinforcement investments, it is important to pay attention to safety standards:

- To guarantee the expected consumption for the network under study, regarding technical and regulatory conditions, and ensuring that the equipment and materials installed in the networks do not exceed their nominal values or their characteristics in normal operation;
- To ensure the existence of available capacity in the network for the reception and delivery of electricity, compatible with the requests formulated by producers and consumers;
- To maintain the quality of electric power supplied, in accordance with the recommendations of NP EN 50160 (Portuguese case).

3.1.2 Representative Scenarios

Traditional distribution network planning is commonly based in load flow calculations that takes into account the peak load conditions to determine the grid dimensioning. Although, with the strong penetration of RES and the phenomenon of reverse power flows, it is necessary to change the design and network management as to accommodate the peak generation conditions.

For network capacity planning, the scenarios of most interest are situations with peak values of demand or generation and with these two critical scenarios arises:

- maximum or typical peak demand and minimum or typical valley generation;
- minimum or typical valley demand and maximum or typical peak generation.

The scenarios will consider seven representative days during the year, with a hourly time frame, corresponding to a variety of realistic and interesting conditions in terms of load demand and distributed generation (DG) (PV and wind power) injection. If the most critical grid operation modes are satisfied, the grid can respond well to the remaining operation cases.

These days will be selected according to the following criteria:

- **Season**: Winter, Spring/Autumn and Summer;
- **Weekday**: weekday, weekend and holiday;
- **Scenarios**: maximum peak load, maximum valley load, maximum peak generation, typical valley load and typical peak generation, typical valley generation and typical peak load.

The first point tends to reflect that electricity demand is subject to fluctuations on a seasonal basis. The second points out that consumption profiles vary between working days, weekends and holidays. The last point follows the fluctuation of energy prices during day and night periods, and highlights the significant scenarios in terms of load and generation conditions that are worth examining.

It is important to notice that both wind and solar are considered intermittent power sources. Both are intermittent by nature, as output fluctuates with weather patterns. On the other hand, there are two power sources with different production diagrams over time, so their production performances during a day, at peak and valley hours, will be different.

Hence, while performing the traditional planning exercise, it is relevant to observe the time variability of consumption and generation profiles in the different scenarios mentioned previously, as well as it is crucial to define future annual increases in load consumption and RES generation.

3.2 Active Distribution Grid Management

The current passive distribution network management is rapidly changing into a future ANM, where the operation is not limited only to network elements, but also allows the control of network participants (demand and generation). The ANM is a core part of the concept "Smart Grid", in which DSOs can contract/control power generation/consumption from DER to solve congestion and voltage problems in the distribution grid.

The DER discussed in this thesis are related to RES generation units flexibility resources, i.e., active participation of producers from RES and load flexibility resources, i.e., the active participation of consumers (demand response).

In the past, technical problems such as overcurrent and voltage limits violation were mitigated by planning network investments/reinforcements and changing the network reconfiguration. Now, DSOs have additional flexibility in the network that allows them to solve the technical problems in the operational domain, instead of solving them only in the planning phase.

Therefore, ANM solutions are accounted as a valid planning alternative to the traditional ones in order to solve possible constraint violations and to improve network performances (e.g. reduce power losses). If some contingencies appear, the ANM procedure tries to solve them initially through the use of flexibility services or in last resort with network upgrades/reinforcements.

It is important to emphasize that traditional investments will be needed at some point of the planning horizon, but is indisputable that ANM planning alternative have the potential to handle many grid issues in short/mid term planning. Thus, the main benefit from the Smart Grid (ANM) planning is the investment deferral.

3.2.1 Operational Flexibility

With the introduction of variable supply sources, power system planners and operators are cognizant that power systems need new ways of balancing supply and demand. The concept of "flexibility" in power systems gained importance:

- "On an individual level, flexibility is the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) in order to provide a service within the energy system." [53]
- "When planning the development of the distribution network, energy efficiency/demand-side management measures and/or distributed generation that might supplant the need to upgrade or replace electricity capacity shall be considered by the distribution system operator." [7]

The flexibility potential (flexible operation/bids from demand and RES) requires the implementation of a proactive and preventive grid management based on forecasts with the possibility to reserve/control loads and DG connected to the distribution grid.

It is important to notice that information about forecasts and corresponding uncertainty is not embedded in this decision-making methodology.

For thesis purposes, it is crucial to state that DER flexibility services are activated/contracted by the DSO to solve/mitigate network problems and are related to load and RES active power curtailment. Hence, load shedding and wind plus PV curtailment are used to balance the system , i.e. maintain the continuous equilibrium of demand and supply in the system to avoid congestion and voltage problems.

The DSO needs to operate in an operational planning domain to anticipate potential network problems and contract day-ahead flexibility to be ready to solve these potential problems in real-time. The goal of the DSO remains the same, i.e., ensure that voltage, congestion and delivery problems are solved, while maintaining the proper operation of the system with adequate levels of safety, reliability and power quality. Additionally, the use of flexibility for managing technical problems can be of greater interest to the DSO, for a deferral of very expensive network investments and expansion as well.

3.2.2 Reserve Balancing Mechanism

Balancing services are necessary to ensure the continuous equilibrium between generation and load in the power system. This leads to the need of a reserve capacity composed of loads and RES generation units able to respond to possible network problems.

The reserve capacity used to balance the energy in the system is known as the regulation reserve, which corresponds to the maximum variation of power of the system in both directions - up or down. The power range, in each direction, is called the reserve or band to go up or down. This reserve is contracted in a regulation market and the offers in the reserve balancing mechanism can be of two different types:

- Upward regulation - requires an increase of generation or reduction of demand;
- Downward regulation - requires an reduction of generation or increase of demand.

Upward and downward flexibility services from DER are contracted in the regulation market at day-ahead time horizon, and used in real-time to manage the grid and solve congestion/voltage problems, accounting with the uncertainty of renewable sources.

First, upward and downward flexibility bids are provide to the DSO and then, DSO contracts the flexibility from DER aggregators based on capacity payments to manage the grid in real-time. The flexibility bids of changing the operating point of the resources (generation or demand) for upward and downward power are defined based on the strategy of each DER aggregator to provide flexibility to DSO.

In Figure 3.1 is illustrated the framework to help DSO solve technical problems through contracting flexibility from DER.

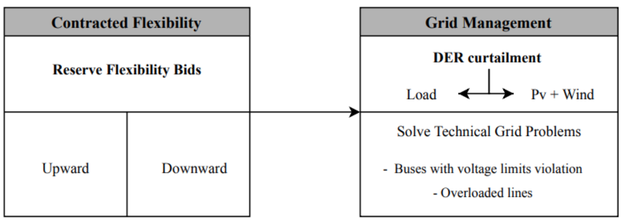


Figure 3.1: Diagram of framework for a predictive distribution grid management

At least, it is important to say that DSO needs to reserve/contract flexibility in advance to use it when needed in real-time operation. Therefore, the amount of contracted flexibility will depend on the expected needs for solving potential congestion/voltage problems in the distribution grid.

In general, DER flexibility is increasingly being used to provide balancing services and to avoid grid problems. Hence, a new market design can emerge to allow DSO to reserve/contract flexibility ahead of delivery requirements.

3.3 Power Distribution Planning

In this chapter it will be discussed the PDP methodology for the two decision-making methodologies described previously in sections 3.1 and 3.2. Among that, some important steps from the PDP methodology will be explained and the differences between the traditional grid reinforcement planning and predictive grid management will be pointed out.

3.3.1 Base Case Scenario

An important step before proceeding with distribution network planning is to establish an interesting base case in order to observe the behavior of the distribution network, over the defined planning horizon.

For thesis purposes, this preliminary scenario represents the year zero of the planning horizon in which there are already DG units from RES connected to the network, and no investments/reinforcements are made in the distribution grid neither DER flexibility is activated/contracted by DSO. Thus, at this point there are no technical problems in the distribution network, but must be closer to engage congestion/voltage problems, so within the next following years of the planning horizon it can be performed network investments or be contracted flexibility by DSO.

It should be noted that in reality, the base case is not mandatory to be close to overcoming the technical constraints of the network. It is in this study case, because the goal is to prove the concepts of traditional grid reinforcement and predictive grid management.

Once the base scenario is defined, an analysis on the grid is made for the planning horizon (years ahead) checking which investments/reinforcements and flexibility services must take place for both DG and load growth conditions.

3.3.2 PDP methodology

The proposed PDP model is applied to the reinforcement of existing MV distribution networks and to the predictive management (ANM) of those networks, in order to accomodate future growth of DG connection (PV and wind power penetration) and forthcoming load growth. Thus, strong renewable penetration and load growth are dominant parameters affecting the power distribution planning.

The schematic of the PDP methodology approach is shown in Figure 3.2.

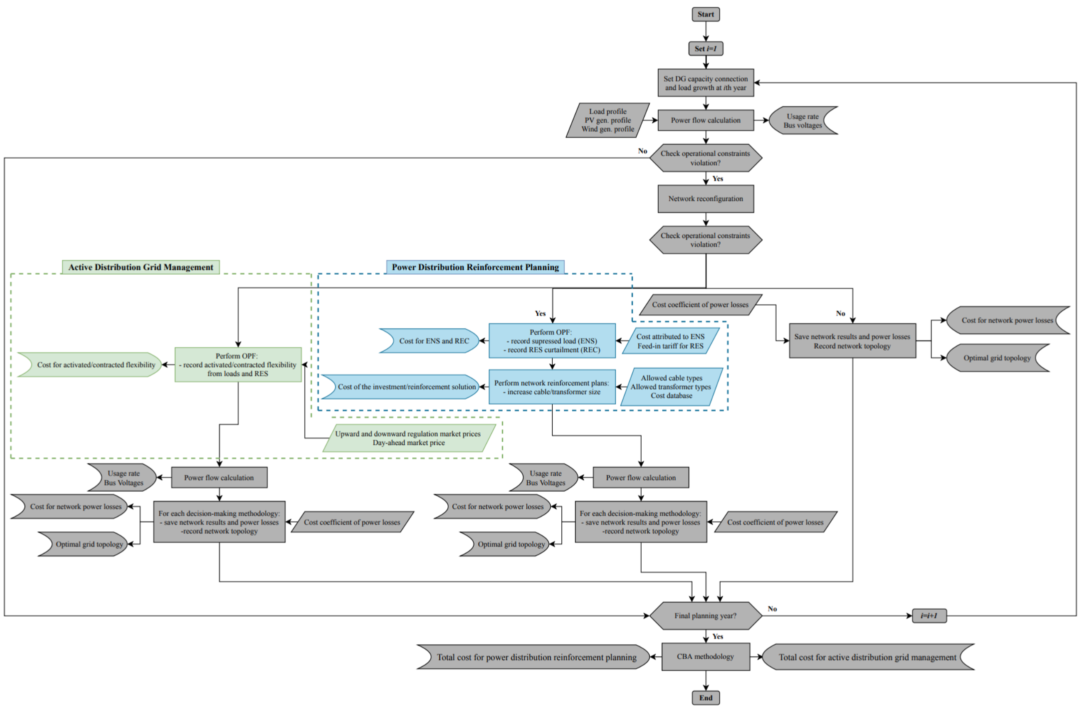


Figure 3.2: Flowchart of the power distribution planning methodologies

3.3.2.1 DG integration and Load Growth

A horizon of 10 years is assumed for the network planning exercise. The horizon is divided into early stages with yearly duration and a given load growth and new DG connected capacity is considered for each year, in order to reproduce a realistic case, i.e., always expect an increase in network consumption and DG capacity connected to the grid.

Concerning the DG units capacity and connection to the distribution network, it is important to adress some rules:

- DG is connected to buses with or without load;
- DG units have unitary power factor ($cos(\phi) = 1$), as well as loads;
- The DG units connected to the network buses are only from RES, i.e., PV and wind power injected to the grid;
- The choice of "candidate" buses to connect DG units is based on the sensitivity coefficients of the Jacobian matrix;
- For simplification purposes, DG units are connected directly to MV nodes, i.e., MV/LV secondary substation are neglected;
- DG installed capacity is considered to be a multiple of the annual peak load, in order to avoid unreal concentrations of DG penetration;
- In all years of the planning horizon, including the base case scenario (year 0), the total RES capacity is 80% PV power production and 20% wind power production, in order to reproduce a real case in terms of production injected by each renewable source technology into the network - PV power dominant over wind power;

- The annual generation increase must take into account the fact that the theoretical maximum of each installation is 10 kW, i.e., the growth rate must be rational so that there are no excessive increases in RES production (e.g., capacity doubled from year to year).

3.3.2.2 Load and Generation Profiles

Profiles concerning load and RES generation are described by multiple time steps, which provide the point of operation of the network in each time step in terms of demand and generation conditions. The demand and generation profiles represent real data regarding demand, wind power and PV production.

These time series have been standardized in order to extrapolate other powers and to apply to different case studies. The data regarding PV and wind generation was standardized in reference to the maximum hourly value of each generation (PV or wind) data. The consumption data was standardized in reference to 80% of the maximum hourly value of all the consumption time steps, because it is not common to reach the maximum contracted power.

Allegedly, one year data regarding consumption, PV and wind power production was provided. However, in the PDP exercise, two possible directions can be followed to represent the hourly variability of demand and generation:

- As mentioned in section 3.1.2, in the traditional network reinforcement planning, seven distinctive daily profiles will be adopted for the whole year to represent the behaviour of distribution network consumers and producers in a year. If the most critical grid operation modes are satisfied, the grid can respond well to the remaining operation cases;

- In the predictive grid management, the PDP will be executed for the entire year (8760 hours). For thesis purposes, the clustering of demand-generation states/periods in a year, similar to the selected representative scenarios in the reinforcement planning, will not be considered.

3.3.2.3 Network Constraints

Grid constraints are of two categories: equality and inequality constraints.

The first ones are simply the verification of Kirchhoff laws, representing the non-linear active and reactive power balance equations by bus, 3.2 and 3.3.

$$P_i = P_{G_i} - P_{D_i}, \forall_i \in \{\text{buses of the network}\} \tag{3.2}$$

$$Q_i = Q_{G_i} - Q_{D_i}, \forall_i \in \{\text{buses of the network}\} \tag{3.3}$$

where,

P_i is the active power flow on bus i [MW]

Q_i is the reactive power flow on bus i [Mvar]

P_{G_i} is the active power generation on bus i [MW]

Q_{G_i} is the reactive power generation on bus i [Mvar]

P_{D_i} is the active power demand on bus i [MW]

Q_{D_i} is the reactive power demand on bus i [Mvar]

The inequality constraints consist of branches (lines/cables and transformers) and bus voltages technical limitations.

To prevent damages and maintain the security of the assets, the current of each branch in the network should be kept bellow the capacity limit during the network operation. The voltage magnitude at each bus should remain within the safe operating limits, to ensure a stable voltage supply for customers and also to prevent damage of network assets.

These constraints are the **network operational constraints**, and in the presented PDP methodology it is verified whether these security constraints are violated or not. These constraints are defined prior to the planning exercise and refer to all lines/cables and transformers capacities, and bus voltage magnitudes respectively, 3.4, 3.5, 3.6.

$$I_{L_j} \leq I_{L_j}^{max}, \forall_j \in \{\text{lines/cables of the network}\} \tag{3.4}$$

$$I_{T_k} \leq I_{T_k}^{rat}, \forall_k \in \{\text{transformers of the network}\} \tag{3.5}$$

$$V_i^{min} \leq V_i \leq V_i^{max}, \forall_i \in \{\text{buses of the network}\} \tag{3.6}$$

where,

V_i is the voltage on bus i [V]

V_i^{min} is the minimum allowed voltage on bus i [V]

V_i^{max} is the maximum allowed voltage on bus i [V]

$I_{L_j}, I_{T_k}, I_{L_j}^{max}, I_{T_k}^{rat}$ previously defined in 3.1 [A]

At this point of the PDP methodology, no further constraints need to be considered. However, when performing the OPF other inequality constraints are need to be mentioned - operational power constraints.

3.3.2.4 Network Reconfiguration

MV distribution network is generally built to be meshed, but operated in a radial fashion. This means that there is a potential to modify the topological configuration by utilising the redundant lines/cables in the network.

Therefore, network reconfiguration takes advantage of the redundant power lines/cables in the network and modifies the paths through which the power flows, in order to find a new radial topology for the distribution network without disconnecting any consumer or producer.

In a certain year of the planning horizon, when congestion/voltage problems occur, the first action for trying to solve the technical problems is to reconfigure the network topology, because it is a network measure that does not involve expensive costs like capital investments/reinforcements or demand/generation flexibility services. The network reconfiguration can relieve the grid problems or, at the best, permanently solve them.

For thesis purposes, the network redundant lines/cables (lines/cables with open switches) were adapted to better suit the study case of the network planning exercise. To determine the optimal grid reconfiguration, different reconfiguration possibilities will be tested, and two possible solutions for congestion/voltage problems might emerge:

- If network reconfiguration applied to the grid solve all the congestion/voltage problems in the planning year, no load or DG unit is disconnected to the grid and there are no need for investments/reinforcements or activate/contract flexibility to solve the grid problems. For this case, the relevant results are saved and DSO will move on to the next planning year.

  If multiple reconfiguration options solve the congestion/voltage problems without suppressing any load or RES, the network operator can choose the topology decision he finds best for future years of distribution planning, because either solution solves the grid problems;

- If the network reconfiguration can relieve and does not solve the congestion/voltage problems, some customers and RES producers will be affected. To that end, the two DSO decision-making methodologies are tested and an OPF must be performed for each case - power distribution reinforcement planning and active distribution grid management.

3.3.2.5 Optimal Power Flow (OPF)

As stated in the 3.3.2.4, if necessary, an AC OPF must be performed for the power distribution reinforcement planning and for the active distribution grid management. The OPF is used to estimate the amount of energy not supplied (ENS) and/or renewable energy curtailment (REC) for the reinforcement planning, and the activated/contracted flexibility from load and RES for the predictive management, while ensuring that the operational constraints are not violated.

The optimal power flow executes the active and reactive power dispatch, respecting the network constraints. In other words, it makes adjustments to loads and DG units according to cost curves and safe operating limits.

The OPF is subject to the network constraints referenced in section 3.3.2.3, i.e. the active and reactive power balance equations and the network operational constraints (branches and bus voltage limitations). However, as said in the mentioned section, before performing the OPF other inequality constraints must be added - **operational power constraints**.

For thesis purposes, these inequality constraints are related to the upper and lower limits of the active power demand of loads and active power injection of DG units. The active power for loads and DG units can be defined as a flexibility for the OPF:

$$P_{D_m}^{min} \leq P_{D_m} \leq P_{D_m}^{max}, \forall_m \in \{\text{buses with load connection of the network}\} \tag{3.7}$$

$$P_{G_n}^{min} \leq P_{G_n} \leq P_{G_n}^{max}, \forall_n \in \{\text{buses with DG connection of the network}\} \tag{3.8}$$

where,

P_{D_m} is the active power demand on bus m [MW]
$P_{D_m}^{min}$ is the minimum allowed active power demand on bus m [MW]
$P_{D_m}^{max}$ is the maximum allowed active power demand on bus m [MW]
P_{G_n} is the active power generation on bus n [MW]
$P_{G_n}^{min}$ is the minimum allowed active power generation on bus n [MW]
$P_{G_n}^{max}$ is the maximum allowed active power generation on bus n [MW]

The operational power constraints are the same for the distribution reinforcement planning and predictive grid management, however the linear costs for active power embedded in the OPF are different.

Power Distribution Reinforcement Planning
This planning process quantifies the ENS and/or REC due to congestion/voltage problems, by computing the suppressed load and/or renewable energy curtailment, i.e the amount of load/generation that cannot be supplied/injected in the network, respectively.

If the grid reconfiguration does not completely solve the technical problems, an OPF with linear costs must be performed for calculating the energy not supplied (ENS) by loads and/or renewable energy curtailment (REC) by DG units.

The linear costs represent the penalties that DSO will have to pay for ENS and/or REC. To the energy not supplied by loads is applied a penalty cost and the reference feed-in-tariff to the energy not injected by RES.

In the traditional planning process, the actions of curtail load and/or generation are executed to allow the distribution network to operate safely until the investment/reinforcement is performed in the network. After the reinforcement plan is done and the congestion/voltage problems avoided, DSO will move on to the next year of the planning horizon.

Active Distribution Grid Management
In the Smart Grid (SG) case, the planning process quantifies the activated/contracted flexibility to prevent congestion/voltage problems and ensure the balance between demand and generation, by requesting the active participation of consumers and producers:

- The active participation of consumers (demand response) or load flexibility is related to load shedding/curtailment, in more general terms, modulation below its given time-variant maximum active power output level;
- The active participation of producers or RES flexibility is related to renewable power feed-in curtailment, i.e, PV and wind power curtailment.

The demand and generation flexibility bids of changing the operating point are defined through an active power control (via curtailment), so it is required a reduction of demand (upward regulation) and a reduction of generation (downward regulation). The upward and downward flexibility services from DER are reserved/contracted by DSO and used in real-time to manage the grid and solve the technical problems.

If the grid reconfiguration does not completely solve the technical problems, an OPF with linear costs must be performed for calculating the activated/contracted flexibility from loads and DG units.

The linear costs represent the capacity payments from DSO, i.e., the upward and downward flexibility activation prices.

In the operational planning process, the actions of load and generation curtailment are contracted by the DSO as flexibility services provided by consumers and producers, to manage the network and avoid congestion/voltage problems in real-time. After the predictive grid management is applied and the technical problems mitigated, DSO will move on to the next year of the planning horizon.

3.3.3 CBA Methodology

Although the CBA methodology is part of the PDP methodology described in section 3.3.2, as it is a separate methodology, it will be described in this chapter.

Once the last year of the planning horizon has been reached, an economic assessment of each DSO decision-making methodology planning must be performed. The cost-benefit analysis is formulated to determine the total cost of each DSO planning solution and also to assess the technical and economical benefits of shifting from a passive planning to a modern planning (SG case), in which is allowed the control of network participants (demand and generation) for PDP. Along with these important points, a sensitivity analysis is also part of the CBA methodology in order to estimate the break-even point.

For thesis purposes, the total cost estimation for both grid planning solutions, power distribution reinforcement planning and active distribution grid management, is considered from the first year to the last year of the planning horizon, i.e., the economic evaluation does not include the base case scenario (year 0).

3.3.3.1 Total Cost Estimation - Power Distribution Reinforcement Planning

During the life cycle of the assets installed in the power grid, two types of incurred costs take place: CAPEX representing the asset investment/reinforcement costs and OPEX representing the operational costs. Asset investment costs are due to line/cable and transformer reinforcements. Operational costs are related to network active power losses.

Also, it is important to consider the outage costs in the economic evaluation, i.e., consumers and producers interruption costs paid by DSO, due to ENS and REC.

Therefore, the cash flows of the three cost vectors (investment, operation and outage) for the network reinforcement program are created. The net present value (NPV) of the total cost for the power distribution reinforcement planning during the planning period T with an interest rate d is calculated by

$$NPV_{RP} = \sum_{t=1}^{T} (InvC_t + OpC_t + OutC_t).(P|F,d,t) \tag{3.9}$$

where,

NPV_{RP} is the net present value of total cost for the reinforcement program [€]

$InvC_t$ are the annual investment/reinforcement costs in year t [€]

OpC_t are the annual operational costs in year t [€]

$OutC_t$ are the annual outage costs in year t [€]

$(P|F,d,t)$ is the present value factor for a single future value

T is the length of cash flows (number of years of the planning horizon)

The $(P|F,d,t)$ is defined by

$$(P|F,d,t) = (P|A,d,t) * (A|F,d,t) = \frac{(1+d)^t - 1}{d(1+d)^t} * \frac{d}{(1+d)^t - 1} = \frac{1}{(1+d)^t} \tag{3.10}$$

where,

$(P|A,d,t)$ is the present value factor for an annuity cash flow
$(A|F,d,t)$ is the sinking fund factor for an annuity cash flow
d is the pre-defined discount rate [%]
t is a certain year of the planning horizon

It is important do address the following points:

- The NPV calculation is the process of finding the equivalent value at some earlier time. NPV calculation is the reverse of future value calculation;
- The discount rate (d) is the rate of interest that converts all costs into their value in the present. It is based on the premise that money received today is worth more than the same amount of money received in the future, because it could be earning interest. Thus, the future value is discounted;
- The economic analysis is made at constant prices, therefore inflation is not considered.

Investment Costs

For thesis purposes, as mentioned in section 3.1.1 and section 3.3.2.1, the replacement of substation HV/MV transformers and the MV/LV transformers are neglected, respectively. Therefore, the investment costs are only related to reinforcement of network MV lines/cables and must be applied in order to efficiently meet the load growth demand and to host large shares of RES.

The network reinforcement planning defines investments/reinforcements in order to avoid congestion/voltage problems and quality service deterioration. Hence, the reinforcement of distribution lines/cables takes place in the preceding year in which technical problems are verified, because the network lines/cables may take months to build.

The annual incurred investment costs for the adopted investment/reinforcement measures regarding the reinforcement program are given by the following equation

$$InvC_t = \sum_{j=1}^{N_l} c_{r_j} * l_j * \gamma^j \tag{3.11}$$

where,

N_l is the total number of network distribution lines/cables
c_{r_j} is the investment cost of reinforcing line/cable j [€/km]
l_j is the length of the distribution line/cable j [km]
γ^j is the reinforcement decision on line/cable j, which can be 0 or 1

Operational Costs

The exploration costs are related to network active power losses. In terms of power losses in network infrastructure, they are only accounted for the network lines/cables, while losses in substation transformers are ignored.

These costs are directly connected to the usage of grid equipment and are system embedded costs, meaning that these are cost estimates for the whole system as opposed to the investment costs, that are only applied to the reinforcement equipment.

Traditional power flow can be used to calculate the active power losses in the network. Then, multiplying the power losses by the cost coefficient, the operational costs are calculated.

In terms of electrical quantities, the power losses of a network line/cable are directly proportional to the current flow in the line/cable, where the proportional coefficient is defined by the cable resistance.

Therefore, the annual operational costs related to active power losses for the reinforcement program can be calculated by

$$OpC_t = \sum_{j=1}^{N_l} c_p * pl_j * 8760 \Leftrightarrow OpC_t = \sum_{j=1}^{N_l} c_p * r_j * I_j^2 * 8760 \tag{3.12}$$

where,

c_p is the cost coefficient of power losses [€/MWh]

pl_j are the active power losses on line/cable j [MW]

r_j is the resistance of line/cable j [Ω]

I_j is the current on line/cable j [A]

It is important to underline that, for the calculation of operational costs in equation 3.12, the network active power losses correspond to the values of the hour with the highest active power losses, among the seven days (scenarios) that were selectively chosen.

Outage Costs

The annual outage costs are calculated based on the total amount of load/generation that cannot be supplied/injected in the network after an outage - ENS and/or REC. These annual costs depend on the network topology and location of the protection devices, and just like the operational costs, these are system embedded costs that are applied to the network loads and DG units.

Being ENS and/or REC the amount of energy (demand and/or generation) that needs to be curtailed to prevent voltage/congestion problems, and taking into account the economic value attributed to ENS and the reference feed-in-tariff to REC (DSO penalty costs), the annual outage costs for the reinforcement program can be calculated by the expression 3.13.

$$OutC_t = \sum_{h=1}^{8760} \sum_{m=1}^{N_{lb}} c^{ENS} * ENS_m + \sum_{h=1}^{8760} \sum_{n=1}^{N_{DGb}} FiT^{RES} * REC_n \tag{3.13}$$

where,

N_{lb} is the total number of network load buses

N_{DGb} is the total number of network DG buses

c^{ENS} is the cost of energy not supplied [€/MWh]

FiT^{RES} is the reference feed-in-tariff applied to RES installations [€/MWh]

ENS_m is the amount of energy not supplied on load bus m [MW]

REC_n is the amount of renewable energy curtailed on DG bus n [MW]

3.3.3.2 Total Cost Estimation - Active Distribution Grid Management

For the predictive grid management, only one type of incurred costs take place: OPEX representing the operational costs. The operational costs are related to network active power losses, but also to the activated/contracted flexibility provided by demand and generation.

Although, as stated in section 3.2, when the flexibility services contracted by DSO can no longer handle the technical problems, it is necessary to perform reinforcements in the grid and therefore CAPEX costs mentioned in section 3.3.3.1 are included in total cost estimation for the ANM planning, if investments are applied to the network.

Hence, depreciating the investment costs due to the fact that in the ANM planning they result from a last resort action, the net present value of the total cost for the active distribution grid management during the planning period T with an interest rate d is calculated by

$$NPV_{ANM} = \sum_{t=1}^{T} OpC_t.(P|F,d,t) \tag{3.14}$$

where,

NPV_{ANM} is the net present value of total cost for the active network management [€]

OpC_t are the annual operational costs in year t [€]

$(P|F,d,t)$ is the present value factor for a single future value

T is the length of cash flows (number of years of the planning horizon)

The $(P|F,d,t)$ was previously defined in equation 3.10.

Operational Costs

The operational planning process quantifies the exploration costs as the network active power losses and the activated/contracted flexibility services provided by DER.

In terms of power losses in network infrastructure, they are only accounted for network lines/cables, while losses in substation transformers are ignored. The way to calculate the operational costs vector from the network active power losses is already explained in section 3.3.3.1.

It is important to underline that, for the calculation of active power losses in equation 3.15, the network active power losses correspond to the values of the hour with the highest active power losses of the entire year.

The flexibility provided by DER to prevent congestion/voltage problems and ensure the balance between consumption and generation is related to the active participation of consumers (load flexibility) and producers (RES flexibility). In more general terms, the actions of load shedding (demand response) and PV and wind power curtailment are defined through upward and downward flexibility services, respectively, so the DSO can activate the amount of flexibility from load and RES needed in real-time to avoid technical problems.

Optimal power flow is executed to calculate the activated/contracted flexibility from loads and DG units. Then, multiplying by upward and downward flexibility activation prices (DSO penalty costs) respectively, the operational costs related to the total flexibility provided by the active participants can be calculated.

Therefore, the annual operational costs related to active power losses and activated flexibility from loads and DG units for the predictive grid management program can be calculated by

$$\begin{aligned} OpC_t &= \sum_{j=1}^{N_l} c_p * pl_j * 8760 + OpC_{load}^{shed,up} + OpC_{DG}^{curt,dw} \\ &= \sum_{j=1}^{N_l} c_p * r_j * I_j^2 * 8760 + OpC_{load}^{shed,up} + OpC_{DG}^{curt,dw} \end{aligned} \tag{3.15}$$

where,
$OpC_{load}^{shed,up}$ are the operational costs from loads upward flexibility (load shedding action) [€]
$OpC_{DG}^{curt,dw}$ are the operational costs from DG units downward flexibility (DG curtailment action) [€]
c_p, pl_j, r_j, I_j previously defined in equation 3.12

The $OpC_{load}^{shed,up}$ and $OpC_{DG}^{curt,dw}$ are defined in equation 3.16 and 3.17.

$$OpC_{load}^{shed,up} = \sum_{h=1}^{8760} \sum_{m=1}^{N_{lb}} f_m^{up} * C_{act}^{up} \Leftrightarrow OpC_{load}^{shed,up} = \sum_{h=1}^{8760} \sum_{m=1}^{N_{lb}} f_m^{up} * (\overline{\pi}_{RM}^{up} - \overline{\pi}_{DA}) \tag{3.16}$$

$$OpC_{DG}^{curt,dw} = \sum_{h=1}^{8760} \sum_{n=1}^{N_{DGb}} f_n^{dw} * C_{act}^{dw} \Leftrightarrow OpC_{DG}^{curt,dw} = \sum_{h=1}^{8760} \sum_{n=1}^{N_{DGb}} f_n^{dw} * (\overline{\pi}_{DA} - \overline{\pi}_{RM}^{dw}) \tag{3.17}$$

where,

f_m^{up} is the active power flexibility provided by load bus m [MW]
f_n^{dw} is the active power flexibility provided by DG bus n [MW]
C_{act}^{up} is the upward flexibility activation price [€ /MWh]
C_{act}^{dw} is the downward flexibility activation price [€ /MWh]
$\overline{\pi}_{RM}^{up}$ is the annual average upward regulation market price [€ /MWh]
$\overline{\pi}_{RM}^{dw}$ is the annual average downward regulation market price [€ /MWh]
$\overline{\pi}_{DA}$ is the annual average day-ahead market price [€ /MWh]

For thesis purposes, the upward flexibility activation price (C_{act}^{up}) is defined as the difference between the annual average upward regulation market price ($\overline{\pi}_{RM}^{up}$) and the annual average day-ahead market price ($\overline{\pi}_{DA}$). The downward flexibility activation price (C_{act}^{dw}) is defined as the difference between the annual day-ahead market price ($\overline{\pi}_{DA}$) and the annual average downward regulation market price ($\overline{\pi}_{RM}^{dw}$).

Break-Even Point
A sensitivity analysis is performed to calculate the break-even point. The break-even point refers to the maximum total cost that DSO is willing to pay for the active distribution network management to be profitable.

The maximum price that DSO can pay for the preditive grid management to be cost-effective is the total cost calculated for the power distribution reinforcement planning, because if the total cost of ANM exceeds the total cost of the traditional reinforcement program, this planning solution will be unprofitable.

Therefore, to reach the break-even point it is important to underline some points:

- The total cost of the power distribution reinforcement planning will be used as the maximum reference price that the active distribution grid management can achieve;
- The amount of flexibility (f_m^{up} and f_n^{dw}) that has been activated/contracted by the DSO over the planning horizon remains the same, and only the upward and downward regulation market prices ($\overline{\pi}_{RM}^{up}$ and $\overline{\pi}_{RM}^{dw}$) will change;
- The $\overline{\pi}_{RM}^{up}$ and $\overline{\pi}_{RM}^{dw}$ will be increased and decreased respectively, in equal ratio, until the total cost of the predictive grid management matches the total cost of the traditional reinforcement planning.

From this last point, two inequality constraints related to the regulation market prices arise:

$$\overline{\pi}_{RM}^{up} \leq \overline{\pi}_{RM}^{up,max} \tag{3.18}$$

$$\overline{\pi}_{RM}^{dw} \geq \overline{\pi}_{RM}^{dw,min} \tag{3.19}$$

where,

$\overline{\pi}_{RM}^{up,max}$ is the maximum annual average upward regulation market price [€/MWh]

$\overline{\pi}_{RM}^{dw,min}$ is the minimum annual average downward regulation market price [€/MWh]

$\overline{\pi}_{RM}^{up}, \overline{\pi}_{RM}^{dw}$ previously defined in equations 3.16 and 3.17 [€/MWh]

As a consequence from constraints 3.18 and 3.19, two more inequality constraints related to flexibility activation prices crop up:

$$C_{act}^{up} \leq C_{act}^{up,max} \tag{3.20}$$

$$C_{act}^{dw} \leq C_{act}^{dw,max} \tag{3.21}$$

where,

$C_{act}^{up,max}$ is the maximum upward flexibility activation price [€/MWh]

$C_{act}^{dw,max}$ is the maximum downward flexibility activation price [€/MWh]

$C_{act}^{up}, C_{act}^{dw}$ previously defined in equations 3.16 and 3.17 [€/MWh]

Therefore, $\overline{\pi}_{RM}^{up,max}$, $\overline{\pi}_{RM}^{dw,max}$, $C_{act}^{up,max}$ and $C_{act}^{dw,max}$ are the allowed prices for the active distribution grid management to be cost-effective.

3.3.3.3 KPIs Assessment

The calculation of key performance indicators (KPIs) is used to assess some technical and economical benefits of shifting from a traditional reinforcement planning to an active network (ANM) planning.

Therefore, some KPIs are computed in order to evaluate the impact of the Smart Grid (ANM) functionality on the power distribution reinforcement planning. These KPIs were adapted from [50] and described as follows:

1. The Deferred Distribution Capacity Investment (DDCI) KPI for the functionality of network reinforcement planning considering the management of distributed flexibility is computed by the following formula:

$$DDCI = \frac{NPV_{RP} - NPV_{ANM}}{NPV_{RP}} * 100\% \tag{3.22}$$

where,

$DDCI$ is expressed in [%] or [€] if multiplied by NPV_{RP}

NPV_{RP}, NPV_{ANM} previously defined in equations 3.9 and 3.14 [€]

In the absence of distribution flexibility, congestion/voltage problems can only be solved by reinforcing the grid. However, the distributed flexibility services provided by DER have a direct impact on the CAPEX, as they may enable delaying such reinforcement needs by eliminating the operational problems that would otherwise require new investments to be made. This leads to a necessity of quantifying the potential for deferring such network reinforcement investments.

Therefore, this KPI is of particular interest to notice the monetary savings/benefits of including active network management (flexibility services) in the PDP. Yet, another important KPI related to the investment deferral to be obtained is the number of years in which the investment was deferred, when distributed flexibility is considered.

Deferring reinforcement may not be a long-term solution and, at some point, the network will have to be reinforced if the need for new capacity increases.

2. The KPI that is associated with the reduction of active power losses when distributed flexibility is considered in PDP, is computed as follows:

$$\Delta PL = \frac{PL_{RP} - PL_{ANM}}{PL_{RP}} * 100\% \tag{3.23}$$

where,

ΔPL is expressed in [%] or [MW] if multiplied by PL_{RP}

PL_{RP} is the total amount of active power losses in the reinforcement planning situation [MW]

PL_{ANM} is the total amount of active power losses in the active network management situation [MW]

Flexibility provided by DER and contracted by DSO can balance locally the consumption and generation, leading to a reduction in power flows and so lower the active power losses. In some cases, the inversion of power flows due to high penetration of RES can lead to an increase in the power losses.

The total amount of active power losses for the reinforcement planning situation (PL_{RP}) and for the active network management situation (PL_{ANM}) are calculated by means of equations 3.12 and 3.15, respectively.

Chapter 4

Case Study and Results

4.1 Introduction

In order to evaluate the suitability of the two DSO decision-making methodologies developed in chapter 3, this chapter presents a case study of PDP over a defined planning horizon. Such planning exercise is aimed to be used in MV networks which is expected to be, in the near future, under stressed operating conditions that may arise as result of the strong DG penetration in the network.

In this regard, a case study is illustrated, presenting some future congestion/voltage problems that DSO could prevent by relying in two possible network planning solutions: power distribution reinforcement planning and active distribution grid management. The case study will be formulated similar to chapter 3.

First of all, the system test data and the chosen software for PDP analysis will be presented, along with a study and important information about system's current stage (year 0 of the planning horizon) and some topics before addressing the PDP over the next years. Then, a technical analysis throughout the planning horizon will be verified, presenting some relevant information regarding the critical years (years with technical problems). Next, the data/parameters used to perform the CBA will be pointed out. Finally, the results information regarding technical and monetary aspects from both planning solutions will be exposed along with the sensitivity analysis and KPIs results. In all sections of this chapter under consideration, relevant images and tables will be presented to sustain some information and the presented results.

4.2 MV Grid: Case Study

The MV network employed in this work is based on a real German MV distribution grid: MV Oberrhein network. This grid is a generic 20 kV network powered by two 25 MVA HV/MV transformers substations. The network supplies 141 MV/LV substations and 6 MV loads through 4 MV feeders. The network layout is meshed, but the network is operated as a radial network with 6 open sectioning points, i.e., 6 redundant lines/cables. The grid also includes geographical information of cables/lines and buses and is assembled from openly available data.

It is important to mention that this network is normally used for studies regarding voltage problems and some adaptations to the original system had to be made, in order to demonstrate the potential of both DSO planning methodologies in situations where there is a risk of voltage but mainly congestion problems across distinct feeders of the network. Therefore, some adjustments in the MV Oberrhein network were needed:

- The two HV/MV transformers rated apparent power were increased (25 MVA to 63 MVA);
- Some network cables cross-sectional area were increased (185 mm^2 to 240 mm^2) and others decreased (240 mm^2 and 185 mm^2 to 95 mm^2);
- As said previously in section 3.3.2.1, the MV/LV secondary substations are neglected and therefore loads and DG units are directly connected to MV nodes;
- According to section 3.3.2.4, the network open sectioning points were amended and disposed in other locations of the network. The MV Oberrhein will operate with only 3 redundant lines;
- Also as said in section 3.3.2.1, the scaling for loads and DG units is unitary, i.e., the power factor for all the loads and static generators assumes a unitary value ($cos(\phi) = 1$).

The geographical representation of the adapted network is presented in Figure 4.1, where the yellow blocks correspond to the HV/MV substations and the blue dots to all the network buses. In appendix A, an alternative one-line diagram of the test system is presented for easier identification of the network feeders.

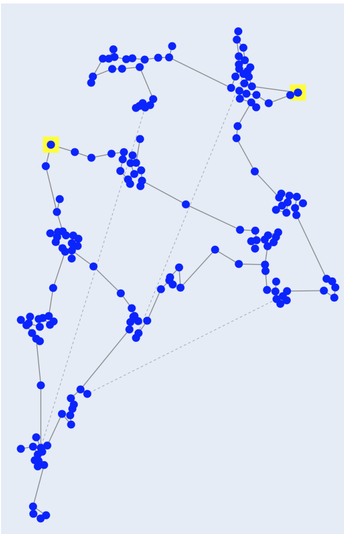


Figure 4.1: MV Oberrhein network

The adapted test system is characterized by operating at 20 kV level. With a total of 179 nodes, 178 lines/cables and load allocated by 147 buses, this network is operated radially when in normal network operating mode.

The load profiles were collected from [54], in which is presented the hourly energy consumption (kWh) values for a real 240-Node Iowa Distribution Test System with one year smart meter data. Then, 147 profiles (number of loads in the network) were selected and as previously said in section 3.3.2.2, these consumption time series were standardized in reference to 80% of the maximum hourly value of all the consumption time steps in a year. Next, the standardized load profiles were multiplied by each respective load installed capacity (already defined in the study network) giving the maximum active power output of each load at each hour. For thesis purposes, the focus in system data is regarding active power, while reactive power data is not relevant for the case study.

The generation (PV and wind) profiles were provided by INESC TEC and collected also with one hour time step over one year of data. The wind power profiles were used in reference to GEFCom2012 and can be verified in [55]. Then, as said also in section 3.3.2.2, the selected number of PV and wind profiles (according to how many DG units will be connected in the grid in the base case scenario and in the future years of the planning horizon), were standardized in reference to the maximum hourly value of each generation (PV or wind) data. Next, the standardized generation profiles were multiplied by each respective static generator (DG unit) installed capacity giving the maximum active power output of each DG unit at each hour. The installed capacity of each static generator is given respecting the last point defined in section 3.3.2.1 and according to load installed capacity if connected to a load bus. For thesis purposes, the DG units only produce active power while reactive power is assigned to zero.

A detailed description of the data concerning the network, including lines/cables and load data, and still the generation data for all the years of the planning horizon (including base case scenario) is also given appendix A. As HV/MV substation transformers reinforcement will not be taken in consideration, data about them will be discarded.

Finally, it is important to mention that all network data were treated and DSO network planning methodologies for the PDP problem were developed using the software Pandapower. This software is an open source python tool for modeling, analysis and optimization of electric power systems. More information about this software tool can be reached at [56], and more specifically information about the MV network used in this work at [57].

4.2.1 Base Case Scenario

As previously said in section 3.3.1 and underlined in section 4.1, the baseline scenario represents the year zero of the planning horizon, in which there are no technical problems in the network. However, in the near future, the system will be under stressed operating conditions and some congestion/voltage problems may crop up. So, within the following years of the planning horizon it will be needed network reinforcements or be contracted flexibility by DSO from DER to prevent the technical problems. In the year zero of the planning horizon (base case scenario) there are already DG units from PV and wind power connected to the network.

This preliminary scenario was created by considering the load to be allocated by the 147 load buses already presented in the test system, and no more loads were created neither connected to the distribution network. To reproduce a realistic case study, it was needed to connect some DG units in the network and for that purpose some rules were required and already explained briefly in section 3.3.2.1 :

- DG units from RES are connected to buses with or without load. If is connected to a load bus, then the installed DG capacity must take into account the value of load installed capacity, i.e., the greater the installed capacity of the load bus, the greater the installed capacity of the DG unit/static generator and vice-versa. Also, considering the theoretical maximum of each installation to be 10 kW and assuming a security margin (1 kW) and also considering that each DG unit correspond to an aggregate of 150 installations (PV or wind), the maximum admited installed capacity for a DG unit is 1350 kW. The annual generation increase capacity also must take in consideration the theoretical maximum of each installation, so there are no irrational growth rates;

- The choice of "candidate" buses to connect DG units is based on the branch current sensitivity coefficients with respect to active power of the Jacobian matrix. This matrix contains sensitivity coefficients for power flow analysis, i.e., it is possible to perceive how sensitive a line/cable is to the consumption or injection of power. The increase in consumed power from the network will affect the branches with highest negative sensitivity indices and the increase in injected power in the network will affect the branches with highest positive sensitivity indices. Therefore, through this information provided by the Jacobian matrix, it is possible to identify the interesting buses to connect DG in order to observe future congestion problems on certain network lines/cables. This process is applied to every year of the planning horizon when connecting DG units in the network and also allows to obtain objectivity in the work in question;

- DG installed capacity is 80% from PV power production and 20% from wind power production and also is considered to be a multiple of the annual peak load. This two guidelines are used to demonstrate that in a distribution network PV power is dominant over wind power and to avoid unreal concentrations of DG penetration, respectively.

It is important to notice that DG units are addressed in software Pandapower as static generators (sgens) and not as generators, because it is not desired to model voltage controlled generators. These static generators are modelled as positive and constant PQ power and can be from two different renewable technologies - PV or wind power.

In the base case scenario, the system presents a peak consumption of 33,47 MW allocated by 147 buses and a peak generation of 16,67 MW allocated by 15 buses. The DG installed capacity is considered to be 55% of the peak consumption and therefore 18,41 MW, in which 80% is from PV power generation (14,728 MW) and 20% from wind power generation (3,682 MW). These values are also sustained by the description of load and generation data provided in sections A.3 and A.4 from appendix A. Furthermore, in Figure 4.2 is illustrated the test system with the inclusion of loads and DG units in the respective buses for the year 0 of the planning horizon.

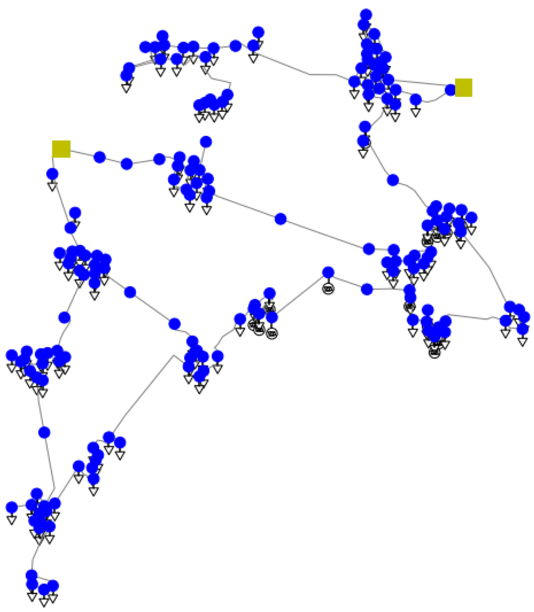


Figure 4.2: MV Oberrhein network with connected loads and DG units - Year 0

Network Operational Constraints

Before verifying the power flow (PF) results of the base case scenario, it is important to establish the network operational constraints. As said in section 3.3.2.3, these inequality constraints are related to lines/cables and transformers capacity limits and bus voltage magnitude limits. Despite these restrictions do not interfere with the PF results, they need to be defined prior to the planning exercise in order to be identified as reference values and to perform the AC OPF.

By using the software Pandapower, the maximum lines/cables and transformers capacity limits ($I_{L_j}^{max}$ and $I_{T_k}^{max}$) are represented by the maximum current loading for all the lines/cables and maximum load utilization relative to rated power for all the transformers, both in percentage values. For all the buses it is necessary to define the admissible range of bus voltage magnitude values, i.e. the maximum and minimum bus voltage limits (V_i^{max} and V_i^{min}), both in per unit values. Further information about these network elements can be consulted in [58, 59, 60]. It is important to notice that these capacity and bus voltage constraint values were assigned according to the information presented in EDP's PDIRD.

Lines/Cables	Transformers HV/MV		Buses	
	Summer	*Winter*		
$I_{L_j}^{max}$ [%]	$I_{T_k}^{max}$ [%]		V_i^{min} [p.u.]	V_i^{max} [p.u.]
110	105	120	0.9	1.1

Table 4.1: Network loading capacity and bus voltage restriction values

EDP addresses the PDP by planning the network mainly for congestion problems rather then voltage problems. Therefore and because the branch lengths are generally short, this case study will focus more on the congestion problems, where the major network operational issues are related with the violation of branch loading capacity limits instead of voltage constraints. As previously said in section 3.1, the reinforcement of substation HV/MV will be neglected and so the violation of transformers maximum loading limit will not be a problem in this case study.

In order to identify possible fragile elements, base case PFs were performed for the entire year (8760h). Since the most interest situations for PDP are scenarios with peak values of demand and generation, the relevant base case PF results for the hourly peak demand and peak generation of the entire year are presented in Tables 4.2, 4.3, 4.4, 4.5 and 4.6, and in Figure 4.3.

Base Case Scenario		
	Peak Load P [MW]	*Peak Generation* P [MW]
HV/MV substations PF	27.09	-2.67
Load	33.47	13.51
Generation	7.03	16.67
Losses	0.56	0.42

Table 4.2: Results of base case PF - Peak load and generation

Branch Index	From Bus	To Bus	Peak Load Loading [%]
0	238	109	19.21995286206508
1	238	40	13.68421658953164
10	197	167	22.0023707555723
100	229	224	2.106439407260145
101	223	227	2.066677098226956
102	227	231	1.958728551273741
103	231	229	1.789382479748997
104	285	288	25.33197587177087
105	288	286	25.92081590913543
106	176	285	24.21059984330924
107	178	176	38.17487989449623
108	178	197	23.94803819324282
109	287	286	27.52253805948279
11	199	167	18.05118118979053
110	200	184	7.296019115516319
111	198	199	11.81498187333539
112	199	181	3.968308642421801
113	198	184	9.807729176429843
114	181	186	1.483006721490371
116	314	301	25.99161684234902
117	301	303	23.53461322556605
118	303	304	27.97380036771891
119	273	315	1.849797515419497
12	168	273	20.16464482333505
120	314	246	24.43198849793834
121	271	305	1.422874069906784
122	312	273	14.07106895966532
123	271	281	9.223572344630684
124	281	312	10.22556161102975
125	271	85	4.444673352847319
126	312	313	1.572977235158077
127	7	6	**53.00211539716926**
128	7	5	1.216198361829538
129	244	1	0.7201512395305633
130	0	4	27.54310216226729
131	241	4	33.15568157973938
132	8	0	25.95228504140266
133	243	2	1.080048671637983
134	245	3	0.7654282160419348
135	240	241	34.06781055071051
136	242	243	46.88550426146161
137	245	244	44.55900221290603
138	244	243	46.0036255909993
139	116	138	5.202351612848259
14	168	246	23.3083286890915

Branch Name	From Bus	To Bus	Peak Load Loading [%]
140	116	111	4.488897991037418
141	110	108	13.57368103357574
142	131	140	2.205931561348663
143	131	133	40.70122015633421
144	141	138	4.088877467796392
145	149	141	2.769415433802757
146	147	149	2.436528657607185
147	64	65	7.058004780521271
148	65	36	0.6770364441677597
149	79	64	7.040472442704774
15	172	131	45.1533431332462
150	79	82	8.506388715097636
151	74	75	18.73727972481143
152	74	101	1.621406809181567
153	110	103	10.90807596297191
154	104	103	10.05158515127115
156	104	106	4.197422373362153
157	86	71	19.15885405039926
158	71	73	17.88624586785345
16	144	172	42.4616375372097
161	73	78	24.36439859813712
162	80	39	37.9030526014678
163	57	53	33.85023204901343
164	46	53	35.04320243163128
165	39	86	19.155518323298
167	42	51	14.88411043609539
168	44	56	24.03788894023403
169	56	84	20.2582741098107
17	253	171	25.29238700088771
170	52	150	43.17741233506293
171	146	150	43.9816815104995
172	117	148	**50.69461012522324**
173	148	120	46.98885043354793
174	118	148	2.84400173790979
175	80	117	**52.02609266729917**
177	146	143	2.005422773501978
178	145	146	42.52016187721721
179	55	145	44.57840881754687
18	171	8	25.20394482793358
180	83	41	13.02079724611449
181	81	77	21.20482906092792
182	77	35	37.95302358416549
183	78	35	24.41244670234713
184	80	119	3.683382892975604
185	81	37	16.18917271345257

Branch Name	From Bus	To Bus	Peak Load Loading [%]
186	81	43	3.242545593306355
187	37	41	14.25393826741361
189	45	47	40.13503198204531
190	47	49	41.49663768093775
191	49	52	42.45241908703581
192	55	120	45.83861620973014
193	6	319	**54.4138433464007**
2	238	221	2.360271072066512
20	170	136	2.200474720443149
21	170	116	2.532463136622293
22	216	195	12.73106274772498
24	195	317	9.259710088382818
25	213	194	8.000451568650085
26	207	194	9.233256218008776
27	269	196	15.36763054107656
28	196	74	17.43608356165273
29	189	82	9.522475464826133
3	221	239	2.07550712281616
30	51	189	12.98511133040767
32	65	190	3.957939848917241
34	192	44	27.96168368482904
35	57	192	31.57944427535744
36	289	72	20.79880096456622
37	289	75	19.37356799536757
38	290	7	**52.34191007104866**
39	290	242	48.98497508506375
4	239	236	2.800006081728541
40	290	240	35.86399090311998
41	269	108	15.27216586475824
42	153	316	6.549591985990679
43	316	159	2.016066982526871
44	316	157	3.302216969132382
45	317	33	9.066372546151456
46	245	298	41.3034138238467
47	298	248	41.40092376601157
48	237	247	8.648407037071138
49	247	40	13.70743175468475
5	169	54	**56.39238664682605**
50	133	248	41.45336562487813
51	237	136	5.409569499845531
52	29	30	14.2756850622576
53	126	29	14.27265280662014
54	30	72	21.97019615584037
55	253	304	29.49850807904884
56	33	104	8.340525961221644

Branch Name	From Bus	To Bus	Peak Load Loading [%]
57	110	31	0.2278334473485332
58	34	76	1.350697667156695
59	45	34	39.697254530797
6	169	275	1.728821208972969
60	32	34	36.81264035795995
61	46	32	36.85655354181553
62	319	126	14.27010440645184
63	50	48	3.092692610207268
64	42	50	16.04339010562299
65	84	50	20.35284088473116
67	54	144	41.69481923125765
68	224	38	3.930159454052522
69	38	161	4.631315028384253
7	169	287	29.14762043483197
70	134	142	13.08308578324157
71	142	235	0.869165084113837
72	142	83	13.31652490008781
73	132	137	17.16040684762316
74	137	95	15.79161781401269
75	132	134	13.41041039241539
76	129	188	2.067075941266475
77	85	129	4.608725559280511
78	98	100	2.166552663791252
79	100	102	18.76705783410733
80	94	102	17.31368487608093
81	100	107	13.56908740263773
82	94	95	20.17718451895744
85	210	215	0.8293449412600804
86	216	215	3.025295273603575
87	219	236	4.783810602464134
90	109	201	11.31185187331394
91	173	107	13.12607750874693
92	205	207	8.498344846961766
93	216	205	8.427289123800806
94	201	213	10.80868133403049
95	173	174	11.36540156346262
96	174	162	8.949323194631562
97	161	162	6.678275143236188
98	157	155	1.167151007256021
99	153	200	7.913029447146975
194	147	118	0.1859908962582034
195	223	275	0.0847466404339988
196	190	129	0.1164735997027782

Table 4.3: MV network branch loadings in base case scenario - Peak load

Branch Index	From Bus	To Bus	Peak Generation Loading [%]
0	238	109	**74.36620332803975**
1	238	40	39.23578439597629
10	197	167	7.782424861070676
100	229	224	14.44181776481755
101	223	227	1.07089574244455
102	227	231	7.540443070628855
103	231	229	7.301042457676439
104	285	288	8.686874405347341
105	288	286	8.975733235245235
106	176	285	7.992842219968843
107	178	176	12.81659236976184
108	178	197	8.244684387806492
109	287	286	9.868065010264734
11	199	167	6.309810409831873
110	200	184	2.868837737940575
111	198	199	4.355756965302096
112	199	181	1.116930040639183
113	198	184	3.817020598102064
114	181	186	0.4714566606629524
116	314	301	11.87296998265147
117	301	303	10.84807066220589
118	303	304	13.25377447003693
119	273	315	1.075476465908836
12	168	273	9.397932333121208
120	314	246	11.08994138175068
121	271	305	0.6520313020366888
122	312	273	7.185794950024889
123	271	281	4.631618661304155
124	281	312	5.139195321174163
125	271	85	2.40086107710209
126	312	313	1.29236360893248
127	7	6	22.29070255028448
128	7	5	0.4611403085046284
129	244	1	0.5732782073397137
130	0	4	12.51757748496009
131	241	4	15.03191547351764
132	8	0	11.99292990329034
133	243	2	0.9392102854990961
134	245	3	0.881025925887489
135	240	241	15.33163143058405
136	242	243	17.97034170657971
137	245	244	16.34206608969966
138	244	243	17.27911732515164
139	116	138	2.110705342087011
14	168	246	10.69586159870384

Branch Name	From Bus	To Bus	Peak Generation Loading [%]
140	116	111	6.202079796532875
141	110	108	40.43450303294912
142	131	140	0.9048078273940231
143	131	133	14.79100991480682
144	141	138	1.84817225388001
145	149	141	1.364206520634619
146	147	149	0.6989399174216742
147	64	65	2.668354346598778
148	65	36	0.5150341863452863
149	79	64	2.621899923784461
15	172	131	16.35793088257545
150	79	82	4.025905013877719
151	74	75	33.81391148068771
152	74	101	0.6547317874817478
153	110	103	41.33115859762175
154	104	103	42.29616571585021
156	104	106	1.627728337225066
157	86	71	27.33563041152457
158	71	73	27.42656441042068
16	144	172	14.77646306591321
161	73	78	43.32970039162092
162	80	39	18.40247713596331
163	57	53	14.15940466470989
164	46	53	14.52257335787372
165	39	86	27.3332345413237
167	42	51	7.055575965092473
168	44	56	11.29759781310081
169	56	84	9.479992257829451
17	253	171	11.63618517905983
170	52	150	21.26697207949622
171	146	150	21.76894559335334
172	117	148	25.26741462390628
173	148	120	24.02318717861312
174	118	148	0.8583676075111987
175	80	117	26.54148775648887
177	146	143	1.033009605728898
178	145	146	20.46410772326938
179	55	145	22.02644785249954
18	171	8	11.44689813999533
180	83	41	42.18286634995253
181	81	77	43.99609466014245
182	77	35	**72.82232510915335**
183	78	35	43.35713348524423
184	80	119	1.304363606901531
185	81	37	46.46102646830268

Branch Name	From Bus	To Bus	Peak Generation Loading [%]
186	81	43	1.49347799367065
187	37	41	41.45440941408343
189	45	47	17.27708901606678
190	47	49	18.54343157472988
191	49	52	18.98090443442578
192	55	120	23.73054199021335
193	6	319	22.6939923075835
2	238	221	5.376769858094001
20	170	136	13.42988415729353
21	170	116	13.66041041177407
22	216	195	**63.63517068903504**
24	195	317	43.70267884154757
25	213	194	41.41757644676471
26	207	194	47.87130494824854
27	269	196	34.04588096184611
28	196	74	33.84707951986085
29	189	82	4.391688541688846
3	221	239	5.617892121463356
30	51	189	5.568416067086593
32	65	190	0.9690699112776202
34	192	44	12.27590622391499
35	57	192	13.5095217140975
36	289	72	33.09416246235971
37	289	75	33.13618570398589
38	290	7	22.09809808253729
39	290	242	18.55132031171491
4	239	236	6.188960812207791
40	290	240	16.05033049098818
41	269	108	40.19162539317052
42	153	316	2.374361796315734
43	316	159	0.9098094163443606
44	316	157	1.190305120155675
45	317	33	43.66152535962662
46	245	298	14.67021083716926
47	298	248	14.92635041822338
48	237	247	29.31406273850736
49	247	40	39.24332707218867
5	169	54	20.04709292168301
50	133	248	15.06386232620648
51	237	136	19.9927082843335
52	29	30	21.37355586423636
53	126	29	21.3714401294604
54	30	72	32.81455957847854
55	253	304	13.71119359152084
56	33	104	43.51293885629534

Branch Name	From Bus	To Bus	Peak Generation Loading [%]
57	110	31	0.2311921135283677
58	34	76	0.4747239102319146
59	45	34	16.89153701491126
6	169	275	0.636246576331337
60	32	34	16.15036369930907
61	46	32	16.24793909737786
62	319	126	21.36965377003166
63	50	48	0.9797650359079307
64	42	50	8.480818313659611
65	84	50	9.676575164745696
67	54	144	14.19387626157461
68	224	38	12.58930960614978
69	38	161	12.23071602048308
7	169	287	10.50414095382975
70	134	142	35.4213232850592
71	142	235	8.108900146120511
72	142	83	42.27436901142877
73	132	137	25.11790919972627
74	137	95	25.76818951904172
75	132	134	28.23824438338476
76	129	188	0.7435619787298677
77	85	129	2.689729333502556
78	98	100	0.8376954844584829
79	100	102	8.98394033529734
80	94	102	17.15192368126892
81	100	107	8.847578597382919
82	94	95	17.12266842041496
85	210	215	1.747327778877137
86	216	215	2.784813670488401
87	219	236	6.240233149851685
90	109	201	44.03829147394298
91	173	107	9.408965478160537
92	205	207	47.72232620166108
93	216	205	47.08205732577559
94	201	213	49.8024133671416
95	173	174	10.01429553823177
96	174	162	11.07249235124868
97	161	162	11.74473464126053
98	157	155	0.4555623421542636
99	153	200	2.613585755447888
194	147	118	0.187087377586801
195	223	275	0.08760556786290653
196	190	129	0.1188753751133705

Table 4.4: MV network branch loadings in base case scenario - Peak generation

The highlighted branches, in Tables 4.3 and 4.4, have more than 50% of their capacity filled in base case and both provide relevant data. Furthermore and according to the PF gradient results observed in Figure 4.3, by distinguishing the two cases (peak load and peak generation) it can be noted that the highlighted values were higher in the case where the generation is maximum. This indicates that scenarios with high penetration of RES, in particular PV and wind power, are critical points in the network.

Regarding voltage constraints, the main concern about DG integration is the possibility of overvoltage, i.e., exceed the maximum bus voltage limit (V_i^{max}). The problem is more likely to happen in nodes at the end of the feeders, but also in nodes surrounded by branches with higher loading capacity.

Bus Index	Peak Load V [p.u.]	Bus Index	Peak Load V [p.u.]	Bus Index	Peak Load V [p.u.]	Bus Index	Peak Load V [p.u.]
0	1.014280022054434	**168**	1.007477545587127	**242**	1.016227005850482	**40**	1.02649790354701
1	1.014483580150919	**169**	0.9891211456462548	**243**	1.015301620439968	**41**	1.011921700270058
100	1.006924158780276	**170**	1.028074682535612	**244**	1.01449649847474	**42**	0.9838442969281547
101	1.028648968433697	**171**	1.013643736864528	**245**	1.013850790651917	**43**	1.013271279471284
102	1.007236355195166	**172**	1.0049238231048	**246**	1.00796139132502	**44**	0.9872176180010148
103	1.026926537771336	**173**	1.004635528347167	**247**	1.0271431187725	**45**	1.00027286942831
104	1.026671018865511	**174**	1.004462283400046	**248**	1.007978394585772	**46**	0.990462241431363
106	1.026602576886301	**176**	0.986832621237531	**253**	1.011889069764196	**47**	1.001308890767706
107	1.006645083013169	**178**	0.9851128664606634	**269**	1.027887773656033	**48**	0.984683403965026
108	1.027561092701978	**181**	0.9825713064851208	**271**	1.006358987716131	**49**	1.002065267342351
109	1.024908342764517	**184**	0.98241388821132	**273**	1.006969454623298	**5**	1.020979890570748
110	1.027236967136766	**186**	0.9825239750516405	**275**	0.9890867877541998	**50**	0.9847232448204731
111	1.028149117683975	**188**	1.00537667954438	**281**	1.006566859910681	**51**	0.9834412754863564
116	1.028081761522337	**189**	0.9826286900052529	**285**	0.9871955263464922	**52**	1.002438832339889
117	1.009682618483527	**190**	0.9812153307253308	**286**	0.9877605339434101	**53**	0.989310532742553
118	1.008915147210272	**192**	0.9877185643497849	**287**	0.9879761641820618	**54**	1.002739150231095
119	1.010705684824495	**194**	1.024659929913952	**288**	0.987515887839697	**55**	1.007479478949858
120	1.008462977967143	**195**	1.024663716132634	**289**	1.029834101143068	**56**	0.9866313332163172
126	1.034739709252539	**196**	1.02836850651872	**29**	1.033090916571161	**57**	0.9887104886100656
129	1.005418660473968	**197**	0.9833372871711298	**290**	1.016857103557923	**58***	1.0
131	1.005587500739293	**198**	0.9825173705758204	**298**	1.011325654446856	**6**	1.030596603795499
132	1.009143070442613	**199**	0.9826653452837744	**3**	1.013837765612711	**64**	0.9813763629581888
133	1.006206184103503	**2**	1.015282716484672	**30**	1.031123395595356	**65**	0.9812886141643175
134	1.009388974209192	**200**	0.9823144179260259	**301**	1.008998238160502	**7**	1.021013079643009
136	1.028064406518292	**201**	1.02478834937268	**303**	1.009328383461368	**71**	1.01798026960758
137	1.00864580378978	**205**	1.024545120482069	**304**	1.009933859589377	**72**	1.030199510427778
138	1.027934434107734	**207**	1.024552080652257	**305**	1.00633980551675	**73**	1.016166260968275
140	1.005578359323744	**210**	1.024491405824786	**31**	1.027240354678996	**74**	1.028663246703468
141	1.027581666101392	**213**	1.024690271314866	**312**	1.00687289445703	**75**	1.029280856528627
142	1.009677623698906	**215**	1.024507392117173	**313**	1.006848871179619	**76**	0.99299680599638
143	1.00509897297157	**216**	1.024555516739626	**314**	1.008393269223717	**77**	1.014021148143978
144	1.003365531616418	**219**	1.025608123917214	**315**	1.006941910991936	**78**	1.015489703931014
145	1.006157750550197	**221**	1.025569551506358	**316**	0.9815728465693019	**79**	0.9815197322555893
146	1.005133585638468	**223**	1.003488592425017	**317**	1.024936300433212	**8**	1.013830109262414
147	1.027433661964485	**224**	1.003554384779987	**318***	1.0	**80**	1.010799558789102
148	1.008961623384553	**227**	1.003518289369358	**319**	1.036874810774315	**81**	1.013337314890714
149	1.027464676035964	**229**	1.003530072101207	**32**	0.9917901232060424	**82**	0.9816850102597702
150	1.003157849755185	**231**	1.003513502616272	**33**	1.025916325015719	**83**	1.010824290276483
153	0.9821810640680662	**235**	1.009675733809474	**34**	0.9930332964483771	**84**	0.9863113021757385
155	0.9814996811921385	**236**	1.025543203681174	**35**	1.015000397965791	**85**	1.005981971918085
157	0.9815246953546113	**237**	1.027894501319242	**36**	0.981278791002247	**86**	1.020990753890672
159	0.9814817484238033	**238**	1.025592653897922	**37**	1.012273241744029	**94**	1.007693140974718
161	1.004134628443878	**239**	1.025519024102857	**38**	1.003966123039429	**95**	1.008124943447548
162	1.00432397988287	**240**	1.016310122084547	**39**	1.022007204138957	**98**	1.006886645517876
167	0.9829363925280856	**241**	1.01552156199549	**4**	1.014715544147578		

Table 4.5: MV network bus voltage magnitudes in base case scenario - Peak load

Bus Index	Peak Generation V [p.u.]	Bus Index	Peak Generation V [p.u.]	Bus Index	Peak Generation V [p.u.]	Bus Index	Peak Generation V [p.u.]
0	1.025467371782076	**168**	1.022068988514734	**242**	1.026447153030655	**40**	1.064728132488374
1	1.025695979331328	**169**	1.016426288736537	**243**	1.026047405373512	**41**	1.028782840482467
100	1.034784307850289	**170**	1.070845526455532	**244**	1.025706083776305	**42**	1.002646303168293
101	1.040360620025723	**171**	1.025142443343222	**245**	1.025437706434806	**43**	1.026458938278126
102	1.034768871589309	**172**	1.021821195853419	**246**	1.022306390351349	**44**	1.004389653513961
103	1.043200179385877	**173**	1.035318485391363	**247**	1.066664652514555	**45**	1.010343631111088
104	1.043981818662453	**174**	1.035381088943578	**248**	1.023061219061131	**46**	1.005861293779863
106	1.043953381778195	**176**	1.015518586421918	**253**	1.024249577048121	**47**	1.010822760193721
107	1.034840364749274	**178**	1.01497595359701	**269**	1.041204724561089	**48**	1.003122969204699
108	1.04175083021513	**181**	1.01405994835469	**271**	1.021488523899771	**49**	1.011185034602816
109	1.059136279916744	**184**	1.01398714206722	**273**	1.021815806191013	**5**	1.029204122913526
110	1.042380248779024	**186**	1.014046216007455	**275**	1.016413020742929	**50**	1.003135511463643
111	1.071012507437622	**188**	1.020930399323773	**281**	1.02159972717462	**51**	1.002443331317749
116	1.07091749654748	**189**	1.002077103703162	**285**	1.015654532336435	**52**	1.011364036815187
117	1.015269278926878	**190**	1.001448747267208	**286**	1.01587518938498	**53**	1.005349596994674
118	1.014863054588624	**192**	1.004625464963611	**287**	1.015962541979824	**54**	1.021009906356323
119	1.015859244430097	**194**	1.057517719939613	**288**	1.015779270897188	**55**	1.014039638910035
120	1.014595734149379	**195**	1.054045683664819	**289**	1.039367270799901	**56**	1.004095338607365
126	1.038522629167223	**196**	1.040651122965969	**29**	1.03849043366607	**57**	1.005080187031177
129	1.020944645442492	**197**	1.01433713457422	**290**	1.026716536997478	**58***	1.0
131	1.022079370091737	**198**	1.014029781788742	**298**	1.024422136574127	**6**	1.034904488369159
132	1.033566231381734	**199**	1.014086857456495	**3**	1.025422816207676	**64**	1.001497674120732
133	1.022333999215832	**2**	1.026030817113711	**30**	1.038463744247136	**65**	1.001464773410693
134	1.033314209108325	**200**	1.013943606876867	**301**	1.022810980092089	**7**	1.029215540542871
136	1.070452751090412	**201**	1.058552930728154	**303**	1.022979867523337	**71**	1.023158758998249
137	1.033940994684137	**205**	1.056072914645194	**304**	1.023284704918139	**72**	1.039096368033992
138	1.070853571207145	**207**	1.056275354749438	**305**	1.021479341301968	**73**	1.023221030889677
140	1.022075461603019	**210**	1.055183732230654	**31**	1.042383686259591	**74**	1.040365337950756
141	1.070690981546275	**213**	1.057909115257075	**312**	1.021763299297516	**75**	1.039819494776407
142	1.032895863794375	**215**	1.055217733251208	**313**	1.021743324386989	**76**	1.007056960317459
143	1.012760435665698	**216**	1.055262173874324	**314**	1.022516070049575	**77**	1.025743103452479
144	1.021239299072626	**219**	1.062384810789876	**315**	1.021799305688686	**78**	1.023831371384892
145	1.013322270940678	**221**	1.062080864002479	**316**	1.013673732332607	**79**	1.001550821499551
146	1.01277888822211	**223**	1.037341274534596	**317**	1.052774324935226	**8**	1.025236711416279
147	1.070624395213661	**224**	1.036915199414846	**318***	1.0	**80**	1.015892914178521
148	1.014874712745046	**227**	1.037355698974734	**319**	1.038577606769482	**81**	1.026490421109747
149	1.070632915046175	**229**	1.037109205437918	**32**	1.006485952910375	**82**	1.001632082516278
150	1.01174067554332	**231**	1.037197850242912	**33**	1.047970345720895	**83**	1.030821615225907
153	1.013897298483862	**235**	1.032957323843806	**34**	1.007068769406838	**84**	1.003935301751672
155	1.013647580296496	**236**	1.062297534138845	**35**	1.024270657299456	**85**	1.021277607614672
157	1.013656298509305	**237**	1.069563704802042	**36**	1.001457658206553	**86**	1.023170190138788
159	1.013632955968168	**238**	1.062046016743482	**37**	1.028215448296366	**94**	1.034555582518931
161	1.035680604696599	**239**	1.06220171165156	**38**	1.035976301964665	**95**	1.034402045995383
162	1.035473299022119	**240**	1.026455525655933	**39**	1.023180750179697	**98**	1.034769625388382
167	1.014186872529313	**241**	1.026077109205849	**4**	1.025687324982278	*	slack buses

Table 4.6: MV network bus voltage magnitudes in base case scenario - Peak generation

Analysing Tables 4.5 and 4.6, some nodes could be identified has potential critical points in the network, regarding overvoltages. In addiction and according to the PF gradient results observed in Figure 4.3, by differentiating the peak load case and peak generation case it can be perceived that in general the bus voltage magnitudes were higher in the case of maximum generation. This indicates that DG integration in the grid leads to voltage rise. However, the relation between voltage variation and DG integration is non-linear: in some cases DG integration leads to voltage drop (because PF in MV level decreases) and in another ones leads to voltage rise. Therefore, attentions must be turned to nodes at end of the feeders.

Finally, for these two peak condition scenarios, in Figure 4.3 is presented the PF gradient results, where a colormap is used to represent the MV branch loadings and bus voltage magnitudes for the year 0 of the planning horizon. Furthermore, in section B.1 of appendix B, detailed PF gradient results for critical lines and buses along the grid feeders are presented, as well as the alternative one-line diagram gradient plot to sustain the information noticed in Tables 4.3, 4.4, 4.5 and 4.6, and to especify Figure 4.3.

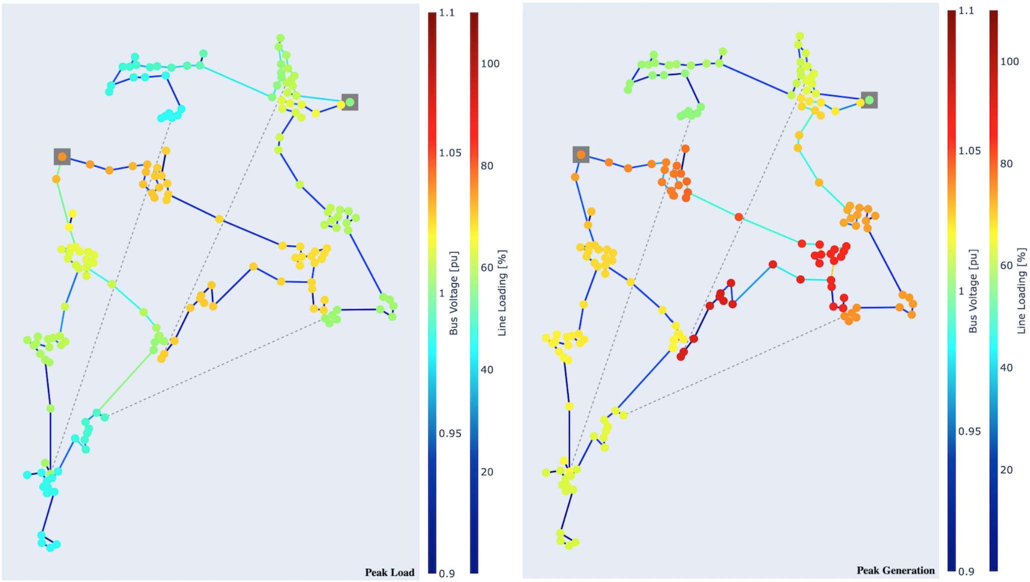


Figure 4.3: PF gradient results for base case scenario - Peak load and generation

Load and DG Growth

As mentioned in section 3.3.2.1, it is assumed a planning horizon of 10 years (including base case) for the PDP in the MV Oberrhein grid. This horizon is divided into stages with yearly duration and from the first year until the end, a given consumption and DG capacity growth is defined for each year. These growth rates are defined in order to reproduce a realistic case, i.e., always expect an increase in network consumption and DG capacity connected to the grid over the years. The consumption growth values were defined based on values from EDP's PDIRD and the DG capacity growth rates were freely established as long as they were rational. It is important to notice that DG growth percentage is in relation to the DG installed capacity in the base case scenario. Therefore, in Table 4.7, the yearly load growth (applied in general to all the loads in the system) and RES capacity growth are presented. In addiction, in section A.4 of appendix A, it is reflected the application of DG capacity growth values over the planning horizon. Also, in section 4.2.2 it is possible to seek the consumption growth over the planning years.

	Planning Horizon									
	Years									
	1	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***
Load Growth [%]	+1.1	+0.7	+0.3	+0.8	+0.8	+1.6	+0.8	+1	+0.9	+0.9
DG capacity growth [%]	+25	+25	+25	+25	+30	+0.25	+0.30	+0.30	+0.20	+0.20

Table 4.7: Load and DG growth

Representative Scenarios

In order to perform the traditional distribution network planning, the load and RES (PV and wind power) generation profiles of seven representative days were selected based on the criteria set out in section 3.1.2. Therefore, distinctive daily profiles will be adopted for the whole year to represent the behaviour of distribution network customers and producers in a year. As mentioned in section 3.3.2.2, this method is only applied to the reinforcement planning, whilst for the predictive grid management (with activation of flexibility) the PDP is executed for the entire year (8760 hours).

Representative Days	
Date	**Characteristics**
09-March-2017	Winter; weekday; maximum peak generation
16-April-2017	Spring; weekend & holiday; typicall valley load & typical peak generation
01-May-2017	Spring; weekday & holiday; typicall valley load & typical peak generation
05-July-2017	Summer; weekday; typical peak load & typical valley generation
17-July-2017	Summer; weekday; maximum peak load
20-July-2017	Summer; weekday; typical peak load & typical valley generation
30-September-2017	Autumn; weekend; maximum valley load

Table 4.8: Representative daily scenarios for power distribution reinforcement planning

All profiles are described in 24 1-hour periods, in order to observe the time variability of consumption and generation throughout the day, and to highlight load/production conditions worth examining. In some daily RES profiles it is feasible to notice the influence of wind power generation over PV solar generation, i.e. the total RES (PV+wind) generation curve is very similar to the typical PV curve behaviour, although with some modulation caused by the wind generation curve.

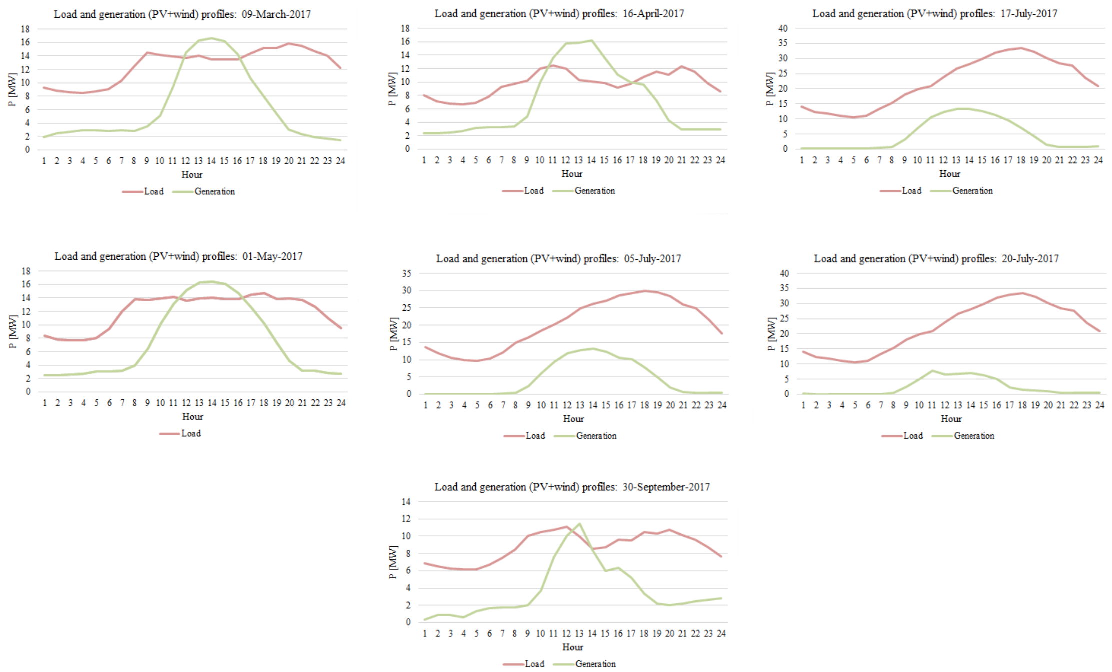


Figure 4.4: Load and RES generation profiles

So far, the continuous increase of new DG connections in the network has been given a great deal of importance as one of the indicative drivers for the occurrence of technical problems in the network. However, the continuous increase in consumption over the years also causes vulnerability to the network and may lead to technical problems. Hence, attention must be turned to hours with high demand and low DG generation and hours with low demand and high DG generation. For example the representative day 16-April-2017 seems to be a very appealing scenario to investigate, since between 12-15h there is a marked difference between consumption and generation injected into the grid by RES, leading to a high risk of finding technical problems on this day.

With the data provided by the distinctive scenarios in Figure 4.4 and the previous Tables presented in this section 4.2.1, it is noteworthy that both peak condition scenarios (demand and generation) are relevant for the reinforcement planning case and in general for the PDP exercise. For illustration purposes, in the years where congestion/voltage problems may appear and so as not to burden this work with even more images, the PF gradient results presented in section 4.2.2 will be regarding the representative scenarios mentioned in Figure 4.4, with the highest hour of branch loadings and/or bus voltage values. The same is applied to the years not described in section 4.2.2. Finally, the non gradient PF results will be regarding the maximum peak load and maximum peak DG generation as expressed in Table 4.2, in order to follow the network behaviour from the base scenario to the last year of the planning horizon and seek the increase in consumption and DG capacity over the years. In section A.4 of appendix A is presented the evolution of the maximum peak generation over the years of the planning horizon.

4.2.2 Technical Analysis

In this section, a technical analysis throughout the planning horizon (10 years) will be presented, with particular emphasis in the years that congestion/voltage problems occurred. Reference will also be made to the actions used by the DSO to address such problems and how these decisions have been performed in the software Pandapower. Further information about some PF results can also be found in appendix B, along with the PF (gradient and non gradient) results for the other years of the planning period not mentioned in this section. Also, in appendix C is presented the new DG connections in the network over the planning years.

Year 2

This year of the planning horizon was the first year where technical problems occurred in the network. These problems were related to congestion and voltage problems, because 2 MV cables and 9 buses (from feeder 1) exceed the restriction values presented in Table 4.1, and these violations were registered in 3 representative days: 09-March-2017, 16-April-2017 and 01-May-2017 (days with high generation), and for the entire year in 164 hours.

According to chapter 3, DSO tries to solve the technical problems first with network reconfiguration by using the redundant cables in the network. The topology reconfiguration action by closing one open sectioning point was well succeeded, all the network problems were solved and neither consumption or production was disconnected from the network. Therefore, there was no need for investments/reinforcements or activate/contract flexibility from DER. In Table 4.9 and Figure 4.5 are presented the PF results for the year 2 of the planning horizon, before and after the network reconfiguration. Further information and detailed PF results regarding overloaded cables and overvoltage buses are presented in section B.3 of appendix B.

From Table 4.9, it can be perceived that in the peak generation scenario, the DG generation represents approximately twice the power demand, leading to a power flow in opposite direction at the HV/MV substations. The same phenomenon happens already in the base case scenario, although in a more balanced amount. Also, in Table 4.2 despite the reverse power flow, the higher integration of DG leads to a reduction in power losses. Nevertheless, in year 2 is observed that further DG penetration makes the power losses matter worse. Regarding voltage constraints, the strong DG injection in the grid causes overvoltage in buses at the end of feeder 1.

	Year 2			
	Before network reconfiguration		**After network reconfiguration**	
	Peak Load	***Peak Generation***	***Peak Load***	***Peak Generation***
	P [MW]	**P [MW]**	**P [MW]**	**P [MW]**
HV/MV substations PF	23.76	-10.70	23.69	-11.23
Load	34.08	12.73	-	-
Generation	11.02	24.46	-	-
Losses	0.61	0.95	0.54	0.43

Table 4.9: PF results in year 2 - Peak load and generation

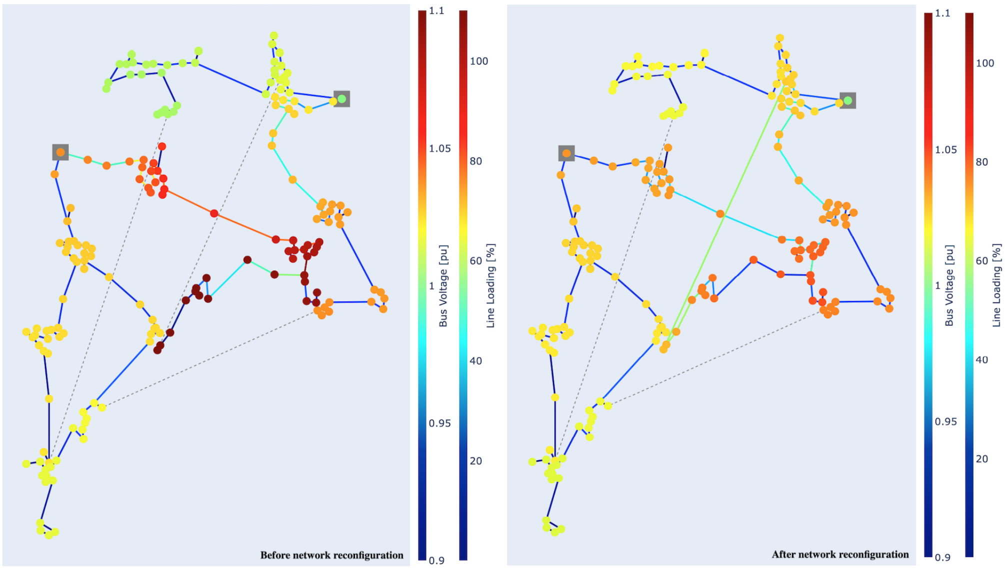


Figure 4.5: PF gradient results in year 2 [Scenario 16-April-2017]

Furthermore, by also looking at Figure 4.5 it can be seen the advantage of redirecting the path through which the power flows to feeder 3. The network reconfiguration leads to a reduction in the active power losses, in both peak load and generation conditions, but mainly in the generation scenario. Also the congestion and voltage problems are solved.

Year 4

In this year of the planning horizon, only congestion problems occur in the grid. One MV cable (from feeder 4) becomes overloaded, and this violation was recorded in one daily representative scenario: 16-April-2017, and for the entire year in 30 hours.

Just like in year 2, the problem was solved by applying network reconfiguration. Hence, nor even this year it was necessary to perform investment in a new cable neither contract flexibility services from demand and generation. In Table 4.10 and Figure 4.6 are presented the PF results for the year 4 of the planning horizon, before and after reconfiguration of the network topology. Further information and detailed PF results regarding the overloaded cable are presented in section B.5 of appendix B.

From Table 4.10 the same conclusions regarding peak generation scenario can be drawn as in the year 2 of the planning horizon. Also, comparing to the power losses values for year 2 after reconfiguration, is possible to perceive that for the peak load scenario the losses were reduced, while for the peak generation case the value increased. Thus, the continuous growth of DG capacity connected to the grid is still leading to higher power losses. Regarding voltage constraints, no problems were identified and the bus voltage magnitudes remained within the safety range.

Year 4				
	Before network reconfiguration		**After network reconfiguration**	
	Peak Load P [MW]	***Peak Generation*** P [MW]	***Peak Load*** P [MW]	***Peak Generation*** P [MW]
HV/MV substations PF	20.42	-18.42	-	-
Load	34.44	13.90	-	-
Generation	14.56	32.66	-	-
Losses	0.46	0.55	0.43	0.53

Table 4.10: PF results in year 4 - Peak load and generation

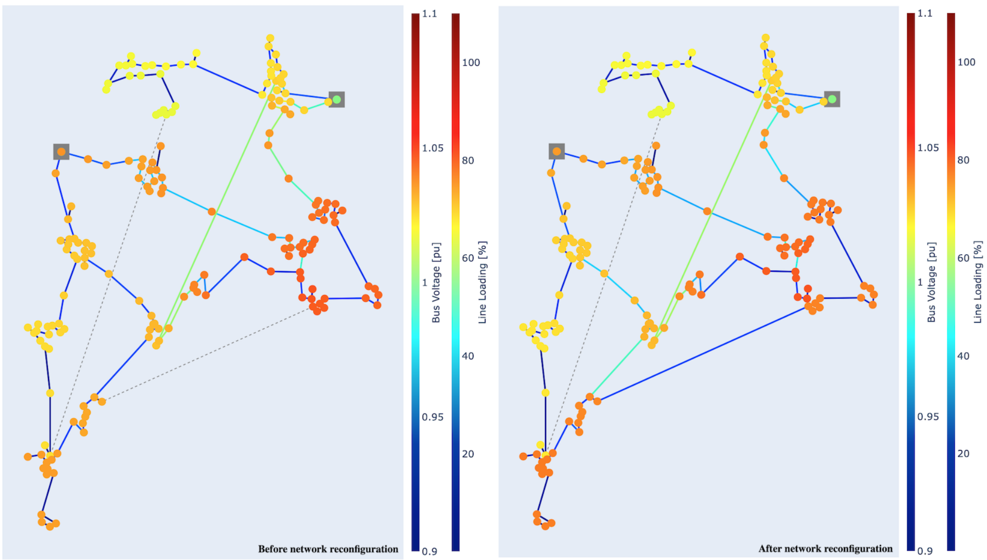


Figure 4.6: PF gradient results in year 4 [Scenario 16-April-2017]

Moreover, by closing one open sectioning point, power losses slightly reduced for both peak conditions and power flow in the HV/MV transformer substations remained the same. In addition, the congestion problem has been solved, but the cable remained with high loading capacity in relation to the maximum loading capacity limit. This particular detail should be taken into account in the future years, as reconfiguration may have solved the problem this year, but not permanently for the planning horizon.

Year 6

In this year of the planning period, the same MV cable from year 4 was again overloaded, and no voltages problems were verified. This violation was recorded on 09-March-2017, 16-April-2017 and 01-May-2017 (days with high generation), and for the entire year in 49 hours. The first action performed by the DSO to solve the congestion problem was again the use of the redundant cables, although this time the last available network reconfiguration only could relieve the problem, i.e., could not solve it permanently. In Table 4.11 and Figure 4.7 are presented the PF results for the year 6 of the planning horizon, before and after network reconfiguration.

From Table 4.11 it can be noted that in the peak generation scenario, the DG generation represents approximately three times power demand, and therefore a severe reverse power flow is redirected to the HV/MV substations. Therefore, as we move forward in the planning years, it is possible to observe an escalating increase in the amount of energy that goes to HV/MV substations. Also, comparing to the year 4 after reconfiguration, it can be noted that for the peak load scenario the losses were reduced, inducing that DG integration can be beneficial for power losses reduction. Although, when there is a large discrepancy between the energy injected and the energy consumed, the strong DG penetration is detrimental to the level of network losses.

Year 6				
	Before network reconfiguration		**After network reconfiguration**	
	Peak Load **P [MW]**	***Peak Generation*** **P [MW]**	***Peak Load*** **P [MW]**	***Peak Generation*** **P [MW]**
HV/MV substations PF	17.26	-27.49	17.23	-27.51
Load	35.25	13.16	-	-
Generation	18.40	41.58	-	-
Losses	0.34	0.84	0.30	0.81

Table 4.11: PF results in year 6 - Peak load and generation

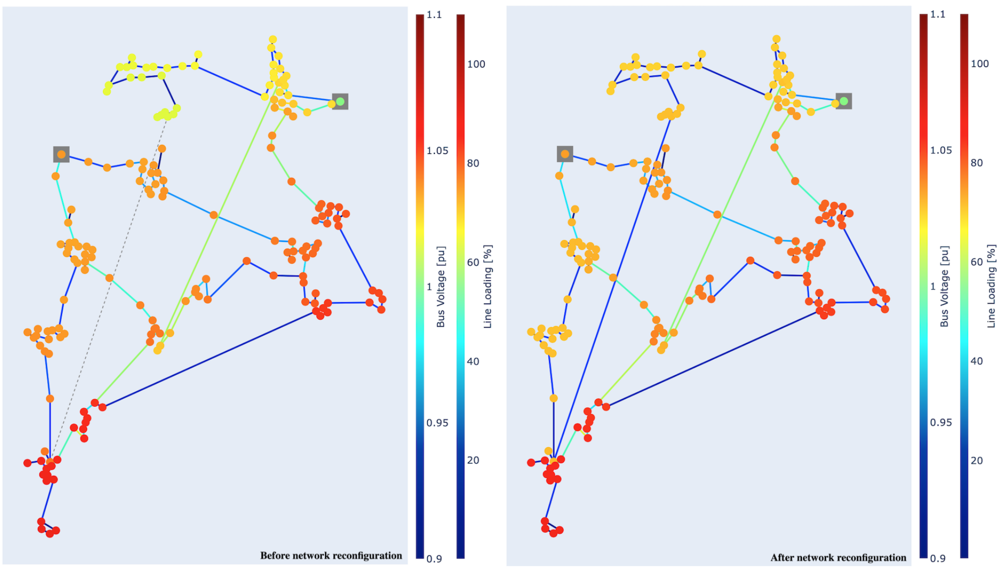


Figure 4.7: PF gradient results in year 6 [Scenario 16-April-2017]

Furthermore, by also taking into account the information provided by Figure 4.7, it can be seen that network topology reconfiguration hardly affected the HV/MV substations power flow and network power losses. Thus, the main advantage by this DSO action is the relief of cable overload capacity. Further information and detailed PF results before and after the network reconfiguration are presented in section B.7 of appendix B.

Despite of that, the grid technical problem must be solved, and therefore the DSO has at his disposal two possible network planning solutions: power distribution network reinforcement or active distribution grid management.

Power Distribution Reinforcement Planning
In this case, the traditional network planning will allow DSO to reinforce the overloaded cable by installing a new cable with a superior cross-sectional area. But, before we move on to the reinforcement action is crucial to quantify the ENS and/or REC due to the overloaded cable.

In the traditional planning process, the actions of curtail load and generation active power are executed to allow the distribution network to operate safely until the investment/reinforcement is performed in the network. For this purpose, it was need to perform multiple OPFs for the representative scenarios presented in Figure 4.4. For the execution of OPFs, the software used was the Pandapower and further information can be found in [61]. Therefore, for assessing the optimization problem it was necessary to establish some parameters:

- For the loads and DG units connected in the network, define the maximum and minimum active power to be considered. These values correspond to the network operational power constraints previously mentioned in section 3.3.2.5 and assume the values 0 MW for minimum active power and the respective (load/ DG unit) operation point/ time step of the year power value as the maximum active power;

- Although, the other network constraints related to branch capacity loadings and bus voltage magnitudes are already defined in Table 4.1, they acquire appropriate importance for the implementation of OPF;

- Cost functions are specified element wise to address the problem and represent linear costs per MW for loads and static generators (DG units). These linear costs are the economic benchmarks (DSO penalties) for ENS and REC (c^{ENS} and FiT^{RES}) and are provided in section 4.2.3. Also, the costs embedded in the OPF must be inserted with negative values to guarantee that the optimization problem found the optimal solution considering the maximization of consumption and generation in the network, i.e., minimizes in general the power curtailed.

For this test system and in regard of the reinforcement planning, some OPFs with cost functions for loads and DG units did not converge, but with only costs attributed to REC (static generators), the multiple OPFs always converged into a optimal solution. Also, paying for generation curtailment is cheaper than load curtailment. Therefore, for the reinforcement planning, the only costs embedded in the optimization problem were for the static generators.

For the representative scenarios, the total estimated REC in year 6 was 4.96E-06 MW and accounted for 9 hours of all the daily scenarios. In Figure 4.9 is presented the total REC per hour of the representative scenarios (expressed values in relation to the entire year) in which RES production had to be curtailed. The highest value was registered in 16-April-2017 at 12 p.m. .

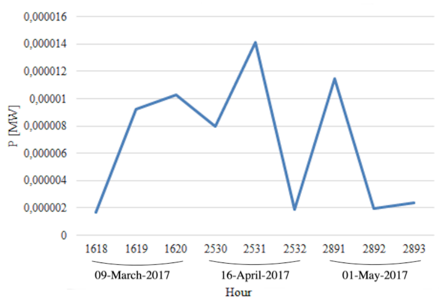


Figure 4.8: DG curtailment for the hours of the representative days in year 6

Afterwards, DSO assesses the impact of replacing the MV cable overloaded. For the chosen test system, the reinforcement with the next upward cross-sectional area cable (185 mm^2) proved to be a poor decision, as with the future integration of DG, this cable would probably be overloaded again or with quite a high capacity loading. In this way and to try to minimize the investment actions on the overloaded cable, it was decided to replace the overloaded asset with the cable of the same standard type but with the 240 mm^2 cross-sectional area, and thus ensure that this cable in the remaining planning years will not exceed the maximum loading capacity limit stipulated. As said in section 3.3.3.1, it is important to notice that the reinforcement of a distribution cable takes place in the preceding year in which technical problems are verified, because network MV cables may take months to build and the planning aims to prevent the network congestion/ voltage problems. In Figure 4.9 is presented the PF results for the year 6 of the planning horizon, after the network reinforcement is performed. Further information and detailed PF results before and after the network reinforcement are presented in section B.7 of appendix B.

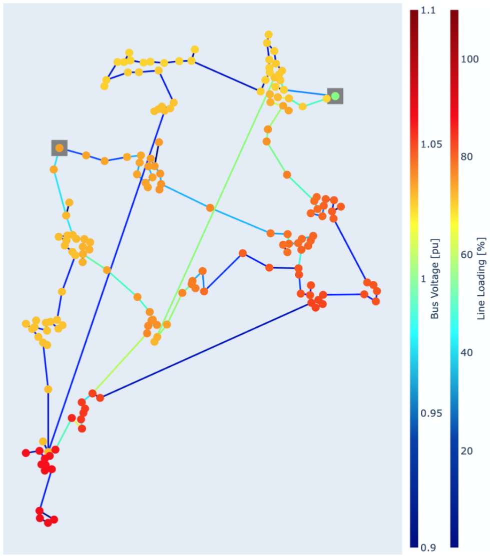


Figure 4.9: PF gradient results in year 6, after network reinforcement [Scenario 16-April-2017]

Therefore, the congestion problem was prevented by means of network reinforcement and the new MV cable is of the type: NA2XS2Y 1x240 RM/25 12/20 kV.

Active Distribution Grid Management

For the predictive grid management, the DSO will prevent the congestion problem by contracting flexibility services from DER (demand and generation). In the software Pandapower, the flexibility will be enabled for the loads (upward) and static generators (downward) in the network. Thus, DSO will pay penalty costs to consumers and producers for them to curtail load and generation, respectively, in order to ensure the equilibrium between demand and generation in the system and, therefore, solve the technical problem.

In this planning process multiple OPFs are performed for the entire year (8760 hours). For the optimization problem the same parameters used in the reinforcement planning are needed, although the cost functions used are related to the upward and downward flexibility activation prices (C_{act}^{up} and C_{act}^{dw}). These values are set out through the upward/downward regulation and day-ahead market prices ($\overline{\pi}_{RM}^{up}$, $\overline{\pi}_{RM}^{dw}$ and $\overline{\pi}_{DA}$), and are defined in section 4.2.3.

For the entire year 6, the total activated flexibility provided by DER was 488.81E-06 MW (361.91E-06 MW from demand and 126.90E-06 MW from generation) for 10 days/25 hours of the entire year. In Figure 4.10 is presented the total load and generation flexibility contracted by the DSO at the hours when such services were required. The highest values for activated load and generation flexibility were registered in 13-02-2017 at 13:00 p.m. (hour 1044 of the year).

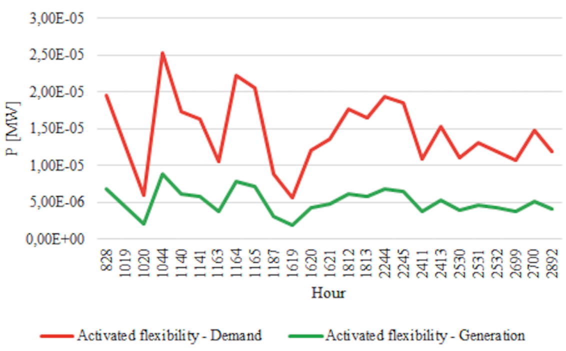


Figure 4.10: Load shedding and DG curtailment in year 6

Year 7

This year of the planning horizon is only accounted in this section for the ANM planning, because for the reinforcement planning the investment in the MV cable in the previous year solve permanently the problem. Therefore, with continuous DG growth capacity in the network, it is expected an even greater overload in the same distribution cable, and therefore an increase in the contracted flexibility by the DSO from demand and generation. Therefore, in Table 4.12 and Figure 4.10 are given the PF results for the two peak conditions and the load plus DG curtailment in the respective hours of this year.

Year 7		
	Peak Load **P [MW]**	***Peak Generation*** **P [MW]**
HV/MV substations PF	16.14	-32.13
Load	35.52	13.26
Generation	19.72	46.74
Losses	0.27	1.25

Table 4.12: PF results in year 7 - Peak load and generation

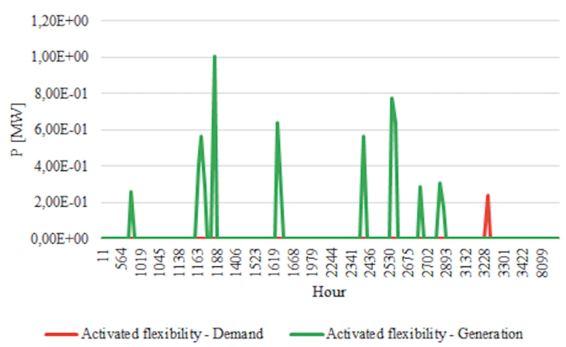


Figure 4.11: Load shedding and DG curtailment in year 7

In year 7 of the planning period, the total contracted flexibility by DSO was 6.40 MW in 50 days/144 hours of the year, being 0.24 MW from upward flexibility services and 6.16 MW from downward flexibility services. The maximum load curtailment was 0.24 MW and registered in 15-05-2017 at 14 p.m. (hour 3229 of the year), also the maximum DG generation curtailment was found in 19-02-2017 at 12 p.m. (hour 1187). By comparing the results from 4.10 and 4.11, it is possible to perceive that when a higher amount of energy needs to be curtailed, the optimization problem relies more on DG curtailment rather than load curtailment, because DSO will have to pay more penalty costs if load curtailment was the first option. Furthermore, with more relevant values regarding activated flexibility in this year, in Figure 4.12 is displayed the percentage of upward/downward flexibility in the respective hours and in relation to the potential load consumption/DG generation. Also in section B.8 of appendix B, more PF information about year 7 is provided.

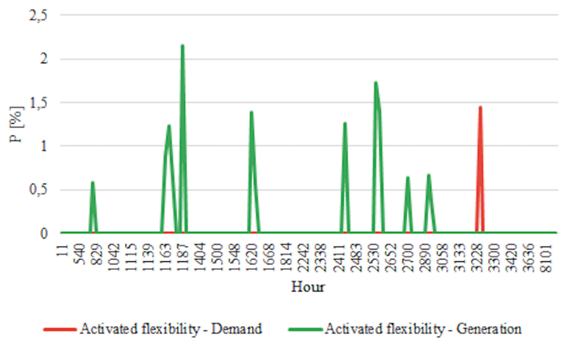


Figure 4.12: Load shedding and DG curtailment in year 7, in relation to potential load consumption and DG production

In the hour of maximum load curtailment, the energy supplied in the test system was 16.60 MW and with the demand response service provided by the loads, the system starts to operate with 16.36 MW of consumption and thus the energy curtailed from loads was 1.45% of the potential consumption value (16.60 MW). The same theory is applied to RES curtailment, where the potential DG production injected in the grid was 46.74 MW and the actual DG generation is 45.74 MW, and so the power curtailed from RES, in the highest hour, was 2.14%.

Year 8

In this year of the planning horizon, two more technical problems were identified. Two MV cables (from the same standard type) from feeder 2 surpassed the maximum loading capacity restriction, and these violations were registered in three representative scenarios: 09-March-2017, 16-April-2017 and 01-May-2017, and for the entire year in 355 hours. As there are no more redundant cables available, network reconfiguration cannot be applied and therefore DSO has to assess both decision-making planning methodologies, just like in year 6. In Table 4.13 is expressed the PF results for the year 8 of the planning horizon.

Power Distribution Reinforcement Planning

For the reinforcement planning, the total estimated REC in year 8 was 5.12 MW and accounted for 9 hours of all daily scenarios. In Figure 4.13 is verified the total REC per hour of the representative scenarios, in which DG had to be curtailed and also the curtailment percentage in relation to the potential DG production. The highest value was registered in 01-May-2017 at 13 p.m. with 1.03 MW. Also, in the hour of maximum REC, the power injected from RES was 49.70 MW, and thus

Year 8		
	Peak Load P [MW]	*Peak Generation* P [MW]
HV/MV substations PF	13.57	-36.20
Load	35.85	13.39
Generation	22.60	51.36
Losses	0.24	1.66

Table 4.13: PF results in year 8 - Peak load and generation

after the active power curtailment, the system starts to operate with 48.67 MW of generation - REC was 2.07% of the potential generation value.

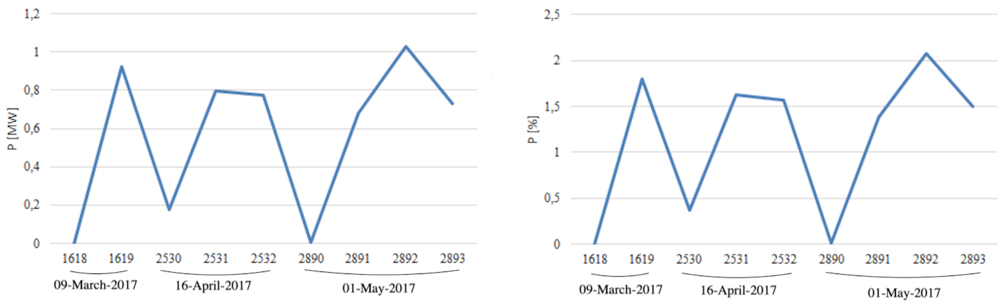


Figure 4.13: DG curtailment for the hours of the representative days in year 8

In this year of the planning period, the REC along the typical scenarios is much higher than the values represented in Figure 4.9, because DSO has to cope with roughly more 10 MW injected by RES which leads to higher capacity loading problems. Also, as a result of the further integration of DG capacity in the grid, the bus voltage magnitudes at the end of the feeder where the MV cables are overloaded (feeder 2) are very close to the maximum voltage limit defined in Table 4.1. Despite of that, until the end of the planning horizon, the bus voltages remain within the safety range.

Furthermore, the two MV cables were replaced by two cables with the same standard type and with the next upward cross-sectional area (185 mm^2), ensuring that no more congestion problems for these cables will occur within the rest of the planning years. Therefore, the overloading capacity problems were prevented by means of reinforcement planning and the new MV cables are of the type: NA2XS2Y 1x185 RM/25 12/20 kV. In Figure 4.14 is presented the PF results for the year 8 of the planning period, before and after the network reinforcements are performed. Also in section B.9 of appendix B, detailed PF results for the overloaded cables before and after reinforcement are provided.

Active Distribution Management

In year 8, the total activated/contracted flexibility by DSO from DER was 176.38 MW in 122 days/355 hours of the year, being 5.20E-03 MW from upward flexibility and 176.37 MW from downward flexibility. These reserved flexibility services were used to balance demand and generation, in order to prevent the MV cables previously referred to overload. The maximum load curtailment was 0.48E-04 MW and verified in 15-03-2017 at 13 p.m. (hour 1764 of the year) and the maximum DG curtailment was 4.53 MW and checked in 19-02-2017 at 12 p.m. Also, the maximum load/generation curtailment, in relation to the potential active power system consumed/produced by all loads/ DG units (15.81 MW/51.36 MW) were 3.05E-04% and 8.82% respectively. Hence, in Figure 4.15 is presented the activated demand/generation flexibility in the hours where such service was required, and also the percentage of upward/downward flexibility in relation to the potential load consumption/DG generation.

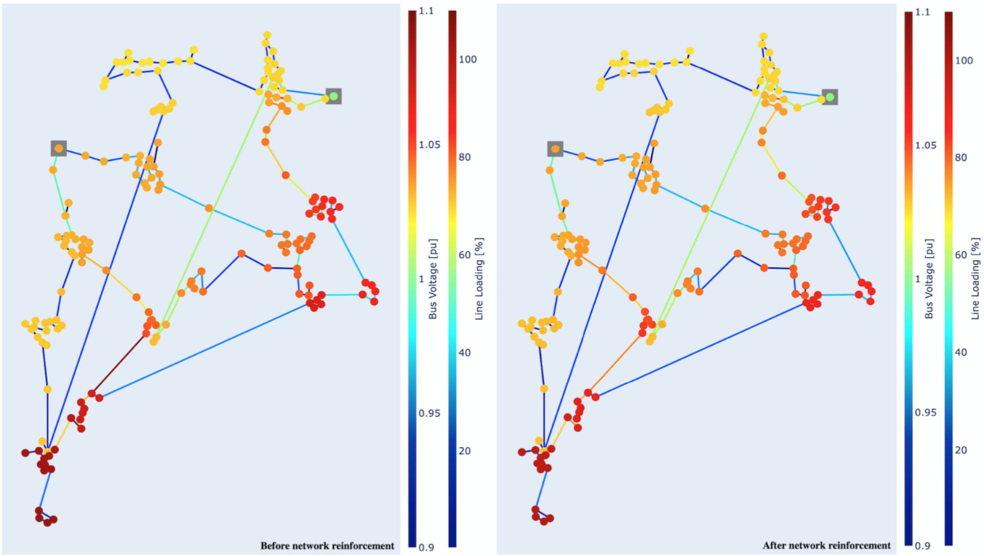


Figure 4.14: PF gradient results in year 8 [Scenario 01-May-2017]

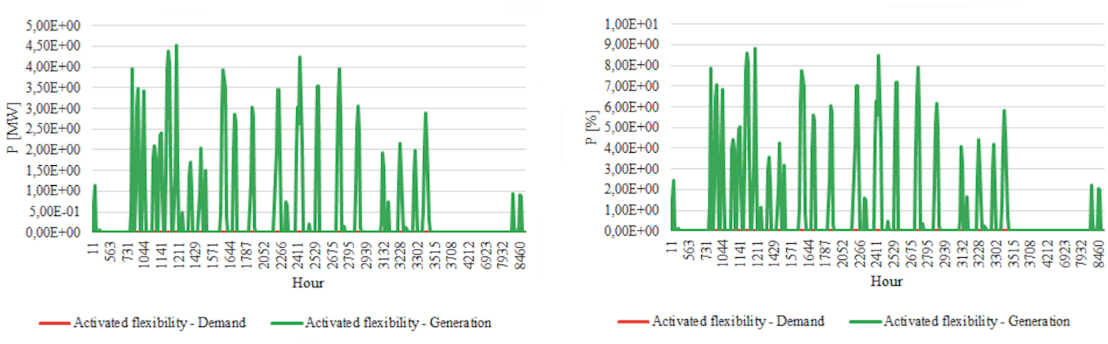


Figure 4.15: Load shedding and DG curtailment in year 8 (MW and %)

Year 9 and 10

From the perspective of traditional network reinforcement, these last two years of planning are not relevant as no further investments has been made in the network. Accordingly, the PF results and the contracted flexibility (via active power curtailment) in both years will be presented. In Table 4.14 is displayed the PF results for both years of the planning period and can be perceived, as expected, further increase in the reverse power flow (PF that is redirected to HV/MV substations) and decrease/increase in the network power losses for the peak demand/generation. In addiction, for the year 10, it can be noted that in the peak load scenario the power injected by RES represents roughly $\frac{2}{3}$ of power demand and thus the system has coped well with the integration of DG, leading to technical benefits. Also, in the peak generation case, the generation from RES stands for more than 4 times the load consumption and as mentioned multiple times, such discrepancy poses mainly congestion problems for the system operator. In order to underpin the data provided by Table 4.14, in sections B.10 and B.11 of appendix B are illustrated PF gradient results for both planning years. Furthermore, the strong penetration of DG will lead the DSO to contract/reserve even more flexibility from DER to be activated in real-time and prevent the technical problems that have cropped up in the past and have become acute over the years. Therefore, in Figures 4.16 and 4.17 are presented the total activated flexibility from DER (loads and DG units) in MW and percentage values, in the hours when active participation of consumers and producers from RES was requested.

	Year 9		**Year 10**	
	Peak Load **P [MW]**	***Peak Generation*** **P [MW]**	***Peak Load*** **P [MW]**	***Peak Generation*** **P [MW]**
HV/MV substations PF	12.49	-39.17	11.11	-42.24
Load	36.15	13.50	36.45	13.61
Generation	23.97	54.88	25.65	58.07
Losses	0.23	1.90	0.23	2.10

Table 4.14: PF results in year 9 and 10 - Peak load and generation

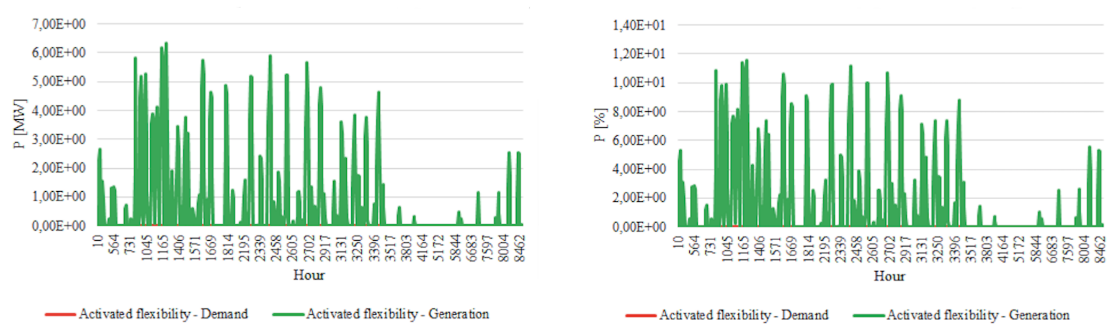


Figure 4.16: Load shedding and DG curtailment in year 9 (MW and %)

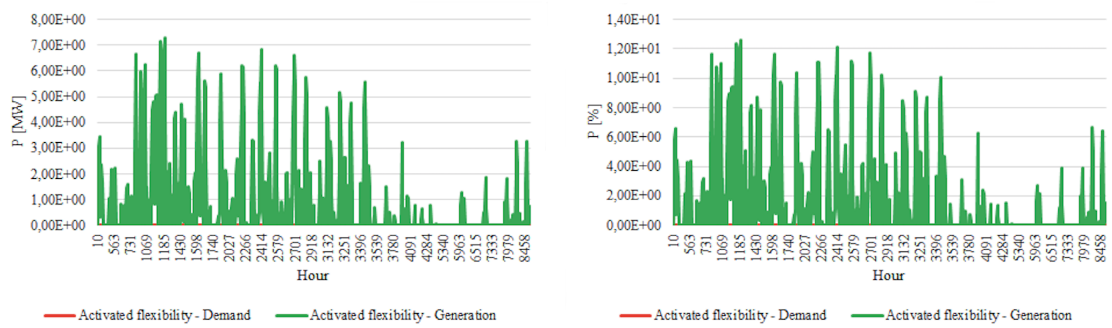


Figure 4.17: Load shedding and DG curtailment in year 10 (MW and %)

In year 9 of the planning period, the total activated upward and downward flexibility from DER by the DSO was 407.55 MW (7.90E-03 MW from demand response and 407.54 MW from DG curtailment, respectively) in 175 days/550 hours of the entire year. The maximum load shedding was 1.53E-04 MW and registered in 27-03-2017 at 12 p.m. (hour 2051) and the maximum DG curtailment was 6.35 MW and verified in 19-02-2017 at 12 p.m. (hour 1187). As said before and comparing to the results from Figure 4.15, a even higher amount of renewable energy was curtailed to guarantee the system balance between demand and generation, in order to prevent the congestion problems. The same pattern can be followed in last year of the planning horizon.

Moreover, in the hour of maximum load/generation curtailment, in relation to the potential active power system consumed/produced (14.7 MW/54.88 MW), the power curtailed from loads/DG units were 1.08E-03%/11.60%.

In the last year of the defined planning horizon, the total amount of reserved flexibility by the DSO to be used in real-time was 616.26 MW in 194 days/658 hours of the year, being 0.14 MW from load (upward) flexibility services and 616.12 MW from DG units (downward) flexibility services. As verified in the previous years, the maximum load curtailment represents a small value (1.08E-03 MW) and found in 01-06-2017 at 15 p.m. (hour 3628). The maximum generation curtailment was 7.29 MW registered in 19-02-2017 at 15 p.m.(hour 1187) and as expected was the highest value in all the planning years, in addition, in the hour with maximum load shedding, the load curtailment via active power was 6.71E-04%, in relation to the potential consumed power (25.01 MW). Also, in the hour with highest curtailment, the power system was expecting to be injected 58.07 MW from DG (RES) units, but the actual injected power was 50.78 MW, leading to 12.55% of generation curtailment.

After assessing the PDP exercise for the defined planning horizon, some major considerations should be retained:

- Given the PF results over the planning years, and the annual growth in consumption as well as the gradual increase in renewable capacity installed in the network, it can be claimed that for the peak load scenario, PF in MV/HV substations and power losses in the network are diminishing. These results reflect the inherent benefits of the on-going integration of DG in the grid, i.e., allowing most of the loads to be supplied by RES, requiring less energy from HV/MV power substations and enabling a reduction in grid losses due to the fact that the DG units are located closer to the consumption sites.

  On the other hand, in the light of the peak generation scenario, it can be reported that the reverse PF towards HV/MV power stations is increasing sharply over the years, as are the ever-increasing network power losses. These results reflect that in circumstances in which there is a large disparity between consumption and generation (network imbalance), the strong and progressive integration of DG will trigger overvoltage problems, but mainly congestion problems in the grid. This case reflects the purpose behind the implementation of the PDP methodology proposed in this work, since such problems will push the DSO to intervene: invest/reiforce network assets or contract flexibility services from DER;

- With reference to the results concerning the upward and downward flexibility services, it should be underlined that the highest level of DG curtailment over the years happens during peak generation (PV and wind power) periods, mainly in the day 19-March-2017 between 12-15 p.m. Also, as the years pass, the technical problems in the network will intensify (e.g., loading capacity of MV lines), which will encourage the DSO to hire more and more flexibility from DER to solve such problems. As a result, the penalties to be paid by DSO will rise to the point where the economic benefit of this new trend in power systems is questioned and perhaps it is worth opting for the traditional solution - network reinforcement. Or, if it is not possible to contract more flexibility from producers and consumers, the DSO is obliged to invest in the network: case of investment deferral.

4.2.3 Parameters of the CBA

Before addressing the CBA with the inclusion of a sensitivity analysis and KPIs assessment, it is important to establish some economic parameters previously mentioned in section 3.3.3. These parameters represent the cost vectors for both planning solutions - reinforcement and ANM. The estimation of the break-even point and KPIs values are a result of both planning solutions technical and monetary appraisal.

In this regard, the following data are assumed:

Discount Rate

The discount rate (d) is rate of interest that converts all costs into their value in the present. It is applied to net present value (NPV) of the total cost for the reinforcement planning and ANM planning. The chosen value for this work corresponds to the current value presented in EDP's PDIRD.

Discount Rate	
d [%]	6.75

Table 4.15: Discount rate

Investment Costs

As refered multiple times, the replacement of substation transformers will not be considered and these costs are only related to the reinforcement of network MV lines/cables.

During the reinforcement planning exercise, whenever a given distribution line/cable comes overloaded at a certain scenario, it will be necessary to reinforce this network asset in order to efficiently meet the load growth demand and to host large shares of RES. At the time to do so, the physical characteristic of the line/cable to be reinforced must be taken into account, in particular its nominal voltage ans cross-sectional area. For thesis purposes, the needed reference installation costs are related to MV underground distribution cables rather then overhead lines. The total cost of installing a new cable is shown in Table 4.16.

The data is based on data from the SuSTAINABLE Project, and since the cost for the 185 mm^2 section MV cable was not referenced, then that value was extrapolated from the reference cost values for 120 mm^2 and 240 mm^2 section cables. The installation costs are applied in the preceding year in which congestion/voltage problems are identified, because the network cables may take months to build.

Investment Costs			
Type	**Cable reference**	**S [mm^2]**	**Cost [€/km]**
MV Underground Power Distribution Cable	NA2XS2Y 1x185 RM/25 12/20 kV	185	67 000.00
MV Underground Power Distribution Cable	NA2XS2Y 1x240 RM/25 12/20 kV	240	78 000.00

Table 4.16: Cost of reinforcing a given branch in the MV test system

Operational Costs

These costs are related to annual network active power losses for the considered planning period and only accounted for the network lines/cables, while losses in substation transformers are neglected. The operational costs depend on the cost coefficient of power losses (c_p), whose value is based on the reference price for power losses at MT level approved by the Portuguese energy regulator entity (ERSE). Table 4.17 presents the respective adopted value.

For the calculation of operational costs in the reinforcement planning the network active power losses correspond to the value of the time step (hour) with the highest power losses among the seven representative days (scenarios). The ANM planning adapted the values of the highest power losses hour in the entire year. These costs are accounted for every year of the planning horizon.

Operational Costs	
c_p[€/MWh]	101.3

Table 4.17: Operational costs data for active power losses

Also, the operational costs for the predictive grid management (ANM planning) must consider another cost vectors along with the power losses costs: operational costs from loads upward flexibility (load shedding action) and operational costs from DG units downward flexibility (DG curtailment action) - $OpC_{load}^{shed,up}$ and $OpC_{DG}^{curt,dw}$. These costs represent the amount of activated/contracted flexibility provided by demand and generation in the respective year of the planning horizon multiplied by upward and downward flexibility activation prices - C_{act}^{up} and C_{act}^{dw}. These values represent the costs that DSO will have to pay to contract/reserve flexibility services provided by DER (loads and DG units from RES), in order to prevent congestion/voltage problems and ensure balance in the system.

As set out earlier in section 3.3.3.2, the up/downward flexibility activation prices are defined as the difference between the annual average upward regulation market price ($\overline{\pi}_{RM}^{up}$) and the annual average day-ahead market price ($\overline{\pi}_{DA}$), and the difference between the annual day-ahead market price ($\overline{\pi}_{DA}$) and the annual average downward regulation market price ($\overline{\pi}_{RM}^{dw}$), respectively. In Table 4.18 are presented the adopted values for both annual average up/downward regulation market prices and annual average day-ahead market price, and as a consequence the up/downward flexibility activation prices are also displayed.

The chosen values for $\overline{\pi}_{RM}^{up}$, $\overline{\pi}_{RM}^{dw}$ and $\overline{\pi}_{DA}$ are based on data from the year 2017 available in REN 2018 summary report regarding MIBEL [62]. These presented values will be fundamental

Operational Costs			
		Label	**Cost [€/MWh]**
Market Prices	Annual average upward regulation	$\overline{\pi}_{RM}^{up}$	71.20
	Annual average downward regulation	$\overline{\pi}_{RM}^{dw}$	36.90
	Annual average day-ahead	$\overline{\pi}_{DA}$	52.5
DSO penalties	Upward flexibility activation from loads	C_{act}^{up}	18.7
	Downward flexibility activation from DG units	C_{act}^{dw}	15.6

Table 4.18: Operational costs data for DER flexibility services

for the estimation of the break-even point, specifically to find $\overline{\pi}_{RM}^{up,max}$, $\overline{\pi}_{RM}^{dw,min}$, $C_{act}^{up,max}$ and $C_{act}^{dw,max}$, previously defined in section 3.3.3.2.

Outage Costs

For the traditional planning process, the actions of curtail load and/or generation are executed to allow the distribution network to operate safely until the investment/reinforcement is performed in the network. Therefore, the monetary values for ENS and REC must be accounted and correspond to DSO penalty costs, based on the economic value attributed to ENS (c^{ENS}) in EDP-D's power distribution reinforcement planning [63] and on the Portuguese reference feed-in-tariff applied to RES installations in 2018 (FiT^{RES}) [64]. The outage costs for a certain year are the amount of ENS and/or REC multiplied by the penalty costs, costs applied annually when demand and/or generation needs to be curtailed to prevent technical problems. Both DSO penalty costs are presented in Table 4.19. Finally, with all the system data costs, the net present value for both planning solution (NPV_{RP} and NPV_{ANM}) can be calculated, and therefore the CBA with the inclusion of sensitivity analysis and KPIs assessment can be adressed.

Outage Costs		
DSO penalties	**Label**	**Cost [€/MWh]**
ENS by loads	c^{ENS}	1300
REC from DG units	FiT^{RES}	95

Table 4.19: Outage costs data for curtailment of demand and renewable generation

4.3 CBA and Sensitivity Analysis

With the technical results described in section 4.2.2 and the key parameters for the CBA already identified in section 4.2.3, the financial results will then be presented. First, the cost vectors and total cost of each DSO planning solution will be shown together with the most relevant technical results. Next, the results of the sensitivity analysis will be provided for the break-even point estimation. Finally, the KPIs will be displayed.

Power Distribution Reinforcement Planning

For this DSO network planning alternative, the total cost depends on three strands: investment costs, operating costs and outage costs. These costs were calculated throught the equations referenced in section 3.3.3.1.

The investment costs concern the installation of 3 MV cables during the planning horizon: one NA2XS2Y 1x240 RM/25 12/20 kV in year 6 and two NA2XS2Y 1x185 RM/25 12/20 kV in year 8. The operational costs are related to the network active power losses and the values that enter for the economic quantification are the highest power loss values among all the hours of the representative scenarios described in Table 3.1.2. The outage costs are related to the REC verified in year 6 and 8. Therefore, the total cost estimation for the reinforcement program (NPV_{RP}) is presented in Table 4.20.

Power Distribution Reinforcement Planning							
Year - t	$InvC_t$ [k€]	$\sum_{j=1}^{N_l} pl_j$ [MW/h]	OpC_t [k€]	$\sum_{h=1}^{8760}\sum_{n=1}^{N_{DGb}} REC_n$ [MW]	$OutC_t$ [k€]	$(P\|F,d,t)$	NPV_{RP}/t [k€]
0							
1	-	0.644	569.512	-	-	0.937	533.501
2	-	0.596	527.025	-	-	0.878	462.483
3	-	0.591	523.225	-	-	0.822	430.115
4	-	0.590	522.089	-	-	0.770	402.043
5	27.659	0.636	562.406	-	-	0.721	425.657
6	-	0.793	701.276	4.960E-06	5.790E-03	0.676	473.895
7	120.341	1.229	1087.281	-	-	0.633	764.462
8	-	1.488	1316.529	5.120	486.39	0.593	780.994
9	-	1.702	1505.52	-	-	0.556	836.328
10	-	1.884	1667.14	-	-	0.520	867.545
						NPV_{RP} [k€]	**5977.022**

Table 4.20: Net present value of the total cost for the reinforcement planning

Active Distribution Network Management

For this trending DSO network planning, the total cost depends only in one vector: operational costs already defined throughout the section 3.3.3.2. Although, if at a particular year of the planning period it is not possible to activate/contract more flexibility from load and generation, it is necessary to perform network reinforcements to solve the technical problems and then investment costs must be taken into consideration in the economic assessment. In this study case, all the investments performed with the reinforcement planning were deferred, i.e., the activation of flexibility prevent all the problems occurred in the planning horizon.

The operational costs are related to network active power losses, but also to the activated flexibility provided by demand and generation. Therefore, the upward and downward flexibility services reflected by load shedding and PV plus wind power curtailment must be quantified. In addition, in this planning case the network active power losses are the highest values among all the hours of the entire year. Table 4.21 shows the total cost estimation for the reinforcement program (NPV_{ANM}).

Active Distribution Grid Management								
Year- t	$\sum_{j=1}^{N_l} pl_j$ [MW/h]	$\sum_{h=1}^{8760}\sum_{m=1}^{N_{lb}} f_m^{up}$ [MW]	$\sum_{h=1}^{8760}\sum_{n=1}^{N_{DGb}} f_n^{dw}$ [MW]	$OpC_{load}^{shed,up}$ [k€]	$OpC_{DG}^{curt,dw}$ [k€]	OpC_t [k€]	$(P\|F,d,t)$	NPV_{ANM}/t [k€]
0								
1	0.654	-	-	-	-	578.204	0.937	541.643
2	0.596	-	-	-	-	527.025	0.878	462.483
3	0.591	-	-	-	-	523.225	0.822	430.115
4	0.590	-	-	-	-	522.089	0.770	402.043
5	0.640	-	-	-	-	566.525	0.721	408.677
6	0.828	3.619E-04	1.268E-04	6.768E-06	1.979E-06	732.922	0.676	495.280
7	1.395	0.242	6.162	4.530E-03	9.613E-02	1234.064	0.633	781.201
8	1.409	0.005	176.370	0.097E-03	2.751	1249.980	0.593	741.242
9	1.496	0.0079	407.542	0.148E-03	6.358	1330.325	0.556	739.004
10	1.575	0.0075	616.119	0.141E-03	9.611	1402.846	0.520	730.014
							NPV_{ANM} [k€]	**5731.701**

Table 4.21: Net present value of the total cost for the ANM planning

Break-Even Point

From the previous Tables 4.20 and 4.21, the key paradigm of this thesis can be answered: the predictive grid management with activation of distributed flexibility services from load and RES is the cost-optimal solution for solving the technical problems that have emerged on the network along the planning years and improving operational aspects, as the traditional network reinforcement planning offers a viable alternative.

Furthermore, a sensitivity analysis is performed to calculate the break-even point. The break-even point refers to the maximum total cost that DSO is willing to pay for the active distribution network management to be profitable, i.e., how much the annual average upward/downward regulation market price can increase/decrease until the total cost of the ANM planning (NPV_{ANM} matches the total cost of the reinforcement planning (NPV_{RP}). As a result, the DSO penalties or flexibility upward/downward activation prices will increase leading to a maximum value for both regulation options (up and down).

Therefore, by maintaining constant the amount of flexibility registered in Table 4.21 and changing (increasing/decreasing) in equal ratio the annual average upward/downward regulation market prices($\overline{\pi}_{RM}^{up}$ and $\overline{\pi}_{RM}^{dw}$) the break-even point is located and the DSO has knowledge how much he can spent until the ANM planning begins to be unprofitable. In Table 4.22 is presented the maximum/minimum annual average upward/downward regulation market prices and the maximum upward/downward flexibility activation prices.

Sensitivity Analysis - Break-Even Point estimation			
		Label	**Cost [€/MWh]**
Market Prices	Maximum annual average upward regulation	$\overline{\pi}_{RM}^{up,max}$	445.36
	Minimum annual average downward regulation	$\overline{\pi}_{RM}^{dw,min}$	-337.26
	Annual average day-ahead	$\overline{\pi}_{DA}$	52.5
DSO penalties	Maximum upward flexibility activation from loads	$C_{act}^{up,max}$	392.86
	Maximum downward flexibility activation from DG units	$C_{act}^{dw,min}$	389.76

Table 4.22: Market and DSO penalty prices from the sensitivity analysis

By last, one interesting point to highlight from Table 4.22 is the fact that for the case where the NPV_{ANM} equals the NPV_{RP}, the DSO will pay higher penalty costs but will receive a monetary contribution from RES producers, i.e., the DG producers will pay to the DSO 337.26 €/MWh to inject renewable energy in the network, hence the negative price for downward regulation is observed. By the way, in Portugal the minimum price that can be assumed in the reserve regulation market is 0 €/MWh, although in other European countries it is accepted negative prices.

KPIs Asssement

For last, it will be assessed technical and economic benefits of shifting from a traditional network planning into a modern planning, with the inclusion of flexibility services. Therefore, in Table 4.23 are presented the results for the two key performance indicators considered in section 3.3.3.3.

KPIs					
		Label	[%]	[k€]	[MW]
Parameters	Net Present Value of total cost for the reinforcement planning	NPV_{RP}		5977.022	
	Total active power losses in the reinforcement planning	PL_{RP}			88940.280
	Net Present Value of total cost for ANM planning	NPV_{ANM}		5731.70	
	Total active power losses in the ANM planning	PL_{ANM}			85620.240
Key performance indicators	Deferred Distribution Capacity Investment	$DDCI$	4.104	24.532	
	Reduction of active power losses	ΔPL	3.733		332004

Table 4.23: Key performance indicators

With the data provided by the Table 3.3.3.3, it is possible to conclude that by allowing DSO to prevent technical problems with distributed flexibility (ANM planning), the system operator can save 4.1% of the total cost of the reinforcement planning (24.5 k€). Also with the implementation of a predictive network management, the grid power losses were reduced by 3.73% in relation to the total active power losses of the reinforcement planning, or in technical terms, 332004 MW which used to be given as losses are avoided.

Finally, in section 3.3.3.3 was mentioned the key indicator related to the number of years in which the investments deferred. For the defined planning horizon, the use of distributed flexibility from DER allow not to defer the network investments but to avoid all the network reinforcements performed in the grid, i.e., it was always possible to activate flexibility to solve the congestion problems. In order to try to identify the number of years in which investment was delayed, the PDP was further simulated beyond the planning horizon (another 15 years). However, even with different connection locations and capacity of the DG units , the OPFs have always converged, i.e., it has always been possible to contract flexibility from demand/generation to solve the network problems. Faced with such a scenario, one can expect that one of the best solution would be to calculate the net present value cumulatively over the years for both planning cases and perceive if there is not a moment when the DSO will pay more for flexibility services than for the reinforcement of an asset, which tends to be a long-term solution that would last for many years. In that case it would then be beneficial to reinforce the network instead of continuing to contract flexibility services from loads and DG.

Chapter 5

Conclusions and Future Work

This chapter presents the main conclusions and contributions of this thesis concerning the proposed PDP methodology embedded with two possible planning solutions for MV distribution networks under massive deployment of distributed generation (DG) and continuous demand growth. Moreover, future work is proposed as complementary efforts to enrich the study developed.

5.1 Conclusions

The continuous growth of RES in power systems as result of ambitious government targets, has been introducing new challenges that call into question the efficiency of the existing power system models and in particular the power distribution planning. Also, with the advent of new technologies, such as the so-called distributed energy resources (distributed generation, storage devices, demand response), it is of most importance to bring up new perspectives and models for the study of electric power systems.

In this context, a modern PDP methodology was proposed from the point of view of considering the traditional network reinforcement planning as reliable solution. On the other hand, the methodology also includes an active network management model to distribution networks with high penetration of DER, including RES, and consider the flexibility of such resources to prevent mainly congestion problems.

Then, the PDP problem is addressed by applying the PDP methodology which includes the reinforcement planning methodology and the ANM planning methodology. When the final year of the planning period is reached, a cost-benefit analysis is performed to assess the total cost of each planning solution and to verify the benefits of shifting from a traditional planning process to a modern one. In addition, a sensitivity analysis was adopted to seek the maximum upward and downward flexibility activation prices that DSO is willing to pay, in order to the ANM planning be cost-effective. Finally, key performance indicators were used to present some technical and economic benefits of using distributed flexibility as a service provided by loads and DG units and reserved/contracted by the DSO.

The main contributions of this thesis aim towards:

- Definition of a modern PDP methodology with the advantage of exploring the potential of flexibility resources. The developed methodology takes into account two DSO decision-making methodologies: traditional grid reinforcement and predictive grid management with activation of flexibility from DER.

  Here the main objective is to simulate a PDP exercise and apply both network solutions to cope with technical problems, mainly congestion problems rather then voltage violations, which arise from extreme scenarios of DG integration;

- Development of a cost-benefit analysis to determine the total cost of each planning solution, embedded with a sensitivity analysis to estimate the maximum price that DSO is willing to pay for flexibility services to be cost-effective and an assessment of key performance indicators to unveil some economic and technical benefits of shifting from a passive network planning to a modern PDP.

Summing up, this thesis focused on the development of an innovative perspective of PDP exercise by allowing the active participation of consumers and RES producers to deal with MV network with potentially stressed operation scenarios induced by strong DG penetration.

5.2 Future Work

In the course of this study, several future research paths were identified. Some suggested developments for the future work perspectives are detailed as follows:

- The developed PDP methodology only takes into account two types of DER: loads and distributed generators. Therefore, different DER with different ownership and purpose (e.g. utility-scale storage systems, electric vehicles) could be integrated in further works of PDP, as a planning resource. Also, instead of only considering active power curtailment (load shedding) as load flexibility, allow the concept of "load shifting", i.e., a short-term reduction in electricity consumption followed by an increase in production at late time when grid demand is lower. In order to embody this concept in the case study, a multi-temporal OPF would also be needed;

- Integration of PV and wind algorithm forecasts in the active network management methodology to cope with the uncertainty characteristic of DG;

- In addition to the distinctive daily profiles used in this thesis, also adopt clustering periods to classify all the demand-generation states in a year, by grouping them in some typical conditions. This will enable to follow in a more rigorous way the variability of demand and generation and decrease the computational burden of the planning calculations;

- Finally, for a case study with much more reconfiguration possibilities, employing a GA to find the network topology that solves the problem, or if the problem can only be mitigated, find the topology that has less ENS/REC for the reinforcement case (fitness function - ENS and REC) and less activated flexibility for the predictive grid management case (fitness function - upward and downward flexibility).

Appendix A

Test System Data

In this appendix, the full data concerning the test MV network presented in chapter 4 is given. In particular, branch, load and PV and wind power generation data are provided.

A.1 MV Oberrhein Network

An alternative one-line diagram of the test system for an easier identification of the network feeders. This MV Oberrhein diagram does not consider the geographical representation of buses and lines/cables, i.e. neglects buses and lines/cables geodata.

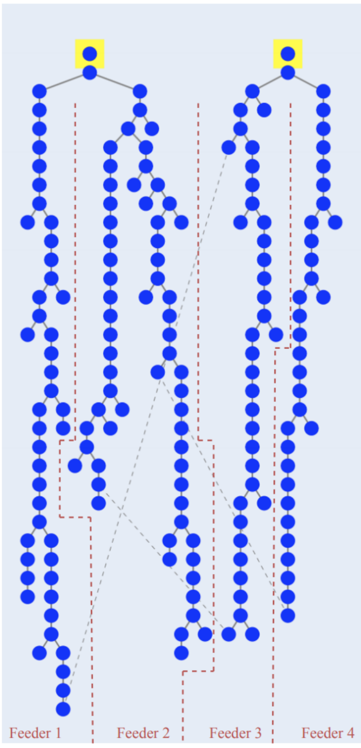


Figure A.1: Alternative one-line diagram for the MV network illustrated in Figure 4.1

A.2 Brach Data

Branch Name	Standard Type	From Bus	To Bus	Length (km)	R (Ω/km)	X(Ω/km)	C (nF/km)	Imax. (kA)	type
Line 0	NA2XS2Y 1x95 RM/25 12/20 kV	238	109	0.586366	0.313	0.132	216	0.252	cs
Line 1	NA2XS2Y 1x185 RM/25 12/20 kV	238	40	1.3735	0.161	0.117	273	0.362	cs
Line 10	NA2XS2Y 1x185 RM/25 12/20 kV	197	167	0.313383	0.161	0.117	273	0.362	cs
Line 100	NA2XS2Y 1x185 RM/25 12/20 kV	229	224	0.2987	0.161	0.117	273	0.362	cs
Line 101	NA2XS2Y 1x185 RM/25 12/20 kV	223	227	0.2355	0.161	0.117	273	0.362	cs
Line 102	NA2XS2Y 1x185 RM/25 12/20 kV	227	231	0.4892	0.161	0.117	273	0.362	cs
Line 103	NA2XS2Y 1x185 RM/25 12/20 kV	231	229	0.2982	0.161	0.117	273	0.362	cs
Line 104	NA2XS2Y 1x240 RM/25 12/20 kV	285	288	0.2384	0.122	0.112	304	0.421	cs
Line 105	NA2XS2Y 1x240 RM/25 12/20 kV	288	286	0.1773	0.122	0.112	304	0.421	cs
Line 106	NA2XS2Y 1x240 RM/25 12/20 kV	176	285	0.2827	0.122	0.112	304	0.421	cs
Line 107	NA2XS2Y 1x95 RM/25 12/20 kV	178	176	0.6151	0.313	0.132	216	0.252	cs
Line 108	NA2XS2Y 1x185 RM/25 12/20 kV	178	197	1.277681	0.161	0.117	273	0.362	cs
Line 109	NA2XS2Y 1x240 RM/25 12/20 kV	287	286	0.1468	0.122	0.112	304	0.421	cs
Line 11	NA2XS2Y 1x185 RM/25 12/20 kV	199	167	0.258	0.161	0.117	273	0.362	cs
Line 110	NA2XS2Y 1x240 RM/25 12/20 kV	200	184	0.2534	0.122	0.112	304	0.421	cs
Line 111	NA2XS2Y 1x185 RM/25 12/20 kV	198	199	0.2138	0.161	0.117	273	0.362	cs
Line 112	NA2XS2Y 1x185 RM/25 12/20 kV	199	181	0.4151	0.161	0.117	273	0.362	cs
Line 113	NA2XS2Y 1x185 RM/25 12/20 kV	198	184	0.1805	0.161	0.117	273	0.362	cs
Line 114	NA2XS2Y 1x185 RM/25 12/20 kV	181	186	0.5618	0.161	0.117	273	0.362	cs
Line 116	NA2XS2Y 1x185 RM/25 12/20 kV	314	301	0.3994	0.161	0.117	273	0.362	cs
Line 117	NA2XS2Y 1x240 RM/25 12/20 kV	301	303	0.2608	0.122	0.112	304	0.421	cs
Line 118	NA2XS2Y 1x185 RM/25 12/20 kV	303	304	0.3696	0.161	0.117	273	0.362	cs
Line 119	NA2XS2Y 1x185 RM/25 12/20 kV	273	315	0.2507	0.161	0.117	273	0.362	cs
Line 12	NA2XS2Y 1x185 RM/25 12/20 kV	168	273	0.4346	0.161	0.117	273	0.362	cs
Line 120	NA2XS2Y 1x185 RM/25 12/20 kV	314	246	0.304	0.161	0.117	273	0.362	cs
Line 121	NA2XS2Y 1x185 RM/25 12/20 kV	271	305	0.2326	0.161	0.117	273	0.362	cs
Line 122	NA2XS2Y 1x185 RM/25 12/20 kV	312	273	0.1183	0.161	0.117	273	0.362	cs
Line 123	NA2XS2Y 1x185 RM/25 12/20 kV	271	281	0.397	0.161	0.117	273	0.362	cs
Line 124	NA2XS2Y 1x185 RM/25 12/20 kV	281	312	0.5202	0.161	0.117	273	0.362	cs
Line 125	NA2XS2Y 1x185 RM/25 12/20 kV	271	85	1.525834	0.161	0.117	273	0.362	cs
Line 126	NA2XS2Y 1x185 RM/25 12/20 kV	312	313	0.2535	0.161	0.117	273	0.362	cs
Line 127	243-AL1/39-ST1A 20.0	7	6	1.600621	0.1188	0.32	11	0.645	ol
Line 128	NA2XS2Y 1x185 RM/25 12/20 kV	7	5	0.4731	0.161	0.117	273	0.362	cs
Line 129	NA2XS2Y 1x185 RM/25 12/20 kV	244	1	0.2978	0.161	0.117	273	0.362	cs
Line 130	NA2XS2Y 1x240 RM/25 12/20 kV	0	4	0.2947	0.122	0.112	304	0.421	cs
Line 131	NA2XS2Y 1x185 RM/25 12/20 kV	241	4	0.4167	0.161	0.117	273	0.362	cs
Line 132	NA2XS2Y 1x240 RM/25 12/20 kV	8	0	0.323471	0.122	0.112	304	0.421	cs
Line 133	NA2XS2Y 1x185 RM/25 12/20 kV	243	2	0.2964	0.161	0.117	273	0.362	cs
Line 134	NA2XS2Y 1x185 RM/25 12/20 kV	245	3	0.2821	0.161	0.117	273	0.362	cs
Line 135	NA2XS2Y 1x185 RM/25 12/20 kV	240	241	0.3965	0.161	0.117	273	0.362	cs
Line 136	NA2XS2Y 1x240 RM/25 12/20 kV	242	243	0.3709	0.122	0.112	304	0.421	cs
Line 137	NA2XS2Y 1x240 RM/25 12/20 kV	245	244	0.2736	0.122	0.112	304	0.421	cs
Line 138	NA2XS2Y 1x240 RM/25 12/20 kV	244	243	0.3288	0.122	0.112	304	0.421	cs
Line 139	NA2XS2Y 1x185 RM/25 12/20 kV	116	138	0.499431	0.161	0.117	273	0.362	cs
Line 14	NA2XS2Y 1x185 RM/25 12/20 kV	168	246	0.3572	0.161	0.117	273	0.362	cs
Line 140	NA2XS2Y 1x185 RM/25 12/20 kV	116	111	0.3164	0.161	0.117	273	0.362	cs
Line 141	NA2XS2Y 1x185 RM/25 12/20 kV	110	108	0.3876	0.161	0.117	273	0.362	cs
Line 142	NA2XS2Y 1x185 RM/25 12/20 kV	131	140	0.070449	0.161	0.117	273	0.362	cs
Line 143	NA2XS2Y 1x240 RM/25 12/20 kV	131	133	0.286	0.122	0.112	304	0.421	cs
Line 144	NA2XS2Y 1x185 RM/25 12/20 kV	141	138	1.5172	0.161	0.117	273	0.362	cs
Line 145	NA2XS2Y 1x185 RM/25 12/20 kV	149	141	0.7192	0.161	0.117	273	0.362	cs
Line 146	NA2XS2Y 1x185 RM/25 12/20 kV	147	149	0.2203	0.161	0.117	273	0.362	cs
Line 147	NA2XS2Y 1x185 RM/25 12/20 kV	64	65	0.2096	0.161	0.117	273	0.362	cs
Line 148	NA2XS2Y 1x185 RM/25 12/20 kV	65	36	0.2393	0.161	0.117	273	0.362	cs
Line 149	NA2XS2Y 1x185 RM/25 12/20 kV	79	64	0.3447	0.161	0.117	273	0.362	cs
Line 15	NA2XS2Y 1x185 RM/25 12/20 kV	172	131	0.253751	0.161	0.117	273	0.362	cs
Line 150	NA2XS2Y 1x185 RM/25 12/20 kV	79	82	0.3271	0.161	0.117	273	0.362	cs
Line 151	NA2XS2Y 1x240 RM/25 12/20 kV	74	75	0.5534	0.122	0.112	304	0.421	cs
Line 152	NA2XS2Y 1x185 RM/25 12/20 kV	74	101	0.146058	0.161	0.117	273	0.362	cs
Line 153	NA2XS2Y 1x185 RM/25 12/20 kV	110	103	0.4817	0.161	0.117	273	0.362	cs
Line 154	NA2XS2Y 1x185 RM/25 12/20 kV	104	103	0.4426	0.161	0.117	273	0.362	cs
Line 156	NA2XS2Y 1x185 RM/25 12/20 kV	104	106	0.2842	0.161	0.117	273	0.362	cs
Line 157	243-AL1/39-ST1A 20.0	86	71	1.081618	0.1188	0.32	11	0.645	ol
Line 158	243-AL1/39-ST1A 20.0	71	73	0.6892	0.1188	0.32	11	0.645	ol
Line 16	NA2XS2Y 1x185 RM/25 12/20 kV	144	172	0.6353	0.161	0.117	273	0.362	cs
Line 161	NA2XS2Y 1x240 RM/25 12/20 kV	73	78	0.4682	0.122	0.112	304	0.421	cs
Line 162	243-AL1/39-ST1A 20.0	80	39	2.5953	0.1188	0.32	11	0.645	ol
Line 163	NA2XS2Y 1x185 RM/25 12/20 kV	57	53	0.3055	0.161	0.117	273	0.362	cs

Branch Name	Standard Type	From Bus	To Bus	Length (km)	R (Ω/km)	X(Ω/km)	C (nF/km)	Imax. (kA)	type
Line 164	NA2XS2Y 1x185 RM/25 12/20 kV	46	53	0.5665	0.161	0.117	273	0.362	cs
Line 165	243-AL1/39-ST1A 20.0	39	86	0.364782	0.1188	0.32	11	0.645	ol
Line 167	NA2XS2Y 1x185 RM/25 12/20 kV	42	51	0.464	0.161	0.117	273	0.362	cs
Line 168	NA2XS2Y 1x185 RM/25 12/20 kV	44	56	0.4202	0.161	0.117	273	0.362	cs
Line 169	NA2XS2Y 1x185 RM/25 12/20 kV	56	84	0.2721	0.161	0.117	273	0.362	cs
Line 17	NA2XS2Y 1x240 RM/25 12/20 kV	253	171	1.299844	0.122	0.112	304	0.421	cs
Line 170	NA2XS2Y 1x185 RM/25 12/20 kV	52	150	0.2854	0.161	0.117	273	0.362	cs
Line 171	NA2XS2Y 1x185 RM/25 12/20 kV	146	150	0.7697	0.161	0.117	273	0.362	cs
Line 172	NA2XS2Y 1x240 RM/25 12/20 kV	117	148	0.2637	0.122	0.112	304	0.421	cs
Line 173	NA2XS2Y 1x240 RM/25 12/20 kV	148	120	0.1966	0.122	0.112	304	0.421	cs
Line 174	NA2XS2Y 1x185 RM/25 12/20 kV	118	148	0.2796	0.161	0.117	273	0.362	cs
Line 175	NA2XS2Y 1x240 RM/25 12/20 kV	80	117	0.3976	0.122	0.112	304	0.421	cs
Line 177	NA2XS2Y 1x185 RM/25 12/20 kV	146	143	0.2933	0.161	0.117	273	0.362	cs
Line 178	NA2XS2Y 1x240 RM/25 12/20 kV	145	146	0.4486	0.122	0.112	304	0.421	cs
Line 179	NA2XS2Y 1x240 RM/25 12/20 kV	55	145	0.5508	0.122	0.112	304	0.421	cs
Line 18	NA2XS2Y 1x240 RM/25 12/20 kV	171	8	0.138829	0.122	0.112	304	0.421	cs
Line 180	NA2XS2Y 1x240 RM/25 12/20 kV	83	41	1.420497	0.122	0.112	304	0.421	cs
Line 181	NA2XS2Y 1x240 RM/25 12/20 kV	81	77	0.5398	0.122	0.112	304	0.421	cs
Line 182	NA2XS2Y 1x95 RM/25 12/20 kV	77	35	0.3546	0.313	0.132	216	0.252	cs
Line 183	NA2XS2Y 1x240 RM/25 12/20 kV	78	35	0.3376	0.122	0.112	304	0.421	cs
Line 184	NA2XS2Y 1x185 RM/25 12/20 kV	80	119	0.4395	0.161	0.117	273	0.362	cs
Line 185	NA2XS2Y 1x240 RM/25 12/20 kV	81	37	1.0952	0.122	0.112	304	0.421	cs
Line 186	NA2XS2Y 1x185 RM/25 12/20 kV	81	43	0.3462	0.161	0.117	273	0.362	cs
Line 187	NA2XS2Y 1x240 RM/25 12/20 kV	37	41	0.4099	0.122	0.112	304	0.421	cs
Line 189	NA2XS2Y 1x185 RM/25 12/20 kV	45	47	0.4463	0.161	0.117	273	0.362	cs
Line 190	NA2XS2Y 1x185 RM/25 12/20 kV	47	49	0.3144	0.161	0.117	273	0.362	cs

Branch Name	Standard Type	From Bus	To Bus	Length (km)	R (Ω/km)	X(Ω/km)	C (nF/km)	Imax. (kA)	type
Line 191	NA2XS2Y 1x185 RM/25 12/20 kV	49	52	0.1516	0.161	0.117	273	0.362	cs
Line 192	NA2XS2Y 1x240 RM/25 12/20 kV	55	120	0.3974	0.122	0.112	304	0.421	cs
Line 193	243-AL1/39-ST1A 20.0	6	319	1.006291	0.1188	0.32	11	0.645	ol
Line 2	NA2XS2Y 1x185 RM/25 12/20 kV	238	221	0.206369	0.161	0.117	273	0.362	cs
Line 20	NA2XS2Y 1x185 RM/25 12/20 kV	170	136	0.6318	0.161	0.117	273	0.362	cs
Line 21	NA2XS2Y 1x185 RM/25 12/20 kV	170	116	0.111569	0.161	0.117	273	0.362	cs
Line 22	NA2XS2Y 1x95 RM/25 12/20 kV	216	195	0.3117	0.313	0.132	216	0.252	cs
Line 24	NA2XS2Y 1x185 RM/25 12/20 kV	195	317	0.695233	0.161	0.117	273	0.362	cs
Line 25	NA2XS2Y 1x240 RM/25 12/20 kV	213	194	0.235111	0.122	0.112	304	0.421	cs
Line 26	NA2XS2Y 1x185 RM/25 12/20 kV	207	194	0.5608	0.161	0.117	273	0.362	cs
Line 27	NA2XS2Y 1x240 RM/25 12/20 kV	269	196	0.5217	0.122	0.112	304	0.421	cs
Line 28	NA2XS2Y 1x240 RM/25 12/20 kV	196	74	0.282642	0.122	0.112	304	0.421	cs
Line 29	NA2XS2Y 1x185 RM/25 12/20 kV	189	82	1.6878	0.161	0.117	273	0.362	cs
Line 3	NA2XS2Y 1x185 RM/25 12/20 kV	221	239	0.617131	0.161	0.117	273	0.362	cs
Line 30	NA2XS2Y 1x185 RM/25 12/20 kV	51	189	1.0726	0.161	0.117	273	0.362	cs
Line 32	NA2XS2Y 1x185 RM/25 12/20 kV	65	190	0.3235	0.161	0.117	273	0.362	cs
Line 34	NA2XS2Y 1x185 RM/25 12/20 kV	192	44	0.3088	0.161	0.117	273	0.362	cs
Line 35	NA2XS2Y 1x185 RM/25 12/20 kV	57	192	0.541347	0.161	0.117	273	0.362	cs
Line 36	NA2XS2Y 1x240 RM/25 12/20 kV	289	72	0.2961	0.122	0.112	304	0.421	cs
Line 37	NA2XS2Y 1x240 RM/25 12/20 kV	289	75	0.48	0.122	0.112	304	0.421	cs
Line 38	243-AL1/39-ST1A 20.0	290	7	0.711079	0.1188	0.32	11	0.645	ol
Line 39	NA2XS2Y 1x240 RM/25 12/20 kV	290	242	0.2418	0.122	0.112	304	0.421	cs
Line 4	NA2XS2Y 1x185 RM/25 12/20 kV	239	236	0.381968	0.161	0.117	273	0.362	cs
Line 40	NA2XS2Y 1x185 RM/25 12/20 kV	290	240	0.261	0.161	0.117	273	0.362	cs
Line 41	NA2XS2Y 1x185 RM/25 12/20 kV	269	108	0.3447	0.161	0.117	273	0.362	cs
Line 42	NA2XS2Y 1x185 RM/25 12/20 kV	153	316	1.620869	0.161	0.117	273	0.362	cs
Line 43	NA2XS2Y 1x185 RM/25 12/20 kV	316	159	0.7819	0.161	0.117	273	0.362	cs
Line 44	NA2XS2Y 1x185 RM/25 12/20 kV	316	157	0.2485	0.161	0.117	273	0.362	cs
Line 45	NA2XS2Y 1x185 RM/25 12/20 kV	317	33	2.611111	0.161	0.117	273	0.362	cs
Line 46	NA2XS2Y 1x240 RM/25 12/20 kV	245	298	1.158236	0.122	0.112	304	0.421	cs
Line 47	NA2XS2Y 1x240 RM/25 12/20 kV	298	248	1.5265	0.122	0.112	304	0.421	cs
Line 48	NA2XS2Y 1x185 RM/25 12/20 kV	237	247	2.033386	0.161	0.117	273	0.362	cs
Line 49	NA2XS2Y 1x185 RM/25 12/20 kV	247	40	0.9969	0.161	0.117	273	0.362	cs
Line 5	NA2XS2Y 1x95 RM/25 12/20 kV	169	54	3.3028	0.313	0.132	216	0.252	cs
Line 50	NA2XS2Y 1x240 RM/25 12/20 kV	133	248	0.8042	0.122	0.112	304	0.421	cs
Line 51	NA2XS2Y 1x185 RM/25 12/20 kV	237	136	0.9474	0.161	0.117	273	0.362	cs
Line 52	243-AL1/39-ST1A 20.0	29	30	0.928584	0.1188	0.32	11	0.645	ol
Line 53	243-AL1/39-ST1A 20.0	126	29	0.777633	0.1188	0.32	11	0.645	ol
Line 54	NA2XS2Y 1x240 RM/25 12/20 kV	30	72	0.7126	0.122	0.112	304	0.421	cs
Line 55	NA2XS2Y 1x185 RM/25 12/20 kV	253	304	1.1359	0.161	0.117	273	0.362	cs
Line 56	NA2XS2Y 1x185 RM/25 12/20 kV	33	104	2.149166	0.161	0.117	273	0.362	cs
Line 57	NA2XS2Y 1x185 RM/25 12/20 kV	110	31	0.810724	0.161	0.117	273	0.362	cs
Line 58	NA2XS2Y 1x185 RM/25 12/20 kV	34	76	0.4702	0.161	0.117	273	0.362	cs
Line 59	NA2XS2Y 1x185 RM/25 12/20 kV	45	34	3.15539	0.161	0.117	273	0.362	cs
Line 6	NA2XS2Y 1x185 RM/25 12/20 kV	169	275	0.3504	0.161	0.117	273	0.362	cs
Line 60	NA2XS2Y 1x185 RM/25 12/20 kV	32	34	0.5802	0.161	0.117	273	0.362	cs
Line 61	NA2XS2Y 1x185 RM/25 12/20 kV	46	32	0.618131	0.161	0.117	273	0.362	cs
Line 62	243-AL1/39-ST1A 20.0	319	126	1.006291	0.1188	0.32	11	0.645	ol
Line 63	NA2XS2Y 1x185 RM/25 12/20 kV	50	48	0.221899	0.161	0.117	273	0.362	cs
Line 64	NA2XS2Y 1x185 RM/25 12/20 kV	42	50	0.936021	0.161	0.117	273	0.362	cs
Line 65	NA2XS2Y 1x185 RM/25 12/20 kV	84	50	1.3413	0.161	0.117	273	0.362	cs
Line 67	NA2XS2Y 1x185 RM/25 12/20 kV	54	144	0.2603	0.161	0.117	273	0.362	cs
Line 68	NA2XS2Y 1x185 RM/25 12/20 kV	224	38	1.804281	0.161	0.117	273	0.362	cs
Line 69	NA2XS2Y 1x185 RM/25 12/20 kV	38	161	0.5903	0.161	0.117	273	0.362	cs
Line 7	NA2XS2Y 1x240 RM/25 12/20 kV	169	287	0.7358	0.122	0.112	304	0.421	cs
Line 70	NA2XS2Y 1x240 RM/25 12/20 kV	134	142	0.3681	0.122	0.112	304	0.421	cs
Line 71	NA2XS2Y 1x185 RM/25 12/20 kV	142	235	0.161971	0.161	0.117	273	0.362	cs
Line 72	NA2XS2Y 1x240 RM/25 12/20 kV	142	83	1.455003	0.122	0.112	304	0.421	cs
Line 73	NA2XS2Y 1x185 RM/25 12/20 kV	132	137	0.4655	0.161	0.117	273	0.362	cs
Line 74	NA2XS2Y 1x185 RM/25 12/20 kV	137	95	0.5305	0.161	0.117	273	0.362	cs
Line 75	NA2XS2Y 1x240 RM/25 12/20 kV	132	134	0.304368	0.122	0.112	304	0.421	cs
Line 76	NA2XS2Y 1x185 RM/25 12/20 kV	129	188	0.3469	0.161	0.117	273	0.362	cs
Line 77	NA2XS2Y 1x185 RM/25 12/20 kV	85	129	2.121868	0.161	0.117	273	0.362	cs
Line 78	NA2XS2Y 1x185 RM/25 12/20 kV	98	100	0.2965	0.161	0.117	273	0.362	cs
Line 79	NA2XS2Y 1x185 RM/25 12/20 kV	100	102	0.2751	0.161	0.117	273	0.362	cs
Line 80	NA2XS2Y 1x185 RM/25 12/20 kV	94	102	0.4285	0.161	0.117	273	0.362	cs
Line 81	NA2XS2Y 1x185 RM/25 12/20 kV	100	107	0.3375	0.161	0.117	273	0.362	cs
Line 82	NA2XS2Y 1x185 RM/25 12/20 kV	94	95	0.3487	0.161	0.117	273	0.362	cs

Branch Name	Standard Type	From Bus	To Bus	Length (km)	R (Ω/km)	X(Ω/km)	C (nF/km)	Imax. (kA)	type
Line 85	NA2XS2Y 1x185 RM/25 12/20 kV	210	215	0.329	0.161	0.117	273	0.362	cs
Line 86	NA2XS2Y 1x185 RM/25 12/20 kV	216	215	0.2607	0.161	0.117	273	0.362	cs
Line 87	NA2XS2Y 1x185 RM/25 12/20 kV	219	236	0.2982	0.161	0.117	273	0.362	cs
Line 90	NA2XS2Y 1x240 RM/25 12/20 kV	109	201	0.3152	0.122	0.112	304	0.421	cs
Line 91	NA2XS2Y 1x185 RM/25 12/20 kV	173	107	2.5282	0.161	0.117	273	0.362	cs
Line 92	NA2XS2Y 1x185 RM/25 12/20 kV	205	207	0.0933	0.161	0.117	273	0.362	cs
Line 93	NA2XS2Y 1x185 RM/25 12/20 kV	216	205	0.386663	0.161	0.117	273	0.362	cs
Line 94	NA2XS2Y 1x185 RM/25 12/20 kV	201	213	0.2724	0.161	0.117	273	0.362	cs
Line 95	NA2XS2Y 1x185 RM/25 12/20 kV	173	174	0.2474	0.161	0.117	273	0.362	cs
Line 96	NA2XS2Y 1x185 RM/25 12/20 kV	174	162	0.2502	0.161	0.117	273	0.362	cs
Line 97	NA2XS2Y 1x185 RM/25 12/20 kV	161	162	0.4588	0.161	0.117	273	0.362	cs
Line 98	NA2XS2Y 1x185 RM/25 12/20 kV	157	155	0.3655	0.161	0.117	273	0.362	cs
Line 99	NA2XS2Y 1x185 RM/25 12/20 kV	153	200	0.291	0.161	0.117	273	0.362	cs
Line 194	NA2XS2Y 1x185 RM/25 12/20 kV	147	118	0.67385	0.161	0.117	273	0.362	cs
Line 195	NA2XS2Y 1x185 RM/25 12/20 kV	223	275	0.3087	0.161	0.117	273	0.362	cs
Line 196	NA2XS2Y 1x185 RM/25 12/20 kV	190	129	0.4339	0.161	0.117	273	0.362	cs

where,

R is the line resistance in ohm per km

X is the line reactance in ohm per km

C is the line capacitance in nano Farad per km

Imax. is the maximum thermal current in kilo Ampere

ol means overhead line

cs means cable system

A.3 Load Data

Load Name	Bus	Load Installed Capacity (MVA)	Peak Load	
			P (MW)	Q (Mvar)
Load 0	103	0.25	0.1464814888489781	0.05076466515850105
Load 1	174	0.63	0.2813592478451389	0.1279269561994226
Load 10	149	0.25	0.03133712268728867	0.05076466515850105
Load 100	200	0.25	0.06181802182330165	0.05076466515850105
Load 101	8	0.4	0.09434482758620691	0.08122346425360168
Load 102	46	0.63	0.2040252744201939	0.1279269561994226
Load 103	134	0.4	0.08644579479041686	0.08122346425360168
Load 104	65	0.63	0.2845942350332594	0.1279269561994226
Load 105	271	0.63	0.4193688907777305	0.1279269561994226
Load 106	286	0.4	0.2189986132399095	0.08122346425360168
Load 107	288	0.25	0.07684164881134578	0.05076466515850105
Load 108	133	0.25	0.1037637379505127	0.05076466515850105
Load 109	314	0.4	0.185219707057257	0.08122346425360168
Load 11	315	0.4	0.2189986132399095	0.08122346425360168
Load 110	43	0.63	0.3916496945010184	0.1279269561994226
Load 111	42	0.4	0.1298629986546962	0.08122346425360168
Load 112	79	0.4	0.1669277827514175	0.08122346425360168
Load 113	219	0.4	0.1317737769232263	0.08122346425360168
Load 114	132	0.4	0.1267642446419237	0.08122346425360168
Load 115	153	0.4	0.1664888361983798	0.08122346425360168
Load 116	107	0.25	0.07933948838014576	0.05076466515850105
Load 117	47	0.4	0.1596560906570104	0.08122346425360168
Load 118	241	0.25	0.1105520635103704	0.05076466515850105
Load 119	244	0.4	0.1162006310521162	0.08122346425360168
Load 12	181	0.4	0.3000921901751614	0.08122346425360168
Load 120	201	0.63	0.3530013642564803	0.1279269561994226
Load 121	41	0.4	0.2405374135203419	0.08122346425360168
Load 122	173	0.4	0.2119208772758277	0.08122346425360168
Load 123	312	0.4	0.2853068756440674	0.08122346425360168
Load 124	109	0.25	0.03745881200463087	0.05076466515850105
Load 125	196	0.63	0.3065501965225502	0.1279269561994226
Load 126	94	0.63	0.3482288975021533	0.1279269561994226
Load 127	129	0.63	0.2989739966082532	0.1279269561994226
Load 128	2	0.25	0.1277948890034076	0.05076466515850105
Load 129	144	0.25	0.08906666101976955	0.05076466515850105
Load 13	45	0.25	0.07137033113133076	0.05076466515850105
Load 130	120	0.25	0.1658534497517549	0.05076466515850105
Load 131	136	0.4	0.1503971639648935	0.08122346425360168
Load 132	137	0.4	0.1701509699546991	0.08122346425360168
Load 133	161	0.4	0.2716225196999905	0.08122346425360168
Load 134	224	0.63	0.2994575077075809	0.1279269561994226

Load Name	Bus	Load Installed Capacity (MVA)	Peak Load	
			P (MW)	Q (Mvar)
Load 135	303	0.25	0.06787203394832132	0.05076466515850105
Load 136	207	0.63	0.2149940923602906	0.1279269561994226
Load 137	229	0.25	0.08816046621070069	0.05076466515850105
Load 138	75	0.25	0.0959361426855189	0.05076466515850105
Load 139	95	0.63	0.3511487964989059	0.1279269561994226
Load 14	106	0.63	0.5250000000000001	0.1279269561994226
Load 140	54	0.4	0.3182989368355222	0.08122346425360168
Load 0	215	0.5	0.2801200546186448	0.1015293303170021
Load 1	6	0.5	0.3096656353314249	0.1015293303170021
Load 2	48	0.5	0.3681411781671354	0.1015293303170021
Load 3	52	0.5	0.06862807582203385	0.1015293303170021
Load 4	55	0.5	0.1696760618516344	0.1015293303170021
Load 5	235	0.5	0.3263106539469286	0.1015293303170021
Load 15	289	0.4	0.2149360223535113	0.08122346425360168
Load 16	110	0.63	0.429243937232525	0.1279269561994226

Load Name	Bus	Load Installed Capacity (MVA)	Peak Load	
			P (MW)	Q (Mvar)
Load 17	1	0.25	0.07626472894875427	0.05076466515850105
Load 18	51	0.4	0.2305334606002758	0.08122346425360168
Load 19	197	0.4	0.2294049394994199	0.08122346425360168
Load 2	194	0.25	0.03826109013435863	0.05076466515850105
Load 20	148	0.25	0.1833853215662406	0.05076466515850105
Load 21	117	0.4	0.1836245409678853	0.08122346425360168
Load 22	145	0.63	0.2826913793103448	0.1279269561994226
Load 23	57	0.4	0.2745032662789119	0.08122346425360168
Load 24	141	0.25	0.1708410453545948	0.05076466515850105
Load 25	100	0.63	0.3723754506719108	0.1279269561994226
Load 26	147	0.4	0.3032342680621022	0.08122346425360168
Load 27	35	0.4	0.2529304269186391	0.08122346425360168
Load 28	313	0.4	0.1812344370275896	0.08122346425360168
Load 29	169	0.63	0.4422387970285167	0.1279269561994226
Load 3	34	0.25	0.1938062838947212	0.05076466515850105
Load 30	273	0.63	0.525	0.1279269561994226
Load 31	195	0.25	0.1728305071740965	0.05076466515850105
Load 32	305	0.25	0.1722348636951769	0.05076466515850105
Load 33	111	0.25	0.1129885173247381	0.05076466515850105
Load 34	227	0.4	0.2752959954741989	0.08122346425360168
Load 35	199	0.4	0.2736171352074966	0.08122346425360168
Load 36	98	0.4	0.2612213466670887	0.08122346425360168
Load 37	50	0.25	0.1528390530261937	0.05076466515850105
Load 38	184	0.25	0.1576148210763596	0.05076466515850105
Load 39	186	0.25	0.1755262154440382	0.05076466515850105
Load 4	76	0.25	0.1603479946933361	0.05076466515850105
Load 40	82	0.25	0.1185324508805672	0.05076466515850105
Load 41	239	0.4	0.3239465250872914	0.08122346425360168
Load 42	143	0.4	0.2393575140412577	0.08122346425360168
Load 43	242	0.4	0.3041432584269663	0.08122346425360168
Load 44	246	0.25	0.1367749532941979	0.05076466515850105
Load 45	172	0.63	0.3231124604012671	0.1279269561994226
Load 46	167	0.63	0.4722168980406989	0.1279269561994226
Load 47	72	0.25	0.1829141682197553	0.05076466515850105
Load 48	119	0.63	0.4489732706206264	0.1279269561994226
Load 49	188	0.4	0.2476252070781754	0.08122346425360168
Load 5	159	0.4	0.2344637706494187	0.08122346425360168
Load 50	269	0.63	0.3380803271052223	0.1279269561994226
Load 51	176	0.25	0.1931729075880863	0.05076466515850105
Load 52	304	0.25	0.1899955178854411	0.05076466515850105
Load 53	4	0.25	0.1374944794375285	0.05076466515850105

Load Name	Bus	Load Installed Capacity (MVA)	Peak Load	
			P (MW)	Q (Mvar)
Load 54	150	0.25	0.09366269189780811	0.05076466515850105
Load 55	49	0.25	0.1137289679305882	0.05076466515850105
Load 56	178	0.4	0.3253057199211046	0.08122346425360168
Load 57	56	0.63	0.4522756763482527	0.1279269561994226
Load 58	190	0.63	0.4735706404021415	0.1279269561994226
Load 59	198	0.4	0.2357064622124863	0.08122346425360168
Load 6	38	0.25	0.1360060120577023	0.05076466515850105
Load 60	287	0.4	0.2221584056056516	0.08122346425360168
Load 61	5	0.25	0.147204048882854	0.05076466515850105
Load 62	281	0.4	0.1142781515038295	0.08122346425360168
Load 63	108	0.4	0.2352267110813208	0.08122346425360168
Load 64	80	0.63	0.4133318425760286	0.1279269561994226
Load 65	170	0.25	0.09340713407134071	0.05076466515850105
Load 66	162	0.63	0.2654303450237019	0.1279269561994226
Load 67	0	0.4	0.2252154808179821	0.08122346425360168
Load 68	140	0.4	0.2660454423584847	0.08122346425360168
Load 69	240	0.4	0.2189184773729783	0.08122346425360168
Load 7	157	0.4	0.2539703590729751	0.08122346425360168
Load 70	118	0.63	0.3443413886997958	0.1279269561994226

Load Name	Bus	Load Installed Capacity (MVA)	Peak Load	
			P (MW)	Q (Mvar)
Load 71	223	0.63	0.2321293064197906	0.1279269561994226
Load 72	301	0.4	0.1623890492995402	0.08122346425360168
Load 73	3	0.25	0.08302303227131044	0.05076466515850105
Load 74	205	0.63	0.1714822728711617	0.1279269561994226
Load 75	210	0.4	0.06895715922704863	0.08122346425360168
Load 76	81	0.63	0.3949778225806452	0.1279269561994226
Load 77	290	0.63	0.02781365724290562	0.1279269561994226
Load 78	138	0.25	0.1492027040974301	0.05076466515850105
Load 79	213	0.63	0.2762105696495652	0.1279269561994226
Load 8	168	0.63	0.3810072363520272	0.1279269561994226
Load 80	53	0.25	0.1423864400641523	0.05076466515850105
Load 81	102	0.63	0.3646188158961882	0.1279269561994226
Load 82	231	0.25	0.1359117246080436	0.05076466515850105
Load 83	236	0.63	0.3093360995850623	0.1279269561994226
Load 84	155	0.25	0.1343848773538708	0.05076466515850105
Load 85	36	0.25	0.06605840760109007	0.05076466515850105
Load 86	316	0.25	0.1533312701360123	0.05076466515850105
Load 87	285	0.25	0.1563519311316209	0.05076466515850105
Load 88	73	0.63	0.4600376759485925	0.1279269561994226
Load 89	77	0.4	0.2301165967086415	0.08122346425360168
Load 9	216	0.4	0.214402719206525	0.08122346425360168
Load 90	189	0.63	0.4245994146908024	0.1279269561994226
Load 91	44	0.63	0.4723035547240412	0.1279269561994226
Load 92	101	0.4	0.1927344663249708	0.08122346425360168
Load 93	192	0.63	0.4324175696414454	0.1279269561994226
Load 94	275	0.25	0.2083333333333334	0.05076466515850105
Load 95	221	0.25	0.05052093121876702	0.05076466515850105
Load 96	146	0.63	0.4281242883170121	0.1279269561994226
Load 97	71	0.4	0.2874608199354406	0.08122346425360168
Load 98	37	0.63	0.3563834196891193	0.1279269561994226
Load 99	245	0.63	0.3823180347755762	0.1279269561994226
	Total	**61.86**	**33.47**	**12.56**

From this moment (year zero) until the end of the planning horizon is assumed a yearly load growth, i.e. the active and reactive power peak load will change over the years.

A.4 Generation Data

Both PV and wind generators (DG units) only produces real active power, i.e. reactive power is always assign to zero. The total values (installed capacity, active and reactive power) are cumulative values over the planning years.

Year of connection in the network	Static Generator Name	Type	Bus	Static Generator Installed Capacity (MVA)	Peak Generation at connection year	
					P (MW)	Q (Mvar)
0	Sgen 153	PV	235	1.239	1.164838105337575	0
	Sgen 154	PV	95	1.348	1.277413958826483	0
	Sgen 155	PV	102	1.35	1.299774335203708	0
	Sgen 156	PV	132	1.141	1.081807806324111	0
	Sgen 157	PV	134	1.329	1.21653375555855	0
	Sgen 158	PV	237	1.35	1.256549099956096	0
	Sgen 159	PV	116	1.346	1.244727531727532	0
	Sgen 160	PV	247	1.347	1.332691490576813	0
	Sgen 161	PV	227	1.141	1.097077913761207	0
	Sgen 162	PV	111	0.987	0.8997670342952108	0
	Sgen 163	PV	219	1.1	0.9634560906515581	0
	Sgen 164	PV	136	1.05	1.003930985414443	0
	Sgen 165	Wind	37	1.247	0.8317490000000001	0
	Sgen 166	Wind	238	1.35	1.0071	0
	Sgen 167	Wind	229	1.085	0.997115	0
		Total		**18.41**	**16.67**	**0**
1	Sgen 168	PV	40	1.35	1.26162336024218	0
	Sgen 169	PV	109	1.032	1.007959190613841	0
	Sgen 170	PV	170	0.875	0.7088762214983714	0
	Sgen 171	PV	131	0.423	0.3851911111111112	0
	Sgen 172	Wind	131	0.92	0.81144	0
		Total		**23.01**	**20.68**	**0**
2	Sgen 173	PV	236	1.21	0.9740248962655602	0
	Sgen 174	PV	239	1.122	0.9568129474940336	0
	Sgen 175	PV	138	0.920	0.780144176046541	0
	Sgen 176	PV	248	0.436	0.3806575844904375	0
	Sgen 177	Wind	317	0.922	0.6918399999999999	0
		Total		**27.62**	**24.46**	**0**
3	Sgen 178	PV	77	1.103	1.025373829274819	0
	Sgen 179	PV	167	1.35	1.255234738263087	0
	Sgen 180	PV	269	1.227	1.030824330598979	0
	Sgen 181	Wind	142	0.92	0.88412	0
		Total		**32.22**	**28.49**	**0**
4	Sgen 182	PV	83	1.348	1.258551982729236	0
	Sgen 183	PV	43	1.346	1.204654467523904	0
	Sgen 184	PV	186	0.986	0.9294339894383101	0
	Sgen 185	Wind	200	0.92	0.85928	0
		Total		**36.82**	**32.66**	**0**

Year of connection in the network	Static Generator Name	Type	Bus	Static Generator Installed Capacity (MVA)	Peak Generation at connection year	
					P (MW)	Q (Mvar)
5	Sgen 186	PV	85	1.35	1.052950819672131	0
	Sgen 187	PV	129	1.203	1.136071548712641	0
	Sgen 188	PV	153	1.075	1.028593644607659	0
	Sgen 189	PV	298	0.788	0.7553595597531049	0
	Sgen 190	Wind	157	1.104	0.7363680000000001	0
		Total		**42.34**	**37.37**	**0**
6	Sgen 191	PV	188	1.075	0.9691605554688718	0
	Sgen 192	PV	181	1.085	0.9652304776345717	0
	Sgen 193	PV	316	0.99	0.9301428231373482	0
	Sgen 194	PV	243	0.538	0.5289446276449574	0
	Sgen 195	Wind	184	0.922	0.8537720000000001	0
		Total		**46.95**	**41.58**	**0**
7	Sgen 196	PV	169	1.25	1.179286067193676	0
	Sgen 197	PV	159	1.1	1.054642231505188	0
	Sgen 198	PV	287	1.102	1.044263134787063	0
	Sgen 199	PV	155	0.964	0.91006993006993	0
	Sgen 200	Wind	198	1.104	0.973728	0
		Total		**52.47**	**46.74**	**0**
8	Sgen 201	PV	199	1.145	0.9534037692747002	0
	Sgen 202	PV	178	1.17	1.027059200227693	0
	Sgen 203	PV	275	1.021	0.762934884423629	0
	Sgen 204	PV	78	1.08	0.835379860932269	0
	Sgen 205	Wind	286	1.104	1.03776	0
		Total		**57.99**	**51.36**	**0**
9	Sgen 206	PV	285	0.985	0.946805407328353	0
	Sgen 207	PV	288	1.043	0.9747208627648839	0
	Sgen 208	PV	32	0.916	0.8946614521339907	0
	Sgen 209	Wind	104	0.736	0.7072959999999999	0
		Total		**61.67**	**54.88**	**0**
10	Sgen 210	PV	213	1.346	1.09045416472778	0
	Sgen 211	PV	197	1.09	0.992572839506173	0
	Sgen 212	PV	104	0.516	0.4153692946058092	0
	Sgen 213	Wind	74	0.738	0.689292	0
		Total		**65.36**	**58.07**	**0**

Appendix B

Power Flow Simulation - Results

In this appendix are presented some detailed info graphics regarding PF gradient results for critical lines and buses. This information only concerns the base case scenario and the years where technical problems occur. For the years where no congestion/voltage problems occur, this appendix provides non detailed PF results and also non gradient PF results. In addiction, for all the years, alternative one-line diagram gradient plots are presented.

B.1 Base Case Scenario - Year 0

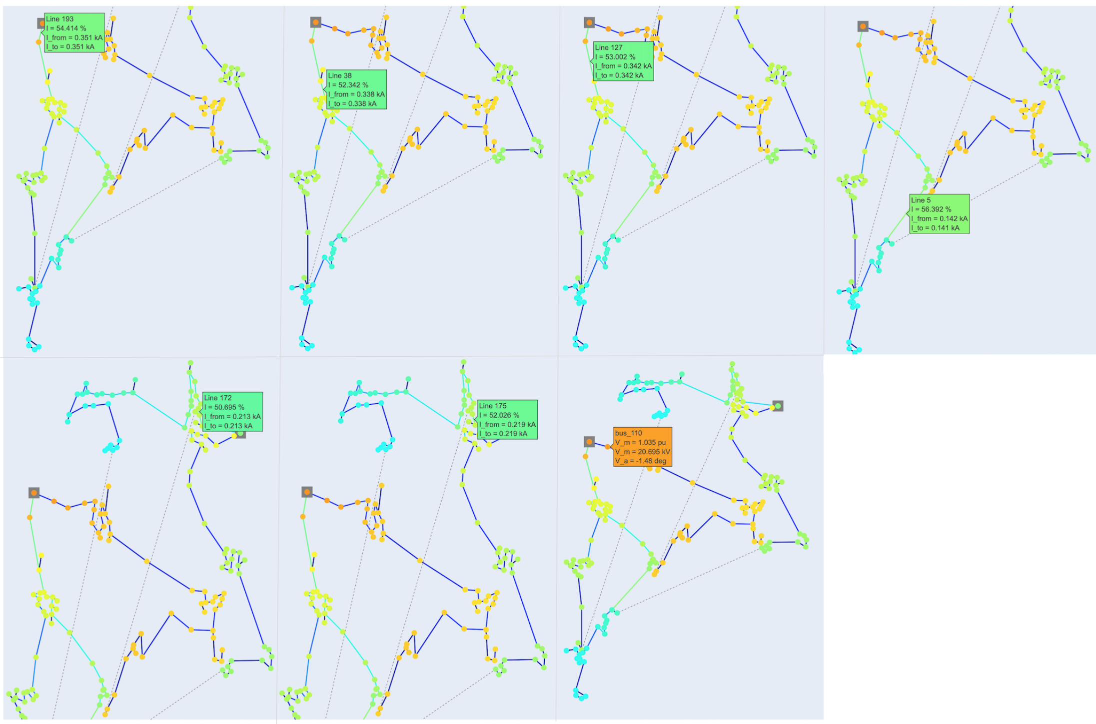


Figure B.1: Detailed PF gradient results for base case scenario - Peak load

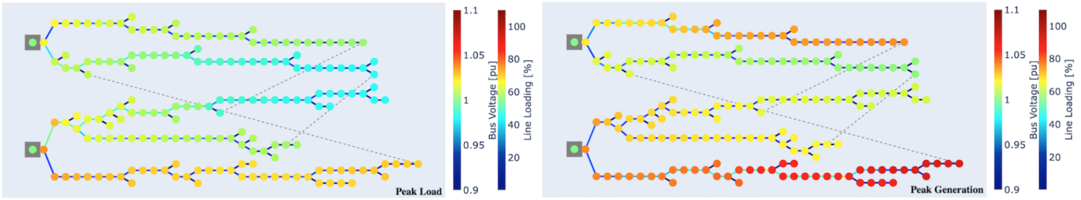


Figure B.2: PF gradient results for alternative one-line diagram in year 0 - Peak load and generation

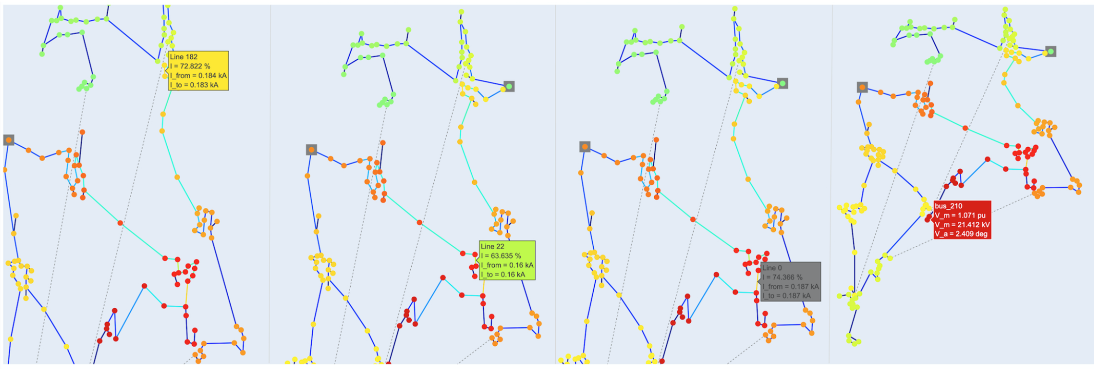


Figure B.3: Detailed PF gradient results for base case scenario - Peak generation

B.2 Year 1

Year 1		
	Peak Load **P [MW]**	***Peak Generation*** **P [MW]**
HV/MV substations PF	25.72	-7.35
Load	33.84	12.64
Generation	8.78	20.68
Losses	0.57	0.63

Table B.1: PF results in year 1 - Peak load and generation

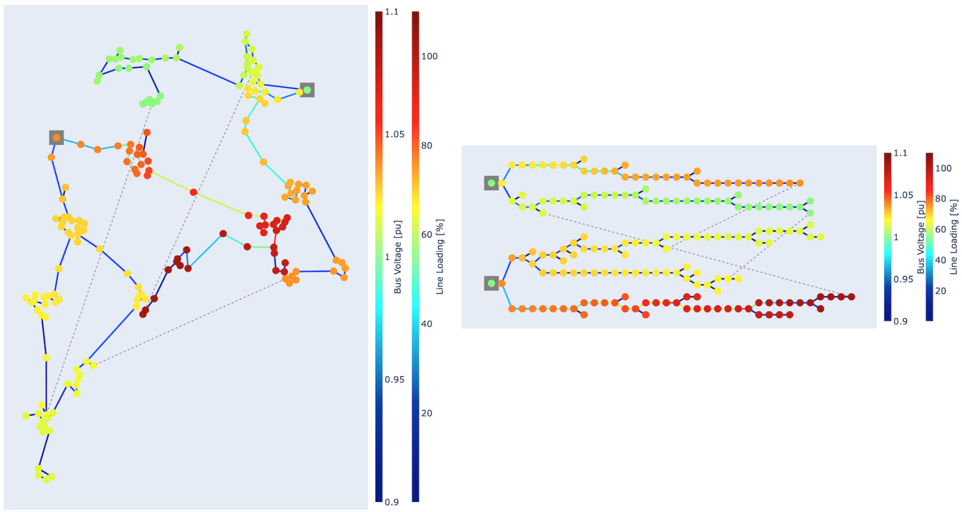


Figure B.4: Non detailed PF gradient results and PF gradient results for alternative one-line diagram in year 1 [Scenario 16-April-2017]

B.3 Year 2

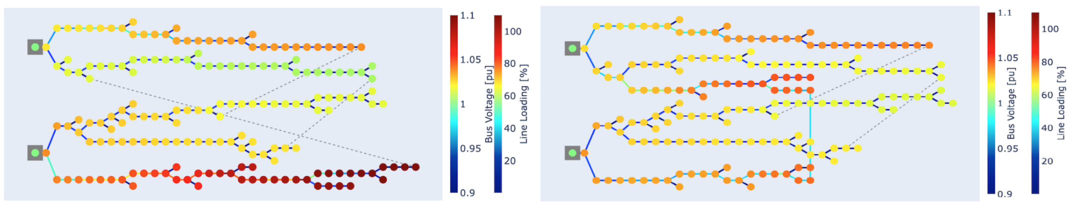


Figure B.5: PF gradient results for alternative one-line diagram in year 2, before and after network reconfiguration [Scenario 16-April-2017]

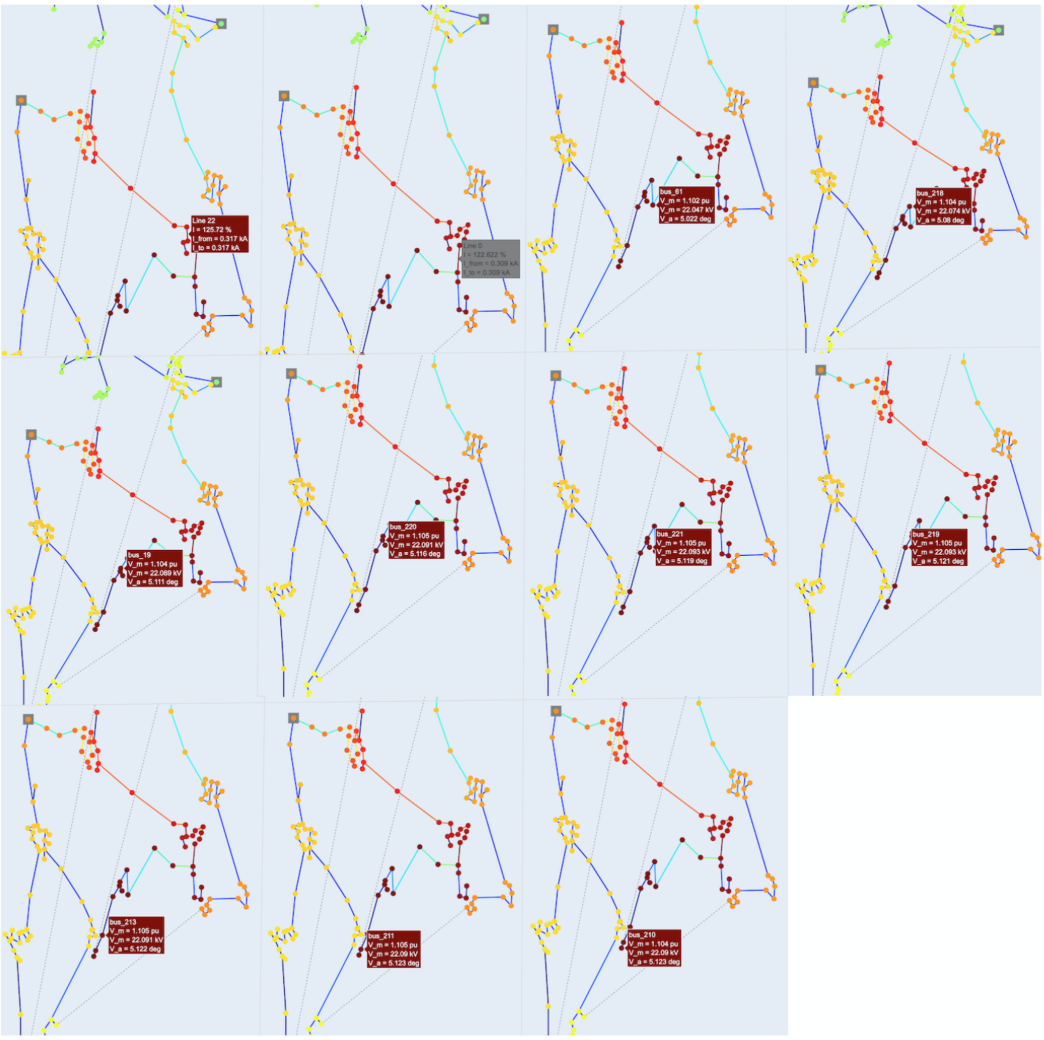


Figure B.6: Detailed PF gradient results in year 2, before network reconfiguration [Scenario 16-April-2017]

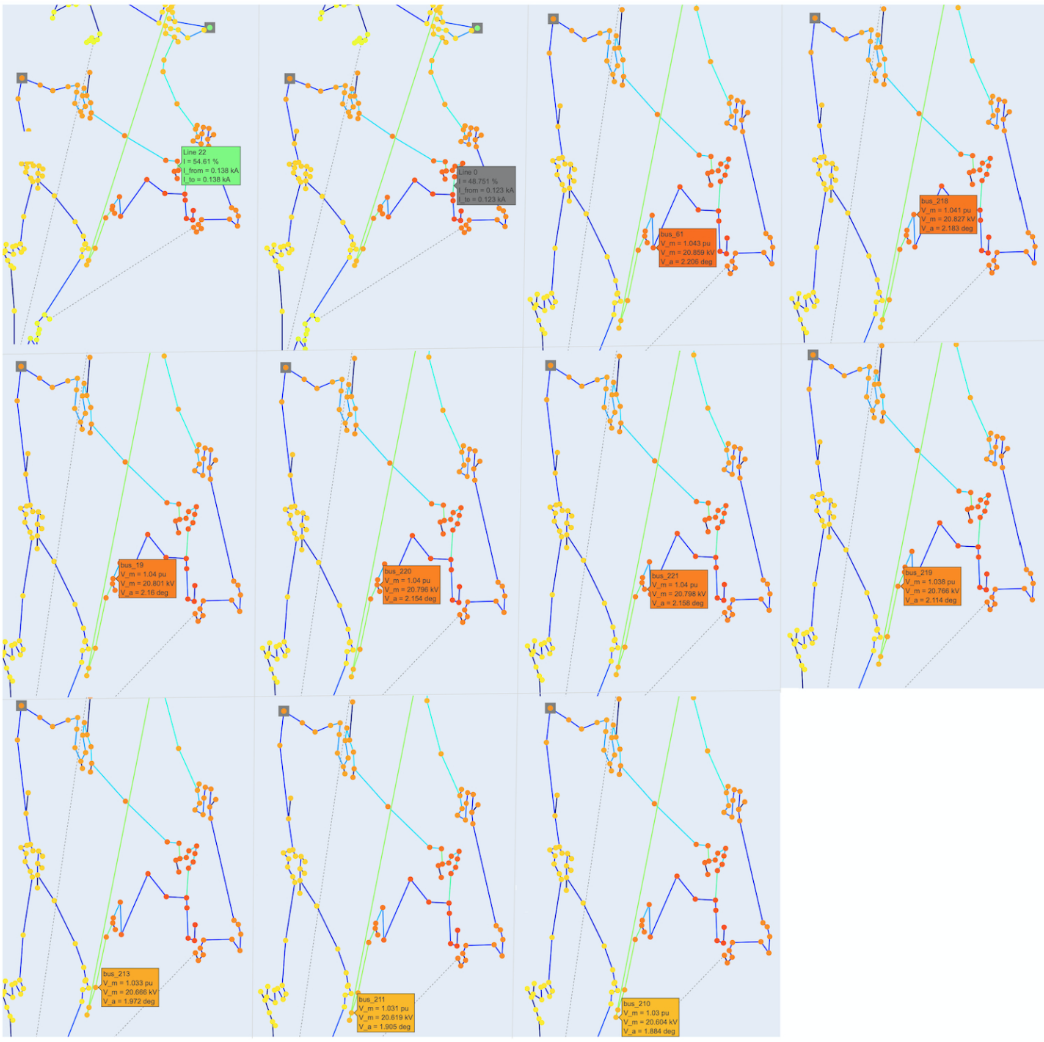
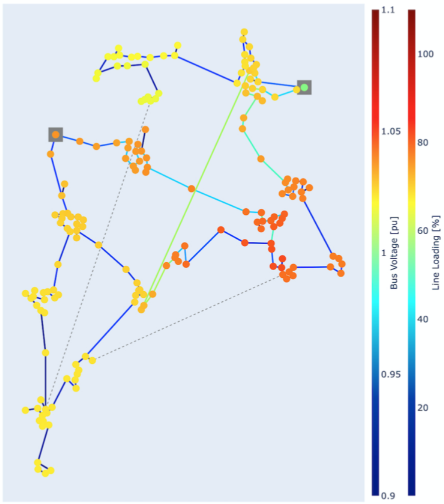


Figure B.7: Detailed PF gradient results in year 2, after network reconfiguration [Scenario 16-April-2017]

B.4 Year 3

Year 3		
	Peak Load P [MW]	*Peak Generation* P [MW]
HV/MV substations PF	21.69	-13.18
Load	34.18	14.79
Generation	13.06	28.49
Losses	0.49	0.44

Table B.2: PF results in year 3 - Peak load and generation



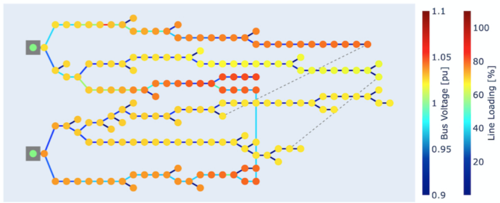


Figure B.8: Non detailed PF gradient results and PF gradient results for alternative one-line diagram in year 3 [Scenario 16-April-2017]

B.5 Year 4

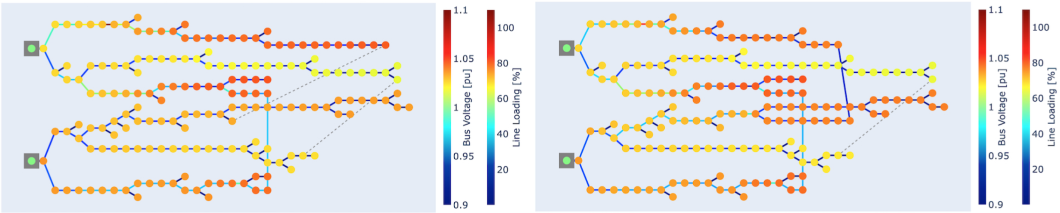


Figure B.9: PF gradient results for alternative one-line diagram in year 4, before and after network reconfiguration [Scenario 16-April-2017]

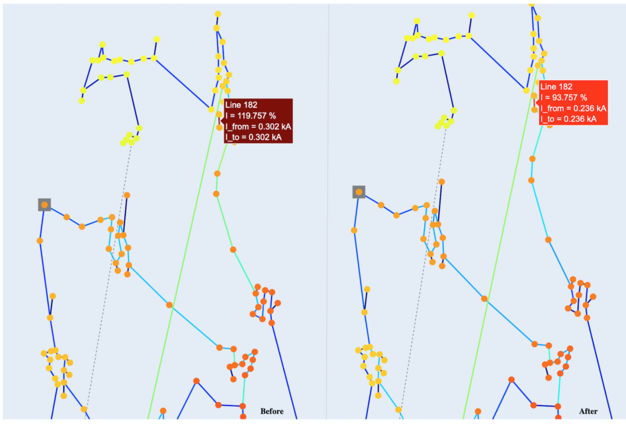


Figure B.10: Detailed PF gradient results in year 4, before and after network reconfiguration [Scenario 16-April-2017]

B.6 Year 5

	Year 1	
	Peak Load **P [MW]**	***Peak Generation*** **P [MW]**
HV/MV substations PF	18.08	-22.65
Load	37.71	14.01
Generation	17.07	37.37
Losses	0.36	0.63

Table B.3: PF results in year 5 - Peak load and generation

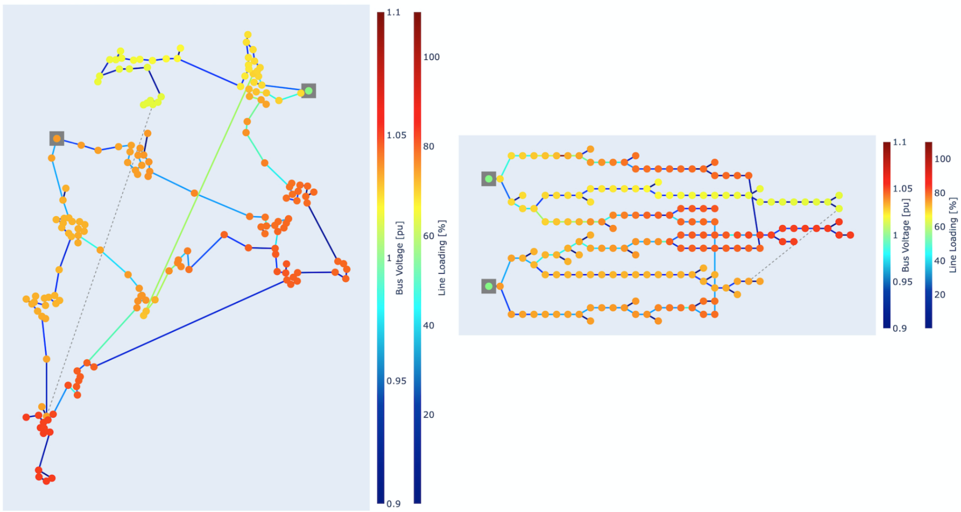


Figure B.11: Non detailed PF gradient results and PF gradient results for alternative one-line diagram in year 5 [Scenario 16-April-2017]

B.7 Year 6

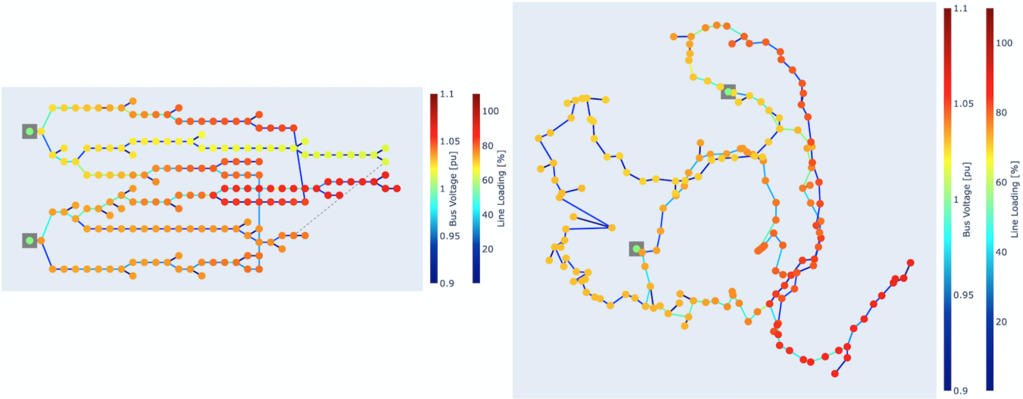


Figure B.12: PF gradient results for alternative one-line diagram in year 6, before and after network reconfiguration [Scenario 16-April-2017]

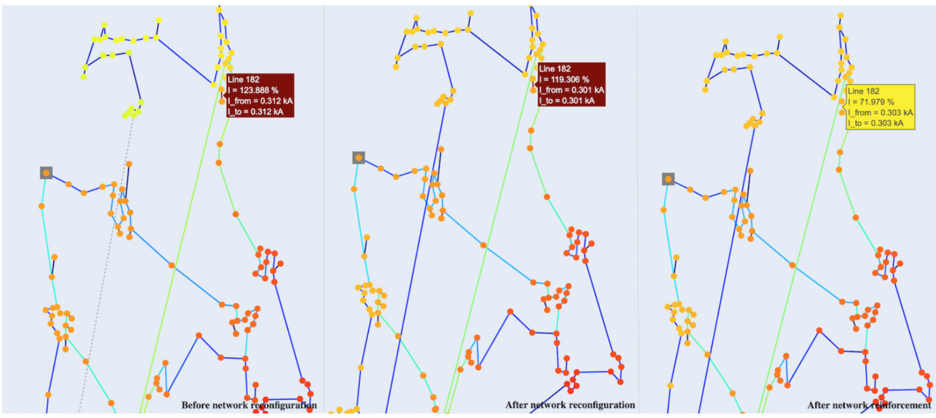


Figure B.13: Detailed PF gradient results in year 6, before and after network reconfiguration and reinforcement [Scenario 16-April-2017]

B.8 Year 7

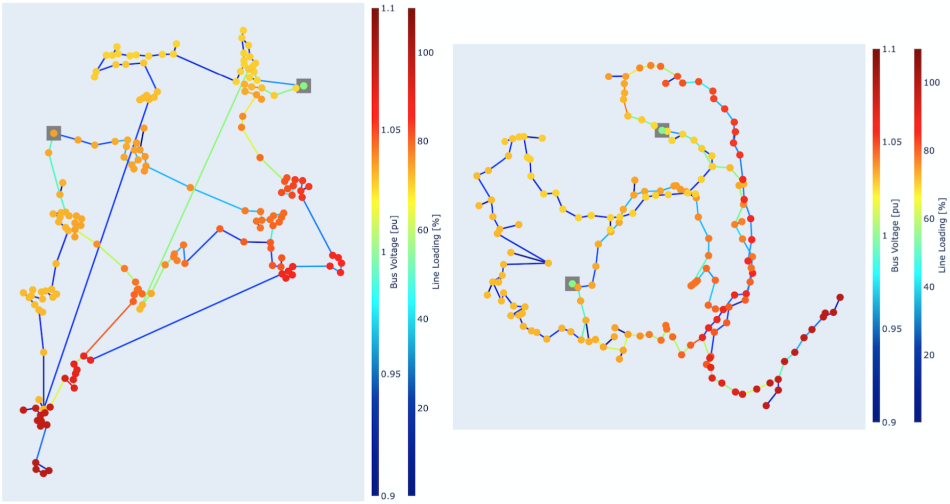


Figure B.14: Non detailed PF gradient results and PF gradient results for alternative one-line diagram in year 7 [Scenario 16-April-2017]

B.9 Year 8

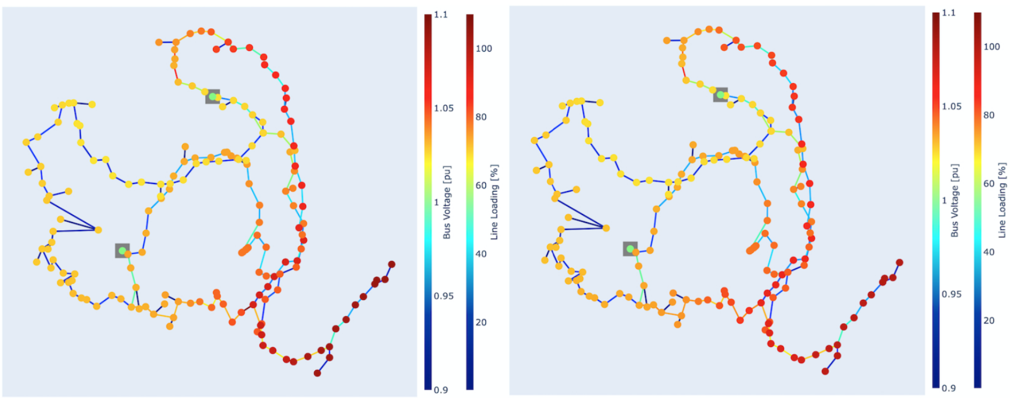


Figure B.15: PF gradient results for alternative one-line diagram in year 8, before and after network reinforcement [Scenario 01-May-2017]

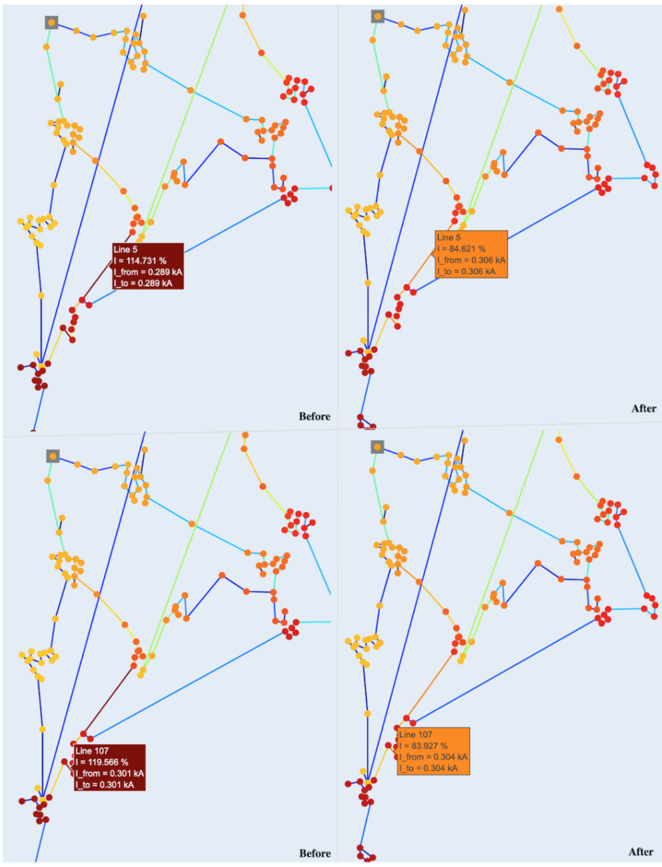


Figure B.16: Detailed PF gradient results in year 8, before and after network reinforcement [Scenario 01-May-2017]

B.10 Year 9

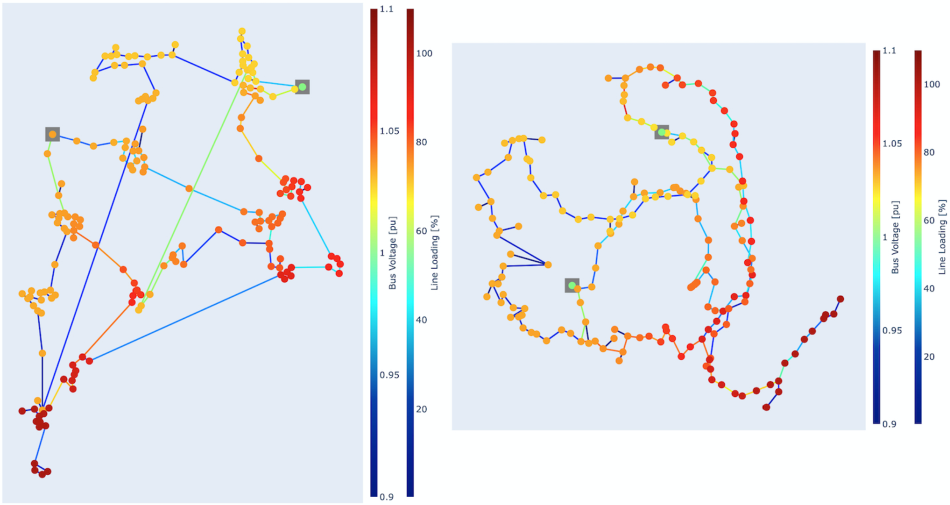


Figure B.17: Non detailed PF gradient results and PF gradient results for alternative one-line diagram in year 9 [Scenario 16-April-2017]

B.11 Year 10

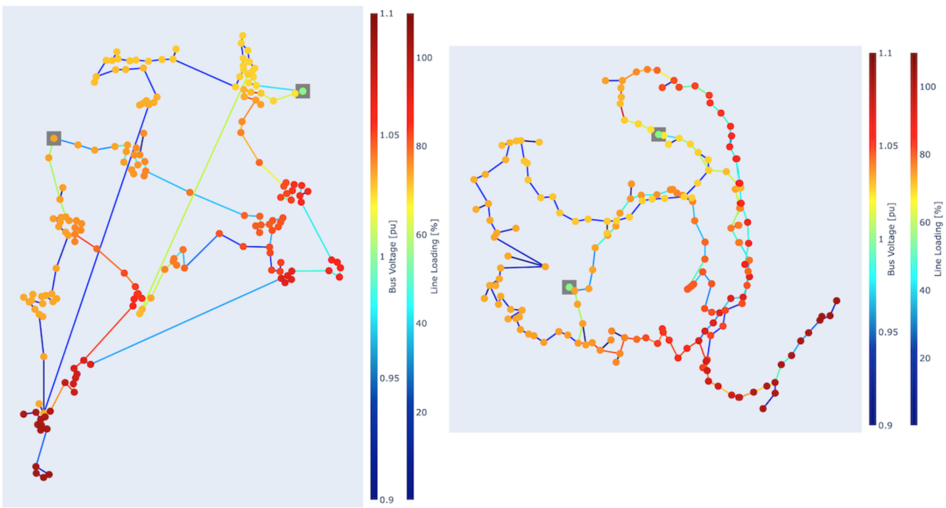
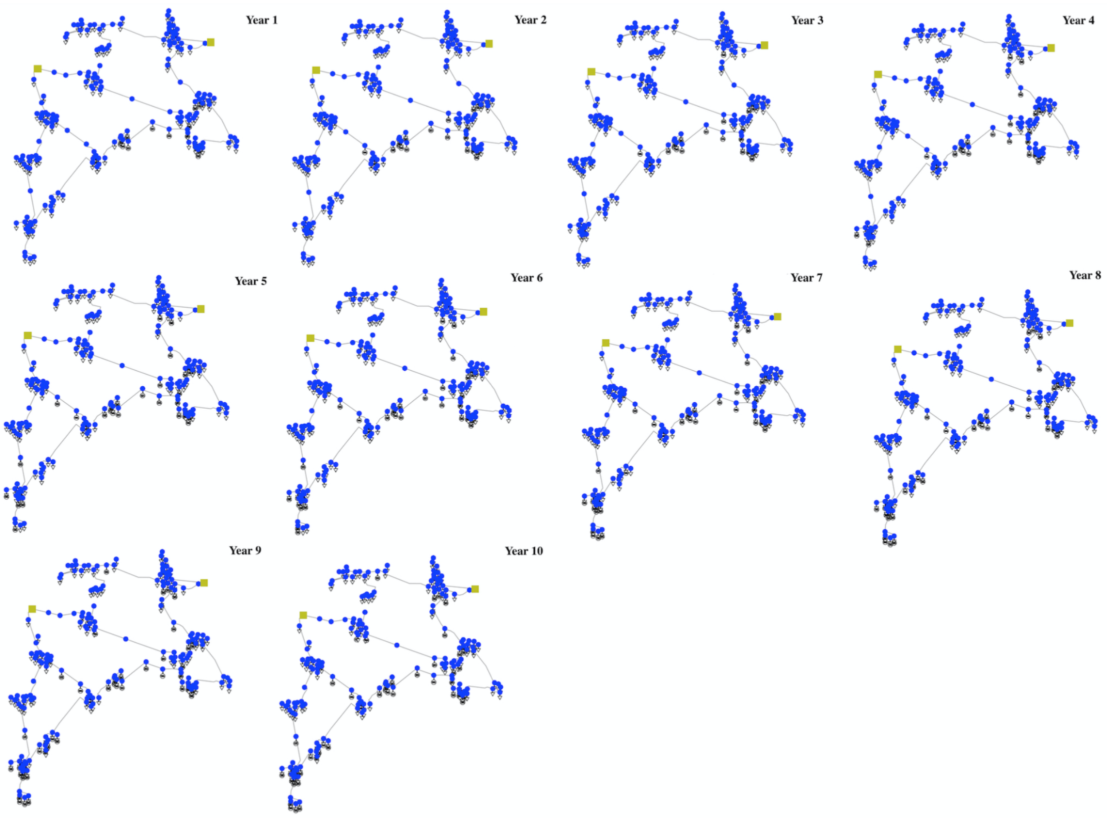


Figure B.18: Non detailed PF gradient results and PF gradient results for alternative one-line diagram in year 10 [Scenario 16-April-2017]

Appendix C

DG growth

In this appendix, the DG growth capacity over the planning horizon will be addressed by presenting some images in which is represented the new DG connections in the network for each year of the defined period. In Figure 4.2 is already represented the DG connections in the grid for the base case scenario - year 0.



References

[1] Variable Distributed Resources and Distribution Networks. Network reinforcement planning considering management of distributed flexibility Lead Beneficiary : INESC Porto. 2012.

[2] Active Distribution Systems and Working Group. *Planning and Optimization Methods for Active Distribution Systems Working Group C6.19*. August 2014.

[3] Andreas Ulbig, Matthias A. Bucher, and Göran Andersson. Operational Flexibility of Power Systems. *Renewable Energy Integration: Practical Management of Variability, Uncertainty, and Flexibility in Power Grids: Second Edition*, pages 201–216, 2017.

[4] Fabrizio Pilo, Gianni Celli, Emilio Ghiani, and Gian Giuseppe Soma. New electricity distribution network planning approaches for integrating renewable. *Wiley Interdisciplinary Reviews: Energy and Environment*, 2013.

[5] Energetica India. *104I Smart Grid Projects in India*. 2012.

[6] L. Sachs B. A. & Wolfman. *Journal of Chemical Information and Modeling*, pages 1689–1699, 2013.

[7] EDSO for Smart Grids. Flexibility: The role of DSOs in tomorrow's electricity market. pages 1–16, 2014. URL: http://www.edsoforsmartgrids.eu/wp-content/uploads/public/EDSO-views-on-Flexibility-FINAL-May-5th-2014.pdf.

[8] João Pedro Gomes Pina Marques. Power Distribution Planning Under Distributed Generation Uncertainty. June 2018.

[9] Robert A. MacDonald, Graham W. Ault, and James R. McDonald. A novel approach to the optimal planning of flexible active distribution networks. *Proceedings of the Universities Power Engineering Conference*, pages 1–5, 2009.

[10] M. O.W. Grond, J. Morren, and J. G. Slootweg. Integrating smart grid solutions into distribution network planning. *2013 IEEE Grenoble Conference PowerTech, POWERTECH 2013*, pages 1–6, 2013.

[11] S. K. Khator and L. C. Leung. Power distribution planning: a review of models and issues. *IEEE Transactions on Power Systems*, pages 1151–1159, August 1997.

[12] Pavlos S. Georgilakis and Nikos D. Hatziargyriou. A review of power distribution planning in the modern power systems era: Models, methods and future research. *Electric Power Systems Research*, pages 89–100, 2015. URL: http://dx.doi.org/10.1016/j.epsr.2014.12.010.

[13] Shi You, Henrik W. Bindner, Junjie Hu, and Philip J. Douglass. An overview of trends in distribution network planning: A movement towards smart planning. *Proceedings of the IEEE Power Engineering Society Transmission and Distribution Conference*, pages 1–5, 2014.

[14] T. Bongers, J. Kellermann, M. Franz, and A. Moser. Impact of curtailment of renewable energy sources on high voltage network expansion planning. *19th Power Systems Computation Conference, PSCC 2016*, 2016.

[15] Angelo L'Abbate, Gianluca Fulli, Fred Starr, and Sd Peteves. *Distributed Power Generation in Europe: technical issues for further integration*. 2007. URL: http://kom.aau.dk/project/edge/repository/02{_}literature/PowerSystem/DG{_}JRC{_}report.pdf.

[16] L. Aleixo, G. Celli, E. Ghiani, S. Jupe, J. Myrzik, L. F. Ochoa, and F. Pilo. A general framework for active distribution network planning. *CIGRE 2013 Lisbon Symposium - Smarts Grids: Next Generation Grids for Energy Trends*, April 2013.

[17] G. Celli, F. Pilo, G. G. Soma, R. Cicoria, G. Mauri, E. Fasciolo, and G. Fogliata. A comparison of distribution network planning solutions: Traditional reinforcement versus integration of distributed energy storage. *A comparison of distribution network planning solutions: Traditional reinforcement versus integration of distributed energy storage. 2013 IEEE Grenoble Celli*, pages 1–6, 2013.

[18] Mikel Armendáriz. PhD Thesis-Cost-effective Communication and Control Architectures for Active Low Voltage Grids. 2017.

[19] Wolfgang Biener, Kilian Dallmer-Zerbe, Benjamin Krug, Gunther Gust, and Bernhard Wille-Haussmann. Automated distribution grid planning considering Smart Grid and conventional grid reinforcement technologies. *International ETG Congress 2015; Die Energiewende - Blueprints for the New Energy Age*, pages 456–461, 2015.

[20] M. Armendáriz, K. Paridari, E. Wallin, and L. Nordström. Comparative study of optimal controller placement considering uncertainty in PV growth and distribution grid expansion. *Electric Power Systems Research*, pages 48–57, 2018. URL: http://dx.doi.org/10.1016/j.epsr.2017.10.001.

[21] Nuno Filipe and Pinto Marinho. LOCAL SHORT-TERM UNCERTAINTIES AND THEIR IMPACT ON THE ECONOMICS OF DISTRIBUTED FLEXIBILITIES. 2014.

[22] Stephan Koch, Francesco Ferrucci, Andreas Ulbig, and Michael Koller. Time-Series Simulations and Assessment of Smart Grid Planning Options of Distribution Grids. *23rd International Conference on Electricity Distribution*, pages 15–18, June 2015.

[23] Sérgio Haffner, Luís Fernando Alves Pereira, Luís Alberto Pereira, and Lucio Sangio Barreto. Multistage model for distribution expansion planning with distributed generation - Part I: Problem formulation. *IEEE Transactions on Power Delivery*, 23(2):915–923, 2008.

[24] Ž.N. Popović and D.S. Popović. Graph theory based formulation of multi-period distribution expansion problems. *Electric Power Systems Research*, pages 1256 – 1266, 2010. URL: http://www.sciencedirect.com/science/article/pii/S0378779610000908.

[25] T Belgin. Distribution System Planning Usign Mixed Integer. pages 37–48, 1998.

[26] Anonino Augugliaro, Luigi Dusonchet, and Eleonora Riva Sanseverino. An Evolutionary Parallel Tabu Search approach for distribution systems reinforcement planning. *Advanced Engineering Informatics*, pages 205–215, 2002.

[27] S. Porkar, A. Abbaspour-Tehrani-Fard, P. Poure, and S. Saadate. Distribution system planning considering integration of distributed generation and load curtailment options in a competitive electricity market. *Electrical Engineering*, pages 23–32, 2011.

[28] Pavlos S. Georgilakis and Nikos D. Hatziargyriou. Optimal distributed generation placement in power distribution networks: Models, methods, and future research. *IEEE Transactions on Power Systems*, pages 3420–3428, 2013.

[29] A. J. Urdaneta, P. C. Paiva, H. Khodr, J. Dominguez-Navarro, and J. M. Yusta. Integral planning of primary-secondary distribution systems using mixed integer linear programming. *2005 IEEE Power Engineering Society General Meeting*, 2005.

[30] S. Ganguly, N. C. Sahoo, and D. Das. Recent advances on power distribution system planning: A state-of-the-art survey. *Energy Systems*, pages 165–193, 2013.

[31] Matthias Resch. Impact of operation strategies of large scale battery systems on distribution grid planning in Germany. *Renewable and Sustainable Energy Reviews*, pages 1042–1063, March 2017. URL: http://dx.doi.org/10.1016/j.rser.2017.02.075.

[32] N. Ponnavaikko, K. S. P. Rao, and S. S. Venkata. Distribution system planning through a quadratic mixed integer programming approach. *IEEE Transactions on Power Delivery*, pages 1157–1163, Oct 1987.

[33] S. Ganguly, N. C. Sahoo, and D. Das. Mono-objective and multi-objective planning of electrical distribution networks using particle swarm optimization. *Applied Soft Computing Journal*, pages 2391–2405, 2011. URL: http://dx.doi.org/10.1016/j.asoc.2010.09.002.

[34] Halit Üster and Homarjun Agrahari. A Benders decomposition approach for a distribution network design problem with consolidation and capacity considerations. *Operations Research Letters*, pages 138–143, 2011. URL: http://dx.doi.org/10.1016/j.orl.2011.02.003.

[35] Ignacio J Ramirez-rosado, Departamento De Ingenieria El, and Electrhica Comunicaciones C P S. Rithms Applied To the Design of Large Pqwe. pages 696–703, 1998.

[36] Vinicius F Martins, Carmen L T Borges, and Senior Member. and Load Response Uncertainties. *IEEE Transactions on Power Systems*, pages 1–9, 2011.

[37] Rn Mahanty and Pbd Gupta. Voltage stability analysis in unbalanced power systems by optimal power flow. *IEE Proceedings-Generation, Transmission and . . .* , pages 201–212, 2004. URL: http://digital-library.theiet.org/content/journals/10.1049/ip-gtd{_}20040098, doi:10.1049/ip-gtd.

[38] N. C. Koutsoukis, P. S. Georgilakis, and N. D. Hatziargyriou. A Tabu search method for distribution network planning considering distributed generation and uncertainties. *2014 International Conference on Probabilistic Methods Applied to Power Systems, PMAPS 2014 - Conference Proceedings*, pages 1–6, 2014.

[39] Víctor Parada, Jacques A. Ferland, Miguel Arias, Pablo Schwarzenberg, and Luis S. Vargas. Heuristic determination of distribution trees. *IEEE Transactions on Power Delivery*, pages 861–869, 2010.

[40] J. A.Peças Lopes, N. Hatziargyriou, J. Mutale, P. Djapic, and N. Jenkins. Integrating distributed generation into electric power systems: A review of drivers, challenges and opportunities. *Electric Power Systems Research*, pages 1189–1203, 2007.

[41] Sherif M. Ismael, Shady H.E. Abdel Aleem, Almoataz Y. Abdelaziz, and Ahmed Faheem Zobaa. Practical Considerations for Optimal Conductor Reinforcement and Hosting Capacity Enhancement in Radial Distribution Systems. *IEEE Access*, pages 27268–27277, 2018.

[42] Quentin Gemine, Efthymios Karangelos, Damien Ernst, and Bertrand Cornelusse. Active network management: Planning under uncertainty for exploiting load modulation. *Proceedings of IREP Symposium: Bulk Power System Dynamics and Control - IX Optimization, Security and Control of the Emerging Power Grid, IREP 2013*, pages 1–9, 2013.

[43] Sara Mohtashami, Danny Pudjianto, Goran Strbac, and A Constants. With Smart Grid Technologies. pages 2656–2664, 2017.

[44] G. Celli, S. Mocci, F. Pilo, and M. Loddo. Optimal integration of energy storage in distribution networks. *2009 IEEE Bucharest PowerTech: Innovative Ideas Toward the Electrical Grid of the Future*, pages 1–7, 2009.

[45] Tiago Soares. Renewable energy sources offering flexibility through electricity markets. *Technical University of Denmark*, 2017.

[46] Bhargav Prasanna Swaminathan. Operational Planning of Active Distribution Networks. 2018.

[47] Julija Vasiljevska and Sebastian Gras. Assessment framework for projects of common interest in the field of smart grids - 2017 update. pages 1–72, 2017. URL: https://ec.europa.eu/jrc, doi:10.2760/37509.

[48] Hugo Carvalho. Metodologia de análise de custo benefício para investimentos em infraestruturas energéticas. 2015.

[49] URL: http://www.cbabuilder.co.uk.

[50] Variable Distributed Resources and Distribution Networks. KPI Assessment Methodology Lead Beneficiary : ICCS / NTUA December. pages 1–27, December 2013.

[51] W J Harder. Key Performance Indicators for Smart Grids Master Thesis on Performance Measurement for Smart Grids. 2017. URL: http://essay.utwente.nl/73032/.

[52] Junyong Liu, Hongjun Gao, Zhao Ma, and Yuanxi Li. Review and prospect of active distribution system planning. *Journal of Modern Power Systems and Clean Energy*, pages 457–467, 2015.

[53] Eurelectric. Flexibility and aggregation - requirements for their interaction in the market. *Ieee Transactions on Power Systems*, January 2015. URL: http://www.eurelectric.org/media/115877/tf{_}bal-agr{_}report{_}final{_}je{_}as-2014-030-0026-01-e.pdf.

[54] URL: http://wzy.ece.iastate.edu/Testsystem.html.

[55] URL: https://www.dropbox.com/s/pqenrr2mcvl0hk9/GEFCom2014.zip?dl=0.

[56] URL: https://pandapower.readthedocs.io/en/v2.4.0/.

[57] URL: https://pandapower.readthedocs.io/en/v2.4.0/networks/mv_oberrhein.html.

[58] URL: https://pandapower.readthedocs.io/en/v2.4.0/elements/line.html.

[59] URL: https://pandapower.readthedocs.io/en/v2.4.0/elements/trafo.html.

[60] URL: https://pandapower.readthedocs.io/en/v2.4.0/elements/bus.html.

[61] URL: https://pandapower.readthedocs.io/en/v2.4.0/opf/formulation.html.

[62] Pt Mibel and Es Mibel. Janeiro-Fevereiro 2018.

[63] General description of EDP-D's power distribution reinforcement planning Enforcing reinforcements by means of "suppressed load". pages 1–6.

[64] URL: http://www.res-legal.eu/search-by-country/portugal/single/s/res-e/t/promotion/aid/feed-in-tariff-tarifas-feed-in/lastp/179/.